Before the Commodity Futures Trading Commission

February 7, 2012 (Updated copy, as of June 11, 2012)

In the Matter of the Application for an Exemptive Order Under Section 4(c) of the Commodity Exchange Act by California Independent System Operator Corporation

In the Matter of the Application for an Exemptive Order Under Section 4(c) of the Commodity Exchange Act by Electric Reliability Council of Texas, Inc.

In the Matter of the Application for an Exemptive Order Under Section 4(c) of the Commodity Exchange Act by ISO New England Inc.

In the Matter of the Application for an Exemptive Order Under Section 4(c) of the Commodity Exchange Act by Midwest Independent Transmission System Operator, Inc.

In the Matter of the Application for an Exemptive Order Under Section 4(c) of the Commodity Exchange Act by New York Independent System Operator, Inc.

In the Matter of the Application for an Exemptive Order Under Section 4(c) of the Commodity Exchange Act by PJM Interconnection, L.L.C.

I. Introduction

Section 722 of the of the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act")[1] added section 2(a)(1)(I)(i) to the Commodity Exchange Act, 7 U.S.C. §1 et seq. (the "Act"), providing that nothing in the Act shall limit the authority of the Federal Energy Regulatory Commission ("FERC") or a State regulatory authority under the Federal Power Act, 16 U.S.C. § 796 et seq. ("FPA"), with respect to an agreement, contract, or transaction that is entered into pursuant to a tariff or rate schedule approved by FERC or a State regulatory authority that is not executed, traded, or cleared on a CFTC-registered entity or trading facility; or is executed, traded, or cleared on a registered entity or trading facility owned or operated by a

[1] Public Law 111–203, 124 Stat. 1376 (2010).

regional transmission organization ("RTO") or an independent system operator ("ISO").[2] In addition, nothing in Section 722 of the Dodd-Frank Act limits or affects any statutory authority of the Commission with respect to such agreements, contracts or transactions.

Section 722 of the Dodd-Frank Act also added section 4(c)(6) to the Act, providing that if the Commission determines that the exemption would be consistent with the public interest and the purposes of the Act, the Commission shall, in accordance with sections 4(c)(1) and 4(c)(2) of the Act, exempt from the requirements of the Act an agreement, contract, or transaction that is entered into pursuant to a tariff or rate schedule approved or permitted to take effect by FERC or by the applicable State authority.[3]

Each of California Independent System Operator Corporation, Electric Reliability Council of Texas, Inc., ISO New England Inc., Midwest Independent Transmission System Operator, Inc., New York Independent System Operator, Inc, and PJM Interconnection, L.L.C. (the "Requestors") hereby applies to the Commission under section 4(c)(6) of the Act and pursuant to Section 712(f)(4) of the Dodd-Frank Act, for a separate Order[4] exempting the transactions defined in this request, each of which is a class of contract, agreement or transaction authorized under a FERC- or Public Utility Commission of Texas ("PUCT")-approved tariff,

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[2] FERC has recognized the New York Independent System Operator and the California Independent System Operator as ISOs, whereas FERC has recognized ISO New England Inc., Midwest Independent Transmission System Operator, Inc., and PJM Interconnection, L.L.C. as RTOs. FERC proposed the concept of ISOs in 1996, in response to the Energy Policy Act of 1992. FERC's Order No. 888 allowed for the creation of ISOs to consolidate and manage the operation of transmission facilities to provide open, non discriminatory transmission service for all generators and transmission customers. In Order No. 2000, FERC formalized the concept of RTOs to oversee electric transmission and operate wholesale markets across a broad territory. The roles, responsibilities, and services of ISOs and RTOs under Order No. 888, Order No. 2000, and other applicable FERC orders and requirements, are substantially similar. Therefore, for ease of reference, they are collectively referenced herein as "ISOs/RTOs."

[3] Section 4(c)(6) as added to the Act by Section 722 of the Dodd-Frank Act reads as follows:

> (6) If the Commission determines that the exemption would be consistent with the public interest and the purposes of this Act, the Commission shall, in accordance with paragraphs (1) and (2), exempt from the requirements of this Act an agreement, contract, or transaction that is entered into—
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> (A) pursuant to a tariff or rate schedule approved or permitted to take effect by the Federal Energy Regulatory Commission;
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> (B) pursuant to a tariff or rate schedule establishing rates or charges for, or protocols governing, the sale of electric energy approved or permitted to take effect by the regulatory authority of the State or municipality having jurisdiction to regulate rates and charges for the sale of electric energy within the State or municipality; or
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> (C) between entities described in section 201(f) of the Federal Power Act (16 U.S.C. 824(f)).

[4] In consultation with the Commission's Staff, the Requestors are filing these consolidated applications for the convenience of the Commission, Requestors and their members and any persons who may support or comment upon the applications. It is critically important to the Requestors that they each receive separate exemptive Orders. For example, should one Requestor later seek an amendment to any exemptive Order granted by the Commission, the other Requestors do not want to incur the expense of participating in future process related to that application. Accordingly, if the Commission decides for any reason to issue a single Order, rather than separate Orders as requested herein, the Requestors respectfully ask that the Commission provide them each with advance notice so they may elect to withdraw their respective applications.

protocol or other relevant governing document, and any persons, including Requestors and their members or other market participants offering, entering into, rendering advice, or rendering other services with respect to the aforementioned contracts, agreements, or transactions, from all provisions of the Act and CFTC rules thereunder, except sections 4b, 4o, 6(c) and 9(a)(2) of the Act to the extent that those sections prohibit fraud or manipulation of the price of any swap, contract for the sale of a commodity in interstate commerce, or for future delivery on or subject to the rules of any contract market.

In making this application, the Requestors do not presume that the Transactions (defined below at pages 6 - 9) are subject to the regulatory oversight of the CFTC. Indeed, as specifically authorized by section 4(c) of the Act and discussed below (at page 11), the Requestors ask the Commission not to determine whether the Transactions fall within its jurisdiction. Nor should this application be read to suggest that the Transactions fall beyond the regulatory jurisdiction of the FERC or the PUCT. On the contrary, as explained in detail below, the Transactions are subject to pervasive regulatory oversight by the FERC and the PUCT. The Requestors make this application, in an abundance of caution, to address those Transactions and services provided by RTOs and ISOs with respect to which someone might attempt to assert that all or some aspect of the Transactions implicates law or regulations administered and enforced by the CFTC. The Requestors make this request for exemptive relief, for the benefit of themselves and their market participants, to avoid the uncertainty that would arise from such an assertion and that would otherwise threaten the orderly operation of the organized wholesale electricity markets administered by each of the Requestors.

For the reasons discussed below, the requested exemptive Orders fulfill the conditions of sections 4(c)(1), 4(c)(2) and 4(c)(6) of the Act and are consistent with the public interest and the purposes of the Act.

II. Requestors

Each entity applying for an exemptive Order under section 4(c)(6) of the Act is an ISO or RTO.

A. <u>ISOs/RTOs</u>

In Order No. 888, FERC encouraged the formation of ISOs as one means of promoting non-discriminatory open access to transmission of electrical power.[5] To further that goal, in Order No. 2000, FERC encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis.[6] The Texas Public Utility Regulatory Act ("PURA") implemented electric deregulation and restructuring and established the role of an independent organization and its functions in that construct.[7] The independent organization can be an ISO or

[5] "Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Facilities," Order No. 888 (Apr. 24, 1996) ("FERC Order No. 888"), *available at* http://www.ferc.gov/legal/maj-ord-reg/land-docs/order888.asp.

[6] "Regional Transmission Organizations," Order No. 2000, 65 FR 809 (Jan. 6, 2000) ("FERC Order No. 2000"), *available at* http://www.ferc.gov/legal/maj-ord-reg/land-docs/RM99-2A.pdf.

[7] PURA § 39.151.

other entity. ERCOT performs the role of the independent organization as an ISO, and the PUCT implements and further defines ERCOT's role through the PUCT substantive rules.[8] FERC and the PUCT concluded that RTOs could improve, among other things, efficiencies in transmission grid management and reliability and facilitate efficient electricity market performance, and thereby benefit consumers.[9]

Today, ISOs/RTOs serve roughly two-thirds of all electricity customers in the United States "by providing transmission service, interconnecting new resources to the transmission grid, and operating organized wholesale electric markets."[10] Each of the ISOs/RTOs is comprehensively regulated by FERC, with the exception of ERCOT, which is comprehensively regulated by the PUCT.

B. The Requestors

The Requestors for exemptive Orders under section 4(c)(6) of the Act are:

1. California Independent System Operator Corporation ("California ISO" or "CAISO"). The California ISO is a nonprofit public benefit corporation organized under the laws of California. The California ISO was established in 1997 pursuant to California Assembly Bill 1890. It was authorized by FERC as an Independent System Operator in 1997 and began operations on April 1, 1998. The California ISO is responsible for the reliable operation of the bulk of the electricity grid in the State of California, comprising the transmission systems of several entities.

2. Electric Reliability Council of Texas ("ERCOT"). ERCOT is the ISO managing the flow of electric power to approximately 23 million Texas customers, representing 85 percent of the state's electric load. ERCOT is a membership-based 501(c)(4) nonprofit corporation, governed by a board of directors and subject to oversight by the PUCT and the Texas Legislature. It began operations on September 11, 1996.

3. ISO New England Inc. ("ISO-NE"). ISO-NE is a nonstock corporation organized under the laws of Delaware and recognized as a 501(c)(3) tax-exempt organization by the Internal Revenue Service. ISO-NE was

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8 PUC SUBST. R. §25.361 ("ERCOT shall perform the functions of an independent organization under the PURA § 39.151 to ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms; ensure the reliability and adequacy of the regional electrical network; ensure that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to the persons who need that information; and ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region.").

9 "Regional Transmission Organizations," FERC Docket No. RM99-2-00 I; Order No. 2000-A (Feb. 25, 2000). ERCOT is an independent system operator that serves as the independent organization charged with similar functions pursuant to Section 39.151 of PURA.

10 The Federal Energy Regulatory Commission "The Strategic Plan; FY 2009-2014," p. 14, *available at* http://www.ferc.gov/about/strat-docs/FY-09-14-strat-plan-print.pdf.

recognized by FERC as an ISO in 1997 and as an RTO in 2005. ISO-NE is responsible for: ensuring the day-to-day reliable operation of New England's bulk power generation and transmission system; overseeing and ensuring the fair administration of the region's wholesale electricity markets; and managing comprehensive, regional planning processes.

4. Midwest Independent Transmission System Operator, Inc. ("MISO"). The MISO is a non-stock, nonprofit corporation organized under the laws of the state of Delaware that supports the constant availability of electricity in all or parts of 13 states and the Canadian province of Manitoba. The MISO was founded in 1998 and was approved as the Nation's first RTO by FERC in 2001.

5. New York Independent System Operator, Inc. ("NYISO"). The NYISO is a not-for-profit corporation organized under the laws of New York. The NYISO began operations at the end of 1999. The NYISO's core responsibilities include the reliable operation of the New York State bulk electricity grid, the administration of New York State's wholesale electricity markets, the administration of the planning process for the New York State electric power system, and the advancement of the technological infrastructure of the electric power system. The NYISO is responsible for the reliable operation of New York's nearly 11,000 miles of high-voltage transmission and the dispatch of over 500 electric power generators. The NYISO administers bulk power markets in accordance with FERC regulation.

6. PJM Interconnection, L.L.C. ("PJM"). PJM is an RTO that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. PJM began the transition to an independent organization in 1993 when the PJM Interconnection Association was formed to administer the power pool. In 1997, PJM became a fully independent organization. In 1997 FERC approved PJM as an ISO. Later, FERC encouraged the formation of RTOs to operate the transmission system in multi-state areas and to advance the development of competitive wholesale power markets. PJM became the nation's first fully functioning RTO in 2001.

III. Transactions, Persons and Services Covered by the Requests

The Requestors seek these exemptions under section 4(c) of the Act to provide greater certainty with respect to the regulatory requirements that apply to each class of contracts, agreements or transactions currently offered or entered into under a FERC- or PUCT-approved tariff, and any person or class of persons offering, entering into, rendering advice, or rendering other services with respect thereto.[11] The Requestors seek legal clarity that such contracts will

[11] With respect to ERCOT, "FERC- or PUCT-approved tariffs" refers to the ERCOT Protocols approved by the PUCT, which are equivalent to the FERC-approved tariffs of other ISOs/RTOs.

be subject only to the Act's anti-fraud and anti-manipulation authorities as reserved under the terms of the requested exemptive Orders.

The Requestors respectfully ask that these Orders apply to each relevant class of contracts, agreements or transactions that is currently offered or entered into under any FERC- or PUCT-approved tariff under which an ISO/RTO operates. Each ISO/RTO operates distinct markets under FERC- or PUCT-approved tariffs that apply specifically to each ISO/RTO market. While the ISOs/RTOs operate pursuant to individual tariffs, they share many commonalities in their markets and operations. Although the current market structures of the individual ISOs/RTOs may vary, it is reasonable to expect that each ISO/RTO will, over time, consider offering under its own individual tariff one or more classes of contract, agreement or transaction that is currently offered under any other ISO/RTO tariff. We thus request that each individual exemptive Order apply collectively to each class of contract, agreement or transaction provided by the ISOs/RTOs. This will provide the appropriate breadth to the exemptive Order so that an individual Requestor will not be required to seek future amendments to offer or enter into contracts, agreements or transactions that are currently offered by any other Requestor.

The classes of contracts, agreements or transactions offered under a FERC- or PUCT-approved tariff within the scope of the Request are for the purchase or sale of any of the following electricity-related products (including generation, demand response or convergence or virtual bids/transactions):

A. Financial Transmission Rights:

1. A "Financial Transmission Right" is a transaction, however named, that entitles one party to receive, and obligates another party to pay, an amount based solely on the difference between the price for electricity, established on an electricity market administered by a Requesting Party, at a specified source (*i.e.*, where electricity is deemed injected into the grid of a Requesting Party) and a specified sink (*i.e.*, where electricity is deemed withdrawn from the grid of a Requesting Party). The term "FTR" includes Financial Transmission Rights, and Financial Transmission Rights in the form of options (*i.e.*, where one party has only the obligation to pay, and the other party only the right to receive, an amount as described above).

2. The FTRs for which the Requestors are seeking exemptive Orders are those where:

    a) Each FTR is linked to, and the aggregate volume of FTRs for any period of time is limited by, the physical capability (after accounting for counterflow) of the electricity transmission system operated by a Requestor offering the contract, for such period;

    b) The Requestor serves as the market administrator for the market on which the FTRs are transacted;

c) Each party to the transaction is a member of the Requestor (or is the Requestor itself) and the transaction is executed on a market administered by that Requestor; and

d) The transaction does not require any party to make or take physical delivery of electricity.

B. <u>Energy Transactions</u>: "Energy Transactions" are transactions in a Day-Ahead Market or Real-Time Market for the purchase or sale of a specified quantity of electricity at a specified location (including Demand Response as described below) where:

1. The price of the electricity is established at the time the transaction is executed;

2. Performance occurs in the Real-Time Market by either

a) Delivery or receipt of the specified electricity, or

b) A cash payment or receipt at the price established in the Real-Time Market; and

3. The aggregate cleared volume of both physical and cash-settled energy transactions for any period of time is limited by the physical capability of the electricity transmission system operated by a Requestor for that period of time.

C. <u>Forward Capacity Transactions</u>: "Forward Capacity Transactions" are transactions in which a Requestor, for the benefit of load-serving entities, purchases any of the following rights:

1. <u>Generation Capacity</u>: the right of a Requestor to:

a) Require certain sellers to maintain the interconnection of electric generation facilities to specific physical locations in the electric-power transmission system during a future period of time as specified in the Requestor's Tariff;

b) Require such sellers to offer specified amounts of electric energy into the Day-Ahead or Real-Time markets for electricity transactions as specified in the Requestor's Tariff; and

c) Require, subject to the terms and conditions of a Requestor's Tariff, such sellers to inject electric energy into the electric power transmission system operated by the Requestor;

2. <u>Demand Response</u>: the right of a Requestor to require that certain sellers of such rights curtail consumption of electric energy from the electric power transmission system operated by a Requestor during a future period of time as specified in the Requestor's Tariff; or

3. Energy Efficiency: the right of a Requestor to require specific performance of an action or actions that will reduce the need for generation capacity or demand response capacity over the duration of a future period of time as specified in the Requestor's Tariff.

In each case, the aggregate cleared volume of all such transactions for any period of time shall be limited to the physical capability of the electricity transmission system operated by a Requestor for that period of time.

D. Reserve or Regulation Transactions: Reserve or Regulation Transactions are transactions:

1. In which a Requestor, for the benefit of load-serving entities and resources, purchases, through auction, or otherwise as permitted in its Tariff, the right, during a period of time as specified in the Requestor's Tariff, to require the seller of such right to operate electric facilities in a physical state such that the facilities can increase or decrease the rate of injection or withdrawal of a specified quantity of electricity into or from the electric power transmission system operated by the Requestor with:

    a) Reserve Transaction: physical performance by the seller's facilities within a response time interval specified in a Requestor's Tariff; or

    b) Area Control Error Regulation Transaction: prompt physical performance by the seller's facilities as specified in the Requestor's Tariff;

2. For which the seller receives, in consideration, one or more of the following:

    a) Payment at the price established in the Requestor's Day-Ahead or Real-Time Market price for electricity applicable whenever the Requestor exercises its right that electric energy be delivered (including Demand Response as described above);

    b) Compensation for the opportunity cost of not supplying or consuming electricity or other services during any period during which the Requestor requires that the seller not supply energy or other services;

    c) An upfront payment determined through the auction administered by the Requestor for this service;

    d) An additional amount indexed to the frequency, duration, or other attributes of physical performance as specified in the Requestor's Tariff; and

3. In which the value, quantity, and specifications of such transactions for a Requestor for any period of time shall be limited to the physical capability

of the electricity transmission system operated by the Requestor for that period of time.

Together, these classes of contracts, agreements or transactions for the purchase and sale of a product or service that is directly related to, and a logical outgrowth of, any Requestor's core functions as an ISO/RTO as provided in the three part test described above, and all services related thereto ("Transactions") are the subject of the Request.

IV. Exemption Criteria of Section 4(c)(6) of the Act

Section 4(c)(6) of the Act, as amended by the Dodd-Frank Act, provides that the Commission shall exempt contracts, agreements or transactions entered into pursuant to a tariff or rate schedule approved or permitted to take effect by FERC, or the regulatory authority of a State if it determines such exemption is consistent with the public interest and the purposes of the Act.[12] Specifically, section 4(c)(6) of the Act provides that:

> If the Commission determines that the exemption would be consistent with the public interest and the purposes of this Act, the Commission shall, in accordance with paragraphs (1) and (2) [of section 4(c) of the Act], exempt from the requirements of this Act an agreement, contract, or transaction that is entered into—
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> (A) pursuant to a tariff or rate schedule approved or permitted to take effect by the Federal Energy Regulatory Commission;
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> (B) pursuant to a tariff or rate schedule establishing rates or charges for, or protocols governing, the sale of electric energy approved or permitted to take effect by the regulatory authority of the State or municipality having jurisdiction to regulate rates and charges for the sale of electric energy within the State or municipality; or
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> (C) between entities described in section 201(f) of the Federal Power Act (16 U.S.C. 824(f)).

Paragraphs (1) and (2) of section 4(c) are incorporated by reference in section 4(c)(6). Paragraph (1) provides that the Commission, after notice and opportunity for hearing, may upon application of any person, exempt any agreement, contract, or transaction and any persons or class of person offering, entering into, rendering advice or rendering other services with respect to that agreement, contract or transaction from any of the requirements of the Act. Paragraph (2) provides that the Commission shall not grant an exemption unless it determines that:

1. the exemption would be consistent with the public interest and the purposes of this Act;

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[12] The Dodd-Frank Act amendments to Section 4(c) are effective on July 16, 2011.

2. the agreement, contract or transaction will be entered into solely between appropriate persons; and

3. the agreement, contract or transaction will not have a material adverse effect on the ability of the Commission or any contract market to discharge its regulatory or self-regulatory duties under the Act.[13]

The Commission has considerable flexibility in exercising its section 4(c) exemptive authority. In order to provide legal certainty, we request that the Commission issue each separate exemptive Order without first making a determination as to the status or classification under the Act of the Transactions. During the legislative process leading to the enactment of Section 4(c) of the Act, the House-Senate Conference Committee noted that "the Conferees do not intend that the exercise of exemptive authority by the Commission would require any determination beforehand that the agreement, instrument, or transaction for which an exemption is sought is subject to the Act. *Rather, this provision provides flexibility for the Commission to provide legal certainty to novel instruments where the determination as to jurisdiction is not straightforward.* Rather than making a finding as to whether a product is or is not a futures contract, the Commission in appropriate cases may proceed directly to issuing an exemption."[14] Specifically, we request that the Commission issue the exemptive Orders without making a determination whether: the (1) Transactions are swaps, futures or option contracts within the meaning of section 1a of the Act; (2) Requestors operate Swap Execution Facilities, or provide clearing services that require registration as a Derivatives Clearing Organization in connection

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13 § 4(c) of the Act provides in part:

> (1) In order to promote responsible economic or financial innovation and fair competition, the Commission by rule, regulation, or order, after notice and opportunity for hearing, may (on its own initiative or on application of any person, including any board of trade designated or registered as a contract market or derivatives transaction execution facility for transactions for future delivery in any commodity under section 5 of this Act) exempt any agreement, contract, or transaction (or class thereof) that is otherwise subject to subsection (a) (including any person or class of persons offering, entering into, rendering advice or rendering other services with respect to, the agreement, contract, or transaction), either unconditionally or on stated terms or conditions or for stated periods and either retroactively or prospectively, or both, from any of the requirements of subsection (a), or from any other provision of this Act . . . .
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> (2) The Commission shall not grant any exemption under paragraph (1) from any of the requirements of subsection (a) unless the Commission determines that—
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> (A) the requirement should not be applied to the agreement, contract, or transaction for which the exemption is sought and that the exemption would be consistent with the public interest and the purposes of this Act; and
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> (B) the agreement, contract, or transaction—
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> (i) will be entered into solely between appropriate persons; and
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> (ii) will not have a material adverse effect on the ability of the Commission or any contract market or derivatives transaction execution facility to discharge its regulatory or self-regulatory duties under this Act.

14 *See* House Conf. Report No. 102–978 (emphasis added).

with the Transactions; or (3) Participants are subject to any requirements under the Act with respect to the Transactions**.**

V. The Requested Exemptions Are Consistent With the Public Interest and Purposes of the Commodity Exchange Act

The Transactions have been, and are, subject to a long-standing, comprehensive regulatory framework for the offer and sale of the Transactions established by FERC, or in the case of ERCOT, the PUCT. Each of the Transactions is part of, and inextricably linked to, the organized wholesale electricity markets that are subject to FERC's (and the PUCT's) regulation and oversight. The regulatory frameworks that FERC and the PUCT administer and that apply to the Transactions, the Requestors and the Participants are consistent with the public interest, as defined by Congress in the FPA and by the Texas legislature in the PURA.[15]

The requested exemptions are consistent with the public interest as defined by the Act. Section 3 of the Act describes the public interests served by the Act as ensuring that the benefits of providing a means for managing or assuming price risk and discovering prices occurs through trading in liquid, fair and financially secure trading facilities. Section 3 describes as the purposes of the Act to foster these public interests by, among other things, deterring and preventing price manipulation or any other disruptions to market integrity; ensuring the financial integrity of all transactions subject to the Act; and protecting market participants from fraudulent or abusive sales practices.

Below we describe the comprehensive nature of the existing regulation of ISOs and RTOs and then measure this regulatory framework against the three purposes specified in Section 3 of the Act.

A. <u>FERC and PUCT Regulation is Comprehensive</u>

The comprehensive regulatory framework adopted, administered and enforced by FERC, by regulating the ISO/RTO markets through which the Transactions are offered and sold, is consistent with the purposes of the Act. As discussed in greater detail below, the regulatory framework established by FERC, like the Commission's, is established through the adoption of broad principles that the individual ISOs/RTOs must meet. Each individual ISO/RTO establishes the exact terms for its operation through a tariff, the terms of which must be approved by FERC.

With respect to ERCOT, PURA and the PUCT establish the requirements that underlie the ERCOT market design. Again, like the Commission's principles, neither PURA nor the PUCT substantive rules prescribe specific requirements of the ERCOT market design; instead, they mandate particular market principles that apply to energy markets and ancillary services. The ERCOT Protocols establish detailed rules to implement the overarching PURA and PUCT mandates. The Protocols must be reviewed and approved by the PUCT and are subject to PUCT oversight. Both the broad principles established by FERC and the PUCT, as well as the individual tariffs and ERCOT protocols approved by FERC and the PUCT should be considered

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15 *See* discussion of declarations of public interest in the FPA and PURA, *infra*, pp. 12-13.

together in determining that the FERC/PUCT regulatory framework is consistent with the public interests and purposes of the Act.

FERC and PUCT regulation of the organized wholesale electricity markets is in the public interest, as provided by Section 201 of the FPA and Section 39.001 of PURA. The FPA became law in 1935 in order to "provide effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce."[16] Section 201(a) of the FPA provides that:

> It is hereby declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to . . . that part of such [electric] business which consists of the transmission of electric energy in interstate commerce . . . is necessary in the public interest, such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.[17]

PURA § 39.001 similarly provides that:

> The legislature finds that . . . the public interest in competitive electric markets requires that . . . electric services and their prices should be determined by customer choices and the normal forces of competition. As a result, this chapter is enacted to protect the public interest during the transition to and in the establishment of a fully competitive electric power industry.

Under Section 201(b)(1) of the FPA, FERC's jurisdiction is comprehensive:

> [T]he Commission shall have jurisdiction over all facilities for such transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce . . . .[18]

PURA § 39.151(d) similarly provides the PUCT with comprehensive jurisdiction, requiring that:

> An independent organization certified by the commission [*i.e.*, ERCOT] is directly responsible and accountable to the commission. The commission has complete authority to oversee and investigate the organization's finances, budget, and operations as necessary to ensure the organization's accountability and to ensure that the organization adequately performs the organization's functions and duties. The organization shall fully cooperate with the commission in the commission's oversight and investigatory functions. The commission may take appropriate action against an organization that does not adequately perform the organization's functions or duties or does not comply with this section, including

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16 *Gulf States Utility Co. v. FPC*, 411 U.S. 747 (1973).

17 16 U.S.C. § 824(a).

18 16 U.S.C. § 824(b)(1).

> decertifying the organization or assessing an administrative penalty against the organization. The commission by rule shall adopt procedures governing decertification of an independent organization, selecting and certifying a successor organization, and transferring assets to the successor organization to ensure continuity of operations in the region.

Moreover, FERC regulates transmission rights pursuant to explicit direction from Congress. Section 217 of the Energy Policy Act of 2005 directed FERC to:

> exercise the authority of the Commission under this Act in a manner that. . . enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial transmission rights) on a long term basis for long term power supply arrangements made, or planned, to meet such needs.[19]

As referenced above, in establishing ISOs/RTOs, FERC set out broad principles that these organizations must meet. FERC Order No. 2000[20] encouraged the formation of ISOs/RTOs to operate the electric transmission grid and to create organized wholesale electric markets.[21] FERC Order No. 2000 established twelve characteristics and functions that an entity must satisfy in order to become an ISO/RTO. These are the "Core Functions" of an ISO/RTO. FERC Order No. 2000 requires an ISO/RTO to demonstrate that it has four minimum characteristics:

> (1) independence from any market participant;
>
> (2) having a scope and regional configuration which enables the ISO/RTO to maintain reliability and effectively perform its required functions;
>
> (3) having operational authority for its activities, including being the security coordinator for the facilities that it controls; and
>
> (4) ensuring short-term reliability.

In addition to these characteristics, an ISO/RTO must demonstrate that it performs the following functions:

> (1) *Tariff administration and design.* The ISO/RTO must employ a transmission pricing system that promotes efficient use and expansion of transmission and generation facilities.

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19 Energy Policy Act of 2005, Pub. Law 109-58, § 1233 (Aug. 8, 2005). *Available at* http://www.doi.gov/pam/EnergyPolicyAct2005.pdf.

20 FERC Order No. 2000 at 4.

21 ISOs actually emerged as a means to comply with FERC Order No. 888, which required open access and required ISOs to have certain features. These features were refined in FERC Order No. 2000 for RTOs but the Order No. 2000 requirements are substantially similar to those set forth in FERC Order No. 888. As a result, we focus our discussion on FERC Order No. 2000.

(2) *Congestion management.* The ISO/RTO must ensure the development and operation of market mechanisms to manage transmission congestion which accommodate broad participation by all market participants, and provide all transmission customers with efficient price signals that show the consequences of their transmission usage decisions.

(3) *Parallel path flow.* The ISO/RTO must develop and implement procedures to address parallel path flow issues within its region and with other regions.

(4) *Ancillary services*. The ISO/RTO must serve as a provider of last resort of all ancillary services required by FERC Order No. 888[22] including ensuring that its transmission customers have access to a real-time balancing market.

(5) *OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC).* The ISO/RTO must be the single OASIS (Open-Access Same-Time Information System) site administrator for all transmission facilities under its control and independently calculate Total Transmission Capacity and Available Transmission Capability.

(6) *Market monitoring.* To ensure that the ISO/RTO provides reliable, efficient and not unduly discriminatory transmission service, it must provide for objective monitoring of markets it operates or administers to identify market design flaws, market power abuses and opportunities for efficiency improvements.

(7) *Planning and expansion.* The ISO/RTO must be responsible for planning, and for directing or arranging, necessary transmission expansions, additions, and upgrades.

(8) *Interregional coordination.* The ISO/RTO must ensure the integration of reliability practices within an interconnection and market interface practices among regions.

ERCOT's core functions are similar to those of its FERC-jurisdictional counterparts.

PURA § 39.151(a) sets forth the principles underlying ERCOT's roles and duties to:

(1) provide access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms;

(2) ensure the reliability and adequacy of the regional electrical network;

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[22] FERC Order No. 888 requires "open access," which means that a transmission owner who procures transmission service must offer nondiscriminatory, similar transmission service to those in search of like services over the transmission owner's own facilities. The order also encourages the formation of a separate Price Exchange to expose electricity market-clearing prices.

> (3) ensure that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to the persons who need that information; and
>
> (4) ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region.

B. FERC and PUCT Regulation is Consistent With the Purposes of the Act

FERC Order No. 2000 and regulation by the PUCT under PURA directly address a number of goals of the Act, including: (a) the operation of fair and liquid markets; (b) ensuring financial integrity of transactions and the avoidance of systemic risk; and (c) the protection of market participants from fraudulent or other abusive practices.[23]

Below we explain how the FERC and PUCT mandates are consistent with the purposes of the Act. The Attachments hereto demonstrate for each of the Requestors, the Transactions and Participants how the FERC- or PUCT-approved tariffs are consistent with the public interest and purposes of the Act as evidenced by the core principles in sections 5b (registration of derivatives clearing organization ("DCO")) and 5h (registration of swap execution facilities ("SEF")), which apply to the clearing and execution of contracts and transactions subject to the Commission's jurisdiction under the Act.

1. Operation of fair and liquid markets

a) Market Rules

Each ISO/RTO codifies rules governing its markets in FERC-approved tariffs or PUCT-approved protocols. FERC-approved tariffs have the force and effect of federal law, while the protocols approved by PUCT have the force end effect of Texas law. Such rules are subject to review by FERC or PUCT, which actively exercise their authority to require that the rules be revised when necessary to achieve the goal of ensuring the ISO/RTO functions are administered consistent with the public interest. In addition, as discussed below, FERC and PUCT have independent rules governing market participant conduct.

FERC and PUCT requirements apply to all aspects of the creation, auction, and wholesale sale for resale of ISO/RTO products, as well as participant requirements, risk management, and supporting financial arrangements relating to the Transactions. FERC and PUCT have exercised comprehensive regulatory oversight over these aspects of Transactions through a long history of orders, which are detailed in Addendum A.

b) Market Monitoring

FERC Order No. 2000 includes the requirement that ISOs/RTOs provide for a market monitoring function. The requirement to provide for market monitoring directly parallels the goal of the Act to "deter and prevent price manipulation or any other disruptions to market

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23 *See* Section 3 of the Act, 7 U.S.C. §5.

integrity." Like the FPA, PURA gives the PUCT express authority to address market power through a variety of means including actions against individual entities for market abuse or ordering the construction of additional transmission to remove system constraints that may facilitate the exercise of market power. PURA establishes an independent market monitor to facilitate achievement of the market efficiencies intended by the establishment of an ISO.

FERC Order No. 2000 requires that an RTO provide a market monitoring function that at a minimum:

> (i) must include monitoring the behavior of market participants in the region, including transmission owners other than the RTO, if any, to determine if their actions hinder the RTO in providing reliable, efficient and not unduly discriminatory transmission service;
>
> (ii) with respect to markets the RTO operates or administers, there must be a periodic assessment of how behavior in markets operated by others (e.g., bilateral power sales markets and power markets operated by unaffiliated power exchanges) affects ISO/RTO operations and how ISO/RTO operations affect the efficiency of power markets operated by others; and
>
> (iii) reports on opportunities for efficiency improvement, market power abuses and market design flaws must be filed with FERC and affected regulatory authorities.[24]

In adopting Order No. 2000, FERC explained that it "has the primary responsibility to ensure that regional wholesale electricity markets served by [ISOs/RTOs] operate without market power." It noted that the minimum components of a market monitoring plan include "examin[ing] the structure of the market, compliance with market rules, behavior of individual market participants and the market as a whole, and market power and market power abuses."[25] FERC also explained that "sanctions and penalties may be appropriate for certain actions such as noncompliance with ISO/RTO rules. However, the monitoring plan should clearly identify any proposed sanctions or penalties and the specific conduct to which they would be applied, provide the rationale to support any sanctions, penalties or remedies (financial or otherwise) and explain how they would be implemented."[26] FERC indicated that market monitoring should include reporting requirements. PURA similarly establishes an independent market monitor whose primary functions are detecting and preventing market manipulation and market design assessment with the goal of enhancing market efficiency,[27] while PUCT rules implement the market monitor's functions.[28]

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[24] FERC Order No. 2000 at 716.

[25] *Id.* at 464.

[26] *Id.*

[27] PURA § 39.1515.

[28] PUC SUBST. R. § 25.365.

More recently, in Order No. 719, FERC amended its regulation "to improve the operation of organized wholesale electric markets" in several areas, including market monitoring.[29] Specifically, FERC required ISOs/RTOs to provide their Market Monitoring Units with access to market data, resources and personnel sufficient to carry out their duties, and that the Market Monitoring Unit report directly to the ISO/RTO board of directors.[30] In addition, FERC required that the Market Monitoring Unit's functions include: (1) identifying ineffective market rules and recommending proposed rules and tariff changes; (2) reviewing and reporting on the performance of the wholesale markets to the RTO or ISO, FERC, and other interested entities; and (3) notifying appropriate FERC staff of instances in which a market participant's behavior may require investigation.[31] FERC also expanded the list of recipients of Market Monitoring Unit recommendations regarding rule and tariff changes, and broadened the scope of behavior to be reported to FERC.[32]

To comply with FERC and PUCT requirements, all ISOs/RTOs have market monitoring programs. The market monitors operate independently of management for the ISOs/RTOs and interact directly with the FERC or the PUCT. In general, the ISOs/RTOs monitor market activity, compliance with the tariff or protocol of the ISO/RTO and compliance with rules that prohibit false or misleading information and market manipulation. The market monitors do so by reviewing a variety of metrics to detect potential manipulative conduct. These include, for example, reviewing market activity to detect excessive or sustained losses or profits arising from virtual bidding or other transactions by an individual participant not consistent with more general market trends or the participant's usual market conduct. In particular, monitors will scrutinize transactions that have a significant impact on an individual transmission constraint so as to increase the participant's revenues from financial transmission rights.

Some of the ISOs/RTOs have both internal market monitoring departments and an external market monitor. Market monitors conduct their market surveillance using sophisticated electronic systems and data from the markets.

When anomalous behavior is detected it is reviewed in more detail. Market monitors may contact a market participant for an explanation of any behavior that appears anomalous or manipulative. If, based on this investigation, the market monitor believes a participant may have violated rules prohibiting false or misleading information and market manipulation, the matter is referred to FERC or the PUCT. The monitors discuss market performance with FERC and PUCT staff on an ongoing basis. The PUCT has full authority to take action to address market power and has an internal enforcement division that works with the independent market monitor and ERCOT, as necessary, to detect and address market power. ERCOT is obligated by law to support and cooperate with the independent market monitor, including providing access to all ERCOT systems, data, and information. These programs are consistent with the goals of the Act

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[29] "Wholesale Competition in Regions with Organized Electric Markets," Order No. 719, 125 FERC ¶ 61,071 (Oct. 17, 2008) ("FERC Order No. 719"), available at http://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf.

[30] *Id.* at P5, P326 – 476.

[31] *Id.*

[32] *Id.*

to "deter or prevent price manipulation or any other disruptions." In addition to reviewing potentially manipulative activity, market monitors also review overall market results and behavior that may not violate the market rules of the ISO/RTO, but may be detrimental to market efficiency or may indicate flaws in market rules or processes.

Each Requestor, in compliance with FERC and PUCT requirements, has in place a program of market surveillance. Greater detail regarding how the market monitoring program of each Requestor satisfies the related CFTC Core Principles is provided in the Attachment hereto.

2. Ensure financial integrity

Parallel to the goal of the Act "to ensure financial integrity of all transactions subject to the Act and the avoidance of systemic risk," FERC is obliged under the FPA to "ensure that all rates charged for the transmission or sale of electric energy in interstate commerce are just, reasonable, and not unduly discriminatory or preferential."[33] FERC has determined that "clear and consistent credit policies are an important element in ensuring rates that are just, reasonable, and not unduly discriminatory or preferential. The management of risk and credit requires a balance between protecting the markets from costly defaults and ensuring that barriers to entry for market participants are not prohibitive."[34] In furtherance of this goal, FERC provided guidance to the ISOs/RTOs on credit-related issues in its Policy Statement on Electric Creditworthiness.[35] With respect to ERCOT, PURA charges ERCOT with ensuring that transactions are accurately accounted for between buyers and sellers.[36] In addition, PUC Rule 25.501(a) requires ERCOT to administer its markets consistent with economic principles to promote economic efficiency. Specific requirements to accomplish this goal include the establishment of appropriate credit rules.[37] ERCOT implements these mandates through its protocols, which, in practice, results in financial responsibility that facilitates financial integrity of the market.

As a result of FERC and PUCT oversight, the ISOs/RTOs have established comprehensive and integrated credit policies to manage the credit risk and protect the financial integrity of the organized wholesale energy markets. These credit policies consider the creditworthiness of market participants, update exposure calculations on a regular basis and establish credit limits for market activity. Further, the ISOs/RTOs review credit rules on a regular basis and update them when needed.

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33 FPA §§ 205, 206;16 U.S.C. §§ 824d, 824e.

34 "Credit Reforms in Organized Wholesale Electric Markets," Order No. 741-A at 102 (Feb. 17, 2011), *available at* http://www.ferc.gov/whats-new/comm-meet/2011/021711/E-6.pdf.

35 109 FERC ¶ 61,186 (2004).

36 Section 39.151 of PURA. *See also* PUC Rule 25.361(b).

37 PUC Rule 25.361(b).

In addition, FERC recently issued Orders No. 741 and 741-A, "Credit Reforms in Organized Wholesale Electric Markets" ("Credit Reform Orders"). These Orders add a new Subpart J to Part 35 of FERC's Regulations.[38] The rules require ISOs/RTOs to:

> (1) limit the amount of unsecured credit extended to any market participant or aggregate corporate family to no more than $50 million;
>
> (2) adopt a settlement period of no more than seven days with an additional seven days to receive payment;
>
> (3) eliminate unsecured credit in the financial transmission rights market;
>
> (4) reinforce the ability of the ISO/RTO to offset market obligations owed to market participants against market obligations owed by market participants;
>
> (5) limit the time period by which a market participant must cure a collateral call to no more than two days;
>
> (6) provide minimum participation criteria;
>
> (7) specify when a market administrator may invoke the "material adverse change" to justify requiring additional collateral; and
>
> (8) provide for consistent applicability of rules to all types of participants.

FERC adopted these changes after determining that shortening the settlement cycle would further reduce risk, as would limiting the use of unsecured credit and eliminating unsecured credit risk in the markets for financial transmission rights. In addition, FERC addressed the issue of mitigating any legal ambiguity as to the ability of ISOs/RTOs to manage defaults and to offset market obligations.

As a result, the ISOs/RTOs either have reexamined or are reexamining issues relating to default and offsetting market obligations. At least one ISO/RTO, PJM, has already formed a separate legal entity to act as the central counter party ("CCP") to each transaction made by market participants in the PJM markets. A number of additional ISOs/RTOs are in the process of assessing the tax and other legal implications were they to form a CCP. For these ISOs/RTOs, forming or becoming a CCP is the preferred course of action assuming that there are no legal or other obstacles. These ISOs are making every effort to expedite resolution of the outstanding legal issues. If, as expected, the legal issues are resolved satisfactorily, forming or becoming a CCP is the likely means by which these ISOs will mitigate issues relating to default and setoff rights, assuming concurrence by their stakeholders. Each ISO/RTO has provided an explanation in the Attachments and Memoranda of Counsel detailing its response to this issue.

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[38] 19 C.F.R. Part 35.

FERC also required the ISOs/RTOs to adopt minimum participation standards for their market participants. In doing so, however, it noted that the criteria "should allow most traditional market participants – including small load-serving entities, municipalities, cooperatives, and other similar participants in organized wholesale electric markets – to participate."[39] As detailed in the Attachments, each of the ISOs/RTOs subject to FERC regulation has taken steps to come into compliance with the Credit Reform Orders. Although ERCOT is not subject to the requirements in FERC's Credit Reform Orders, ERCOT has, or is in the process of, implementing through its stakeholder process a number of revisions to its credit and financial security risk management protocols that will bring ERCOT market participation standards in substantial agreement with those of the FERC-regulated ISOs/RTOs.

The ISOs/RTOs ensure financial integrity, in part, through the risk management requirements that apply to their market participants. In accordance with the Credit Reform Orders, and in addition to the minimum capitalization criteria that each ISO/RTO applies, discussed in greater detail in the Attachments, all of the ISOs/RTOs have included or are in the process of implementing the requirement that all market participants meet minimum capitalization requirements and have in place risk management policies, procedures and internal controls appropriate to their trading activities in the ISO/RTO markets in which they participate.[40] All of the ISOs/RTOs require an annual certification by a responsible officer of the market participant that the market participant has in place risk management policies, procedures and internal controls appropriate to the nature of its trading activities.

In addition, the ISOs/RTOs subject to FERC regulation submitted supplemental compliance filings addressing their proposed verification programs. Many of the ISOs/RTOs have proposed programs, described broadly below, to verify that market participants that pose significant risks in their markets have such risk management policies and internal controls in place.

The verification programs developed by the ISOs/RTOs require certain market participants to submit their risk management policies and internal controls to the ISO/RTO for review. Such market participants may include all new applicants, may be selected randomly, and/or may be selected based upon certain risk factors. Risk factors include, the markets in which a participant transacts, the magnitude of the market participant's transactions, the volume of the participant's open positions, amount of collateral at risk, and other factors that are indicative of the risk the participant poses to the ISO/RTO (such as whether the participant is hedging or speculating).[41]

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[39] "Credit Reforms in the Wholesale Electricity Markets; Notice of Proposed Rulemaking," at 16 (Jan. 21, 2010).

[40] These risk management policies and controls may be specifically required for particular Transactions, such as FTRs.

[41] As detailed in the Attachments hereto, the details of the certification and verification regimes may differ somewhat among the various ISOs/RTOs**,** including differences in determining which market participants may be subject to verification, when such market participants must submit their risk management policies, and the time periods for curing any deficiencies in a market participant's risk management policies.

The ISOs/RTOs (or a designated third party) will review and confirm that a market participant's risk management policies, procedures, and controls reflect certain criteria. These criteria generally are the same criteria as those suggested by the Committee of Chief Risk Officers ("CCRO") and include:

(1) addressing market, credit, and operational risk;

(2) segregating roles, responsibilities, and functions in the organization;

(3) establishing delegations of authority that specify which transactions traders are authorized to enter into;

(4) ensuring that traders have sufficient training in systems and the markets in which they transact;

(5) placing risk limits to control exposure;

(6) requiring reports to ensure that risks are adequately communicated throughout the organization;

(7) establishing processes for independent confirmation and/or review of trading activities and executed transactions; and

(8) establishing periodic valuation or mark-to-market of risk positions as appropriate.

3. Customer Protection

A third goal of Section 3 of the Act is the protection of market participants from fraudulent or other abusive practices.[42] The protections that have been required by FERC with respect to the Transactions and related services are tailored to the wholesale nature of the markets. The FPA and the implementing regulations prohibit deceptive practices in language similar to Section 6(c)(1) of the Act, added by Dodd-Frank.[43] Section 25.503 of the PUCT

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42 *See* Section 3 of the Act, 7 U.S.C. § 5.

43 FPA § 222, 16 U.S.C. § 824v; 18 C.F.R. § 1c.2(a) (implementing FPA Section 222). FPA Section 222 provides:

> It shall be unlawful for any entity…directly or indirectly, in connection with the purchase or sale of electric energy or the purchase or sale of transmission services subject to the jurisdiction of the Commission,
>
> To use or employ any device, scheme, or artifice to defraud,
>
> To make any untrue statement of a material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading, or
>
> To engage in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity.

substantive rules establishes standards that the PUCT applies in monitoring the activities of entities participating in the ERCOT markets, including standards that protect customers from "unfair, misleading, and deceptive" practices.[44] Moreover, under Section 824e of the FPA, FERC has unique rate regulation powers to ensure that wholesale electricity prices are just and reasonable. This jurisdiction provides FERC with an additional tool in protecting market participants from abusive practices.

The PUCT rules prohibit activities that cause prices that are not reflective of competitive market forces or that adversely affect the reliability of the electric network. The prohibited activities include, *inter alia*, executing pre-arranged offsetting trades, conducting trades that result in a misrepresentation of the financial condition of the organization, engaging in fraudulent behavior related to participation in the wholesale market, colluding with other market participants to manipulate the price or supply of power, allocate territories, customers or products, or otherwise unlawfully restrain competition, engaging in market power abuse such as economic or physical withholding.

As part of the comprehensive regulatory oversight that FERC exercises over the ISO/RTO markets, FERC has the power to impose remedies, including significant civil penalties, for violations such as fraud and other abusive practices. Similarly, PURA authorizes the PUCT to impose civil penalties as necessary to address or eliminate market power abuse and other violations.[45]

VI. Enforcement.

A. Enforcement Oversight

The Requestors, Transactions and Participants are subject to comprehensive enforcement regimes pursuant to their tariffs/protocols and FERC/PUCT oversight. Nevertheless, as noted above, the Requestors are not seeking exemptions from sections 4b, 4o, 6(c) or 9(a)(2) of the Act to the extent that those sections prohibit fraud in connection with transactions subject to the Act, or manipulation of the price of any swap or contract for the sale of a commodity in interstate commerce or for future delivery on or subject to the rules of any registered entity.

In addition to the market monitoring function required by FERC, the FERC-regulated Requestors, Transactions and Participants are subject to oversight by FERC's Office of Enforcement, Division of Energy Market Oversight, which conducts real-time monitoring of all markets subject to FERC's jurisdiction in its Market Monitoring Center. Daily information for each electricity market is posted at http://www.ferc.gov/market-oversight/mkt-electric/overview.asp. Moreover, the Division of Energy Market Oversight maintains regular communication with the independent ISO/RTO market monitors and analyzes all reports from the market monitors. FERC's Office of Energy Market Regulation also maintains regular communication with the ISOs/RTOs.

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[44] PUC SUBST. R. § 25.503(a).

[45] PURA § 39.157.

With respect to ERCOT, to facilitate the PUCT's oversight of ERCOT and its Transactions and Participants, PURA provides the PUCT with a broad array of administrative tools to monitor ERCOT, including the imposition of reports, system of accounts, audits and inspections.[46] In overseeing the ERCOT region, the PUCT is tasked with assessing and correcting any market power issues that arise within the state.[47]

FERC and the PUCT also have broad investigative authority under FPA Section 307[48] and PURA Section 39.157, respectively. For instance, while conducting an inquiry, FERC not only has the power to require that testimony be taken in a deposition but also to "administer oaths and affirmations, subpoena witnesses, compel their attendance, take evidence, and require the production of any books, papers, correspondence, memoranda, contracts, agreements, or other records" relevant to its inquiry.[49] If an individual refuses to appear, testify or produce documents in compliance with a FERC subpoena, FERC is able to resort to the courts in order to enforce its subpoena power.[50] Further, any person who refuses to comply with FERC's subpoena authority can be found guilty of a misdemeanor requiring a fine of not more than $1,000 and/or imprisonment up to one year.[51] The PUCT has similarly broad investigatory authority. Either based on a complaint or upon its own initiative, the PUCT has investigatory authority to perform a fact-finding review. In doing so, the PUCT staff may contact a market participant and request an explanation of the activities in question. If after the initial review, the PUCT staff determine that there is evidence of a violation, the PUCT may conduct a formal investigation pursuant to Section 22.261 of the PUCT substantive rules.[52]

Since 2005, FERC has had civil penalty authority of up to $1 million per day, per violation for violations of the FPA, FERC regulations, or Orders (which includes violations of ISO/RTO tariff provisions).[53] FERC also can exercise its equitable authority to require disgorgement of profits as the minimum remedy for violations.[54] In addition, the FPA provides for criminal liability of up to $1 million and imprisonment of up to 5 years for individuals who

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46 *See* PURA § 39.151(d-1).

47 PURA §§ 39.155 & 39.157. PURA § 39.157 provides:

> On a finding that market power abuses or other violations of this section are occurring, the commission shall require reasonable mitigation of the market power by ordering the construction of additional transmission or distribution facilities, by seeking an injunction or civil penalties as necessary to eliminate or to remedy the market power abuse or violation . . ., by imposing an administrative penalty . . ., or by suspending, revoking, or amending a certificate or registration as authorized by Section 39.356.

48 FPA § 307, 16 U.S.C. § 825f.

49 *Id.*

50 *Id.*

51 *Id.*

52 *See* PUC SUBST. R. § 25.503.

53 FPA § 316A, 16 U.S.C. § 825o-l.

54 *Policy Statement On Enforcement*, Issued October 20, 2005, Docket No. PL06-1-000.

willfully violate the statute.[55] Moreover, individuals who willfully violate FERC's rules and regulations can be fined up to $25,000 for every day that the violation occurs.[56] The FPA also empowers courts to permanently or temporarily prohibit violators from engaging in the business of purchasing or selling electric energy or transmission services.[57]

Upon a finding of market power abuse and/or other violations, the PUCT may impose civil penalties as necessary to eliminate or remedy the market power abuse and/or violation.[58] Each day a violation occurs is a separate violation, and the PUCT may impose up to $25,000 in penalties per violation, per day.[59]

B. <u>FERC and PUCT Authority to Address Fraud, Manipulation and False Information.</u>

Although the Requestors are not seeking exemptions from the CFTC's anti-fraud or anti-manipulation authorities, it is important to note that the Requestors, Transactions and Participants are also subject to pervasive oversight by FERC and the PUCT for such prohibited conduct. As discussed above, the FPA and the implementing regulations, and PURA and the

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[55] FPA § 316, 16 U.S.C. § 825o.

[56] *Id.*

[57] FPA § 314, 16 U.S.C. § 825m.

[58] PURA § 39.157. PURA § 39.157(a) provides:

> For purposes of this subchapter, market power abuses are practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition, including practices that tie unregulated products or services to regulated products or services or unreasonably discriminate in the provision of regulated services. For purposes of this section, "market power abuses" include predatory pricing, withholding of production, precluding entry, and collusion. A violation of the code of conduct provided by Subsection (d) that materially impairs the ability of a person to compete in a competitive market shall be deemed to be an abuse of market power.

[59] In determining the amount of penalty, Section 22.246(c) of the PUCT substantive rules provides for consideration of the following factors:

> (A) the seriousness of the violation, including the nature, circumstances, extent, and gravity of any prohibited acts, and the hazard or potential hazard created to the health, safety, or economic welfare of the public;
>
> (B) the economic harm to property or the environment caused by the violation;
>
> (C) the history of previous violations;
>
> (D) the amount necessary to deter future violations;
>
> (E) efforts to correct the violation; and
>
> (F) any other matter that justice may require, including, but not limited to, the respondent's timely compliance with requests for information, completeness of responses, and the manner in which the respondent has cooperated with the commission during the investigation of the alleged violation.
>
> PUC SUBST. R. § 22.246(c).

PUCT substantive rules prohibit manipulative or deceptive practices in language similar to Section 6(c)(1) of the Act. FPA Section 221 prohibits the willful filing of false information relating to the price of electricity or the availability of transmission capacity.[60] PUC Rule 25.503 also protects consumers from unfair, misleading and deceptive practices and market power. These protections are effectuated by several means, including, but not limited to, specific prohibitions on fraud, misrepresentations, collusion or market power abuse.[61] The PUCT has specific authority to prevent market power abuse and to investigate any such behavior.[62]

FERC regulations applicable to electric markets prohibit, among other things, false or misleading information in any communications with FERC-approved market monitors, RTOs, or ISOs, and false or misleading reporting to publishers of price indices.[63] In addition to the prohibited activities described above, the PUCT substantive rules provide that Participants must provide accurate and factual information and "shall not submit false or misleading information, or omit material information, in any communication with ERCOT or with the [PUCT]."[64] Furthermore, Participants must provide "true, accurate, and reasonably complete" data and information to market publications and publishers of surveys and market indices and exercise due diligence to prevent the release of materially inaccurate or misleading information.[65]

C. Cooperation in Enforcing the Prohibitions on Fraud and Market Manipulation

The ISOs/RTOs and associated IMMs devote substantial resources to market surveillance and oversight, as do FERC, the PUCT and the CFTC. The FERC-regulated ISOs/RTOs refer to FERC's Division of Enforcement information that is developed in the course of their oversight of the markets regarding market anomalies or other indications that a possible violation has occurred. ERCOT and the ERCOT independent market monitor, established by the PUCT, reports directly to the PUCT and communicates any concerns it has regarding market design flaws or other issues it may observe in ERCOT's operations.[66]

In this regard, the ISOs/RTOs note that certain of the processes that they must follow in providing information relating to oversight of their markets and trading thereon are mandated to a large degree by the applicable statutory and regulatory authority, tariffs or protocols. Accordingly, although the intent of the ISOs/RTOs is to be responsive to the CFTC's requests for information and to assist the Commission as necessary in fulfilling its mission under the Act, the ISOs/RTOs must do so in accordance with the processes established by their tariffs or protocols. For example, certain of the tariffs may require that an ISO/RTO notify its members prior to providing information in response to a subpoena. Because the processes for responding

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60 FPA § 221, 16 U.S.C. § 824u.

61 PUC SUBST. R. § 25.503(g).

62 PURA § 39.157 and PUC Rule 25.503(l).

63 18 C.F.R. § 35.41.

64 PUC SUBST. R. § 25.503(f).

65 PUC SUBST. R. § 25.503(f).

66 PURA § 39.1515.

to requests for information from regulatory authorities is subject to FERC or PUCT oversight, the ISOs/RTOs note that insofar as the Commission may have needs for information from the ISOs/RTOs to fulfill its mission under the Act, such information would be available to the Commission under the procedures agreed upon by the agencies.

In response to provisions of the Energy Policy Act of 2005, the Commission and FERC entered into a memorandum of understanding (MOU) regarding the sharing of information and the confidential treatment of proprietary energy trading data on October 12, 2005.[67] As noted by the Commission's then-Chairman Reuben Jeffery, "[t]his MOU will result in a more effective and efficient working relationship with FERC. It will enable both agencies to work actively to assure the price integrity of the markets for natural gas and other energy products."[68]

Moreover, under section 720 of the Dodd-Frank Act,[69] the Commission and the FERC have been instructed by Congress to enter into a MOU to "share information that may be requested where either Commission is conducting an investigation into potential manipulation, fraud, or market power abuse in markets subject to each Commission's regulation or oversight." By adopting section 720 of the Dodd-Frank Act, Congress has provided a mechanism under which information relating to the markets operated by the ISOs/RTOs may be made available to the Commission. The ISOs/RTOs stand ready to cooperate in the arrangements for sharing such information under existing procedures and any new procedures that may be established under a future MOU. Similarly, we understand that the PUCT is prepared to work with the Commission to establish an appropriate information sharing process. By providing such information under arrangements agreed to jointly by the Commission and FERC or PUCT, the regulators will be able to ensure that they do not place conflicting legal obligations on the ISOs/RTOs.

VII. The Appropriate Person Requirement

Section 4(c)(2)(B)(i) of the Act requires that, in order to grant the exemptions requested herein, the Commission must determine that the agreements, contracts, or transactions that will be subject to the exemptions will be "entered into solely between appropriate persons." The term "appropriate persons," is defined for these purposes to include, *inter alia*, corporations or other business entities with net worth exceeding $1,000,000 or total assets exceeding $5,000,000."[70] "Appropriate persons," also includes "[s]uch other persons that the Commission determines to be appropriate in light of their financial or other qualifications, or the applicability of appropriate regulatory protections."[71]

In Order No. 741, FERC directed each of the ISOs/RTOs to establish minimum criteria for market participants.[72] FERC did not specify the criteria the ISOs/RTOs should apply, but

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67 http://www.cftc.gov/opa/press05/opa5127-05.htm.

68 *Id.*

69 Public Law No. 111–203, 124 Stat. 1376 (2010).

70 Section 4(c)(3)(F) of the Act.

71 *Id.* § 4(c)(3)(K).

72 FERC Order No. 741 at 131.

rather directed them to establish criteria through their stakeholder processes.[73] Accordingly, each of the FERC jurisdictional ISOs/RTOs submitted to FERC proposals to establish minimum criteria for participation in their markets. Although ERCOT is not subject to the requirements FERC's Credit Reform Orders, ERCOT is reviewing its participant eligibility standards to ensure that they are consistent with the requirements of Section 4(c). These proposals were accepted by FERC subject to a supplemental compliance filing to provide for verification of risk management policies and procedures.

Although there is some variation among the minimum participation criteria adopted by each ISO/RTO, included in each is a baseline capitalization requirement that participants have net worth of at least $1 million or total assets of at least $10 million.[74] Each ISO/RTO requires those entities not meeting the baseline capitalization requirement to post financial security.

The criteria of some ISOs/RTOs also reduce the financial security posting requirement for certain entities that maintain only small positions on the markets of the ISO/RTO and therefore expose the ISOs/RTOs to minimal risk. These entities are instead required to post additional financial security with the ISO/RTO in an amount that would depend on the size of their positions. In this regard, a notable number of participants in the markets of some ISOs/RTOs include cooperatives, municipalities or other forms of public corporate entities which are authorized to own, lease and operate electric generation, transmission or distribution facilities. Such entities' participation in the ISO/RTO may be necessary to make electricity available within the entire grid for a region. Nevertheless, they are "appropriate persons" because of their active participation in the generation, transmission or distribution of electricity and the knowledge of the wholesale energy market that they have as a consequence of their participation in the physical markets. Moreover, the municipal entities are entitled to recover their costs for native load service through governmentally established retail rates and, accordingly, are able to provide a form of financial security (*i.e.*, the ability to request a retail rate increase to cover increased costs) that is unavailable to other participants in the energy markets. As such, the risk of default by such entities is materially lower than it is for other Market Participants. As acknowledged by the CFTC Staff in comments on FERC Order No. 741, reducing the capitalization requirements for entities with small positions is necessary to ensure that traditional market participants, such as municipalities and cooperatives, continue to have access to the ISO/RTO markets.[75]

The minimum participation standards set by the ISOs/RTOs will enhance their efforts to ensure that all participants in their markets are "appropriate persons." All ISO/RTO market participants that do not meet the financial requirements of Section 4(c)(3)(F) of the Act should be determined by the Commission to be "appropriate persons" in light of their other

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[73] *Id*. at 132.

[74] ISO NE's proposal, for example, would exempt from this capitalization requirement entities that have a credit rating of BBB-/Baa3 or higher.

[75] March 29, 2010 letter from Ananda K. Radhakrishnan, Director, Division of Clearing and Intermediary Oversight, Commodity Futures Trading Commission regarding Credit Reforms in Organized Wholesale Electric Markets, Federal Energy Regulatory Commission Docket Number RM10-13-000, n. 19, *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12304687.

qualifications, including their traditional participation in the wholesale markets for electricity and the minimal degree of risk that they pose to the ISO/RTO markets.[76]

VIII. The Exemptions Will not Have a Material Adverse Effect on the Ability of the CFTC or any Contract Market to Discharge its Regulatory Function

The Commission's ability to discharge its statutory mandates will not be adversely affected by the requested exemptions. Under Section 4(d) of the Act, the Commission will retain authority to conduct investigations to determine whether Requestors are in compliance with any exemption granted in response to this request. As noted above, the requested exemptions would also preserve the Commission's existing enforcement jurisdiction over fraud and manipulation. This is consistent with section 722 of the Dodd-Frank Act, the existing MOU between the FERC and the Commission and other protocols for inter-agency cooperation. The Requestors will continue to retain records related to the Transactions, consistent with existing obligations under FERC and PUCT regulations.

The regulation of exchange-traded futures contracts and significant price discovery contracts ("SPDCs") will be unaffected by the requested exemptions. Futures contracts based on electricity prices set in the Requestors' markets that are traded on a designated contract market and SPDCs will continue to be regulated by and subject to the requirements of the Commission. No current requirement or practice of the ISOs/RTOs or of a contract market will be affected by the Commission's granting the requested exemptions.

IX. Conclusion and Proposed Exemptive Orders

As demonstrated above and set out in more detail in the Attachments hereto, FERC and PUCT impose on the Requestors, Transactions and Participants comprehensive regulation that is comparable to that of the Commission's Core Principles. Accordingly, this aspect of the regulatory framework applicable to the ISOs/RTOs is consistent with the public interest and the purposes of the Act as evidenced by the Core Principles with respect to markets and clearing organizations.

Despite this general comparability, there are, nevertheless, differences in the regulatory schemes administered by the Commission and FERC or PUCT that reflect the different missions with which they have been charged by Congress and the Texas legislature. In contrast to the Commission's role as a price neutral regulator, FERC's regulations and the rates, terms and conditions in ISO/RTO tariffs must satisfy the statutory standards of the FPA. Under the FPA, wholesale power rates of public utilities, including all charges under ISO/RTO tariffs, must be just and reasonable and not unduly discriminatory or preferential.[77] The FPA imposes an obligation on FERC to ensure that the markets administered by ISOs/RTOs meet this standard and do not result in rates or market charges that are unjust, unreasonable, unduly discriminatory or preferential.[78] Although FERC has significant discretion to determine how best to regulate

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[76] Section 4(c)(3)(K) of the Act.

[77] FPA §§ 201, 205, 206; 16 U.S.C. §§ 824, 824d(a), 824(e).

[78] *Id.*, § 824e(a).

ISO/RTO markets, the FPA requires that FERC only approve rates within a zone of reasonableness; FERC cannot approve market rules which could produce prices outside of such a zone.[79] FERC's approach to oversight of ISO/RTO markets reflects this statutory mandate. ERCOT is not subject to the FPA, but it is subject to the PURA and PUCT substantive rules, which impose comparable standards on the operation of the ERCOT market, including ensuring efficient markets and nondiscriminatory access for all buyers and sellers of electricity.

The exemptive Orders are being requested because, while FERC and the PUCT regulation is essentially comparable to that of the Act's Core Principles, there are differences in the details, as illustrated in the Attachments. The requested exemptive relief would ensure that the public interest in regulating these markets is met "in a manner so as to ensure effective and efficient regulation."[80] For these reasons, the proposed exemptions would be consistent with the public interest. Moreover, the Transactions would only be entered into between appropriate persons, and the Transactions will not have a material adverse effect on the ability of the Commission or any contract market to discharge its regulatory or self-regulatory duties under the Act.

Accordingly, the Requestors ask that the Commission issue Orders under section 4(c)(6) of the Act, in order to provide greater certainty with respect to the regulatory requirements that will apply to the Requestors, Transactions and Participants. The Requestors ask that the Commission grant the exemptions without determining whether: (1) the Transactions are swap, futures or option contracts within the meaning of section 1a of the Act; and (2) Requestors operate SEFs, DCMs or provide clearing services in connection with the Transactions.

The text of the Requested Orders is as follows:

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[79] *See, e.g.*, *Farmers Union Cent. Exchange, Inc. v. FERC*, 734 F.2d 1486, 1509 (D.C. Cir. 1984).

[80] *See* section 720 of the Dodd-Frank Act.

Order of the Commodity Futures Trading Commission Exempting Specified Instruments Under Section 4(c)(6) of the Commodity Exchange Act

(a) Scope.

This Order of Exemption shall apply to any contract, agreement or transaction:

(1) offered or entered into in a market pursuant to a Requesting Party's Tariff, such Tariff having been approved or permitted to take effect by;

(i) the Federal Energy Regulatory Commission, or

(ii) with respect to ERCOT, the Public Utility Commission of Texas; and

(2) which is for the purchase or sale of one of the following electricity-related products;

(i) FTRs, as defined in paragraph (b)(2);

(ii) Energy Transactions, as defined in paragraph (b)(3);

(iii) Forward Capacity Transactions, as defined in paragraph (b)(4)); or

(iii) Reserve or Regulation Transactions, as defined in paragraph (b)(5).

(b) **Definitions.**

(1) "Tariff" means a Requesting Party's "tariff," "rate schedule," "protocol" or "other governing document."

(2) "Financial Transmission Right" (FTR) means:

(i) A transaction, however named, that entitles one party to receive, and obligates another party to pay, an amount based solely on the difference between the price[81] for electricity, established on an electricity market administered by a Requesting Party, at a specified source (*i.e.*, where electricity is deemed injected into the grid of a Requesting Party) and a specified sink (*i.e.*, where electricity is deemed withdrawn from the grid of a Requesting Party). The term "FTR" includes Financial Transmission Rights, and Financial Transmission Rights in the form of options (*i.e.*, where one party has only the obligation to pay, and the other party only the right to receive, an amount as described above).

[81] "Price" can mean one or more components of a locational marginal price – e.g, energy, congestion, and losses, if and as applicable.

(ii) The FTRs to which this Order applies are those where:

(A) Each FTR is linked to, and the aggregate volume of FTRs for any period of time is limited by, the physical capability (after accounting for counterflow) of the electricity transmission system operated by a Requesting Party offering the FTR, for such period;

(B) The Requesting Party serves as the market administrator for the market on which the FTRs are transacted;

(C) Each party to the transaction is a member of the Requesting Party (or is the Requesting Party itself) and the transaction is executed on a market administered by that Requesting Party; and

(D) The transaction does not require any party to make or take physical delivery of electricity.

(3) "Energy Transaction" means transactions in a Day-Ahead Market or Real-Time Market for the purchase or sale of a specified quantity of electricity at a specified location (including Demand Response as described in paragraph 1(c)(ii)) where:

(i) The price of the electricity is established at the time the transaction is executed;

(ii) Performance occurs in the Real-Time Market by either,

(A) Delivery or receipt of the specified electricity, or

(B) A cash payment or receipt at the price established in the Real-Time Market; and

(iii) The aggregate cleared volume of both physical and cash-settled energy transactions for any period of time is limited by the physical capability of the electricity transmission system operated by a Requesting Party for that period of time.

(4) "Forward Capacity Transactions" means transactions in which a Requesting Party, for the benefit of load-serving entities, purchases any of the following rights:

(i) <u>Generation Capacity</u>: the right of a Requesting Party to require:

(A) Certain sellers to maintain the interconnection of electric generation facilities to specific physical locations in the electric-power transmission system during a future period of time as specified in the Requesting Party's Tariff (which includes a tariff, rate schedule or protocol);

(B) Such sellers to offer specified amounts of electric energy into the Day-Ahead or Real-Time markets for electricity transactions; and

(C) Subject to the terms and conditions of a Requesting Party's Tariff, such sellers to inject electric energy into the electric power transmission system operated by the Requesting Party;

(ii) Demand Response: the right of a Requesting Party to require that certain sellers of such rights curtail consumption of electric energy from the electric power transmission system operated by a Requesting Party during a future period of time as specified in the Requesting Party's Tariff; or

(iii) Energy Efficiency: the right of a Requesting Party to require specific performance of an action or actions that will reduce the need for generation capacity or demand response capacity over the duration of a future period of time as specified in the Requesting Party's Tariff.

In each case, the aggregate cleared volume of all such transactions for any period of time shall be limited to the physical capability of the electricity transmission system operated by a Requesting Party for that period of time.

(5) "Reserve or Regulation Transactions" means transactions:

(i) In which a Requesting Party, for the benefit of load-serving entities and resources, purchases through auction or as otherwise permitted by its Tariff, obtains the right, during a period of time as specified in the Requesting Party's Tariff, to require the seller of such right to operate electric facilities in a physical state such that the facilities can increase or decrease the rate of injection or withdrawal of a specified quantity of electricity into or from the electric power transmission system operated by the Requesting Party with:

(A) Reserve Transaction: physical performance by the seller's facilities within a response time interval specified in a Requesting Party's Tariff; or

(B) Area Control Error Regulation Transaction: prompt physical performance by the seller's facilities;

(ii) For which the seller receives, in consideration, one or more of the following:

(A) Payment at the price established in the Requesting Party's Day-Ahead or Real-Time Market price for electricity applicable whenever the Requesting Party exercises its right that electric energy be delivered (including Demand Response as described in 1(c)(ii));

(B) Compensation for the opportunity cost of not supplying or consuming electricity or other services during any period during which the Requesting Party requires that the seller not supply energy or other services;

(C) An upfront payment determined through the auction administered by the Requesting Party for this service;

(D) An additional amount indexed to the frequency, duration, or other attributes of physical performance as specified in the Requesting Party's Tariff; and

(iii) In which the value, quantity, and specifications of such transactions for a Requesting Party for any period of time shall be limited to the physical capability of the electricity transmission system operated by the Requesting Party for that period of time.

(6) "Day-Ahead Market" means an electricity market administered by a Requesting Party on which the price of electricity at a specified location is determined, in accordance with the Requesting Party's Tariff, for specified time periods, none of which is later than the second operating day following the day on which the Day-Ahead Market clears.

(7) "Real-Time Market" means an electricity market administered by a Requesting Party on which the price of electricity at a specified location is determined, in accordance with the Requesting Party's Tariff, for specified time periods within the same 24-hour period.

(8) "Requesting Party" means each of those Regional Transmission Organizations and/or Independent System Operators that submitted, on [Date] a request for exemption under Section 4(c)(6) of the Commodity Exchange Act.

(c) Exemption.

The Commission, pursuant to section 4(c)(6) of the Commodity Exchange Act, as amended (the "Act"), hereby exempts, subject to the conditions specified herein, the offer and sale of agreements, contracts, and transactions as specified in paragraph (b) of this Order and any person or class of persons offering, entering into, rendering advice, or rendering other services with respect thereto from all provisions of the Act and Commission regulations, except in each case sections 4b, 4o, 6(c) and 9(a)(2) of the Act to the extent that these sections prohibit fraud in connection with transactions subject to the Act, or manipulation of the price of any swap or contract for the sale of a commodity in interstate commerce or for future delivery on or subject to the rules of any registered entity, and from the requirement to provide information to the Commission as expressly permitted by their respective tariffs or protocols or as provided for under section 720 of the Dodd-Frank Wall Street Reform and Consumer Protection Act, 15 U.S.C. 8308.

Respectfully submitted,

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Addendum A

List of FERC Orders Regulating the ISOs/RTOs:

Pennsylvania-New Jersey-Maryland Interconnection, et al., 81 FERC ¶ 61,257 (1997) – order accepting proposals to restructure the PJM power pool as an Independent System Operator, including the implementation of locational marginal pricing and a proposal to establish Fixed Transmission Rights[82] (November 25, 1997)

Pacific Gas & Elec. Co., et al., 81 FERC 61,122 (1997) – order conditionally authorizing the California ISO to begin operations (October 30, 1997)

Central Hudson Gas & Electric Corp., et al., 86 FERC ¶ 61,062 (1999) – order accepting proposals to comprehensively restructure the wholesale electric market in New York and establish the NYISO, including proposals for Transmission Congestion Contracts, financial instruments that protect the holder from congestion costs when the system is constrained (January 27, 1999)

PJM Interconnection LLC, 87 FERC ¶ 61,054 (1999) – order accepting PJM proposal to auction Fixed Transmission Rights (April 13, 1999)

California Independent System Operator Corp., 87 FERC ¶ 61,143 (1999) – order accepting California ISO proposal for Firm Transmission Rights (May 3, 1999)

PJM Interconnection LLC, 91 FERC ¶ 61,148 (2000) – letter order accepting PJM procedures for a two-settlement system, which includes both day-ahead and real-time markets and the ability of market participants to submit increment and decrement bids for virtual supply and demand as a hedging tool (May 18, 2000)

ISO New England, Inc., et al., 91 FERC ¶ 61,311 (2000) – order accepting ISO-NE proposals for congestion management and multi-settlement systems, including explicit virtual demand bidding (June 28, 2000)

New York Independent System Operator, Inc., et al., 97 FERC ¶ 61,091 (2001) – order accepting virtual bidding proposal and related market mitigation measures (October 25, 2001)

New England Power Pool and ISO New England Inc., 100 FERC ¶ 61,287 (2002) – order accepting ISO-NE proposal for standard market design based on locational marginal

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[82] Different ISOs and RTOs use different terms to identify their respective financial transmission rights (“FTRs”) including fixed transmission rights, transmission congestion contracts, financial transmission rights, and congestion revenue rights.

pricing, including Financial Transmission Rights and both virtual supply and demand bidding (September 20, 2002)

Midwest Independent Transmission System Operator, Inc., 102 FERC ¶ 61,196 (2003) – order accepting MISO petition seeking approval of the principal components of market rules based on locational marginal pricing, including Financial Transmission Rights and virtual bidding in the day-ahead market (February 24, 2003)

Midwest Independent Transmission System Operator, Inc., 102 FERC ¶ 61,280 (2003) – order accepting market mitigation measures for virtual bidding (March 13, 2003)

PJM Interconnection, LLC, 104 FERC ¶ 61,309 (2003) – order accepting PJM credit requirements applicable to virtual bidding (September 22, 2003)

Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, 116 FERC ¶ 61,077 (2006) – final rule requiring Independent System Operators and Regional Transmission Organizations to make available long-term firm transmission rights, issued pursuant to section 1233(b) of the Energy Policy Act of 2005 (July 20, 2006)

California Independent System Operator, Inc., 116 FERC ¶ 61,274 (2006) – order accepting California ISO proposed tariff to implement a wholesale electric market design based on locational marginal pricing, including proposed terms for Congestion Revenue Rights (September 21, 2006)

Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681-A, 117 FERC ¶ 61,201 (2006) – order clarifying certain aspects of Order No. 681 (November 16, 2006)

PJM Interconnection, LLC, 117 FERC ¶ 61,220 (2006) – order accepting PJM proposal to establish Long-Term Transmission Rights (November 22, 2006)

Midwest Independent Transmission System Operator, Inc., 119 FERC ¶ 61,143 (2007) – order accepting MISO Order No. 681 compliance proposal for long-term firm transmission rights and modified rules to allocate short-term transmission rights (May 17, 2007)

California Independent System Operator, Inc., 120 FERC ¶ 61,023 (2007) – order accepting California ISO long-term firm transmission right proposal to comply with Order No. 681 (July 6, 2007)

ISO New England Inc. and New England Power Pool, 122 FERC ¶ 61,173 (2008) – order accepting ISO-NE long-term firm transmission right proposal to comply with Order No. 681 (February 25, 2008)

New York Independent System Operator, Inc., 123 FERC ¶ 61,044 (2008) – order accepting NYISO long-term firm transmission right proposal to comply with Order No. 681 (April 16, 2008)

Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008)

Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681-B, 126 FERC ¶ 61,254 (2009) – final rule affirming and clarifying certain aspects of Order Nos. 681 and 681-A (March 20, 2009)

PJM Interconnection, LLC, 126 FERC ¶ 61,280 (2009) – order accepting PJM proposal to allocate Auction Revenue Rights in connection with Long-Term Transmission Rights to comply with Order No. 681 (March 27, 2009)

New York Independent System Operator, Inc., 129 FERC ¶ 61,164 (November 20. 2009) - order accepting NYISO filing in compliance with Order 719

California Independent System Operator, Inc., 130 FERC ¶ 61,122 (2010) – order accepting California ISO's conceptual convergence bidding (*i.e.*, virtual bidding) design policy filing (February 18, 2010)

California Independent System Operator, Inc., 133 FERC ¶ 61,039 (2010) – order accepting California ISO tariff provisions to implement convergence bidding (October 15, 2010)

List of PUCT Orders Regulating ERCOT:

Application of the ERCOT ISO for Certification as an Independent Organization to Perform Transmission and Distribution Access, Reliability, Information Exchange, and Settlement Functions, Docket No. 22061, Final Order (January 31, 2001).

Proceeding to Approve a Program Administrator for the Renewable Energy Trading Program and to Develop Procedures for Registration and Certification of Renewable Energy Facilities, Project No. 22200, Final Order (May 10, 2000).

Petition of the Electric Reliability Council of Texas (ERCOT) for Approval of the ERCOT Protocols, Docket No. 23220, Final Order (March 14, 2001).

Rulemaking Proceeding on Wholesale Market Design Issues in the Electric Reliability Council of Texas, Project No. 26376, Final Order (September 22, 2003).

Rulemaking Proceeding Concerning Implementation of a Nodal Market Design for the Electric Reliability Council of Texas, Project No. 30160, Order Adopting Amendments to SUBST. R. 25.501 (October 29, 2004).

Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to Subst. R. 25.501, Docket No. 31540, Final Order (April 5, 2006).

Rulemaking Relating to the Accountability and Performance of the Electric Reliability Council of Texas, Project No. 38338, Order Adopting Amendments to PUC Subst. R. §§25.361, 25.362, and 25.363 (March 2, 2011).

CERTIFICATION PURSUANT TO 17 C.F.R. § 140.99(c)(3)(i) and (ii)

The undersigned hereby certifies that the material facts set forth in the attached Application for an Exemptive Order, dated as of February 7, 2012, and updated on June 11, 2012, are true and complete to the best of my knowledge.

Pursuant to Commodity Futures Trading Commission Rule 140.99(c)(3)(ii), California Independent Service Operator Corporation hereby undertakes that, if at any time prior to issuance of such order, any material representation made in this application by California Independent Service Operator Corporation ceases to be true and complete, it will promptly inform the Commission staff in writing of any change in facts and circumstances.

By:______________________ Dated: June 11, 2012
Name: Nancy Saracino
Title: VP and General Counsel
For California Independent Service Operator Corporation

CERTIFICATION PURSUANT TO 17 C.F.R. § 140.99(c)(3)(i) and (ii)

The undersigned hereby certifies that the material facts set forth in the attached Application for an Exemptive Order, dated as of February 7, 2012, and updated on June 11, 2012, are true and complete to the best of my knowledge.

Pursuant to Commodity Futures Trading Commission Rule 140.99(c)(3)(ii), Electric Reliability Council of Texas, Inc. hereby undertakes that, if at any time prior to issuance of such order, any material representation made in this application by Electric Reliability Council of Texas, Inc. ceases to be true and complete, it will promptly inform the Commission staff in writing of any change in facts and circumstances.

By: William Magness

Name: Bill Magness

Title: Vice President & General Counsel

For Electric Reliability Council of Texas, Inc.

Dated: June 11, 2012

CERTIFICATION PURSUANT TO 17 C.F.R. § 140.99(c)(3)(i) and (ii)

The undersigned hereby certifies that the material facts set forth in the attached Application for an Exemptive Order, dated as of February 7, 2012, and updated on June 11, 2012, are true and complete to the best of my knowledge.

Pursuant to Commodity Futures Trading Commission Rule 140.99(c)(3)(ii), ISO New England Inc. hereby undertakes that, if at any time prior to issuance of such order, any material representation made in this application by ISO New England Inc. ceases to be true and complete, it will promptly inform the Commission staff in writing of any change in facts and circumstances.

By:______________________________

Name: Raymond W. Hepper

Title: Vice President, General Counsel & Corporate Secretary

For ISO New England Inc.

Dated: June 11, 2012

CERTIFICATION PURSUANT TO 17 C.F.R. § 140.99(c)(3)(i) and (ii)

The undersigned hereby certifies that the material facts set forth in the attached Application for an Exemptive Order, dated as of February 7, 2012, and updated on June 11, 2012, are true and complete to the best of my knowledge.

Pursuant to Commodity Futures Trading Commission Rule 140.99(c)(3)(ii), Midwest Independent Transmission System Operator, Inc. hereby undertakes that, if at any time prior to issuance of such order, any material representation made in this application by Midwest Independent Transmission System Operator, Inc. ceases to be true and complete, it will promptly inform the Commission staff in writing of any change in facts and circumstances.

By:______________________________ Dated: June 11, 2012

Name: Matthew R. Dorsett

Title: Attorney

For Midwest Independent Transmission System Operator, Inc.

CERTIFICATION PURSUANT TO 17 C.F.R. § 140.99(c)(3)(i) and (ii)

The undersigned hereby certifies that the material facts set forth in the attached Application for an Exemptive Order, dated as of February 7, 2012, and updated on June 11, 2012, are true and complete to the best of my knowledge.

Pursuant to Commodity Futures Trading Commission Rule 140.99(c)(3)(ii), New York Independent System Operator, Inc. Corporation hereby undertakes that, if at any time prior to issuance of such order, any material representation made in this application by New York Independent System Operator, Inc. ceases to be true and complete, it will promptly inform the Commission staff in writing of any change in facts and circumstances.

By: Robert E. Fernandez / RK

Name: Robert E. Fernandez

Title: General Counsel

For New York Independent System Operator, Inc.

Dated: June 11, 2012

CERTIFICATION PURSUANT TO 17 C.F.R. § 140.99(c)(3)(i) and (ii)

The undersigned hereby certifies that the material facts set forth in the attached Application for an Exemptive Order, dated as of February 7, 2012, and updated on June 11, 2012, are true and complete to the best of my knowledge.

Pursuant to Commodity Futures Trading Commission Rule 140.99(c)(3)(ii), PJM Interconnection, L.L.C. hereby undertakes that, if at any time prior to issuance of such order, any material representation made in this application by PJM Interconnection, L.L.C. ceases to be true and complete, it will promptly inform the Commission staff in writing of any change in facts and circumstances.

By: Dated: June 11, 2012
Name: Vince Duane
Title: Vice President and General Counsel
For PJM Interconnection, L.L.C.

Attachment A

DCO Core Principle A: Compliance

(i) IN GENERAL.—To be registered and to maintain registration as a derivatives clearing organization, a derivatives clearing organization shall comply with each core principle described in this paragraph and any requirement that the Commission may impose by rule or regulation pursuant to section 8a(5).

(ii) DISCRETION OF DERIVATIVES CLEARING ORGANIZATION.—Subject to any rule or regulation prescribed by the Commission, a derivatives clearing organization shall have reasonable discretion in establishing the manner by which the derivatives clearing organization complies with each core principle described in this paragraph.

Responses:

The Requestors' practices are consistent with the Core Principles for DCOs. Given that the Requestors are principally regulated by FERC and the PUCT and the differences between the Requestors and registered DCOs, the Requestors in some cases achieve compliance with the Core Principles using different methods than those ordinarily employed by registered DCOs. This discretion is expressly permitted by Core Principle A(ii). As demonstrated below, the Requestors' practices and the comprehensive regulatory regime of FERC and the PUCT achieve the goals of and are consistent with the policies of the Act. Accordingly, the exemptions requested herein are in the public interest.

Attachment B—DCO Core Principle B: Financial Resources

(i) In General.—Each derivatives clearing organization shall have adequate financial, operational, and managerial resources, as determined by the Commission, to discharge each responsibility of the derivatives clearing organization.

(ii) Minimum Amount of Financial Resources.—Each derivatives clearing organization shall possess financial resources that, at a minimum, exceed the total amount that would—

> (1) enable the organization to meet its financial obligations to its members and participants notwithstanding a default by the member or participant creating the largest financial exposure in extreme but plausible market conditions; and
>
> (2) enable the derivatives clearing organization to cover operating costs of the derivatives clearing organization for a period of 1 year (as calculated on a rolling basis).

Responses:

Attachment B—DCO Core Principle B: Financial Resources

California ISO

The CAISO maintains adequate financial, managerial, and operational resources to discharge its responsibilities as an organized wholesale electricity market.

Managerial Resources

FERC Order No. 888 sets forth the principles used by FERC to assess ISO proposals and requires that ISOs have appropriate incentives for efficient management and administration, and that they should procure the services needed for such management and administration in an open competitive market.[1] Section 22.6 of the CAISO Tariff provides, in relevant part:

> The CAISO shall engage sufficient staff to perform its obligations under this CAISO Tariff in a satisfactory manner consistent with Good Utility Practice. The CAISO shall make its own arrangements for the engagement of staff and labor necessary to perform its obligations hereunder and for their payment. The CAISO shall employ (or cause to be employed) only persons who are appropriately qualified, skilled and experienced in their respective trades or occupations.

The CAISO bylaws require the CAISO to have certain officers, including a Chief Financial Officer.[2] The CAISO's governing documents do not otherwise specify the managerial or operational resources that must be available for any given function.

With respect to market participant credit, CAISO has two employees who report to the Manager, Credit and Corporate Insurance who reports to the Chief Financial Officer. The credit group uses a credit tracking system that determines whether a market participant has sufficient credit to submit bids, including convergence (i.e. virtual) bids and bids in Congestion Revenue Right ("CRR") auctions. This credit tracking system is integrated with a second software system, Oracle Financials, that CAISO uses as a credit repository to track the aggregate credit limit and Estimated Aggregate Liability (discussed below) for each market participant. Oracle Financials draws Estimated Aggregate Liability information from CAISO settlements and other market systems.

The CAISO credit group also subscribes to two services: Moody's KMV and Global Credit Services. It uses this information to set and periodically adjust unsecured credit limits and guaranty limits for market participants who are eligible for unsecured credit.

Financial Resources

The CAISO is revenue neutral with respect to all market transactions. To cover its operating costs, CAISO levies, on a monthly basis, a Grid Management Charge[3] comprised of

[1] *See* FERC Order No. 888 at pp. 283-824 (Apr. 24, 1996), *available at* http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt.

[2] *See* Amended and Restated Bylaws of California Independent System Operator, Article V.

[3] CAISO Tariff § 11.22.

four categories of costs: (1) CAISO Operating Costs; (2) CAISO Other Costs and Revenues; (3) CAISO Financing Costs; and (4) CAISO Operating and Capital Reserves Costs.[4] The Grid Management Charge is adjusted annually, based on expected costs for the following year, [5] and allocated to market participants based on the level of their usage of various services provided by CAISO.[6] The formulas used to calculate the Grid Management Charge are explained in Appendix F of the CAISO Tariff.

In its Policy Statement on Creditworthiness, Docket No. PL05-3-000 (2004), the FERC noted that, as non-profit entities that operate markets on behalf of their market participants, ISOs generally must socialize losses arising from a market participant's default across other market participants. Accordingly, the CAISO focuses on reducing the risk of such losses by assessing the creditworthiness of market participants and requiring market participants to have sufficient unsecured credit, to post financial security, or both, in an amount sufficient to cover their estimated liabilities at all times.

Operational Resources

The CAISO's markets and settlements are automated. The market systems and transactional data are protected by an electronic security perimeter with highly secured access points and two-factor authentication. The data and systems are backed up on a regular basis, through a process that is monitored.

Section 12 of the CAISO Tariff specifies the credit requirements for market participants. Each market participant has an obligation to maintain an aggregate credit limit that is at least equal to the market participant's estimated aggregate liability. The estimated aggregate liability is based on all charges and settlement amounts for which a market participant is liable or reasonably anticipated by CAISO to be liable.[7] The procedures for calculating the estimated aggregate liability are described in the CAISO Business Practice Manual for Credit Management.[8]

A market participant's aggregate credit limit can be established through an unsecured credit limit with CAISO, posting financial security with CAISO, or a combination of the two.[9] A market participant's unsecured credit limit is set by CAISO based on review of information about the market participant's financial health, including financial statements, Moody's KMV Estimated Default Frequency and credit ratings (when available).[10] Market participants are required to provide CAISO notice of any material change in their financial condition within five days after such a material change becomes known, or reasonably should become known, to the

[4] *Id*. § 11.22.2.

[5] *Id*. § 11.22.2.6.

[6] *Id*. §§ 11.22.5.1 – 5.9.

[7] *Id*. § 12.1.3.

[8] *See* Business Practice Manual for Credit Management, pp. 45-57, *available at* https://bpm.caiso.com/bpm/bpm/version/000000000000151.

[9] CAISO Tariff, Appendix A, definition of "Aggregate Credit Limit."

[10] *Id*. § 12.1.1.

market participant.[11] In lieu of or in addition to the establishment of an unsecured credit limit, a market participant may post financial security. Acceptable forms of financial security are enumerated in Section 12.1.2 of the CAISO Tariff.

Specific credit requirements are imposed for Congestion Revenue Rights ("CRRs") and for virtual bidding.[12]

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11 *Id*. § 12.1.1.5.

12 *Id*. §§ 12.6, 12.8.

Attachment B—DCO Core Principle B: Financial Resources

ERCOT

A. Organization and Resources

ERCOT's financial resources and related requirements are comparable to this core principle. The PURA, PUCT Substantive Rules and the Protocols authorize ERCOT to collect fees that are adequate to fund its operations so that it can satisfactorily fulfill its duties. PURA Section 39.151(e) authorizes ERCOT to charge a fee to cover its costs:

> [t]he commission may authorize an independent organization that is certified under this section to charge a reasonable and competitively neutral rate to wholesale buyers and sellers to cover the independent organization's costs.

Section 25.363 (c) of the PUCT Substantive Rules implements this authority:

> Allowable expenses. Expenses and capital outlays in the budget shall be based upon ERCOT's expected cost of performing its required functions as described in PURA § 39.151(a) and this chapter. To determine whether the costs are reasonable and necessary, the commission may consider the budget justification provided by ERCOT, the ERCOT long-term operations plan, costs incurred by market participants and other independent system operators for similar activities, costs incurred in prior years, capital projects identified in the budget, and to any other information and data considered appropriate by the commission. . . Only those expenses that are reasonable and necessary to carry out the functions described in PURA § 39.151 and this chapter shall be included in allowable expenses.

The fees authorized by PURA and the PUCT Substantive Rules are linked to ERCOT's functions, as established by both of those authorities.[13] One of ERCOT's specifically prescribed functions is managing credit.[14] ERCOT's other core functions, established pursuant to PURA § 39.151(a)(1)-(4), include:

- ensuring access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms;

- ensuring the reliability and adequacy of the regional electric network;

[13] PURA § 39.151(e); P.U.C. SUBST. R. 25.363(c).

[14] P.U.C. SUBST. R. 25.361(b)(2).

- ensuring that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to the persons who need that information; and

- ensuring that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region.[15]

Bullet points (1) and (4) above encompass the concept of equitable accounting for credits and charges, which necessarily assigns credit and/or obligations to the appropriate parties (*i.e.*, to those Market Participants entitled to credits and/or obligated to pay for charges). To facilitate this result, ERCOT must implement appropriate credit measures to make sure Market Participants can manage their obligations under reasonably foreseeable circumstances.

These statutory functions are incorporated in PUCT regulations and the ERCOT Protocols.[16] Section 25.361(b) of the PUCT Substantive Rules, which is reproduced in the ERCOT Protocols, states in relevant part:

> Functions. ERCOT shall perform the functions of an independent organization under the PURA § 39.151 to ensure access to the transmission and distribution systems for all buyers and sellers of electricity on nondiscriminatory terms; ensure the reliability and adequacy of the regional electrical network; ensure that information relating to a customer's choice of retail electric provider is conveyed in a timely manner to the persons who need that information; and ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region. ERCOT shall . . . administer settlement and billing for services provided by ERCOT, including assessing creditworthiness of market participants and establishing and enforcing reasonable security requirements in relation to their responsibilities under ERCOT rules[.][17]

As noted above, Section 25.363(c) authorizes ERCOT to collect a fee to perform its functions. Accordingly, because managing credit risk is one of its specifically prescribed functions, ERCOT is allowed to include the costs associated with performing this function in the fee charged to support the operations of the organization.

Moreover, ERCOT Executive Management, Human Resources and the ERCOT Enterprise Risk Management group, which includes the credit function, annually assess staffing and budget needs to ensure the Enterprise Risk Management group has adequate resources to

[15] Public Utility Regulatory Act, TEX. UTIL. CODE ANN. § 39.151 (Vernon 1998 & Supp. 2005) (PURA).

[16] P.U.C. SUBST. R. 25.361(b) and Protocol Section 1.2(1), respectively.

[17] P.U.C. SUBST. R. 25.361(b) (emphasis added).

perform its functions, as prescribed by the PUCT Substantive Rules, and specifically implemented by the ERCOT Protocols and other relevant documents, such as the ERCOT Credit Policy. Presently, the Enterprise Risk Management group is staffed with nine full time employees.

As discussed above, ERCOT's core functions drive the fee it charges to support its functions, including credit and risk management. Section 1.2 of the Protocols prescribes ERCOT's core functions and supports the fee charged by ERCOT to fund its credit and risk management functions. ERCOT submits its budget and associated fees to the PUCT for approval.[18]

Section 9 of the Protocols provides procedures to mutualize default risk across ERCOT's markets.[19] These procedures support ERCOT's ability to fund its operations by ensuring such costs are not borne by ERCOT, and, therefore, do not affect the adequacy of ERCOT's fee to fund its operations and functions. This also ensures that ERCOT can meet its financial obligations to its Market Participants. ERCOT members agree to be subject to the relevant settlement procedures by executing the Standard Form Market Participant Agreements, which binds them to comply with the Protocols, including the mutualized risk process (*i.e.*, short-pay and uplift) prescribed by Section 9.

ERCOT's Financial Corporate Standard is a Board-approved standard, but it is not referenced in the ERCOT Protocols. ERCOT's Financial Corporate Standard requires ERCOT to:

- Provide a five year strategic plan in conjunction with its annual budget;
- Maintain an investment grade rating;
- Fund at least 40% of its capital expenditures with revenues; and
- Maintain adequate liquidity to meet its operating needs.

B. Minimum Amount of Financial Resources and Recovery of Operating Costs

ERCOT's requirements regarding its minimum amount of financial resources are comparable to this core principle. ERCOT does not fund market defaults. Defaults are funded by market participants.[20]

ERCOT collateralizes the estimated exposure for counterparties, including CRR Account Holders ("CRRAHs") through the application of credit rules approved by the market participants

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[18] P.U.C. SUBST. R. 25.363(d).

[19] ERCOT Protocol Section 9.19(e) and 9.19.1. The short-pay and uplift process discussed in ERCOT Protocol Section 9.19(e) and 9.19.1 are the "mutualized risk" process for ERCOT.

[20] ERCOT Protocol Section 9.19(e) and 9.19.1.

and by ERCOT's Board of Directors. These rules require counterparties to post collateral for 100 percent of a counterparty's estimated exposure, less any approved unsecured credit.[21]

ERCOT updates its credit and collateral requirements on a daily basis based on recent historical data. Because financial transmission rights are sold based on the most updated system model at that time and are updated based on recent historical data, collateral obligations are always based on plausible system conditions.

If a default occurs and there is inadequate collateral for a particular participant, a short payment, if any, is handled in a two step process.

- First, all Market Participant Invoice Recipients due a credit are "short-paid" on a pro rata basis.
- Second, approximately six months later, short-paid entities will be reimbursed when the cost of the short-pay is uplifted or socialized across the market. ERCOT calculates an allocation factor for each Counter-Party (parent entity to the QSEs and CRRAHs) with activity in the month prior to the default month using data from the calendar month prior to the month in which the default occurred.[22]

In addition, as explained above, the PURA, PUCT Substantive Rules and ERCOT Protocols authorize ERCOT to collect fees that are adequate to fund its operations such that it can satisfactorily fulfill its duties.

ERCOT also maintains a Financial Corporate Standard that requires ERCOT, Inc. to: (a) provide a five year strategic plan in conjunction with its annual budget; (b) maintain an investment grade rating; (c) fund at least 40 percent of its capital expenditures with revenues; and (d) maintain adequate liquidity to meet its operating needs.[23] This standard is reviewed and updated annually by its Board of Directors. ERCOT uses a mix of fees and debt capacity to meet these requirements. ERCOT's Financial Corporate Standard presently requires liquidity based on: (1) six months of forecasted Scheduled Debt Service, other than principal payments reasonably expected to be refinanced; (2) two months of average Cash Operating and Maintenance Expenses, net of projected administrative fee receipts; (3) two months of budgeted project expenditures; and (4) to the extent CRR auction revenues have been utilized to fund ERCOT working capital and project expenditure needs, two months of estimated CRR repayment obligations expected to be paid, net of projected CRR auction receipts during the same period.

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21 ERCOT Protocol Section 16.11.1.

22 ERCOT Protocol Section 9.19(d) and 9.19.1.

23 ERCOT Corporate Standard CS3.1, *Financial Corporate Standard*, at Section 3.0.

Attachment B—DCO Core Principle B: Financial Resources

ISO New England

ISO-NE has adequate financial, operational, and managerial resources to discharge its responsibilities as (i) the operator of New England's bulk transmission system, (ii) developer and administrator of New England's wholesale electricity markets and (iii) New England's power system planner.

Financial Resources

ISO-NE possesses financial resources to meet its financial obligations to its members. The ISO's obligations are set out in its contracts with its participants, including the Market Participant Service Agreement, Participants Agreement and Transmission Operating Agreement. In turn, Section IV.A of the Transmission, Markets and Services Tariff establishes a mechanism through which the ISO recovers its expenses to fulfill these obligations. Section IV.A.2 provides that, "Section IV.A of the Tariff is the means by which the ISO collects the revenues necessary to carry out its administrative functions in each calendar year, and contains rates, charges, terms and conditions for the following Services, which together encompass the functions carried out by the ISO: (1) Scheduling, System Control and Dispatch Service (Schedule 1 hereto); (2) Energy Administration Service (Schedule 2 hereto); and (3) Reliability Administration Service (Schedule 3 hereto)." Schedule 2, for Energy Administration Service, is the mechanism for collecting ISO's expenses for "the functions required to provide" Energy Administration Service. These functions include, but are not limited to: billing preparation; market power monitoring and mitigation for the Energy Market; sanctions activities; operation of FTR auctions; and market assessment and reports.

Each year, ISO-NE establishes a budget necessary to fulfill its obligations for the subsequent year. This budget is approved by ISO-NE's independent Board of Directors after review with stakeholders, and is ultimately filed with FERC, which approves the justness and reasonableness of the budget. Once established, the amount of this budget is recovered through the rates set forth in Section IV.A of the Tariff.

ISO-NE also files annually, in advance of the operating year, revised tariff rates to enable ISO-NE to collect its revenue requirement from participants. *See* Tariff Section IV.A.2.1. The annual revenue requirement includes significant contingency funds.

Thus, ISO-NE's Tariff includes provisions that ensure that ISO-NE will recover its expenses, even, as discussed below in "Default Resources," in the event of a significant participant default.

Default Resources

Defaults are socialized after realizing any collateral specific to the defaulting participant, late payment funds, funds in the payment shortfall account and possible insurance claims paid for protracted defaults. *See* Billing Policy, Exhibit ID of the Tariff. Further, a default by an ISO-NE market participant is shared by like market participants. *See* Billing Policy, Exhibit ID of the Tariff, Section 3. Thus, the risk to ISO-NE is minimal.

ISO-NE also maintains third party default insurance provided by Atradius Trade Credit Insurance Inc., which holds an A- Issuer Credit Rating by A.M. Best Company. Obligations of all Market Participants extended unsecured credit by the ISO are covered under this credit policy, which carries a limit of annual liability of $117,000,000 with a $500,000 annual aggregate deductible. The policy insures ISO-NE against losses due to insolvency, default and other contingencies. *See* Section IX of the Financial Assurance Policy.

Further, ISO-NE maintains Late Payment Accounts as a cushion against defaults up to $1 million. It is funded with penalty fees paid by participants that make late payments, and accrued interest. *See* Section 4 of the Billing Policy. Last, ISO-NE has third party financing to provide short-term financing of a Payment Default Shortfall Fund. *See* Section 5 of the Billing Policy.

Operating Resources

As noted above, ISO-NE fulfills three primary responsibilities. As system operator, ISO-NE is the independent entity that centrally operates an integrated electric power system that generates and transmits electricity over a high-voltage electric power system. In New England, thousands of miles of transmission lines span the six states, moving electricity from power plants, distribution resources and connections with neighboring power systems to the companies that deliver the electricity to consumers. ISO New England owns none of the infrastructure—power plants, transmission lines, or other power resources.

From the state-of-the-art control room, certified system operators consider a large number of variables that can at any moment affect the production and flow of electricity across the grid to ensure enough power is generated and gets to where it is needed. ISO-NE monitors power plants for unexpected outages and transmission lines for overloads, and it tracks weather and other events to forecast electricity demand. In case of an emergency outage or increased demand due to changes in weather, the operators also can call on reserves—power plants and resources on standby and ready to produce power at a moment's notice. The market rules for the reserve markets are located at Section III.9 and III.10 of the Tariff. For a broader overview of ISO-NE's reserve markets, see also the presentation at http://www.iso-ne.com/support/training/courses/wem101/16_reserve_mkt_overview_and_settlements.pdf.

ISO-NE also can call on manufacturers and businesses to cut their electricity use temporarily. These are known as Real-Time Demand Response ("RTDR") Resources and Real-Time Emergency Generation ("RTEG") Resources. RTDR and RTEG Assets are individual end-use customers that a demand response provider aggregates into a RTDR and RTEG Resource, respectively. RTDR and RTEG Resources are required to reduce consumption when dispatched by the ISO in response to RTDR and RTEG Event Hours, respectively. Definitions of all of these terms are in Section I.2.2. of the Tariff. Section III.13.1.4.5. defines the dispatch of RTDR and RTEG Resources. For a broader overview of ISO-NE's demand response programs, see also the presentation at http://www.iso-ne.com/support/training/courses/wem101/18_overview_of_dr_in_iso-ne_markets.pdf, which provides an overview of ISO-NE's demand response programs. ISO-NE may also limit exports to neighboring grids if power supplies are constrained within New England. See Section III.1.11.4 of the Tariff.

Attachment B—DCO Core Principle B: Financial Resources

ISO-NE is also the developer and administrator of the wholesale electricity markets in New England. Through competitive bids, the energy market produces a price for approximately 900 locations across the region's grid. Several other wholesale electricity products are bought and sold through wholesale markets to ensure real-time and long-term reliability of the power system. "Capacity" is a market product that ensures that the power system has adequate resources to meet demand for electricity now and in the future. "Ancillary services" are a group of market services that ensure reliability of the power system at all times and especially during periods of heavy demand or system emergencies. Load servers and suppliers must buy these products, along with the electric energy, from power plants and other resources. New England's markets are designed to produce accurate and transparent price signals, while providing a level playing field that encourages participation by a mix of diverse entities and interests. ISO-NE regularly modifies the market rules, which includes a process of consultation with stakeholders and approval of all changes by FERC, to enhance the efficiency of the markets and to stay in step with technological and resource developments.

As system planner, ISO-NE performs comprehensive power system analysis and transmission planning to ensure that the region has adequate infrastructure over the long term. ISO-NE identifies electricity consumption patterns and growth; adequacy of resources to meet demand; and issues related to power plant fuel supplies, fuel diversity, environmental requirements, and integration of new technologies. ISO-NE also responds to requests for economic analysis of various resource-expansion scenarios.

ISO-NE has many other responsibilities. Some are technical, such as coordinating how power plants, transmission lines and other resources connect to and operate on the grid, and managing resource registration and performance auditing. Others involve interaction with stakeholders to manage an extensive, open process for developing the rules that govern ISO-NE's three functions. Moreover, ISO-NE processes and produces vast amounts of data (most notably, day-ahead and real-time energy prices) for hundreds of locations across the grid, every five minutes and hourly. The pricing data is made publicly available. Financially, ISO-NE clears the markets and provides billing services to the buyers and sellers of wholesale electricity. In terms of analysis and monitoring, ISO-NE issues weekly, monthly, quarterly, and annual markets reports on a variety of topics, and monitors market behavior and performance to ensure participants' compliance with the market rules and that the markets are fair, competitive and free of manipulation. ISO-NE provides technical support and training to help companies engage in business in a highly sophisticated and complex marketplace. Last, ISO-NE's employees provide all of the other functions necessary for the operation of a business, including legal, human resources, and communications.

In sum, ISO-NE has one facility in New England that houses its approximately 500-person workforce of power system engineers, economists, computer scientists and others who fulfill ISO-NE's three critical responsibilities. ISO-NE has complete financial independence from companies doing business in the marketplace, which is crucial to making sure the markets are fair and competitive, and that the power system is operated and coordinated objectively.

Attachment B—DCO Core Principle B: Financial Resources

MISO

A. Organization and Resources

MISO is a non-stock, not-for-profit organization managed by an independent Board of Directors and officer team pursuant to the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. (hereinafter referred to as the "MISO Agreement" or "Transmission Owners Agreement" in subsequent attachments). MISO operates two operational control centers, one in Carmel, Indiana and one in St. Paul, Minnesota. In addition, MISO maintains a back-up operational control center capable of carrying out the full operations of MISO if necessary.

B. Financial Resources and Recovery of Operating Costs

As a not-for-profit organization, MISO remains revenue neutral with respect to all market transactions. As such, the amount of money MISO pays out to market participants for the settlement of market transactions is limited to the amount of money it collects from market participants for the settlement of market transactions. See Section 7 of and Attachment L to the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff (hereinafter referred to as the "Tariff" in subsequent attachments). In the event that payments received from Market Participants that owe funds are less than payments due to Market Participants that are net owed funds, MISO will (a) allocate the deficit *pro rata* to Market Participants that are net owed funds; and (b) upon deeming such amounts as uncollectible, uplift the deficit to all Market Participants based on respective activity for the applicable billing period. See Section 7 of the MISO Tariff. Tariff, Sections 7.8(b) P.1 and 7.10 P.1 of Tariff

MISO recovers its operating costs through cost recovery rate calculations set forth in the MISO Tariff and approved by FERC. The operating costs of MISO are allocated to the specific services MISO provides to its members and market participants. Generally, these costs are allocated to members and market participants through Schedules 10, 16 and 17 of the MISO Tariff. Schedule 10 of the Tariff provides for recovery of operating costs associated with providing transmission service, reliability related services and other general services. Schedule 16 of the Tariff provides for recovery of operating costs associated with the provision of Financial Transmission Rights ("FTRs") and Schedule 17 provides for the recovery of costs associated with the administration of MISO's energy and operating reserve markets. See generally, Schedules 10, 16 and 17 to the MISO Tariff. Tariff Schedule 10, Section II.A, P. 1; Schedule 16, Section I, Ps. 1 and 2; Schedule 17, Section I, Ps. 1 and 2. The cost recovery adders in these schedules are adjusted each month based on expected costs for the following month and true-up costs from the prior month.

Attachment B—DCO Core Principle B: Financial Resources

New York ISO

A. Financial Resources

The NYISO is a New York not-for-profit corporation that is revenue neutral with respect to all market transactions.[24] NYISO Market Participants make payments into and receive payments from a clearing account operated by the NYISO as trustee for the benefit of Market Participants. *See* Services Tariff Section 7.1; OATT Section 2.7.1. The NYISO does not take title to funds held in the ISO Clearing Account or commingle those funds with its operating funds. *See* Services Tariff Section 7.1; OATT Section 2.7.1. As such, Market Participant transactions do not create payment obligations to or from the NYISO in its own right.

As trustee of the ISO Clearing Account, the NYISO's obligation to pay Market Participants is limited to the amount of money Market Participants pay into the ISO Clearing Account. Further, NYISO Services Tariff Section 7.2.3.4 requires the ISO to pay "all net monies owed to a [Market Participant] in its weekly invoice or monthly invoice from the ISO Clearing Account…." In the event there are insufficient funds in the ISO Clearing Account to pay all net monies owed to a Market Participant on the date those monies are due, the NYISO could short-pay Market Participants to the extent sufficient funds are not available in the ISO Clearing Account.[25]

On April 30, 2012 the NYISO submitted proposed tariff revisions to FERC, in compliance with FERC Order No. 741, that if accepted will modify the tariff provisions referenced in the two preceding paragraphs and establish the NYISO as the single counterparty to Market Participant transactions. The NYISO, as the counterparty, will take title to the products that are the subject of the transactions it administers. By taking title, payment obligations will flow to or from the NYISO in its own name and right. To protect the NYISO against insolvency, the NYISO also proposed tariff revisions to limit the NYISO's liability for monies owed to Market Participants for a given settlement period to the amount the NYISO recovers from Market Participants for that settlement period plus the amount of Market Participant monies held by the NYISO in its Working Capital Fund. A copy of this filing is available at: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2012/04/NYISO_Order_741_Tariff_Filing_all_docs_4-30-12.pdf. The NYISO requested a July 1, 2012 effective date for these tariff revisions.

In addition, as discussed in detail in Attachment C, *infra,* all NYISO Market Participants are required to maintain sufficient unsecured credit and/or post financial security that is sufficient to ensure that their expected financial obligations are covered at all times. *See* Services Tariff Sections 26.4.1and 26.6 (first paragraph).

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24 Capitalized terms in the NYISO's responses that are not otherwise defined in this letter have the meanings set forth in the NYISO's Open Access Transmission Tariff ("OATT") and the NYISO's Market Administration and Control Area Services Tariff ("Services Tariff").

25 *See* Services Tariff Section 7.2.3.4. The NYISO interprets the requirement to pay Market Participants "from the ISO Clearing Account" as limiting the NYISO's payment obligation to the amount of money held in the ISO Clearing Account.

Further, as discussed in detail in Section B below, the NYISO also maintains a Working Capital Fund (with funds contributed by Market Participants) that the NYISO may use to cover Market Participant non-payments or to temporarily offset imbalances in NYISO cash flows. *See* OATT Section 28. Currently, the Working Capital Fund has an available balance of $33 million. The NYISO also maintains a revolving credit facility that the NYISO may use to temporarily offset imbalances in NYISO cash flows. Currently, the NYISO can draw on the revolving credit facility up to $50 million.

B. NYISO Mechanisms to Maintain Liquidity and Fulfill Payment Obligations in the Event of Default

In the event of a payment default, the NYISO takes action in accordance with Services Tariff Section 7.5 and OATT Section 2.7.5, as discussed in detail in Attachment G, *infra*. Notwithstanding the fact that the NYISO has the right to short-pay, if necessary, the NYISO has also developed mechanisms to maintain market liquidity by avoiding short-payment in the event of a default. In addition to having the right to draw upon the defaulting Market Participant's collateral, the NYISO has the ability to offset temporary imbalances in cash flow, and thereby pay Market Participants in full, by drawing upon its Working Capital Fund (currently $33 million) and/or its revolving credit facility (currently $50 million). *See* OATT Section 28.6.2. The NYISO will then replenish these funds with amounts recovered from the defaulting Market Participant or through the NYISO's bad debt loss mutualization tariff provisions. *See* OATT Section 27.3; Attachment G, *infra*.

On October 1, 2011, in compliance with FERC Order No. 741, the NYISO shortened its settlement cycle from a monthly cycle to a weekly cycle. This transition to a weekly settlement cycle decreased the NYISO's market exposure by approximately 68% by reducing the settlement cycle from 50 days to 16 days. In November 2011, in recognition of this decreased risk, the NYISO reduce its Working Capital Fund reserve from $46.5 million to $33 million.

Under the NYISO's historical monthly invoicing system, the $96.5 million previously available to the NYISO to maintain liquidity ($46.5 million in the Working Capital Fund and $50 million in the credit facility) was over and above funds held as collateral on behalf of individual Market Participants and sufficiently covered any historical shortfalls in cash flow resulting from Market Participant payment defaults. Since the NYISO's inception in 1999, only five Market Participants have ever had monthly invoices in excess of $96.5 million. Four of those Market Participants are traditional utility companies (*i.e.,* transmission owners, generators, LSEs, and energy service companies) and all five have timely payment histories.

Under the NYISO's current weekly invoicing system, the NYISO has approximately $83 million available to offset temporary shortfalls in cash flow ($33 million in the Working Capital Fund and $50 million in the credit facility), which amount is over and above funds held as collateral on behalf of individual Market Participants. At the same time, Market Participant weekly payment obligations are approximately 25% of prior monthly invoice amounts. This $83 million reserve provides the NYISO with more than sufficient funds available to cover the largest potential default based on historical data (i.e., 25% of the largest single invoiced amount in NYISO history).

Nonetheless, in the unlikely event that an uncollateralized default were to exceed the funds available to the NYISO through the Working Capital Fund and credit facility, the NYISO tariff provisions would permit the NYISO to short-pay Market Participants to the extent necessary.

C. Operational Resources

The NYISO operates in accordance with an annual budget. The annual budget is approved by the NYISO Board of Directors ("Board") pursuant to Section 5.08 of the New York Independent System Operator Agreement ("ISO Agreement"),[26] following consultation with NYISO Market Participants pursuant to Section 7.02 of the ISO Agreement. The NYISO recovers its annual budget pursuant to Section 6.1.2 of Schedule 1 of the NYISO OATT.

In accordance with these provisions, the NYISO recovers its annual budget through a weekly charge that allocates anticipated annual costs to Market Participants through a fixed rate. The categories of recoverable operating costs are described in Schedule 1 of the OATT. The fixed rate is adjusted annually based on the anticipated annual operating costs and the anticipated volume of market transactions. A Market Participant default should not impair the NYISO's ability to cover its operating costs because the NYISO will continue recovering from all other Market Participants sufficient funds to pay its operating expenses. In addition, as stated in Section A above, the NYISO segregates its operating funds from its ISO Clearing Account funds and is obligated to pay Market Participants only with those funds available in the ISO Clearing Account.

D. Managerial Resources

Section 5.08 of the ISO Agreement establishes that the Board has the ultimate responsibility for the operation of the NYISO. The NYISO is governed by a 10-member Board whose members have backgrounds in the power industry, finance, academia, technology, communications and the law. Pursuant to its authority under Section 5.08 of the ISO Agreement, the Board has established the organizational structure of the NYISO.

Reporting directly to the NYISO CEO (who reports to the Board) are the following:

- Senior Vice President and Chief Operating Officer;
- Senior Vice President and Chief Information Officer;
- Senior Vice President, Market Structures;
- Vice President and Chief Financial Officer;
- Vice President, Enterprise & Customer Services and Chief Compliance Officer;
- Vice President, System and Resource Planning;
- Vice President, External Affairs;
- General Counsel;
- Director, Internal Audit;

[26] The ISO Agreement is available on the NYISO's website(click on "NYISO Agreement") at: http://www.nyiso.com/public/markets_operations/documents/legal_regulatory/index.jsp.

- Director, Market Mitigation and Analysis;
- Executive Regulatory Policy Advisor;
- Senior Advisor; and
- Board Secretary and Corporate Secretary.

The NYISO's organizational structure also includes an Internal Audit Department that reports directly the NYISO Board. Within this organizational framework, the NYISO employs a diverse, well-educated and well-trained workforce of approximately 500 individuals.[27] Given the technical complexity of the NYISO's operations, many NYISO employees possess Master's degrees or PhDs.

Most involved with the NYISO's financial resources is the Finance Department, managed by the Chief Financial Officer. The Finance Department is responsible for accounting, budgeting, treasury, credit, contract administration, procurement, and settlements processes and controls. The NYISO's Credit Manager reports to the Chief Financial Officer and oversees the day-to-day credit and credit-related risk management activities. The Credit Manager is supported by four employees who assist with the monitoring of the NYISO's credit risks.

[27] NYISO management views employee training and education as critical to the success of its operations. NYISO employees receive annual training on the NYISO's Code of Conduct and compliance obligations through Intranet-based courses. In addition, day-long compliance training sessions are held for all management personnel, including officers, directors, managers and supervisors. These training sessions address a range of topics pertinent to the NYISO's overall Compliance Program, including, data security, record retention, and business ethics.

Attachment B—DCO Core Principle B: Financial Resources

PJM

A. Organization and Resources.

PJM[28] does not view itself as operating a clearing organization in the sense sought to be regulated by the CEA. Nevertheless, PJM's financial, operational, and managerial resources are sufficient for it to perform its functions as a FERC-approved RTO. PJM operates pursuant to FERC-approved market rules, including the PJM Open Access Transmission Tariff ("PJM Tariff") and the PJM Operating Agreement ("PJM OA"), and a FERC-approved credit policy ("Credit Policy") that require its members to post collateral.

Sections 9 and 10 of the PJM OA set forth the requirements related to PJM's managerial and operational resources. Section 9 stipulates the minimum number of PJM officers and their primary responsibilities, including those of the Treasurer to whom both PJM's credit and risk management departments report. Further, Section 10.4 requires PJM's President to "[m]aintain an appropriately trained workforce" to fulfill all of PJM's responsibilities in the PJM OA and PJM Tariff. For example, PJM's Credit Policy includes several references to credit application reviews, unsecured credit allowance evaluations, credit monitoring, and other responsibilities for which PJM must maintain an appropriately trained workforce. Per the PJM OA and PJM Tariff, PJM employs engineering and financial professionals to administer, bill and provide settlement services for the markets that PJM administers.[29]

PJM's credit department includes a credit manager and three credit analysts. Additionally, PJM's Chief Financial Officer approves collateral reductions and returns and any collateral calls based on the material adverse change provisions of PJM's Credit Policy. Below are brief summaries of the knowledge, skills and abilities of the PJM personnel responsible for administering PJM's Credit Policy:

- Chief Financial Officer – 25 years of accounting and financial experience, including public accounting, budget and analysis, financial management, treasury and credit management responsibilities; 13 years with PJM, including over six years as the executive responsible for the credit function; holds a Bachelor of Science in Accounting from Lehigh University and a Master of Business Administration from The Wharton School at the University of Pennsylvania.

- Credit Manager – Five years electrical engineering experience followed by 25 years of financial experience, including 19 years in the electricity industry with

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28 PJM as used here is intended to include PJM Interconnection, L.L.C. and PJM Settlement, Inc., which is a separate corporate entity that serves as the counterparty to transactions in PJM markets.

29 *See* PJM OA, Section 10.1 (establishment of the Office of Interconnection); Section 10.4 (requiring the Office of Interconnection to, among other things, "[m]aintain an appropriately trained workforce, and such equipment and facilities, including computer hardware and software and backup power supplies, as necessary or appropriate to implement or administer this Agreement."); Schedule 1, Section 3.2.7 (establishing billing procedures for the spot energy market); Schedule 1, Section 3.4.3 (establishing billing procedures for transmission customers); PJM Tariff, Section 7 (same).

the last 13 years specifically engaged in electricity industry credit; ten years with PJM as Credit Manager; holds a Bachelor of Science in Electrical Engineering from Syracuse University and a Master of Business Administration from the Darden School at the University of Virginia; currently pursuing a Master of Science in Finance at Penn State University.

- Senior Credit Analyst – 30 years of energy industry experience including 15 years financial analysis and another three years credit analysis; holds a Bachelor of Business Administration in Finance from Texas Christian University and a Master of Business Administration from the University of Houston; Certified Public Accountant in Texas.

- Senior Credit Analyst – Fourteen years of credit analysis including 11 years with PJM as a Senior Credit Analyst; holds a Bachelor of Science in both Economics and Marketing from Temple University.

- Senior Credit Analyst – Eight years work experience including one year as Cost Analyst and 4 years with PJM as a Credit Analyst; holds a Bachelor of Arts in Business Administration – Finance, with concentration in Computer Applications in Business from York College in New York.

In addition to their formal education, PJM's Credit Manager and Credit Analysts have regularly attended training at both dedicated training conferences and the International Energy Credit Association ("IECA") annual conferences. The credit department staff also undergoes regular regulatory compliance and security training at PJM and participates in internal PJM training on markets and operations. Examples of recent training attended by Credit Department personnel include:

- Fundamentals of Energy Contract Administration: Negotiating ISDA's (IECA)
- Derivatives and Structured Products in Energy (IECA)
- Fundamentals of Bank Credit Risk Analysis (IECA)
- Understanding Letters of Credit (IECA)
- Beyond Fundamentals of Financials Risk (IECA)
- Credit Quality of Municipalities (IECA)
- Credit Quality of Financial Institutions (IECA)
- Moody's EDF Training
- Analyst Training in Power and Gas Sector (SNL Center for Finance Education)
- Essentials of Utility Finance (SNL)

- Energy Regulation Fundamentals (Enerdynamics)
- Electric System Fundamentals (Enerdynamics)
- Fundamentals of Energy Efficiency and Demand Response (Enerdynamics)

B. Financial Resources and Recovery of Operating Costs.

PJM maintains sufficient financial resources to meet its financial obligations to its members notwithstanding a default by the member creating the largest financial exposure for that organization in extreme but plausible market conditions. PJM also is able to cover its operating costs for a period of one year. However, the manner in which PJM achieves these objectives, although comparable to a DCO, reflects the unique structure and characteristics of an RTO. For example, PJM does not require financial resources to cover member defaults. Instead, member defaults in excess of posted collateral are mutualized amongst the non-defaulting members per Section 15.2.2 of the PJM OA.

In addition, PJM charges its members and recovers its administrative costs through the PJM OA Schedule 3 and PJM Tariff Schedules 9-1 through 9-6. These rate schedules allow PJM to collect all operating costs from its members based on the volume of their transactions. Section 6.3 of the PJM OA addresses Liquidating Distributions of any net assets to PJM's members after the satisfaction of all liabilities in the case of termination or liquidation of PJM. PJM's Tariff does not allow PJM to accumulate retained earnings or accumulate paid-in-capital, but it does support a reserve of approximately $15 million.[30] In addition to this amount, Section 5.1 of the PJM OA authorizes PJM to maintain working capital lines of credit of $65 million, equating to approximately 25 percent of PJM's annual operating costs. Further, as authorized in Section 16.7 of the PJM OA, PJM maintains $450 million business interruption insurance that would provide cash flow to PJM in the event that PJM is unable to bill its expenses to PJM members, due to physical or technological reasons, and PJM has exhausted both the reserve and the working capital line of credit. Given that PJM's annual operating costs are approximately $250 million, PJM maintains sufficient financial resources to cover its operating costs for one year.

Further, as of December 31, 2010, PJM has had access to $200 million in unused borrowing capacity on existing debt facilities to meet immediate cash needs before billings and collections from market participants. PJM also has a strong Aa3 investment-grade credit rating from Moody's Investor Services that would support incremental borrowing capacity if necessary. In the worst case scenario, the liquidation provisions of PJM's OA Section 18.18.3 would require PJM's members to pay all costs required to fulfill all of PJM's liabilities if the organization were to terminate operations and be liquidated.

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[30] *See* PJM Tariff, Schedules 9 through 9-6. Specifically, the stated rate settlement filed in FERC Docket No. ER05-1181 on April 18, 2006 and approved by FERC on May 26, 2006 to be effective June 1, 2006, and as subsequently amended, describes PJM's authority under these stated rate schedules to accumulate a financial reserve up to 6 percent of annual stated rate revenues. This equates to approximately $13 - $15 million, depending upon each calendar year's actual stated rate revenues. Other than the allowed financial reserve, stated rate revenues in excess of PJM's actual costs are refunded to PJM's members in the calendar quarter subsequent to when they were collected.

Attachment C

DCO Core Principle C: Participant and Product Eligibility

(i) IN GENERAL.—Each derivatives clearing organization shall establish—

> (I) appropriate admission and continuing eligibility standards (including sufficient financial resources and operational capacity to meet obligations arising from participation in the derivatives clearing organization) for members of, and participants in, the derivatives clearing organization; and
>
> (II) appropriate standards for determining the eligibility of agreements, contracts, or transactions submitted to the derivatives clearing organization for clearing.

(ii) REQUIRED PROCEDURES.—Each derivatives clearing organization shall establish and implement procedures to verify, on an ongoing basis, the compliance of each participation and membership requirement of the derivatives clearing organization.

(iii) REQUIREMENTS.—The participation and membership requirements of each derivatives clearing organization shall—

> (I) be objective;
>
> (II) be publicly disclosed; and
>
> (III) permit fair and open access.

Responses:

Attachment C—DCO Core Principle C: Participant and Product Eligibility

California ISO

CAISO Tariff Section 4 contains admission and eligibility standards for various types of CAISO market participants, including the two types of market participants that bid in the CAISO markets: (1) scheduling coordinators, and (2) CRR holders. Scheduling coordinators are required to certify to having met several specific conditions listed in the CAISO Tariff. This certification must include a demonstration of capability to perform the functions of a scheduling coordinator, and that it meets the financial requirements set out in Section 12 of the Tariff.[31] Scheduling coordinators must also meet certain administrative and technical requirements, including undergoing training and testing regarding the use of CAISO's market, operating and technical systems, as well as providing the CAISO with an emergency plan by which the scheduling coordinator will ensure that its operations and contacts with the CAISO can be maintained during an emergency.[32]

To register as a CRR holder, candidate CRR holders are required to complete an application to the CAISO.[33] With the application, candidate CRR holders must include the financial security information required by Section 12 of the CAISO Tariff[34] and proof of, or expected completion of, training required of CRR holders.[35] CRR participants must have a minimum amount of available credit, in a secured form of financial security such as a letter of credit, escrow account or cash, in order to participate in a CRR auction ($100,000 of secured available credit for the auction of monthly CRRs and $500,000 of secured available credit for the auction of year-long CRRs).[36] They can use all of their available credit for the auction.

As a portfolio of bids of one or more CRRs is submitted, the CAISO system calculates the portfolio credit requirement, based on bid curves and credit margin values for each individual CRR bid portfolio, and compares it to the secured available credit limit. If the portfolio credit requirement is less than or equal to the secured available credit, the portfolio of bids is accepted. If the portfolio credit requirement is greater than the secured available credit, the portfolio of bids is rejected.

Pursuant to FERC Order No.741, the CAISO has adopted specific minimum requirements for market participation.[37] The minimum participation requirements would include an attestation from an officer of each market participant that the market participant, or the

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31 CAISO Tariff § 4.5.1; *see* Attachment B, "Financial Resources."

32 CAISO Tariff § 4.5.1.1.10.1; Business Practice Manual for Scheduling Coordinator Certification & Termination and Convergence Bidding Entity Registration & Termination (Jan. 21, 2011), *available at* https://bpm.caiso.com/bpm/bpm/version/000000000000120.

33 *Id*. § 4.10.1.5.1; Business Practice Manual for Candidate CRR Holder Registration (Feb. 3, 2009), *available at* https://bpm.caiso.com/bpm/bpm/version/000000000000016.

34 *See* Attachment B, "Financial Resources."

35 CAISO Tariff § 4.10.1.5.1.

36 *Id*. § 12.6.2.

37 FERC Order No.741, *Credit Reforms in Organized Wholesale Electric Markets*, (Oct. 21, 2010), *available at* http://www.ferc.gov/whats-new/comm-meet/2010/102110/E-3.pdf.

company to which it outsources its risk management function, adheres to certain risk management principles and practices. Additionally, unless a market participant has either $1,000,000 of tangible net worth or $10,000,000 of total assets, it will be required to post as much as $500,000 of secured collateral with the CAISO that the market participant cannot use for collateral or any other market activity. Reviews will be performed every six months to allow market participants to reduce their posted collateral based upon their highest estimated aggregate liability during the prior six months, but not to less than $100,000.

Market participants will also be required to certify that they have procedures in place to respond to ISO invoices, payments and collateral requests, and CRR market participants will be required to undergo annual training (as currently required by the CAISO Tariff).

On December 14, 2011, the CAISO submitted a compliance filing regarding its minimum participation verification process that provides for annual CAISO review and verification, as detailed in the CAISO's Business Practice Manual for Credit Management, of a prospective or existing market participant's risk management policies, procedures and controls applicable to the CRR trading activities, if the prospective or existing Market Participant has a CRR portfolio that meets certain risk criterion set forth in the Business Practice Manual. The risk criterion is based on standards developed jointly by the ISOs/RTOs and will be conducted according to generally accepted industry risk management standards that may be developed from time to time and shall include but not be limited to confirmation that:

- The Market Participant's risk management framework is documented in a risk policy addressing market, credit and operational liquidity risks that has been approved by the Market Participant's risk management governance function, which includes appropriate corporate persons or bodies that are independent of the Market Participant's trading functions, such as a risk management committee, a designated risk officer, a board or board committee, or a board or committee of the Market Participant's parent company;
- The Market Participant maintains an organizational structure with clearly defined roles and responsibilities that segregate front-, middle-, and back-office functions to as high a level as is practicable;
- Delegations of Authority specify the transactions into which traders are allowed to enter;
- The Market Participant ensures that traders have adequate training and experience relative to their Delegations of Authority in systems and the markets in which they transact;
- As appropriate, risk limits are in place to control risk exposures;
- Reporting is in place to ensure risks are adequately communicated throughout the organization;
- Processes are in place for independent confirmation of executed transactions; and

Attachment C—DCO Core Principle C: Participant and Product Eligibility

- As appropriate, there is periodic valuation or mark-to-market of risk positions.

Product eligibility

The products that are the subject of this request for a Section 4(c) Order are all reviewed and approved by FERC and are described in and governed by the CAISO Tariff.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

ERCOT

A. Admission and Continuing Eligibility Standards.

Participant Eligibility. ERCOT's participation eligibility requirements are comparable to those required by this core principle. ERCOT requires each entity to meet eligibility requirements to participate in the ERCOT market.[38] Counterparties may participate as Qualified Scheduling Entities ("QSEs") in the energy markets and as CRRAHs in the financial transmission rights markets.[39] The eligibility requirements include, in relevant part, the satisfaction of the following:

- Demonstrating the capability to perform the functions of a CRRAH or QSE;[40]
- Demonstrating the capability of complying with the requirements of all ERCOT Protocols and Operating Guides;[41]
- Satisfying all applicable credit requirements;[42]
- Demonstrating the ability to pay its debts as they come due (ERCOT may request evidence if ERCOT believes that a QSE or CRRAH is failing to comply with this requirement);[43]
- Providing bank account information and arrange for electronic system transfers for two-way confirmation;[44] and
- Assuming financial responsibility for all settlement charges under the ERCOT Protocols.[45]

Any entity is eligible to obtain QSE or CRRAH designation, subject to the satisfaction of ERCOT's membership and credit criteria.[46] Once qualified, a market participant is obligated to meet all relevant market participation requirements/standards on an ongoing basis.

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38 Section 16 of the ERCOT Protocols establishes registration and qualification requirements for all market participants.

39 ERCOT Protocol Sections 16.2.1 and 16.8.1.

40 ERCOT Protocol Sections 16.8.1(1)(d) and 16.2.1(1)(d).

41 ERCOT Protocol Sections 16.8.1(1)(e) and 16.2.1(1)(e).

42 ERCOT Protocol Sections 16.8.1(1)(f) and 16.2.1(1)(f).

43 ERCOT Protocol Sections 16.8.1(1)(g) and 16.2.1(1)(g).

44 ERCOT Protocol Sections 16.8.1(1)(h) and 16.2.1(1)(h).

45 ERCOT Protocol Sections 16.8.1(1)(i) and 16.2.1(1)(i).

46 Entity generally means any natural person, partnership, municipal corporation, cooperative corporation, association, governmental subdivisions, or public or private organization.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

The PUCT Substantive Rules, the ERCOT Standard Form Agreement executed by QSEs and CRRAHs, and the ERCOT Protocols establish each ERCOT market participant's obligation to comply with all relevant market rules.[47]

In addition to the eligibility requirements noted above, the PUCT has established minimum financial requirements for applicants seeking what are known as "Option 1" and "Option 2" Retail Electric Providers ("REPs") certification in the ERCOT market.[48] In the ERCOT market construct, REPs are the companies that sell to and collect payment from end user electricity customers.

An Option 1 REP certificate is for a REP whose service offerings are defined by a geographic service area as set forth in the rule.[49] An Option 2 REP certificate is for a REP whose service offerings are limited to specifically identified customers, each of whom contracts for one megawatt or more of capacity.[50]

The minimum financial requirements in the PUCT's REP Rule focus on the REP's access to sufficient capital, and provide REPs two options. The Rule provides that a REP or its guarantor[51] must be able to demonstrate and maintain:

- An investment-grade credit rating documented by reports of a credit reporting agency;[52] or

- Tangible net worth greater than or equal to $100 million, a minimum current ratio (current assets divided by current liabilities) of 1.0, and a debt to total capitalization ratio not greater than 0.60, where all calculations exclude unrealized gains and losses resulting from valuing to market the power contracts and financial instruments used as supply hedges to serve load, and such calculations are supported by an affidavit from an executive officer of the REP attesting to the accuracy of the calculation.[53]

Alternatively, a REP must demonstrate shareholders' equity, determined in accordance with generally accepted accounting principles, of not less than $1,000,000 for the purpose of obtaining certification. The shareholders' equity must be documented by the audited and unaudited financial statements of the REP for the most recent quarter. The REP or its guarantor

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47 *See* P.U.C. SUBST. R. § 25.503 (f)(2), ERCOT Protocols, Section 22, Attachment A: Standard Form Market Participant Agreement, Section 5.A, Participant Obligations, and ERCOT Protocol Sections 16.1(1), 16.2.1(1)(b), 16.2.1(6), 16.3(1), 16.4(1), 16.5(1), 16.6(1), 16.8.1(1) and (3).

48 *See* P.U.C. SUBST. R. 25.107(f)(1) and (d)(3). The financial requirements in Subsection (f) of the rule do not apply to "Option 3" REPs who sell electricity exclusively to a retail customer from a distributed generation facility located on a site controlled by the customer. These rules are established pursuant to PURA § 39.352.

49 P.U.C. SUBST. R. 25.107(d)(1).

50 P.U.C. SUBST. R. 25.107(d)(2).

51 P.U.C. SUBST. R. 25.107 (f)(4)(G) sets forth capital requirements for guarantors.

52 P.U.C. SUBST. R. 25.107(f)(1)(A)(i).

53 P.U.C. SUBST. R. 25.107(f)(1)(A)(ii).

must also provide and maintain an irrevocable stand-by letter of credit payable to the PUCT with a face value of $500,000 for the purpose of maintaining certification.[54] The PUCT Rule includes requirements that REPs provide the PUCT with specific, detailed documentation demonstrating compliance.[55]

In addition to the requirements established by the PUCT for REPs, ERCOT is in the process of establishing capitalization requirements for all participation in the ERCOT market, as discussed below. However, currently an entity's participation in the ERCOT market is effectively limited by:

- Requiring collateral for 100% of estimated exposure subject to any approved unsecured credit.[56] Exposure is updated daily.
- Enforcing a credit limit within the CRR Auction and for Day-Ahead Market transactions based on unsecured credit allowed or collateral posted in excess of what is required per the daily exposure requirement.[57]

Through its stakeholder process, ERCOT is in the process of developing new eligibility requirements that are comparable to those required by FERC Order No. 741. Proposed eligibility requirements specify that counterparties must:

- Have appropriate expertise in markets,
- Have appropriate operational capabilities to respond to ERCOT directions,
- Meet minimum capitalization requirements, and
- Maintain a risk management framework appropriate to the ERCOT markets in which it transacts or wishes to transact.

Counter-Parties will be required to provide an annual certification that they have met these requirements, attested by an officer of the company.

Proposed capitalization requirements are higher for counterparties transacting or wishing to transact in CRR markets. Counterparties who fail to meet the capitalization requirements would be required to post an "Independent Amount" in addition to any collateral posted with respect to market positions. Within the scope of the proposed eligibility requirements, market participants would be subject to periodic verification of their risk management framework to be performed either by ERCOT or an agent acting on ERCOT's behalf.[58]

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54 P.U.C. SUBST. R. 25.107(f)(1)(B).

55 P.U.C. SUBST. R. 25.107(f)(4).

56 ERCOT Protocol Section 16.11.1.

57 ERCOT Protocol Sections 16.11.4.6, 16.11.4.6.1, and 16.11.4.6.2.

58 Nodal Protocol Revision Request 438, which will incorporate a new Protocol Section 16.16.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

B. Standards for Determining the Eligibility of Agreements, Contracts, or Transactions.

This core principle has very limited application to ERCOT's operations. While ERCOT does not clear the transactions in its markets, ERCOT does:

- Utilize a Standard Form Market Participant Agreement for all Counter-Parties that requires market participants to comply with the ERCOT Protocols, which govern transactions/participation in the ERCOT markets.[59] This ensures that all contracts meet predefined criteria.
- Enforce collateral constraints in both its Day Ahead Market and in its CRR Auctions to ensure that transactions are adequately collateralized.[60]

ERCOT expects to adopt the central counterparty structure; however, this structure will not involve clearing, as that term applies to a derivatives clearing organization or swap execution facility (*i.e.*, the central counterparty does not act as a financial intermediary, nor is there is any novation of transactions to a central counterparty).

C. Required Procedures.

ERCOT has procedures to verify, on an ongoing basis, compliance with each participation and membership requirement that are comparable to those required by this core principle. Each CRRAH and QSE is obligated to: [61]

- Meet its relevant eligibility requirements and obligations under the Protocols on an on-going basis;
- Notify ERCOT of any changes in its situation that affect its ability to meet its eligibility requirements;
- Sign a market participant agreement and update it annually;
- Attest each year that it meets the relevant requirements;
- Update information related to its eligibility as necessary; and
- Respond to requests from ERCOT for information.

[59] *See* ERCOT Protocol Section 22: Attachment A, *Standard Form Market Participant Agreement*.

[60] ERCOT Protocol Sections 16.11.4.6, 16.11.4.6.1, and 16.11.4.6.2.

[61] Each of the below requirements is established in Section 16 of the protocols, which addresses all registration and qualification requirements for participation in the ERCOT markets.

ERCOT is developing new requirements consistent with FERC Order Nos. 741 and 741-A. After those requirements are established, it will also be necessary for each Counter-Party to attest annually that it is in compliance with market participation eligibility and capitalization requirements and, in some cases, provide appropriate documentation supporting the sufficiency of the Counter-Party's risk management framework with respect to the ERCOT markets in which it transacts or wishes to transact. [62]

D. Requirements.

ERCOT's participation and membership requirements are comparable to those of this core principle. The general membership requirements, rights, and obligations are established in the ERCOT Bylaws and available to the public on the ERCOT website.[63] The rules for participation in the ERCOT markets are prescribed by the ERCOT Protocols and are public and also available on the ERCOT website.[64]

ERCOT is a non-profit organization and is required to be independent from the market and to provide access to the transmission system on non-discriminatory terms.[65] ERCOT's markets, including its CRR market and all associated rules, are subject to that requirement. This facilitates objective rules in terms of substance and access. In addition, ERCOT is obligated to develop its market rules in concert with its Market Participants and other interested parties in an open, transparent committee process.[66] To that end, a Market Participant body (the Technical Advisory Committee, or, "TAC"), as well as other relevant Market Participant subcommittees, participate in such rule development.[67] All Protocols and other relevant ERCOT documents are publicly available and are posted on the ERCOT website.[68] This construct ensures that market participation and membership requirements are objective and open.

As noted above, ERCOT intends to amend certain of its participation and membership requirements consistent with FERC Order Nos. 741 and 741-A and will apprise the CFTC of any changes thereto.

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62 Nodal Protocol Revision Request 438, which will incorporate a new Protocol Section 16.16.

63 ERCOT Bylaws, Section 3.1, Section 3.3, and Section 3.6.

64 ERCOT Protocol Section 16, *Registration and Qualification*.

65 PURA Section 39.151(a) and (b), P.U.C. SUBST. R. 25.361(b) and ERCOT Protocol Section 1.2.

66 P.U.C. SUBST. R. 25.501(m).

67 ERCOT Bylaws Article 5, Section 5.2.

68 *See*: http://www.ercot.com/mktrules/nprotocols/current.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

ISO New England

ISO-NE has appropriate admission and continuing eligibility standards for its members and for determining the eligibility of agreements, contracts or transactions of its wholesale electricity market. These complement an extremely limited allocation of unsecured credit, as well as billing practices that limit participants' exposure.

Participant Eligibility

ISO-NE establishes the participant eligibility requirements through its Tariff. The eligibility requirements are specific for each of the markets discussed below. As discussed below, the participant eligibility requirements are objective and transparent, permitting access by any person or entity that meets the requirements.

Municipal Market Participants

ISO-NE's customer base consists of many municipal market participants. For the purposes of ISO-NE's financial assurance policy, a municipal participant is defined as: (i) a "Publicly Owned Entity … except for an electric cooperative or an organization including one or more electric cooperatives …; or (ii) a municipality, an agency thereof, a body politic or a public corporation that is created under the authority of any state or province that is adjacent to one of the New England states; authorized to own, lease and operate electric generation, transmission or distribution facilities; and has been approved for treatment as a Municipal Market Participant by the ISO after consultation with the NEPOOL Budget and Finance Subcommittee." *See* ISO-NE Tariff, Exhibit IA, § II.

Although each of the municipal market participants may not be an Eligible Contract Participant ("ECP"), they nonetheless are "appropriate persons" for purposes of the 4(c) exemption. Their participation in ISO-NE's electricity market is necessary in order to make electricity available to the whole grid in the New England region, and they are entitled to recover their costs for native load service through governmentally established retail rates. Accordingly, they are able to provide a form of financial security (*i.e.,* the ability to request a retail rate increase to cover increased costs) that is unavailable to other participants in the New England energy markets. As such, the risk of default by such entities is materially different from other market participants. Nonetheless, these entities are not permitted to use unsecured credit in association with any FTR market activity.

Moreover, as active participants in the cash markets, these entities have the requisite knowledge and sophistication to be participants in the ISO-NE markets, in a manner appropriate to their operations. Furthermore, as discussed below, ISO-NE holds these entities to appropriate financial standards and monitors their financial viability on an ongoing basis.

Investment Grade rated municipal entities are currently subject to credit limit caps of \$25 million for market obligations and \$25 million for transmission obligations. *See* ISO-NE Tariff Exhibit IA, §§ II.D.2 and II.E.3.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

Forward Capacity Market Participant Requirements

ISO-NE operates a physical Forward Capacity Market on roughly a three-year forward basis (with reconfiguration auctions to "balance" the needs for Installed Capacity with anticipated load as the Capacity Commitment Period approaches). ISO-NE has financial assurance requirements for its Forward Capacity Market. *See* Section VII of the Financial Assurance Policy. To participate in this market, resources must be approved through a rigorous qualification process to ensure that they can deliver energy to the electric system during the Capacity Commitment Period. See Section III.13.1 of the Tariff. When a resource receives a Capacity Supply Obligation through these Forward Capacity Auctions, it is obligated to offer its energy into the day-ahead and real-time energy markets. Delivery risk resulting from the acquisition of a Capacity Supply Obligation by a non-commercial resource is mitigated by the existence of financial assurance requirements that, by the time of the commitment period, equal approximately three months of the cost of new entry.

Requirements for Participation in the FTR Market

Participation in the FTR auctions is not limited to entities that have specific obligations to serve load. See the definition of "Eligible FTR Bidder" in Section I.2.2 of the Tariff. To participate, entities must, among other requirements: complete ISO-NE prescribed training in the functioning of the FTR market (see Section VI of the Financial Assurance Policy); sign a Market Participant Service Agreement that obligates them to abide by the terms of the ISO's Tariff (see definitions of "FTR-Only Market Participant" and "Market Participant" in Section I.2.2. of the Tariff); and be credit-worthy (see Section VI of the Financial Assurance Policy and the definition of "Eligible FTR Bidder" in Section I.2.2 of the Tariff). ISO-NE does not operate a secondary or bilateral market for FTRs. While there are no specific quantity limits on the number of FTRs a Market Participant can purchase, the collateral requirements (no unsecured credit is permitted for meeting FTR obligations) and the physical limitations of the system inherently limit purchases. The internal market monitor analyzes the FTR auctions, including participant positions, for any behavior constituting market abuse.

Due Diligence of Issuers

Only qualifying banks may issue irrevocable letters of credit. As provided in Section X.B.1 of ISO-NE's Financial Assurance Policy (ISO-NE Tariff, Exhibit IA), each such bank must be on ISO-NE's "List of Eligible Letter of Credit Issuers." To be included on the List of Eligible Letter of Credit Issuers, the bank must be organized under the laws of the United States or any state thereof, or be the U.S. branch of a foreign bank and: (i) be recognized by the Chicago Mercantile Exchange ("CME") as an approved letter of credit bank; or (ii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch (so long as its letter of credit is confirmed by a bank that is recognized by CME as an approved letter of credit issuer); or (iii) have a minimum long-term debt rating (or, if the bank does not have minimum long-term debt rating, a minimum corporate rating) of "A-" by S&P, or "A3" by Moody's, or "A-" by Fitch and be approved by ISO-NE in ISO-NE's sole discretion. Because the ratings described in clauses (ii) and (iii) are minimum ratings, a bank will not be considered to have satisfied the requirement of those clauses if any applicable rating from the Rating

Agencies falls below the levels listed in those clauses. In addition, no Posting Entity may provide a letter of credit that has been issued or confirmed by a bank that is affiliated with it. ISO-approved banks include those found at the following link: http://www.cmegroup.com/clearing/financial-and-collateral-management/list-of-approved-banks.html. ISO-NE requires that letters of credit conform to its template. *See* ISO-NE Tariff, Exhibit IA, Attachment 2. No letter of credit bank may issue or confirm letters of credit under ISO-NE's Financial Assurance Policy in an amount exceeding either: (i) $100 million in the aggregate for any single Posting Entity; or (ii) $150 million in aggregate for a group of Posting Entities that are Affiliates. *See* ISO-NE Tariff, Exhibit IA, § X.B.1.

Program for Monitoring Admission Eligibility

As set out in Section II.B of the Financial Assurance Policy (ISO-NE Tariff, Exhibit IA), ISO-NE engages in credit review procedures for all municipal and non-municipal applicants that include a review of the following:

1. Audited financial statements for the two most recent years, or the period of its existence, if less than two years, or, if such audited statements are unavailable, the ISO, in its sole discretion, may designate alternate financial statement requirements;

2. Unaudited financial statements for its last concluded fiscal quarter, if they are not included in such audited annual financial statements, that are certified by a Senior Officer. These and the audited statements must include, to the extent available:

    a. Balance sheets

    b. Income statements

    c. Statements of cash flows

    d. Notes to financial statements

    e. Annual and quarterly reports

    f. 10-K, 10-Q and 8-K Reports;

3. At least one bank reference;

4. Three utility company credit references, or three major trade payable vendor references;

5. Relevant information as to any known or anticipated material lawsuits, as well as any prior bankruptcy declarations by the Applicant or by its predecessor(s), if any; and

6. A completed ISO credit application.

Also, each Applicant that intends to establish a Market Credit Limit or a Transmission Credit Limit must submit all current rating agency reports from Standard and Poor's, Moody's and/or Fitch to ISO-NE. *See* ISO-NE Tariff, Exhibit IA, § II.B.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

ISO-NE prepares a report, or causes a report to be prepared, regarding the financial viability of every applicant and submits the report to its Participants Committee within three weeks of submission of an application. *See* ISO-NE Tariff, Exhibit IA, § II.B.

As part of the Market Participant Services Agreement, members must also register each asset that seeks eligibility to sell or purchase services in the New England Markets. Each member also must comply with ISO-NE's operating documents, including registration information, approval of interconnection application, compliance with metering requirements, and providing electrical operating information. *See* Market Participant Services Agreement (Attachment A to the ISO-NE Tariff), Section 3.3.

Additional Eligibility Requirements

The FERC Credit Ruling requires that ISOs include language in their tariffs specifying "minimum participation criteria to be eligible to participate in the organized wholesale electric market, such as requirements related to adequate capitalization and risk management controls." Credit Ruling ¶131. FERC noted that the order "did not mandate a single set of criteria for all participants in a market." Credit Ruling Rehearing ¶33.

ISO-NE's objective with regard to compliance with this requirement was to establish minimum participation criteria to protect market efficiency and minimize default exposure. In regard to information disclosure, ISO-NE now requires participants to annually submit: (i) a list of Principals; (ii) a list of any material criminal or civil litigation involving the customer or applicant, or any of the Principals of the customer or applicant, arising out of participation in any U.S. wholesale or retail energy market in the past five years; (iii) a list of sanctions involving the customer or applicant, or any of the Principals of the customer or applicant, imposed by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets where such sanctions were either imposed in the past five years or, if imposed prior to that, are still in effect; (iv) a written summary of any bankruptcy, dissolution, merger, or acquisition of the customer or applicant in the preceding five years; and (v) a list of current retail and wholesale electricity markets-related operations in the United States, other than in the New England Markets. If members fail to provide required information, the ISO shall provide notice affording a two-business-day cure period. Continued failure to comply would result in market suspension. The ISO also determines whether the applicant, market participant or any of its principals are included on any relevant list maintained by the U.S. Office of Foreign Asset Control. *See* Financial Assurance Policy at Section II.A.1.

ISO-NE also requires that participants have minimum capitalization in the form of tangible net worth of at least $1 million or total assets of at least $10 million. In the alternative, participants must have a BBB-/Baa3 or better governing rating. *See* Financial Assurance Policy at Section II.A.4.

Although ISO-NE has implemented a capital-based eligibility requirement to participate in its market modeled on the minimum capitalization criteria of the Commodity Exchange Act's capital-based eligibility as an Eligible Contract Participant, we believe that the minimum capital requirement is only a rough metric. In this regard, we are aware that minimum capital requirements based on financial data alone can suffer from evaluation problems (for example, balance sheet assets may be inflated due to mark-to-market errors and suspect liquidity assumptions).

For the limited purpose of determining eligibility to participate in the ISO-NE market, we believe that it is equally appropriate to rely upon the existence of an investment grade corporate credit rating of BBB- (or equivalent) or better. Rating agencies take many factors into consideration in assigning ratings, including a host of qualitative and quantitative measures such as capitalization levels, capital structure, funding and liquidity measures, issuer's risk management policies/procedures, etc. While we recognize that rating agency methodologies have been called into question lately, we believe it appropriate to utilize such ratings for the limited purpose of establishing the eligibility to participate in our market. In this regard, we believe that the threshold for a participant to secure an investment grade issuer credit rating (or unsecured debt rating) from Moody's, S&P and/or Fitch indicates the same type of sophisticated entity that is appropriately eligible to participate in the market as indicated by the eligibility requirement of $1 million in tangible net worth or $10 million in assets. Moreover, we believe that the threshold for a participant to secure an investment grade issuer credit rating (or unsecured debt rating) from Moody's, S&P and/or Fitch is at least equivalent to, but likely more onerous than, establishing capitalization levels of greater than $1 million in tangible net worth or $10 million in assets.

Of course, market participants that have met the minimum eligibility requirement to participate in the ISO-NE markets (irrespective of whether it is based on the minimum capital requirement or an acceptable credit rating) will be held to the same financial assurance requirements as all other market participants should they seek to transact in the markets in such a way that introduces any level of credit risk. In this regard, ISO-NE has the authority to limit the trading levels or take other appropriate action under ISO-NE's material adverse change provisions provided for under the ISO-NE Tariff. *See* ISO-NE Tariff, Exhibit IA (Financial Assurance Policy), § XI.A.

For participation in markets other than the FTR market, the capitalization requirements do not apply to entities with financial assurance requirements (excluding FTR requirements) of lower than $100,000. Customers and applicants having a financial assurance requirement of $100,000 or greater that fail to meet the capitalization requirements must provide additional financial assurance as calculated in the table below. Furthermore, regardless of the level of financial assurance requirements of a customer or applicant that fails to meet the capitalization requirements, that customer or applicant will be prohibited from trading FTRs with a tenor of greater than one month and will be required to provide additional financial assurance in an amount equal to 15% of any FTR requirements calculated for that customer. Failure to provide this incremental collateral requirement will result in the suspension of that customer's ability to trade any FTR product until the deficiency is rectified.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

Total financial assurance requirement (excluding FTR Requirements and any additional financial assurance required pursuant to Section II.A.4)	Additional financial assurance required
$100,000 to $249,999.99	$25,000
$250,000 to $499,999.99	$50,000
$500,000 to $999,999.99	$100,000
$1,000,000 to $9,999,999.99	$200,000
$10,000,000 or greater	$500,000

An applicant that fails to provide the full amount of additional financial assurance required, as described in the above chart, will be suspended from participating in the New England Markets until the deficiency is rectified. *See* ISO-NE Tariff, Exhibit IA (Financial Assurance Policy), § II.A.4(c)(iii).

Ongoing Program for Monitoring for Compliance

ISO-NE requires that each market participant annually submit certificates that attest that the participant has: risk management procedures and internal controls appropriate to the risks that it enters in the market; trained personnel related to its participation in New England Markets; and procedures in place to effectively communicate with ISO-NE. *See* Financial Assurance Policy at Section II.A.1.b.

If, based on these reviews, which include all information provided by the applicant or market participant as described above, ISO-NE determines that the commencement or continued participation of an applicant or market participant may present an unreasonable risk to the markets or market participants, ISO-NE will inform the market participant, as well as all of its market participants, of its concerns and proposed actions. ISO-NE shall take into consideration other participants' recommendations before taking any action. If ISO-NE chooses to impose measures other than prohibition (in the case of an applicant) or termination (in the case of a customer) of participation in the New England Markets, then it shall be required to make an informational filing with FERC as soon as reasonably practicable after taking such action. If ISO-NE chooses to prohibit (in the case of an applicant) or terminate (in the case of a customer) participation in the New England Markets, then it must file for FERC approval of such action, and the prohibition or termination shall become effective only upon final FERC ruling. *See* ISO-NE Tariff, Exhibit IA (Financial Assurance Policy), § II.A.1.b.

ISO-NE has also filed with FERC, in December 2011, a proposal to include an additional step involving the submission by FTR market participants of those entities' risk management procedures. Specifically, FTR customers with FTR transactions in any currently open month of more than 1,000 MW must submit to ISO-NE by April 30 of each year their written risk management policies, procedures and controls that are applicable to participation in the FTR market. Entities seeking to participate in the FTR market also need to provide the written policies, procedures and controls prior to participating in the FTR market. In addition, ISO-NE may ask any other applicant or customer to submit the written risk management policies, procedures and controls applicable to its participation in the New England Markets. ISO-NE may require these submissions based on identified risk factors that include, but are not limited to, the markets in which the customer is transacting or in which the applicant seeks to transact, the magnitude of the customer's transactions or the applicant's potential transactions, or the volume of the customer's open positions. The ISO will assess whether the policies, procedures and controls received from the applicant or customer conform to prudent risk management practices, which include, but are not limited to: (i) addressing market, credit and operational risk; (ii) segregating roles, responsibilities and functions in the organization; (iii) establishing delegations of authority that specify which transactions traders are authorized to enter into; (iv) ensuring that traders have sufficient training in systems and the markets in which they transact; (v) placing risk limits to control exposure; (vi) requiring reports to ensure that risks are adequately communicated throughout the organization; (vii) establishing processes for independent confirmation of executed transactions; and (viii) establishing periodic valuation or mark-to-market of risk positions as appropriate.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

MISO

A. Market Participant Registration, Operational Capacity and Training

Section 38.2 of the MISO Tariff provides the requirements that must be met for an entity to qualify as a Market Participant. Section 38.2.2 provides specific requirements for entities seeking market participant status including the required demonstration of operational capacity and technical capabilities to participate in the markets administered by MISO.

MISO also maintains a Market Registration Business Practices Manual ("BPM") that provides additional detail and required forms for participation in the MISO markets. This BPM and the MISO Tariff are provided publically on MISO's website at https://www.midwestiso.org/LIBRARY/Pages/Library.aspx.

In addition to the posting of the MISO Tariff and Market Registration BPM, MISO conducts extensive voluntary training with new members prior to integration and offers periodic and annual training for market participants. The training is conducted both at MISO headquarters and off-site locations.

B. Required Financial Resources

Section 38.2.2 of the MISO Tariff requires a market participant applicant to provide any financial security required by MISO pursuant to its credit policy in Attachment L of the Tariff. MISO's Credit Policy establishes initial credit requirements for each entity seeking market participant status that must be satisfied before the entity is deemed a market participant and provided access to transact business in MISO's markets. Attachment L, Implementation, Section I. Attachment L also requires Market Participants to maintain sufficient financial security to meet their obligations on an ongoing basis.

Pursuant to FERC Order 741, MISO has developed and filed with FERC proposed revisions to the Tariff including minimum capitalization requirements and an officer certification that must be executed by each Market Participant on an annual basis. The certification form includes the following declarations:

1. Training. Employees or agents transacting, or planning to transact, in markets or services provided pursuant to the MISO Tariff on behalf of the Tariff Customer or Applicant have received or will receive applicable training[4] with regards to their participation under the MISO Tariff as a condition of being authorized to transact on behalf of Tariff Customer.

2. Risk Management. Tariff Customer or its agent maintains current written risk management policies and procedures that address those risks that could materially affect Tariff Customer's ability to pay its MISO invoices when due, including, but not limited to credit risks, liquidity risks and market risks.

3. Operational Capabilities. Tariff Customer has appropriate personnel resources, operating procedures and technical abilities to promptly and effectively respond to MISO

communications and directions related to, but not limited to, settlements, billing, credit requirements, and other financial matters.

4. Capitalization. Tariff Customer will satisfy and maintain the minimum capitalization or alternative capitalization requirements applicable to the level of service Tariff Customer transacts or plans to transact, as detailed in Section III of Attachment L to the Tariff.

MISO has included in its proposed Tariff language the ability to request verification of the attestations provided in the executed annual officer certification form.

In addition to the annual certification requirement, MISO has included in its proposed Tariff revisions a new section that details all of the minimum criteria for participation. The new section includes the required deadlines for executing and submitting the annual certification form and the requirements associated with minimum capitalization.

In summary, the minimum capitalization requirements may be satisfied by demonstrating minimum tangible net worth or minimum total assets. Verification of such minimums must be demonstrated using audited financial statements provided by the participant. If a participant does not desire to qualify for minimum capitalization using audited financial statements, or if the minimum tangible net worth or total asset values are not satisfied, the participant may provide alternative capitalization in the form of cash collateral or a letter of credit.

Tariff Customers seeking authorization to participate in any or all service categories must provide sufficient evidence to demonstrate a minimum tangible net worth of $1 million or minimum total assets of $10 million. Tariff Customers seeking authorization to participate in any or all service categories with the exception of monthly and/or annual FTR markets must demonstrate a minimum tangible net worth of $500,000 or minimum total assets of $5 million.

As an alternative, if a Tariff Customer does not qualify for minimum capitalization as described above, it may qualify for participation by providing alternative capitalization in the form of financial security. The levels of financial security required are specific to the level of participation desired.

Financial Security provided by the Tariff Customer to satisfy the alternative capitalization requirement must be provided and maintained until all obligations associated with the customer's level of participation have expired and in advance of entering into any additional obligations. Fifty percent (50%) of the applicable Financial Security related to alternative capitalization is set aside and unavailable for Tariff Customer to use for participation in any service category, while the remaining 50% will be available for Tariff Customer to use in the service categories in which Tariff Customer is authorized to participate.

The ability to provide the required levels of financial security demonstrates that the participant has available liquidity appropriate to the service categories in which it is participating. By restricting use of half of the financial security provided for the alternative capitalization, MISO will have available a reserve of funds to cover unforeseen events that may cause larger than normal charges as a result of congestion or movement in flows.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

New York ISO

A. Registration and Eligibility Standards, Generally

The NYISO's FERC-approved tariffs are available to the public through the NYISO's website at: http://www.nyiso.com/public/markets_operations/documents/tariffs/index.jsp. The registration requirements and eligibility standards (*e.g.*, financial and operational requirements) for all NYISO Market Participants, including Market Participants in the Transmission Congestion Contract ("TCC") market, are set forth in Services Tariff Sections 8, 9 and 26 and OATT Sections 2.14, 3.5, 3.6, and 29. The terms and conditions for participating in NYISO-administered markets, and all other provisions of the NYISO's tariffs, are incorporated by reference in service agreements entered into with each Market Participant in the form set forth in Services Tariff Section 16 and OATT Sections 7 and 8.

B. Financial Security Requirements

A Market Participant that has satisfied the relevant registration and credit requirements – including the minimum participation requirements recently implemented in compliance with FERC Order No. 741 – may participate in the TCC market or may engage in Virtual Transactions in the Day-Ahead market.[69] Attachment K to the Services Tariff ("Services Tariff Section 26") and Attachment W to the OATT ("OATT Section 29")[70] require that a Market Participant has, at all times, adequate financial resources to meet its estimated financial obligations to the NYISO by requiring that each Market Participant allocate unsecured credit or post financial security (e.g., cash, letter of credit, or surety bond) in an amount that is sufficient to cover its credit requirements.

The NYISO establishes separate credit requirements for each of its product and service categories based on the unique characteristics associated with each product or market. Collectively, these credit requirements form the Market Participant's "Operating Requirement." The Operating Requirement is the "measure of a Customer's expected financial obligations to the ISO based on the nature and extent of that Customer's participation in ISO-Administered Markets." *See* Services Tariff Section 26.4.1. A Market Participant's Operating Requirement represents the Market Participant's total credit requirement to the NYISO and is the sum of the separate credit requirements (e.g., TCC Component, ICAP Component) for each market in which the Market Participant participates (e.g., TCC market, ICAP market). A Market Participant is required to allocate financial security in an amount equal to or greater than its Operating Requirement. Market Participant contributions to the Working Capital Fund do not offset these financial security requirements.

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[69] Registration requirements also apply to the resale of TCCs in the NYISO market. The NYISO offers monthly and bi-annual opportunities for the resale of TCCs, which are used much more frequently than the bilateral secondary markets. To resell a TCC in a NYISO market, a NYISO customer must meet the registration and credit requirements referenced above.

[70] Services Tariff Section 26 is incorporated by reference in OATT Section 29.

Market Participants with strong financial health may also apply for unsecured credit to satisfy their credit requirements except for their TCC market credit requirements. *See* Services Tariff Sections 26.4 - 26.6. Since November 12, 2009, the NYISO has not allowed Market Participants to use unsecured credit to meet TCC credit requirements. *See* Services Tariff Section 26.5.

The NYISO accepts irrevocable letters of credit as collateral that are issued or guaranteed by an approved U.S. or Canadian commercial bank with a minimum "A" rating from Standard & Poor's, Fitch, Moody's, or Dominion. *See* NYISO Services Tariff Section 26.6.1.2. The NYISO regularly reviews financial industry news and standard industry indicators regarding the financial strength of issuers. The NYISO also monitors the concentration of the number and dollar amount of letters of credit by issuer.

A Market Participant may either qualify for unsecured credit based on its own financial strength, or based on the financial strength of its parent company with a parental guarantee. *See* NYISO Services Tariff Section 26.5.1. A Market Participant may not obtain unsecured credit in excess of the NYISO's unsecured credit limit by using a parental guarantee. *See* NYISO Services Tariff Sections 26.5. The maximum amount of unsecured credit available to any one Market Participant, or group of affiliated Market Participants is $50 million. *See* NYISO Services Tariff Section 26.5.2. For example, a Market Participant that has a $50 million parental guarantee and independently qualifies for $50 million in unsecured credit would have a maximum unsecured credit limit of $50 million. If this Market Participant applied $49 million of its $50 million in unsecured credit against existing credit requirements, then the Market Participant would have $1 million of unused unsecured credit available to meet new credit requirements.

C. TCC-Specific Credit Requirements

A customer seeking to participate in the NYISO's TCC market must meet two credit requirements. The first credit requirement is known as the "Bidding Requirement." The purpose of the Bidding Requirement is to secure payments due at the time TCCs are awarded. The second requirement is known as the "holding requirement" and is the TCC Component of the Operating Requirement. The purpose of the TCC Component of the Operating Requirement is to secure payment obligations due during the life of the TCCs awarded and is discussed in Section C.2, *infra.*

1. TCC Bidding Requirements

A customer participating in a TCC auction may submit both positive and negative bids to purchase TCCs. A positive bid, if successful, obligates the customer to *pay* the NYISO, at the time of the TCC award, the market clearing price for the TCC.[71] In contrast, a negative bid, if

[71] The customer then anticipates receiving Congestion Rent payments from the NYISO over the term of the TCC, based on the transmission congestion between the two points that make up the TCC, in an amount that exceeds the TCC market clearing price.

successful, entitles the customer to *receive* payment from the NYISO, at the time of the TCC award, equal to the market clearing price for the TCC.[72]

The Bidding Requirement for TCCs, set forth in Services Tariff Section 26.4.3(i), requires each customer that submits a bid to purchase a TCC to provide the greater of (1) 100% of the bid amount or (2) the appropriate term-based minimum credit requirement as collateral prior to the commencement of the TCC auction. To reduce the likelihood of a Market Participant purchasing more TCCs than the amount for which it could post the collateral required by the TCC holding requirement, the NYISO and Market Participants agreed to establish minimum credit requirements for bidding on TCCs as a mechanism to ensure that potential TCC holders would be able to (1) pay the purchase price for any TCCs they bid to buy, and (2) post the collateral required to hold those TCCs.

The NYISO initially proposed a minimum bidding requirement of $5,000/MW, which amount would have provided a very high level of assurance that the credit requirement for bidding on a TCC would equal or exceed the credit requirement for holding the TCC. After analyzing how alternative minimum bidding requirements would have performed on Market Participant bids and awards in fall 2005, spring 2006 and fall 2006 auctions, the NYISO and its Market Participants ultimately agreed to lower minimum bidding requirements. Lower minimum bidding requirements are appropriate because even very successful bidders would not be awarded all of the TCCs for which they submitted bids. The overall percentage of successful bids ranged from 7.4% to 14.2% in these auctions.

After a Market Participant submits its TCC bids, the NYISO will, as part of the bid validation process, compare the maximum offering exposure for the TCC bids to that Market Participant's available TCC collateral. If the Market Participant has insufficient collateral to cover its maximum offering exposure then the NYISO will reject all of those bids. The NYISO will notify the Market Participant, via the automated system, of the invalidation of the bids and the Market Participant can adjust and resubmit bids and/or offers, or provide additional collateral, if the bidding period for the auction is still open. The NYISO rejects any bid that lacks sufficient credit support upon bid submittal, which is prior to running the power flow analysis to determine TCC auction awards.

2. <u>TCC Component of the Operating Requirement</u>

A customer awarded TCCs must initially satisfy the baseline credit requirement for holding TCCs set forth in Services Tariff Section 26.4.2.3(a). Subsequently, a customer will be required to provide additional collateral, pursuant to Services Tariff Section 26.4.2.3(b), if the customer's entire portfolio of TCCs creates a net projected obligation that exceeds the total amount of collateral already provided pursuant to the baseline requirement. With respect to the NYISO's monitoring of a Market Participant's exposure in the TCC market, the NYISO calculates each TCC holder's net projected obligation on its entire portfolio of TCCs several

[72] The customer then anticipates making Congesting Rent payments to the NYISO over the term of the TCC, based on the transmission congestion between the two points that make up the TCC, in an amount that is less than the TCC market clearing price.

times each week pursuant to Services Tariff Section 26.4.2.3(b) (discussed in more detail below) and compares this amount to the TCC holder's posted TCC collateral. Any increase in financial exposure would be managed by the NYISO's adjustment to a TCC holder's TCC credit requirements. Engineering events such as generation or transmission outages could affect financial exposure by altering the future payments due to the NYISO from a particular TCC holder, as could changes in fuel prices, changes in weather forecasts, changes in the level of economic activity, and changes in market rules.

The NYISO developed the equations set forth in Services Tariff Section 26.4.2.3(a) based on a statistical analysis of historical TCC auction prices and TCC congestion payments during the four year period from spring 2002 through spring 2006, and of the dispersion of actual TCC congestion payments around the expected level of payments, as measured by auction clearing prices. Through this analysis the NYISO identified a number of variables that materially affected the relationship between price and dispersion, including whether the TCC sources or sinks in Zone J or Zone K,[73] the duration of the TCC, and, in the case of one-month and six-month TCCs, the month or season of the TCC.

Accordingly, the equations set forth in Section 26.4.2.3(a) control for these variables when applied to determine the appropriate holding requirement for a TCC. The one-month and six-month TCC equations are set at a 97% probability, and the one-year TCC equation is set at a 95% probability, based on historical auction data, that the credit requirement for holding a TCC would equal or exceed the Congestion Rents for the TCC. The purpose of the equation in Services Tariff Section 26.4.2.3(b) is to protect the NYISO against under collateralization in the event that fluctuations in the amount or direction of transmission congestion significantly alter the projected Congestion Rents. A material change in the Congestion Rents for a TCC is typically the result of a sudden, unexpected event, such as an unplanned equipment outage or significant, unexpected change in weather conditions. The NYISO estimates projected TCC payments for each TCC based on the average Congestion Rents for that TCC during the previous 90 days, as opposed to the average Congestion Rents over a longer period, because the expected Congestion Rents for a TCC are more closely aligned with recent fluctuations in congestion. In addition, averaging Congestion Rents over a shorter time period results in more conservative collateral requirements.[74] The NYISO also includes in its equation for determining the credit holding requirement for a TCC, the net amount owed to the NYISO for Congestion Rents. *See* Services Tariff Section 26.4.2.3(b).

D. Specific Credit Requirements for Virtual Transactions

To participate in Virtual Transactions, a customer must have financial security – in an acceptable form of collateral posted with the NYISO or available unsecured credit – that is sufficient to cover any bids submitted plus the net amount owed to the NYISO for any settled

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73 Zone J and Zone K represent the New York City and Long Island regions of the New York Control Area ("NYCA") respectively.

74 The NYISO is currently reviewing historical Congestion Rent data and analyzing the average of past Congestion Rents over 10 to 90 days to determine the appropriateness of using a less than 90 day average when estimating the current market value of one-month, six-month, and one-year TCCs.

Virtual Transactions outstanding. *See* Services Tariff Sections 26.4.1, 26.4.2 (first paragraph), and 26.4.2.5. Virtual Transaction bids submitted by a customer with insufficient collateral/unsecured credit are automatically rejected, and the NYISO's tariffs also allow the NYISO to immediately suspend a customer's trading privileges in the event the customer exhausts its collateral/unsecured credit.[75]

With respect to the Virtual Transaction Component of the Operating Requirement, the amount of credit support required for both the Virtual Supply and Virtual Load credit requirements of the Virtual Transaction Component is based on the price differential between the energy price in the Day-Ahead Market and the Real-Time Market, calculated over a period starting April 1, 2005[76] and ending with the end of the preceding calendar month, with adjustments for the time of day, season and Load Zones.[77] At present, Market Participants are only permitted to submit virtual bids on a zonal basis; hence the credit coverage requirement for Virtual Transactions is based on the price dispersion for these Load Zones.

E. Additional Minimum Participation Criteria in Response to FERC Credit Order No. 741

In accordance with FERC Order No. 741, the NYISO added additional minimum participation criteria, including capitalization requirements, to its tariffs effective October 1, 2011. Specifically, Services Tariff Section 26.1.1(d) requires all NYISO applicants and Market Participants to meet one of the following capitalization criteria in order to participate in NYISO-administered markets:

1) $10 million in assets based on the Market Participant's, or its guarantor's with the provision of an unlimited guaranty in compliance with Services Tariff Section 26.5.4, most recent audited financial statements;

2) $1 million in tangible net worth based on the Market Participant's, or its guarantor's with the provision of an unlimited guaranty in compliance with Services Tariff Section 26.5.4, most recent audited financial statements; or

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75 The NYISO's adjustment of each Market Participant's TCC credit requirements in light of the net mark-to-market value of TCCs in the Market Participant's portfolio is discussed in Attachment D, *infra*, as is the NYISO's system of marking-to-market on a daily basis each Market Participant's Virtual Transaction credit requirement.

76 On February 1, 2005, the NYISO deployed the SMD2 (Standard Market Design) computer platform to replace its Legacy platform used to dispatch the New York electricity system in real-time and to determine real-time energy prices. The NYISO limited the scope of its analysis of the Virtual Transaction credit requirements to include only data from the SMD2 platform because software design changes and other factors affecting the determination of Energy prices in the Real-Time Market prior to the implementation of SMD2 could make the price differential data from pre-SMD2 time periods less reliable as an indicator of prospective price dispersion. For similar reasons, the NYISO started its historical analysis with April 1, 2005, instead of February, 1, 2005, because adjustments to the February and March 2005 SMD2 data as a result of the platform transition could make the data from those time periods less reliable.

77 The New York Control Area is divided into 11 geographical areas referred to as Load Zones and identified by the letters A-K. A map depicting the eleven existing Load Zones, designated "A" through "K," is posted on FERC's website at http://www.ferc.gov/market-oversight/mkt-electric/new-york.asp.

3) If a Market Participant cannot meet either (1) or (2), it must post $200,000 ($500,000 if participating in the TCC market) with the NYISO. Such funds cannot be used to satisfy that Market Participant's credit requirements.

In addition, each Market Participant trader authorized to bid in the TCC market or participate in Virtual Transactions must successfully complete the NYISO-administered online training specific to those products. *See* NYISO Services Tariff Section 26.1.1(b). The NYISO anticipates offering such training online beginning January 1, 2012. The training will include a test to evaluate user understanding and successful completion of the training course.

Each Market Participant must submit an annual certification, signed by a duly authorized officer, attesting to the Market Participant's compliance with all minimum participation criteria. *See* NYISO Services Tariff Section 26.1.2. Each Market Participant must certify annually to the following:

1) that the Market Participant maintains current, written risk management policies and procedures that address those risks that could materially and adversely affect the Market Participant's ability to pay its NYISO invoices when due, including, but not limited to, credit risks, liquidity risks, and market risks;
2) that all employees and agents of the Market Participant with the right to bid, offer, or schedule in the NYISO-administered markets have appropriate training and/or experience to transact in such markets;
3) that all employees and agents of the Market Participant with the right to bid on Virtual Transactions or TCCs has successfully completed the designated NYISO-administered training course on Virtual Transactions and/or TCCs, as applicable;
4) that the Market Participant has appropriate personnel resources and technical abilities to allow the Market Participant to promptly and effectively respond to all communications and directions from the NYISO related to settlements, billing, credit requirements and other financial matters; and
5) that the Market Participant is in compliance with the NYISO's minimum capitalization requirements.

The NYISO implemented this certification requirement effective October 1, 2011 and has received all initial certifications from its active Market Participants. Those Market Participants who failed to provide a certification form and/or failed to meet the minimum participation requirements were suspended or terminated from participation in NYISO-administered markets.

F. Verification of Market Participant Risk Management Policies

Pursuant to Services Tariff Section 26.1.3, the NYISO may require any Market Participant, at any time, to submit its risk management policies and description of internal controls to the NYISO for review. This provision requires Market Participants to submit to the

NYISO, upon request, "any information or documentation reasonably required for the ISO to monitor and evaluate [a Market Participant's] creditworthiness and compliance with requirements set forth in the ISO Tariffs, ISO Procedures, and/or ISO Agreements related to settlements, billing, credit requirements, and other financial matters." *See* NYISO Services Tariff Section 26.1.3.

In addition , Services Tariff Section 26.1.3.1(a) requires each applicant for the TCC market to submit its risk management policies and procedures to the NYISO for verification prior to commencing any activity in the TCC market. Services Tariff Section 26.1.3.1(b) requires each Market Participant in the TCC market to maintain on file with the NYISO a copy of its risk management policies and procedures. Moreover, Services Tariff Section 26.1.3.1(c) categorically subjects to verification each Market Participant in the TCC market with a concentration of negative or low positive TCCs in any month in the immediately preceding 36 months because these TCC concentrations pose the greatest risk of payment default. Holders of negative TCCs must make congestion payments to the NYISO. Low positive TCCs run a disproportionately high risk of becoming negative TCCs. The requirements of Services Tariff Sections 26.1.3.1(b) and (c) do not apply, however, to Market Participants in the TCC market that solely own Grandfathered Rights, Grandfathered TCCs, and/or Fixed Price TCCs, which products are used to hedge congestion costs.

Further, Services Tariff Section 26.1.3.1(d) allows the NYISO to annually select for verification 10-20% of Market Participants that are not already subject to verification pursuant to Services Tariff Section 26.1.3.1(c). Market Participants randomly selected for risk management verification and satisfactorily verified are excluded from such verification based on a random selection for the subsequent two years.

Services Tariff Section 26.1.3.2 sets forth eight criteria that the NYISO will assess when reviewing a Market Participant's risk management policies and procedures. These eight criteria were developed in conjunction with the other ISOs/RTOs and no stakeholders objected to these criteria. For each Market Participant subject to risk management verification, continued eligibility to participate in the NYISO-Administered Markets is conditioned upon the NYISO notifying the Market Participant of successful completion of the NYISO's verification.

Attachment C—DCO Core Principle C: Participant and Product Eligibility

PJM

A. Admission and Continuing Eligibility Standards.

Although not all DCO core principles apply in RTO markets, the material provisions of PJM's membership criteria and creditworthiness requirements generally are comparable to this DCO core principle.

As required by the FERC, PJM is an open access transmission provider. To qualify as a PJM member an entity must:

- Be a transmission owner, a generation owner, another supplier, an electric distributor, or an end-use customer;

- Accept all obligations of members set forth in the PJM OA, which include: maintenance of adequate records and provision of data to allow for coordination of PJM operations; maintenance of certain required equipment and facilities; performance of adequate training for personnel; sharing certain operation costs; compliance with PJM manuals and PJM directives in managing emergencies; cooperation with other members in planning and operation of facilities in the PJM region; and compliance with certain reporting obligations; and

- Satisfy certain credit requirements including completion of a credit application that confirms the member's financial obligations to PJM.[78]

In addition, in response to the requirements of FERC Order No. 741, PJM made its compliance filing to revise the PJM Tariff to include minimum participation requirements.[79] On September 15, 2011, FERC conditionally accepted these tariff revisions subject to a further compliance filing.[80] The PJM Tariff currently includes a two-pronged set of minimum participation requirements in response to the FERC's Order No. 741. The first prong requires market participants to provide an annual certification by a senior officer during a period beginning January 1 and ending April 30. For market participants applying to become new PJM members, such certification must be provided together with the prospective member's credit application. Appendix 1 to Attachment Q of the PJM Tariff, PJM's Credit Policy, sets forth the certification form, which requires representations that:

- The senior officer has signature authority;

[78] PJM OA Section 11.6.

[79] Order No. 741 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER11-3972-000 (June 30, 2011).

[80] *PJM Interconnection, L.L.C.*, 136 FERC ¶ 61,190 (2011).

- All employees or agents transacting in the PJM markets on behalf of the market participant, have received appropriate training and are authorized to transact on behalf of the market participant;[81]

- The participant has written risk management policies, procedures, and controls, approved by Participant's independent risk management function and applicable to transactions in the PJM markets in which it participates and for which employees or agents transacting in markets or services provided pursuant to the PJM Tariff or PJM Operating Agreement have been trained, that provide an appropriate, comprehensive risk management framework that, at a minimum, clearly identifies and documents the range of risks to which Participant is exposed, including, but not limited to credit risks, liquidity risks and market risks;[82]

- Certain FTR participants must certify to the following additional risk management measures specific to the FTR markets;[83]

- An FTR Participant (as defined in Attachment Q to the PJM Tariff) must make either of the following 3.a. or 3.b. additional representations:

3.a. Participant transacts in PJM's FTR markets with the sole intent to hedge congestion risk in connection with either obligations Participant has to serve load or rights Participant has to generate electricity in the PJM Region ("physical transactions") and monitors all of the Participant's FTR market activity to endeavor to ensure that its FTR positions, considering both the size and pathways of the positions, are either generally proportionate to or generally do not exceed the Participant's physical transactions, and remain generally consistent with the Participant's intention to hedge its physical transactions.[84]

3.b. On no less than a weekly basis, Participant values its FTR positions and engages in a probabilistic assessment of the hypothetical risk of such positions using analytically based methodologies, predicated on the use of industry accepted valuation methodologies.

Such valuation and risk assessment functions are performed either by persons within Participant's organization independent from those trading in PJM's FTR

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[81] "Appropriate" training is (i) comparable to generally accepted practices in the energy trading industry and (ii) commensurate and proportional in sophistication, scope, and frequency to the volume of transactions and the nature and extend of risk taken by the participant.

[82] "Independent risk management function" includes "appropriate corporate persons or bodies that are independent of the Participant's trading functions, such as a risk management committee, a risk officer, a Participant's board or board committee, or a board or committee of the Participant's parent company."

[83] The PJM Credit Policy defines an "FTR Participant" as "any Market Participant that is required to provide Financial Security in order to participate in PJM's FTR auctions."

[84] This paragraph 3.a incorporates the tariff revisions PJM submitted on November 29, 2011 in Docket No. ER11-3972-002 in compliance with FERC's September 15, 2011 order in the same docket, and which are pending FERC action.

markets or by an outside firm qualified and with expertise in this area of risk management.

Having valued its FTR positions and quantified their hypothetical risks, Participant applies its written policies, procedures and controls to limit its risks using industry recognized practices, such as value-at-risk limitations, concentration limits, or other controls designed to prevent Participant from purposefully or unintentionally taking on risk that is not commensurate or proportional to Participant's financial capability to manage such risk.

Exceptions to Participant's written risk policies, procedures and controls applicable to Participant's FTR positions are documented and explain a reasoned basis for the granting of any exception.

Participant has provided to PJM, in accordance with Section II A. of Attachment Q to the PJM Tariff, a copy of its current governing risk management policies, procedures and controls applicable to its FTR trading activities.

- The participant has appropriate personnel, operating procedures and technical abilities to promptly and effectively respond to all PJM communications and directions;

- Participant has demonstrated compliance with the Minimum Capitalization criteria set forth in the PJM Credit Policy that are applicable to the PJM market(s) in which Participant transacts, and is not aware of any change having occurred or being imminent that would invalidate such compliance.

- The officer has read and understands the provisions of Attachment Q of the PJM Tariff applicable to Participant's business in the PJM markets, including those provisions describing PJM's minimum participation requirements and the enforcement actions available to PJM of a Participant not satisfying those requirements. The officer acknowledges that the information provided is true and accurate to the best of the officer's belief and knowledge after due investigation; and the potential consequences of making incomplete or false statements in the Certification.[85]

If the participant fails to comply with these provisions, or the certification itself, the participant will be ineligible to transact in the PJM markets and PJM will arrange to have the Participant's access to the PJM markets disabled until PJM receives the Participant's certification.

Furthermore, certain FTR Participants must provide PJM with a copy of their current governing risk control policies, procedures and controls. These FTR Participants include those who: (1) cannot represent that they transact in the FTR markets with the sole intent to hedge

[85] This bullet includes the description of the tariff revisions PJM submitted on November 29, 2011 in Docket No. ER11-3972-002 in compliance with FERC's September 15, 2011 order in the same docket, and which are pending FERC action.

congestion risk in connection with either obligations the Participant has to serve load or rights the Participant has to generate electricity in the PJM Region ("physical transactions"); and (2) initially represent they transact FTRs with the sole intent to hedge congestion risk in connection with their physical transactions but who, in PJM's judgment (based on PJM's insight derived from its role in billing and settling all of a participant's market activity), in fact are not eligible to make that representation and are unable to offer PJM additional information to convince PJM otherwise. PJM will review these FTR Participants' risk policies, procedures, and controls to determine whether they appear generally conform to prudent risk management practices for entities trading in FTR-type markets. PJM has begun discussions with the Committee of Chief Risk Officers to explore whether that organization can establish a range of industry standard practices addressing internal risk controls applicable to FTR trading. If such standards emerge, PJM may, following stakeholder discussion, conduct its verification against such standards. Additionally, PJM may outsource the verification process to a third party. If an FTR Participant cannot or does not make the required representations, PJM will terminate going forward the participant's rights to purchase FTRs in the FTR market and may terminate the FTR Participant's rights to sell FTRs in the PJM FTR market.

PJM also has proposed a periodic compliance verification process, under which PJM will review and verify, as applicable a Participant's risk management policies, practices and procedures pertaining to the Participant's activities in the PJM markets.[86] Such review will include verification that: (1) the risk management framework is documented in a risk policy addressing market, credit and liquidity risks; (2) the Participant maintains an organizational structure with clearly defined roles and responsibility that clearly segregates trading and risk management functions; (3) there is clarity of authority specifying the types of transactions into which traders are allowed to enter; (4) the Participant has requirements that traders have adequate training relative to their authority in the systems and PJM markets in which they transact; (5) as appropriate, risk limits are in place to control risk exposures; (6) reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organization; (7) processes are in place for qualified independent review of trading activities; and (8) as appropriate, there is periodic valuation or mark-to-market of risk positions. If principles or best practices relating to risk management in PJM-type markets are published by a third-party industry association, PJM, following stakeholder discussion and notice, may apply such principles or best practices in determining the sufficiency of the Participant's risk controls. PJM may select Participants for review on a random basis and/or based on identified risk factors, such as, but not limited to, the PJM markets in which the Participant is transacting, the magnitude of the Participant's transactions in the PJM markets, or the volume of the Participant's open positions in the PJM markets. PJM may retain outside expertise to perform this review and verification. A Participant's continued eligibility to participate in the PJM markets is conditioned upon PJM notifying the Participant of successful completion of PJM's verification. If within 14 days of notification of unsuccessful completion of the verification process, the Participant demonstrates to PJM that it has filed with FERC an appeal of PJM's risk management verification determination, then the Participant will retain its transaction rights pending FERC's determination on the appeal.

[86] PJM Tariff, Attachment Q, Section Ia.A (as revised by PJM's further compliance filing submitted to FERC on November 29, 2011 in Docket No. ER11-3972-002)).

The second prong addresses participant capitalization requirements. Pursuant to Attachment Q of the PJM Tariff, a participant establishes full compliance through audited financials showing either tangible net worth in excess of $1 million or tangible assets in excess of $10 million if the participant is active in the FTR market, and half of either amount if the participant is not active in the FTR market. Compliance could be established either by the participant itself or through a guaranty from a compliant guarantor.

Participants that are not fully compliant would be allowed to transact through a third party who meets the eligibility standards, or through the provision of collateral (only cash or a letter of credit held by PJM). The "collateral option" requires a minimum $500,000 of collateral for participants that are active in the FTR market and $200,000 of collateral for participants that are active in virtual bidding but not FTRs. A 10% reduction would be assessed on all collateral beyond those minimums and the remaining collateral value would then be available to satisfy PJM's normal credit requirements.

A participant also could meet the compliance requirements, without triggering additional minimum participation requirements, through use of Auction Revenue Rights ("ARR") credits (credits related to physical load obligations).

All entities that meet the membership criteria and the applicable minimum participation criteria, may participate in PJM's markets, including participation in the FTR market. Participants who are virtual bidders, lacking physical assets, may submit virtual bids and offers which establish a position in the day-ahead market (such a position is, in turn, settled in the real-time market). Consequently, speculators who meet PJM's minimum participation requirements and are PJM members can participate in the FTR market and the day-ahead or real-time energy market.

With respect to the secondary, bilateral market for FTRs, although any entity is able to purchase FTRs from current holders in the secondary, bilateral FTR market, consent from PJM is required for a seller to effectuate such a delegation of the FTR obligations to the buyer. Such consent is based upon PJM's assessment of the buyer's ability to perform the obligations, including meeting the applicable creditworthiness requirements, transferred in the bilateral agreement. If PJM's consent to a delegation is *not* provided, then title to the FTR does *not* transfer to the third party and the original holder retains all rights and obligations associated with the FTR.[87]

Based on these membership criteria and creditworthiness requirements, the overwhelming majority of PJM's members are generators, power marketers, load serving entities, or other market participants who have the relevant experience and resources to manage risk proactively and effectively. Most PJM members fall within the CEA definition of an "eligible contract participant" or an "eligible commercial entity." As such, these entities are

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[87] PJM Tariff, Attachment K Appendix, Section 5.2.2(d)(iii).

substantially capitalized, sophisticated organizations that are able to manage effectively the risks associated with participating in PJM's markets (*e.g.*, PJM members have the capacity to model and monitor the markets to anticipate and manage risk).

Although some PJM members do not fall within the CEA definitions of an "eligible contract participant" or an "eligible commercial entity," PJM permits these entities to participate in its markets for policy reasons. For example, as CFTC Staff noted in their comments to FERC's Order No. 741 Notice of Proposed Rulemaking, certain entities such as municipalities and electric cooperatives need access to PJM's wholesale electric market to serve their customers. Although such entities may have limited financial resources, they pose little risk to PJM and its members because their market activity also is limited.

Currently, two special provisions of the PJM Tariff apply to municipal electric systems. First, per PJM's Credit Policy in Attachment Q to the PJM Tariff, PJM may consider additional factors such as the municipal electric system's taxing authority or independent ratemaking authority in addition to the factors considered when assessing any other member's potential unsecured credit limit for purposes of assessing a municipal electric company's ability to obtain an unsecured credit allowance. Second, in recognition that municipal electric systems may, at times, face unique circumstances that could temporarily prevent their ability to make payments when due on a weekly bill issued pursuant to Section 7.1(b) of the PJM Tariff, PJM may allow a municipal electric system to make arrangements with PJM whereby PJM would extend trade credit to the municipal electric system sufficient to enable it to make payment on a weekly bill provided that the following conditions are met:

- PJM determines, in its sole discretion, that it has sufficient excess working capital available to complete financial settlement with other market participants;
- The municipal electric system reimburses PJM for the actual cost of such working capital;
- The municipal electric system provides PJM with a binding representation that it has all legal rights and authority to enter into the arrangement with PJM;
- PJM will continue to issue weekly bills to the municipal electric system in accordance with PJM Tariff Section 7.1(b) and the municipal electric system will make payment as due under the weekly bills using the proceeds it obtains under its arrangement with PJM. Reimbursement of these amounts, including PJM's actual costs of working capital, shall be due from the municipal electric system at the time payment is due for the invoice issued under PJM Tariff Section 7.1A(a);
- The aggregate of all financed amounts and accrued obligations shall not exceed the Working Credit Limit available to the municipal electric system;
- The municipal electric system provides PJM with at least one week of notice (though PJM may waive this provision); and

- The accumulated duration of such postponed payments shall not exceed three months in a rolling twelve-month period.

PJM may terminate this payment option at any time it determines that its excess working capital is no longer sufficient to allow further or continued extension financing. In such cases, PJM must attempt to give five business days, but not less than three business days, notice to the affected municipal electric system and may call for immediate reimbursement of any outstanding amounts owed by the municipal electric system. In the time since this second provision has been included in PJM's Tariff, no municipal electric system has requested that it be allowed to settle monthly instead of the usual weekly billing and settlement.

PJM permits virtual traders, which are essentially small liquidity providers, to participate in its FTR and other markets. This is consistent with FERC's policy directive to establish efficient markets.[88] The CFTC Staff Comments to the FERC Order 741 NOPR presuppose, and are based on, a market model that utilizes a clearinghouse. The ISO/RTO markets, however, do not have clearing members who provide intermediary services to other entities. It would be incompatible with PJM's FERC-approved tariff to require market participants to transact through an intermediary, such as a futures commission merchant ("FCM"), in order to transact in the PJM market.

In addition, while PJM does not have different levels of membership, it establishes different credit requirements for participating in certain markets.[89]

- <u>Energy Market.</u> For PJM's energy market, regulation market and other ancillary service markets, credit requirements are established based upon both historical and current activity.
- <u>Capacity Market.</u> In PJM's capacity market, credit requirements are established for companies posing a risk of non-compliance in an amount equal to the possible net penalty they may be assessed. Those requirements must be met before offering capacity to the auction.
- <u>FTR Market.</u> In the FTR market, unsecured credit is not allowed, and collateral, which is required on a portfolio basis based upon path-specific historical values, must be established prior to bidding into the auction. The maximum level that a participant can bid is constrained by the credit they are afforded prior to bidding.
- <u>Virtual Biding.</u> Virtual bidding is not a separate market, but is integrated with the physical energy market. Virtual bidding may be used to hedge physical activity; however, all virtual bids are subject to review, and participants bidding at excessive levels must have all subsequent bids screened prior to acceptance.

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[88] *See e.g.,* PJM Interconnection L.L.C., 104 FERC ¶ 61,309, at P 20 (2003) ("Generally speaking, [FERC] agree[s] that virtual bidding can provide market benefits such as increased market liquidity and price convergence between the day ahead and real time markets.)

[89] PJM Tariff, Attachment Q, Sections II.D (Peak Market Activity), III (Virtual Bidding), IV (Reliability Pricing Model), and V (FTR market).

As noted above, PJM members may transact through another eligible member. These members are not intermediaries. Instead, they essentially act as a "credit sleeve" and are considered a principal. The principal becomes the member responsible for all transactions with PJM.[90] PJM intends that any such arrangement where "members may transact through another eligible member," as that phrased is used in PJM's summary of its FERC Order 741 compliance filing, would be between a qualified member and a company that may not be able to, or may not choose to, transact directly in PJM as a member. In such a scenario, PJM would not be a party to or need to be informed of the arrangement between those two companies. PJM would consider the transacting member the party to all transactions into which it enters and thus responsible to PJM for fulfilling all related obligations and requirements under the PJM Tariff and OA.

B. Standards for Determining the Eligibility of Agreements, Contracts, or Transactions.

PJM does not submit or accept agreements, contracts or transactions for clearing. PJM only provides its own products and services that have been approved by the FERC.

C. Required Procedures.

PJM reviews each member's compliance with its membership criteria and creditworthiness requirements on an ongoing basis. For example, PJM monitors publicly available information on its members on a daily basis for credit rating downgrades or other material adverse changes.[91] PJM also regularly monitors members' positions to ensure that they remain within available credit allowances.[92] Annually, PJM conducts a comprehensive credit review of members that are permitted to use unsecured credit.[93] PJM's Credit Policy further requires that market participants provide notice of any material change to its credit application.[94]

PJM's rules implementing FERC Order No. 741 require annual certification from PJM members attesting that the member satisfies PJM's minimum participation requirements, as summarized above.[95] In addition, PJM requires certain FTR Participants to submit a copy of their current governing risk control policies, procedures and controls applicable to their FTR trading activities. PJM will review such documentation to verify that it appears generally to conform to prudent risk management practices for entities trading in FTR-type markets. If principles or best practices relating to risk management in FTR-type markets are published, as

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90 *See* PJM standard short form "Declaration of Authority" available at http://www.pjm.com/about-pjm/member-services/~/media/about-pjm/member-services/membership-assistant/doa-full-responsibility-transfer.ashx.

91 PJM Tariff, Attachment Q, Section II.E.

92 PJM Interconnection, L.L.C., *Credit Overview and Supplement*, Version 2.2 (Dec. 16, 2011) pages 3-4 "Credit Monitoring," *available at* http://www.pjm.com/about-pjm/member-services/~/media/pjm-settlement/credit/pjm-credit-overview.ashx.

93 PJM Tariff, Attachment Q, Section I.B.

94 PJM Tariff, Attachment Q, Section I.B.3.

95 *See* discussion above on "Participant and Product Eligibility."

may be modified from time to time, by a third-party industry association, such as the Committee of Chief Risk Officers, PJM, following stakeholder discussion and notice, may apply such principles or best practices in determining the fundamental sufficiency of the FTR Participant's risk controls. Such FTR Participant's eligibility to participate in the PJM FTR markets is conditioned on PJM notifying such FTR Participant that its annual certification, including the submission of its risk policies, procedures and controls, has been accepted by PJM.[96]

D. Requirements.

PJM's FERC-approved membership criteria and creditworthiness requirements are objective, publicly disclosed, and permit fair and open access to PJM's markets. PJM membership is open to anyone who submits a membership application and meets the criteria set forth in the PJM OA.[97] The membership process is open to the public and includes disclosures of identifying company information as well as creditworthiness information. Entities that do not qualify for unsecured credit may participate in PJM's markets by posting appropriate collateral, as determined by the entity's market activity. Capacity and FTR markets restrict participation based on the level of collateral provided. In the initial year of a member's participation in the energy market, energy market activity requires a minimum of $50,000 credit, and a collateral call is issued if activity reaches 75% of the provided amount. [98]

[96] PJM Tariff, Attachment Q, Section Ia.A (as modified by proposed revisions submitted to FERC in compliance with September 15, 2011 Order on June 30, 2011 Order No. 741 Compliance Filing of PJM Interconnection, L.L.C., Docket No. ER11-3972-002 (Nov. 29, 2011)).

[97] This information is available on PJM's website at http://www.pjm.com/about-pjm/member-services/become-a-member.aspx.

[98] *See* PJM Interconnection, L.L.C., Credit Overview and Supplement, Version 2.2 (Dec. 16, 2011) pages 8-9, *available at* http://www.pjm.com/about-pjm/member-services/~/media/pjm-settlement/credit/pjm-credit-overview.ashx.

Attachment D

DCO Core Principle D: Risk Management

(i) IN GENERAL.—Each derivatives clearing organization shall ensure that the derivatives clearing organization possesses the ability to manage the risks associated with discharging the responsibilities of the derivatives clearing organization through the use of appropriate tools and procedures.

(ii) MEASUREMENT OF CREDIT EXPOSURE.—Each derivatives clearing organization shall—

> (I) not less than once during each business day of the derivatives clearing organization, measure the credit exposures of the derivatives clearing organization to each member and participant of the derivatives clearing organization; and
>
> (II) monitor each exposure described in subclause (I) periodically during the business day of the derivatives clearing organization.

(iii) LIMITATION OF EXPOSURE TO POTENTIAL LOSSES FROM DEFAULTS.—Each derivatives clearing organization, through margin requirements and other risk control mechanisms, shall limit the exposure of the derivatives clearing organization to potential losses from defaults by members and participants of the derivatives clearing organization to ensure that—

> (I) the operations of the derivatives clearing organization would not be disrupted; and
>
> (II) nondefaulting members or participants would not be exposed to losses that nondefaulting members or participants cannot anticipate or control.

(iv) MARGIN REQUIREMENTS.—The margin required from each member and participant of a derivatives clearing organization shall be sufficient to cover potential exposures in normal market conditions.

(v) REQUIREMENTS REGARDING MODELS AND PARAMETERS.—Each model and parameter used in setting margin requirements under clause (iv) shall be—

> (I) risk-based; and
>
> (II) reviewed on a regular basis.

Responses:

Attachment D—DCO Core Principle D: Risk Management

California ISO

As discussed in Attachment B, the CAISO tariff requires that market participants maintain unsecured credit and/or post financial security that is sufficient to meet their estimated aggregate liability at all times.[99] The CAISO calculates estimated aggregate liability based on all charges and settlement amounts for which such market participant is liable or reasonably anticipated by the CAISO to be liable.[100] The estimated aggregate liability of each market participant is calculated daily.[101]

The CAISO provides a notification to market participants whenever their estimated aggregate liability exceeds 90% of their unsecured credit and posted financial security.[102] Collateral calls are made whenever a market participant does not have sufficient unsecured credit and financial security to cover its estimated aggregate liability (*i.e.*, the market participant's estimated aggregate liability is greater than 100% of their unsecured credit and/or posted financial security).[103] Market participants have two business days to post additional financial security after a request is made by the CAISO.[104] A dispute process is available if a market participant believes that the additional financial security requested by the CAISO is unnecessary. But even if the dispute process has been initiated, the requested additional financial security must still be posted within two business days.[105] In the event that a market participant fails to post additional financial security in response to a request from the CAISO, or fails to do so within the requisite two business day period, the CAISO has a wide array of remedies available, including bringing an enforcement action and assessing a variety of sanctions against the market participant.[106]

Section 12.5.1 of the CAISO Tariff describes the remedies available to the CAISO as follows:

> If a Market Participant's Estimated Aggregate Liability, as calculated by CAISO, at any time exceeds its Aggregate Credit Limit, CAISO may take any or all of the following actions:
>
> (a) The CAISO may withhold a pending payment distribution.

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99 CAISO Tariff, § 12.1.

100 *Id.* § 12.4. A detailed description of the estimated aggregate liability calculation is included in the Business Practice Manual for Credit Management at pp. 45-57, *available at* https://bpm.caiso.com/bpm/bpm/version/000000000000121.

101 Business Practice Manual for Credit Management, p. 58.

102 CAISO Tariff, § 12.4.

103 *Id.*

104 *Id.* § 12.4.1. The CAISO has proposed to reduce this period to 2 days.

105 *Id.* § 12.4.2.

106 *Id.* § 12.5.

(b) The CAISO may limit trading, which may include rejection of Bids, including Self-Schedules, rejection or cancellation of Inter-SC Trades in their entirety (i.e., both sides of the Inter-SC Trade) at any time, and/or limiting other CAISO Market activity, including limiting eligibility to participate in a CRR Allocation or CRR Auction. In such case, the CAISO shall notify the Market Participant of its action and the Market Participant shall not be entitled to participate in the CAISO Markets or CRR Auctions or submit further Bids, including Self-Schedules, or otherwise participate in the CAISO Markets until the Market Participant posts an additional Financial Security Amount that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability.

(c) The CAISO may require the Market Participant to post an additional Financial Security Amount in lieu of an Unsecured Credit Limit for a period of time.

(d) The CAISO may restrict, suspend, or terminate the Market Participant's CRR Entity Agreement or any other service agreement.

(e) The CAISO may resell the CRR Holder's CRRs in whole or in part, including any Long Term CRRs, in a subsequent CRR Auction or bilateral transaction, as appropriate.

(f) The CAISO will not implement the transfer of a CRR if the transferee or transferor has an Estimated Aggregate Liability in excess of its Aggregate Credit Limit.

In addition, the CAISO may restrict or suspend a Market Participant's right to submit further Bids, including Self-Schedules, or require the Market Participant to increase its Financial Security Amount if at any time such Market Participant's potential additional liability for Imbalance Energy and other CAISO charges is determined by the CAISO to be excessive by comparison with the likely cost of the amount of Energy reflected in Bids or Self-Schedules submitted by the Market Participant.

The CAISO also has remedies available if a market participant posts financial security late on multiple occasions (*see* CAISO Tariff section 12.5.2), or if it pays invoices late on multiple occasions (*see* tariff section 11.29.14). For example, CAISO may require the market participant to post additional financial security in an amount equal to the highest level of that market participant's estimated aggregate liability for the preceding 12 months and hold that additional amount for at least twelve months.

Specific credit requirements apply to convergence bidders pursuant to CAISO Tariff Section 12.8. These include dynamic credit checks on the value of convergence bids.

Attachment D—DCO Core Principle D: Risk Management

Calculation of Estimated Aggregate Liability

A market participant's estimated aggregate liability is calculated using several variables, including "CRR portfolio value," "CRR auction limit," and "CRR auction awards." The virtual bid components of estimated aggregate liability are: "virtual bid reservation," "virtual day-ahead" and "virtual real-time." Each of these variables is discussed, in turn, below.

"CRR portfolio value" is the prospective value of the CRR portfolio—either the auction price or a value calculated from historical locational marginal prices, whichever method yields a more conservative result (*i.e.,* greater collateral requirement), plus an additional margin. This value is calculated daily and the estimated aggregate liability is adjusted accordingly, typically on a weekly basis.

"CRR auction limit" is the maximum amount of credit available to an auction participant. This value is set at the start of an auction and updated periodically throughout the auction to reflect other activity in the CAISO's markets, such as new settlement statements, payments made or additional collateral posted. Throughout the auction, bid values are aggregated by portfolio and compared to the CRR auction limit. If the value of the bid portfolio is less than or equal to this amount, the bid is accepted; otherwise the entire bid portfolio is rejected. Once a bid portfolio is accepted the available collateral is reduced by the bid portfolio value.

"CRR auction awards" is the liability amount, based on the clearing prices of the awarded CRRs, at the conclusion of the auction. It replaces the CRR auction limit. This amount remains until it is invoiced, at which point CRR auction awards is zeroed out and the sum is reflected instead in the published estimated aggregate liability component.

"Virtual bid reservation" is the amount of available credit necessary to cover the sum of the estimated value of all virtual bids submitted. This value remains in place until the close of the day-ahead market, at which time the updated estimated value of awarded bids are recorded in the virtual day-ahead estimated aggregate liability component. The "virtual day-ahead" value remains until the close of the hour-ahead scheduling process or the real-time market, at which time the estimated liability of the virtual award is recorded in the "virtual real-time" estimated aggregate liability component. An example of how the estimated aggregate liability is managed throughout the life of a virtual bid follows:

EAL Component	Virt'l Bidding	Close of DA	Close of RT
Virtual Bid Reservation	$100	N/A	N/A
Virtual Day-Ahead (awards)	N/A	$80	N/A
Virtual Real Time (clear)	N/A	N/A	$85

The amounts in the virtual bidding and close of day-ahead time frames are always debits. At close of real-time, however, the amount can be a debit or a credit.

Attachment D—DCO Core Principle D: Risk Management

Credit Requirements for CRR Holders

Specific credit requirements are imposed for participants in CRR auctions and CRR holders.[107] As noted in Attachment B, the CAISO has eliminated the use of unsecured credit in the CRR market except for Federal market participants meeting certain requirements mandated by FERC. Non-Federal Candidate CRR holders and CRR holders will be required to post secured collateral sufficient to meet their pre-CRR auction requirements and their CRR holding requirements.[108] As a matter of administrative practice, once a bid is submitted in the auction, secured collateral necessary to meet the pre-CRR auction requirement will be set aside and not available to cover collateral obligations arising from any other market activities.[109]

The credit requirement for holding a CRR is intended to cover the cost of holding a CRR when the settlement of the marginal cost of congestion is calculated for the day-ahead market, plus a credit margin to address uncertainty associated with CRRs due to the fact that they involve future obligations (over a month, season, year). Because most CRRs are "obligations," the CRR holder can either collect revenue or incur charges, depending on conditions on the transmission grid. If the CRR is expected to generate a charge to the CRR holder, there is a credit requirement associated with that CRR that is based on either recent auction prices or the expected value of the CRR using historical locational marginal prices,[110] plus an additional credit margin.[111] These valuations are updated at least monthly based on additional experience and extraordinary conditions on the transmission system.[112] If, by this calculation, the CRR is expected to generate revenue for the CRR holder, the expected revenue can reduce the holder's overall credit requirement for its CRR portfolios.

While expected revenue can reduce the overall credit requirement for CRRs, there are two limitations.[113] First, this expected revenue cannot reduce the CRR holder's estimated aggregate liability ("if the sum is negative, the CRR holder's Estimated Aggregate Liability shall not be reduced," *i.e.,* CRRs cannot offset the EAL of other market liabilities). Similarly, if a CRR holder has been allocated CRRs, and the complete portfolio of allocated CRRs is expected to generate revenue, this expected revenue will not reduce any credit requirement that stems from CRRs it holds that were acquired through the auction.

Section 12.6.3 of the CAISO tariff calls for netting of "offsetting CRRs." The term "offsetting CRRs" refers to CRRs that are generated to reflect load migration between Load Serving Entities ("LSEs"). When load moves from one LSE to another, a portion of the CRRs allocated to the LSE that lost load are transferred to the LSE that gained load. CAISO systems

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107 *Id.* § 12.6.

108 *Id.* §§ 12.1.3.1.1, 12.6.

109 The timing of the availability of deposited collateral is an administrative practice implemented through the software that operates the market and is not required by the Tariff.

110 *See* CAISO Tariff §§ 12.6.3.2, 12.6.3.3.

111 *See id.* § 12.6.3.4.

112 *See id.* § 12.6.3.1(c).

113 *See id.* § 12.6.3.1(b).

reflect the transfer of CRRs away from the LSE that lost load by assigning counter-flow CRRs to that LSE. As stated in Section 12.6.3.1(b) of the CAISO Tariff, the credit requirements are calculated on each CRR that is held and only the "offsetting CRRs" – which reflect the cancellation of certain CRRs – are netted.

CAISO allows a similar "cancellation" or "sale" of CRRs acquired through the auction. A CRR entity may effectively cancel or sell a CRR by acquiring a counter-flow CRR for the same points, time period and time-of-use. For example, if an entity acquired a 10 MW CRR from A to B in the annual auction for the on-peak period for January through March, it could "cancel" or "sell" a part of this CRR for the month of January by subsequently acquiring a 5 MW CRR from B to A in the January monthly auction for the on-peak period. When the January settlement for these two CRRs is calculated, the effect would be to settle 5 MW of A to B. Therefore, the credit exposure is only for the 5 MW portion of the CRR from A to B.

As noted above, the credit requirement is based upon the relative risk of positions, taking into account netting of offsetting obligations. Credit requirements for CRR portfolios are calculated daily. In addition, the CAISO may recalculate a CRR holder's credit requirements in the event of an extraordinary circumstance, such as an extended transmission outage. These updated credit requirements are then reflected in the market participant's estimated aggregate liability calculation, and requests for additional collateral are made as described earlier.

Attachment D—DCO Core Principle D: Risk Management

ERCOT

A. Risk Management.

ERCOT's risk management tools and procedures are comparable to those required by this core principle.

Authorization

ERCOT is authorized to manage credit risk. As discussed above, PURA § 39.151 (a)(1)-(4) prescribes the overarching functions of ERCOT, including the requirement to ". . . ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region." This broad charge is implemented in the first instance by the PUCT Substantive Rules, and then further by the ERCOT Protocols.[114] This discretion is not contingent on a material adverse change, but gives ERCOT the right, both market wide and on a case by case basis, to ensure market participants are adequately collateralized relative to their market obligations.

The PUCT Substantive Rules mirror provisions in PURA, including the obligation to "…ensure that electricity production and delivery are accurately accounted for among the generators and wholesale buyers and sellers in the region." The PUCT's regulations go on to prescribe several overarching functions, including ERCOT's duty to " administer, on a daily basis, the operational and market functions of the ERCOT system . . . as set forth in . . . [the] ERCOT [Protocols]" and "administer settlement and billing for services provided by ERCOT, *including assessing creditworthiness of market participants and establishing and enforcing reasonable security requirements in relation to their responsibilities under [the] ERCOT-[Protocols]*."[115]

As discussed above, the legislative and regulatory construct that governs ERCOT requires it to establish credit and security rules for the ERCOT markets. Accordingly, ERCOT has the ability and the *obligation* to ensure the potential financial risks associated with participation in its market are mitigated pursuant to appropriate credit/security rules. This obligation is reflected in the ERCOT Protocols.[116] In addition, risk management is one of the qualifications for unaffiliated Board members specified in the ERCOT Bylaws.[117]

Organization and Process

ERCOT's Vice President of Credit and Enterprise Risk Management is responsible for managing all corporate risk, including market credit risk. The Enterprise Risk function is charged with identifying and prioritizing risks to the organization on an ongoing basis,

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114 P.U.C. SUBST. R. 25.361(b)(2) and ERCOT Protocol Sections 1.2, and, specifically, Section 16.11, which addresses financial security requirements for market participants.

115 P.U.C. SUBST. R. 25.361(b)(2) and ERCOT Protocol Sections 1.2, and, specifically, Section 16.11.

116 ERCOT Protocol Section 16.11.

117 ERCOT Bylaws, Section 4.3(b)(2)(i).

communicating risks to management and stakeholders, and supporting effective risk management processes, standards and governance.

Controls within the scope of the Statement on Standards for Attestation Engagements (SSAE) 16 are monitored on an ongoing basis to ensure ongoing suitability by a group within the Credit and Enterprise Risk Management function. These Standards are designed to provide assurance that proper internal controls relevant to financial reporting are in place. Furthermore, ERCOT is subject to annual SSAE16 compliance audits.

Within the Credit organization, process controls are in place to ensure adequate measurement, monitoring and reporting of all Counter-Party credit exposures and to monitor Counter-Party credit-worthiness on an ongoing basis.

ERCOT employs an Internal Audit function with independent reporting to the Board. Internal Audit supports effective enterprise risk management by developing a risk-based audit plan, testing controls, and providing recommendations for improvement.

Finally, ERCOT employs experienced staff throughout the organization, including its credit staff, and provides education and training opportunities so as to support an environment in which employees are proficient in identifying and acting on organization risks as appropriate.

Tools

ERCOT utilizes an automated system to calculate credit exposure. The Credit Monitoring and Management system (CMM):

- Calculates exposure daily from data received every day, including holidays and weekends, from source systems (including a full CRR inventory, updated payments received, and updated exposure calculations);[118]
- Aggregates exposure at a Counter-Party level to ensure that a Counter-Party's overall credit risk is considered;[119]
- Highlights entities that are at or near their credit limit for action by Credit staff;
- Sends updated Available Credit Limits (ACL) daily to both the CRR system and the Day Ahead Market system;[120]

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[118] ERCOT Protocol Section 16.11.4.1.

[119] ERCOT Protocol Section 16.11.4.1.

[120] ERCOT Protocol Sections 16.11.4.6, 16.11.4.6.1, and 16.11.4.6.2.

- Posts reports at least daily for Counter-Parties that details how their exposure is calculated and provides their ACL;[121]

In addition, both the Day Ahead Market system and the CRR Auction engine enforce credit constraints.[122]

Market Procedures

Market Participants are required to meet specific eligibility requirements to participate in the ERCOT markets.[123] This is a structural risk management tool that acts as an *ex ante* approach to mitigating potential market defaults.

Market eligibility also is contingent upon compliance with all applicable requirements in the ERCOT Protocols.[124] ERCOT has sole discretion to suspend a CRRAH's or a QSE's rights as a Market Participant if it reasonably determines that such suspension is an appropriate remedy for failure to satisfy any applicable Protocol requirement.[125]

Key aspects of ERCOT's credit process provide that ERCOT:

1) Establishes unsecured credit for Counter-Parties within the boundaries defined in its Creditworthiness Standard. Unsecured credit is subject to a $50 million limit and is granted solely within ERCOT's discretion. [126]

2) Monitors daily for changes in creditworthiness of Counter-Parties, Guarantors and banks, and takes action as needed.[127]

3) Accepts a limited number of forms of collateral: third party guarantees; unconditional, irrevocable Letters of Credit (LCs); surety bonds with ERCOT as beneficiary; or cash.[128]

    a. Utilizes standard forms to ensure strong and consistent terms and conditions are applied.

4) Accepts LCs and Guarantees only from entities that meet the Creditworthiness Standards. ERCOT's Creditworthiness Standard requires that any Letters of Credit must be: (1)

[121] ERCOT Protocol Section 16.11.4.7.

[122] ERCOT Protocol Sections 16.11.4.6, 16.11.4.6.1, and 16.11.4.6.2.

[123] ERCOT Protocol Sections 16.2.1 and 16.8.1; NPRR 438, which will incorporate a new Protocol Section 16.16.

[124] Participants are required to sign a market participant Standard Form Agreement that obligates them to comply with ERCOT rules. ERCOT Protocol Section 22, Attachment A, Section 5.A.

[125] ERCOT Protocol Sections 16.2.1 and 16.8.1; NPRR 438, which will incorporate a new Protocol Section 16.16.

[126] ERCOT Protocol Section 16.11.2 and ERCOT Creditworthiness Standards.

[127] ERCOT Protocol Section 16.11.5.

[128] ERCOT Protocol Section 16.11.3.

issued by a bank with a minimum rating of A- with Fitch or S&P or A3 with Moody's; (2) issued on the Standard Form document approved by the Board of Directors; and (3) accepted subject to the review and approval of ERCOT. ERCOT has the right to not accept a letter of credit from a bank that it deems "at risk."[129] ERCOT periodically reviews the concentration of letters of credit issued by a particular issuer to: (1) understand what, if any, concentration issues may exist in its markets; (2) educate market participants about concentration risk and determine what further actions, if any, are necessary; and (3) if a bank is determined to be "at risk", identify all collateral that may need to be replaced or addressed in some other way.

5) Ensures that the combined settlement and payment process occurs promptly.

    a. Day Ahead Market activity, including settlement of most CRRs, occurs within 14 days.[130]

    b. Real Time Market activity settlement currently occurs within 21 to 31 days.[131]

        i. In 2011, Protocol changes were approved that will ensure that approximately 90% of Real Time days are settled and paid within 15 days with the average combined settlement and payment cycle being no more than 15 days. Settlement and payment timelines longer than the above are due to holiday schedules. Implementation of this change is expected in 2012.

        ii. All outstanding receivables are included in ERCOT's credit exposure calculation and are collateralized as required by ERCOT Protocols.[132]

6) Updates credit exposure for all markets and for all market participants at least once each day, including holidays and weekend, to ensure exposure is adequately covered, including mark–to–market values for CRRs.[133]

    a. Forward exposure for CRRs is determined for all CRRs held based on auction clearing price and recent historical pricing.[134]

    b. ERCOT currently allows Counter-Parties to net current obligations (*e.g.*, DAM or RT markets) with forward CRR positions *if:* a) they have granted ERCOT a first priority security interest; or b) they are a Cooperative or Electric Cooperative or an entity created under Texas Water Code (TWC) § 222.001, Creation. However, Protocol changes have been approved that will restrict or eliminate netting of

[129] ERCOT Corporate Standard CS3.2, *Investment Corporate Standard*, at Appendix A.

[130] ERCOT Protocol Sections 9.2.4, 9.3 and 9.4.1.

[131] ERCOT Protocol Sections 9.5.4; 9.6 and 9.7.1.

[132] ERCOT Protocol Section 16.11.4.3.

[133] ERCOT Protocol Section 16.11.4.1.

[134] ERCOT Protocol Section 16.11.4.5

current exposure from DAM and RT activity with CRR forward mark–to–market positions. Implementation of this change is expected in 2012.[135]

7) Requires Counter-Parties (CRRAHs and QSEs) to post collateral for 100% of calculated market exposure, net of unsecured credit.[136]

8) Operates all ERCOT market activity under one credit limit, utilizing both collateral and unsecured credit.[137]

    a. Under approved revisions to ERCOT protocols, CRR Auction and CRR forward mark–to–market values will be fully collateralized rather than subject to unsecured credit. Implementation of this revision is expected in 2012.

9) Restricts a Counter-Party's participation in the DAM and future CRR Auctions to the lesser of their Available Credit Limit (ACL) or their self-imposed limit. The ACL is equal to an entity's unsecured credit (if any) plus collateral less its Total Potential Exposure (TPE). Market Participants are prohibited from participating in the DAM and future CRR Auctions if their TPE exceeds their credit limit. When approved changes to the ERCOT rules described in (8) above are implemented, unsecured credit will not be available for CRR positions.[138]

10) Requires Counter-Parties to provide ERCOT with all necessary information (*e.g.*, audited and unaudited financials) for themselves or their Guarantors as well as notification of any status change that may affect unsecured credit rights, if applicable to ensure ERCOT has the information it needs to evaluate credit risk in the market.[139]

11) If an entity's TPE equals or exceeds its credit limit (*e.g.*, its financial security plus its unsecured credit, if applicable), ERCOT:

    a. Requires the entity to post additional collateral within two bank business days.[140] Until corrected:

        i. ERCOT can withhold any other payments due to that entity;[141] and

        ii. ERCOT systems prohibit participation in the DAM or upcoming CRR Auctions that would create potential liability since the entity's Available Credit Limit is zero.

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135 ERCOT Protocol Section 16.11.4.1.

136 ERCOT Protocol Section 16.11.1.

137 ERCOT Protocol Sections 16.11.4.1 and 16.11.4.6.

138 ERCOT Protocol Sections 16.11.4.6, 16.11.4.6.1, and 16.11.4.6.2.

139 ERCOT Protocol Section 16.11.5 (1).

140 ERCOT Protocol Section 16.11.5 (3).

141 ERCOT Protocol Section 16.11.5 (3).

b. A participant is in payment breach if it does not pay an invoice when due or post collateral within two bank business days.[142]

c. Requires the entity to cure a payment breach within two bank business days.

   i. The breaching entity may be restricted from any participation in DAM activity and future CRR Auctions until the payment breach is cured.

   ii. The consequences of a default are that the participant's rights to participate in all ERCOT markets may be terminated.[143]

d. In particular, if a market participant violates its credit obligations, ERCOT may terminate, expel, suspend, or sanction a Member. In addition, Sections 16.11.6.1 and 16.11.6.2 specifically provide for the following remedies:

   i. No Payments by ERCOT to the defaulting participant;

   ii. Draw on, hold or distribute funds of the participant;

   iii. Aggregate amounts owed by breaching participant and immediately due;

   iv. Repossess and resell CRRs held by the participant (sale proceeds offset debt);

   v. Declare forfeit and resell CRRs held by the participant (sale proceeds offset debt);

   vi. Honor cleared CRRs but remove them from the participant's account and use proceeds to offset debt; and

   vii. Revoke the participant's rights and terminate its outstanding agreements (the market participant remains liable for all debt and consequences for termination/revocation).

      1. On revocation of some or all of the Market Participant's (*i.e*., those that directly serve load/REP under PUCT rules) rights or termination of the Market Participant's agreements and on notice to the Market Participant and the PUCT, ERCOT shall initiate a mass transition of the Market Participant's retail customers pursuant to Section 15.1.3, Mass Transition, without the necessity of obtaining any order from or other action by the PUCT.

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142 ERCOT Protocol Section 16.11.6.

143 ERCOT Protocol Section 16.11.6.

B. Measurement of Credit Exposure.

ERCOT's procedure for measuring and monitoring credit exposure is comparable to that required by this Core principle. Under ERCOT Protocols, ERCOT:

1) Updates credit exposure for all markets and for all market participants at least once each day, including holidays and weekend, to ensure exposure is adequately covered, including mark–to–market values for CRRs.[144]

    a. Historical Real Time, DAM and CRR activity is updated through the prior day.

    b. Forward exposure for CRRs is determined for all CRRs held based on auction clearing price and recent historical pricing.[145]

    c. Forward risk for markets other than the CRR market is currently estimated using the:

        i. "Average Daily Day Ahead Liability Extrapolated" (or DALE) component of the Estimated Aggregate Liability (EAL) calculation. The DALE is used to estimate forward risk based on recent Day-Ahead Market activity. The DALE uses a 16 day multiplier to accommodate forward risk. Because the calculation is based on settled data, it is inherently based on the historical prices and volumes in the Day-Ahead Market. This multiplier is not based on the Day-Ahead Market settlement cycle but is simply a mechanism to provide for forward risk based on recent Day-Ahead Market activity.

        ii. "Average Daily Transaction Extrapolated" (or ADTE) component of the EAL. The ADTE is used to estimate ERCOT's forward risk based on recent Real-Time Market activity. ERCOT's credit exposure takes the highest Average Daily Transaction Extrapolated component calculated in the last sixty days. The ADTE is based on an average of 14 days of initial settlement statements for Real-Time Market activity, multiplied by 40. ERCOT uses 40 as a multiplier to accommodate approximately 20 days of incurred but unbilled Real-Time Market activity and approximately 20 days of forward risk. Because the calculation is based on settled data, it is inherently based on the historical prices and volumes in the Real-Time Market. This is the primary mechanism by which ERCOT provides for forward risk based on recent Real-Time Market activity.

        In conjunction with other changes made in 2011, Protocol changes were approved that will: (1) Reduce the ADTE multiplier related to incurred but unbilled Real-Time Market activity to reflect the more timely

[144] ERCOT Protocol Section 16.11.4.1.

[145] ERCOT Protocol Section 16.11.4.5.

settlement of this activity; and (2) Establish a minimum collateral requirement for forward risk based on underlying risk factors. These revisions will be implemented in 2012.

iii. Forward risk for markets other than the CRR market is reviewed for reasonableness. ERCOT recognizes that: (a) prices and volumes incurred in the future may differ from those used in any particular exposure component; and (b) activity can flip between the Day-Ahead Market and the Real-Time Market. ERCOT looks at the overall calculated exposure relative to potential default risk when evaluating the adequacy of required collateral.[146]

d. Updates credit exposure intra-day for payments and/or other new information.

e. Currently allows Counter-Parties to net current obligations (e.g. DAM or RT markets) with forward CRR positions ***if*****:** (a) they have granted ERCOT a first priority security interest or (b) they are an Electric Cooperative or an entity created under Texas Water Code (TWC) § 222.001.[147]

  i. In 2011, Protocol changes were approved that will eliminate netting of current exposure from DAM and RT activity with CRR forward mark–to–market positions.

f. Requires Counter-Parties (CRRAHs and QSEs) to post collateral for 100% of Total Potential Exposure ("TPE"), net of unsecured credit.[148]

g. Operates all ERCOT market activity under one credit limit, utilizing both collateral and unsecured credit. As described further below, unsecured credit for CRR positions will not be available when the approved rules changes become effective.[149]

  i. In 2011, Protocol changes were approved that will ensure that the CRR Auction and CRR forward mark–to–market values are fully collateralized rather than be subject to unsecured credit.

h. Restricts a Counter-Party's participation in the DAM and future CRR Auctions to the lesser of their Available Credit Limit ("ACL") or their self-imposed limit. The ACL is equal to an entity's unsecured credit (if any) plus collateral less its

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[146] ERCOT Protocol Section 16.11.4.3.

[147] ERCOT Protocol Section 16.11.4.1.

[148] ERCOT Protocol Section 16.11.1.

[149] ERCOT Protocol Sections 16.11.4.1, 16.11.4.6, 16.11.4.6.1, and 16.11.4.6.2.

TPE. Market participants are prohibited from incurring potential liability in the DAM and future CRR Auctions if their TPE exceeds their credit limit.[150]

i. CRR Auction - The lesser of the ACL or self-imposed credit limit is enforced by the CRR engine as a constraint in the solution and ensure no combination of bids and clearing prices will exceed the credit limit.[151] The CRR engine determines which CRRs to award by dividing the per MW economic benefit of each bid (defined as the Bid Price per MW less the Clearing Price per MW) by the per MW budget impact of each bid (as defined in Protocol 7.5.5.3(1)) and then ranking the results. Using this calculation, bids with higher values will clear before bids with lower values. The cutoff value for this number (above which bids clear, below which bids do not clear) is the value of the shadow price for the binding constraint as visible in the Market Operator display.

ii. In addition, there are quantitative limits to the amount of CRRs than an entity can bid to buy. The quantitative limit for each CRRAH is the lesser of the total amount of available transactions divided by the number of participants, or a maximum of 10,000 transactions. Speculators cannot purchase more than the relevant limit. For example, if there are 1,000,000 available transactions in an auction and there are 101 participants, each participant is limited to 9,901 transactions *(i.e.*, 1,000,000/101). For the same number of transactions and 99 participants, the limit would be 10,000 transactions, because that is the maximum allowed per participant, and application of the above formula in that case *(i.e.*, 1,000,000/99) would exceed the 10,000 transaction ceiling. Once the auction is complete, there are no limits on the number of CRRs that an entity can obtain and hold through the bilateral market.[152]

C. Limitation of Exposure to Potential Losses From Defaults.

ERCOT's margin requirements and other risk control mechanisms are comparable to this core principle. ERCOT does not fund market losses. Losses from defaults are funded by market participants.[153] In addition, as noted above, ERCOT expects to adopt a central counterparty structure.

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150 ERCOT Protocol Sections 16.11.4.1, 16.11.4.6, 16.11.4.6.1, and 16.11.4.6.2.

151 ERCOT Protocol Section 7.5.5.3.

152 ERCOT Protocol Section 7.5.2.

153 ERCOT Protocol Sections 9.19, 9.19.1, and 9.19.2.

Attachment D—DCO Core Principle D: Risk Management

Margin requirements and other risk control mechanisms in place to limit market participant losses.

As noted above, ERCOT updates exposure calculations daily. If an entity's TPE equals or exceeds its credit limit (e.g. its financial security plus its unsecured credit, if applicable), ERCOT:

1) Requires the entity to post additional collateral within two bank business days. Until corrected:

    a) ERCOT can withhold any other payments due to that entity; and

    b) ERCOT systems prohibit participation in the DAM or upcoming CRR Auctions that would result in additional potential liability since the entity's Available Credit Limit is zero.

2) A participant is in payment breach if it does not pay an invoice when due or post collateral within the two bank business days allowed.[154]

3) Requires the entity to cure a payment breach within two bank business days.[155]

4) The breaching entity may be restricted from any participation in DAM activity and future CRR Auctions until the payment breach is cured

5) The consequences of a default are that the participant's rights to participate in all ERCOT markets may be terminated.[156]

In particular, if a market participant violates its credit obligations, ERCOT may terminate, expel, suspend, or sanction the market participant. In addition, Section 16.11.6.1 and 16.11.6.2 specifically provide for the following remedies:

- No payments by ERCOT to the defaulting participant;
- Draw on, hold, or distribute funds of the participant;
- Aggregate amounts owed by breaching participant and immediately due;
- Repossess and resell CRRs held by the participant (sale proceeds offset debt);
- Declare forfeit and resell CRRs held by the participant (sale proceeds offset debt);

[154] ERCOT Protocol Sections 16.11.5 and 16.11.6.

[155] ERCOT Protocol Sections 16.11.5 and 16.11.6.

[156] ERCOT Protocol Sections 16.11.5 and 16.11.6.

- Honor cleared CRRs but remove them from the participant's account and use proceeds to offset debt; and

- Revoke the participant's rights and terminate its outstanding agreements (the market participant remains liable for all debt and consequences for termination/revocation.)

  - On revocation of some or all of the Market Participant's (*i.e.*, those that directly serve load/REP under PUCT rules) rights or termination of the Market Participant's agreements and on notice to the Market Participant and the PUCT, ERCOT shall initiate a mass transition of the Market Participant's retail customers pursuant to Section 15.1.3, Mass Transition, without the necessity of obtaining any order from or other action by the PUCT.[157]

If a default occurs and there is inadequate collateral (*e.g.*, possibly due to unexpected market conditions) for a particular participant, a default, if any, is handled in a two step process.

- First, all Invoice Recipients (QSEs and/or CRRAHs) due a credit are "short-paid" on a pro rata basis.

- Second, approximately six months later (to utilize true-up quality data), short-paid entities will be reimbursed when any net loss is uplifted or socialized across the market. ERCOT calculates the loss allocation factor for each Counter-Party by dividing the Counter-Party's maximum MWh activity by the sum of the maximum MWh activity determined for all Counter-Parties. In determining each Counter-Party's maximum MWh activity, ERCOT considers the Counter-Party's QSE and CRRAH volumetric activity in the Real-Time Market, Day-Ahead Market, and the CRR Auction for each Operating Day in the calendar month prior to the default month. To mitigate the effects of any large defaults, no more than $2,500,000 can be uplifted in each 30-day billing cycle.[158]

ERCOT Protocols require ERCOT to provide a market notice: (a) in the event of a Mass Transition; or (b) whenever an invoice will be short paid, identifying the short-paying entity and the amount of short payment.

ERCOT has successfully managed several defaults in the last nine years, although none have occurred in the CRR market, which opened in December 2010. ERCOT procedures for handling Mass Transition and loss socialization have been tested and have proved effective. Below is a list of the defaults experienced in the ERCOT energy market and the related uplifted losses.

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157 ERCOT Protocol Sections 16.11.5 and 16.11.6.

158 ERCOT Protocol Sections 9.19 and 9.19.1.

	(in thousands)
2003 default	
Texas Commercial Energy (approx)	15,000
Subtotal 2003 default	15,000
2005 / 2006 defaults	
AZOR	25
USAVE	210
Energy West (fka Franklin Power)	394
Utility Choice	5,043
Bridgepoint	145
Subtotal 2005/2006 defaults	5,817
2008 defaults	
NPC	1,537
HWY3	1,164
Sure	1,260
Pre-Buy	108
Lunch	93
Subtotal 2008 defaults	4,161
2011 defaults	
Abacus	616
Total defaults	25,594

D. Margin Requirements.

ERCOT's margin requirements and other risk control mechanisms are comparable those required by this core principle. ERCOT:

1) Updates credit exposure for all markets and for all market participants at least once each day, including holidays and weekend, to ensure exposure is adequately covered, including mark–to–market values for CRRs. Further discussion of what is included in the daily update may be seen in Attachment D.A, above.

2) Updates credit exposure intra-day for payments and/or other new information.

3) Restricts a Counter-Party's participation in the DAM and CRR Auctions to the lesser of its Available Credit Limit (ACL) or its self-imposed limit.

4) DAM Bids and Offers are screened at submission – Bids and offers are limited by available credit.

   Bids – Collateral is required for all positive bids, at a level between (a) recent historical prices (using a percentile of recent historical prices); and (b) actual bid amount. Collateral within that range is based on the Counter-Party's recent activity.

   Offers – Collateral is required for the DA-RT price difference using a percentile of recent historical prices.[159]

5) CRR Auction activity – Bids and offers are limited by available credit. If ERCOT determines that CRR exposure is not being adequately collateralized, Section 16.11.4.1 allows ERCOT to adjust its collateral requirements.[160] ERCOT's systems also provide a mechanism for adjusting how ERCOT calculates credit exposure.

E. Requirements Regarding Models and Parameters.

ERCOT's models and parameters for margin requirements and other risk control mechanisms are comparable to those required by this core principle. ERCOT Protocols require that DAM, CRR, and key Credit Management System ("CMS") credit parameters be reviewed at least annually. Furthermore, credit models and parameters are risk based.

- CMS - Historical risk is measured on a timely basis and collateralized;[161]
- CMS - Forward CRR mark–to–market values for all CRRs held are determined using both auction clearing prices and recent historical DAM values. Values are updated daily based on current DAM valuations;[162]
- CMS - Forward values for RT and DAM markets are based on recent historical activity and are evaluated for reasonableness;[163]
- DAM credit parameters use a percentile of recent historical prices to determine exposure;[164]
- CRR Auction – the auction solution ensures that awarded CRRs are within credit constraints;[165]

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159 ERCOT Protocol Section 4.4.10.

160 ERCOT Protocol Section 16.11.4.1 (3).

161 ERCOT Protocol Sections 16.11.4.1, 16.11.4.3, 16.11.4.4, 16.11.4.5, 16.11.4.6, and 16.11.5.

162 ERCOT Protocol Sections 16.11.4.1, 16.11.4.3, 16.11.4.4, 16.11.4.5, 16.11.4.6, and 16.11.5.

163 ERCOT Protocol Sections 16.11.4.1, 16.11.4.3, 16.11.4.4, 16.11.4.5, 16.11.4.6, and 16.11.5.

164 ERCOT Protocol Section 4.4.10.

165 ERCOT Protocol Section 7.5.5.3.

In each case the parameter values are recomputed on an ongoing basis, thereby ensuring that market risk is reflected in credit exposure calculations.

Attachment D—DCO Core Principle D: Risk Management

ISO New England

Measurement of Credit Exposure

ISO-NE calculates all Market Participants' obligations (*i.e.,* credit exposure) each business day in the morning and again throughout the day for those Market Participants that participate in auctions related to the FTR market, virtual transactions and the Forward Capacity Market. See Section III.B.1. and III.B.2. of Section IA to the Tariff (the Financial Assurance Policy) for the calculation that is performed. The timing of this calculation is outlined in more detail ISO-NE's internal business processes. Those that are found to have insufficient collateral available during the morning credit check are provided a margin call with a cure date of 10:00 A.M. Eastern Time of the following business day. Failure to meet such margin calls results in market suspension effectuated the same day. *See* ISO-NE Tariff, Exhibit IA, § III.B.2.c. There is no cure period afforded to those that are insufficiently collateralized to meet the obligations resulting from their FTR bids, virtual bids and offers, and FCM bids and offers. ISO-NE will simply reject the bids of under-collateralized trades in these markets, thereby preventing the entity from taking on the incremental risk. See III.B.3.a, c and d of Section IA to the Tariff (the Financial Assurance Policy). Participants must also supply proof of financial viability. *See* Section II of the Financial Assurance Policy.

ISO-NE maintains frequent contact and communication with those market participants that incur margin calls and/or bid rejections to ascertain the cause of such conditions and to assist the market participants in maintaining continued compliance with ISO-NE's credit rules. These communications are a vital part of ISO-NE's credit risk management function and contribute to the information stream utilized in assessing the potential application of ISO-NE's rights under the Material Adverse Change provisions of its Tariff. *See* the MAC discussion below.

Default Protection

As noted above in Section II (Financial Resources), ISO-NE's Tariff includes provisions that ensure that ISO-NE will recover its expenses, even in the event of a significant participant default. First, priority of payments (as established in the Billing Policy) is such that ISO-NE's administrative costs are paid first from collections. Second, defaults are socialized after realizing any collateral specific to the defaulting participant, late payment funds (composed of penalty fees paid by participants that i) make late payments, ii) incur greater than 5 margin calls or payment defaults in a 365-day rolling period, or iii) become suspended from the New England Markets), funds in the payment shortfall account (third-party financed), and possible insurance claims paid for protracted defaults. *See* Section IX of the Financial Assurance Policy (regarding the insurance); Section III of the Financial Assurance Policy (regarding serial notice and suspension penalties); Section 4 of the Billing Policy (regarding the late payment fund); and Section 4 of the Billing Policy (regarding the Payment Default Shortfall Fund). Further, an uncovered default by an ISO-NE market participant is shared by like market participants. *See* Billing Policy, Exhibit ID of the Tariff, Section 3. This policy addresses Core Principle D (iii)(II) in that it reduces the likelihood that non-defaulting participants are exposed to losses that they cannot anticipate or control. In other words, given the segregated default pools, unsecured credit exposure is largely optional.

Attachment D—DCO Core Principle D: Risk Management

Unsecured Credit

As of January 25, 2011 ISO-NE no longer accepts as a viable form of financial assurance affiliate guarantees. No form of guarantee is currently permissible for meeting an applicant or participant's credit requirements under ISO-NE's financial assurance policy. Those that are afforded the rights to unsecured credit must qualify for such an extension based upon the merits of that market participant alone without the benefit of reliance upon the balance sheet of a parent or affiliate. By no longer accepting guarantees, ISO-NE's unsecured credit exposure has been significantly reduced and is largely limited to only those market participants that are transacting to serve native load obligations.

Risk Management Program

FERC Order No.741 mandates that the "limit on the use of unsecured credit should be no more than $50 million per entity, including the corporate family to which an entity belongs." Credit Ruling Rehearing ¶9. To address the areas where ISO-NE did not comply with this limit, ISO-NE has lowered the Transmission Credit Limits for Rated Non-Municipal Market Participants and Rated Non-Market Participant Transmission Customers from $75 million to $50 million, and lowered the total credit limits (*i.e.,* the sum of the Market Credit Limit and the Transmission Credit Limit) for Rated Non-Municipal Market Participants and Non-Market Participant Transmission Customers from $75 million to $50 million. ISO-NE has also implemented an aggregate cap of $50 million on the utilization of unsecured credit from ISO-NE by all corporate Affiliates. This cap applies to the sum of any Market plus Transmission credit limits being utilized by all Affiliates at any single point in time. *See* the Financial Assurance Policy at Section II.D.

Material Adverse Change

As part of the risk management program, participants are required to notify ISO-NE if they experience a material decrease in their financial status ("material adverse change"). ISO-NE can also make a collateral call upon a material adverse change. *See* Section XI.A of the Financial Assurance Policy.

FERC Order No.741 requires that ISOs make tariff revisions to clarify when they can invoke the "material adverse change" clause. The order requires that ISOs' Financial Assurance Policies state illustrative examples of which circumstances entitle the ISO to invoke the material adverse change ("MAC") clause to compel a market participant to post additional collateral, cease one or more transactions or take other measures to restore confidence in the participant's ability to safely transact. The Order also requires that ISOs use tools that are sufficiently forward looking to assist in making its determination to invoke its MAC rights. Also, according to the Order, when the ISO is compelled to invoke the MAC clause, it must provide reasonable advance written notice to a market participant, when feasible. Such notice must be signed by an authorized representative of the ISO and contain the reasoning behind invocation of the MAC. Credit Ruling ¶¶*149, 151.* While ISO-NE was largely in compliance with the FERC's requirements for MAC, it has revised Section XI.A of the Financial Assurance Policy to add to the current illustrative list of events and/or conditions that constitute the invocation of the MAC clause. Specifically, the ISO added the following: sanctioning of the entity by FERC, SEC, CFTC, etc., or any state regulatory authority; and significant change in market capitalization.

Section XI.A also provides that, if ISO-NE determines that there has been a material adverse change, ISO-NE may require a different form of financial assurance, an additional amount of financial assurance, or both. As specifically directed in Order No. 741, the new provisions also give ISO-NE added flexibility to require that the Market Participant or Non-Market Participant Transmission Customer cease one or more transactions in the New England Markets or take other measures to restore ISO-NE's confidence that the entity can safely transact in the New England Markets.

Finally, if ISO-NE determines that there is a material adverse change in the financial condition of a Market Participant or Non-Market Participant Transmission Customer, then ISO-NE must provide to that Market Participant or Non-Market Participant Transmission Customer a signed written notice two Business Days before taking any of the actions described above, and the notice must explain the reasons for ISO-NE's determination of the material adverse change. For additional collateral requests greater than or equal to $25 million, the CFO shall first consult, to the extent practicable, with the ISO's CEO, COO, and General Counsel.

Order No.741 specifies that, in the event that a MAC has been declared, the ISOs must "establish a two-day limit to post additional collateral due to invocation of a 'material adverse change' clause or other provision of an ISO/RTO tariff." Credit Ruling ¶160. ISO-NE has modified Section XI.A such that each financial assurance default that can be cured through the provision of additional financial assurance has a cure period of no greater than two business days; provided that a customer will have five days in the event of a financial assurance default related to a downgraded investment grade rating or a default regarding non-commercial Forward Capacity Market capacity supply obligations.

Margin Requirements

Margin requirements in ISO-NE are calculated using historical data and estimates of potential future exposure for the purposes of minimizing default exposure. Settled markets are collateralized on a dollar-for dollar basis as the obligations become known. Margin requirements for market activity that has not yet been settled are based upon estimates of potential future exposure, the mechanics of which vary depending on the market. For physical hourly markets (e.g., day ahead energy, real-time energy, ancillary services) the ISO utilizes recent historical settlements to estimate potential future exposure in these markets. Specifically, the methodology presumes each market participant will incur returns over the unknown period (generally 2 to 4 business days depending on the market) equal to the net loss that market participant has experienced over the prior six days of similar market activity. If the market participant achieved a net profit over that period, it is assumed that entity did not incur a loss during the unsettled period and will not incur an incremental margin requirement. However, any losses during the prior six days will be presumed to persist during the unsettled period and thus the market participant must post margin to cover the potential "future" exposure of these spot markets. See Section III.A of the Financial Assurance Policy (Exhibit IA of the Tariff).

A similar approach is applied to those miscellaneous charges that accrue on a monthly basis. However, the ISO has identified those monthly markets that pose a material credit risk and has created more customized approaches to margining such market activity. Specifically, there are separate and distinct margining models related to the FTR Market and the Forward

Capacity Market (both the buy side and the sell side). For those resources with a capacity delivery obligation in the Forward Capacity Market without a commercially tested resource capable of making good on such obligation, margin requirements are calculated to equal approximately three months of the cost of new entry by the time of the commitment period. This potential future exposure is meant to estimate the replacement cost as well as to serve as a performance bond of sorts to assure market participants are sufficiently motivated to make good on their delivery obligation. Margin requirements are also calculated on the buy side of the capacity market for those load entities that are required to pay for the purchase of such capacity obligations. This margin requirement is based upon actual clearing prices and expected load levels to perform as a pre-settlement of sorts to ensure the buy side is sufficiently collateralized prior to incurring such capacity charges.

In both the Virtual Market and the FTR Market, proxies are established based on historical data which are then used to estimate the potential future exposure of individual market positions. Again, collateral is required in advance of bids being awarded for both the FTR and Virtual Markets, and, as such, provides for an opportunity for bid rejection in advance of the obligation being awarded. Once actual settlement information is established, the proxy-based potential future exposure estimates are replaced with actual settlement margin requirements.

The ISO regularly re-evaluates the effectiveness of these margining approaches by conducting back-casting analyses to identify any opportunities for improvements.

Attachment D—DCO Core Principle D: Risk Management

MISO

A. Credit Policy and Measurement of Credit Exposure

MISO's Credit Policy in Attachment L to the Tariff establishes that, prior to becoming a Market Participant of MISO, each applicant must have an approved credit application and establish a Total Credit Limit for services under the Tariff, including, without limitation, Transmission Service and Market Activities. Tariff, Attachment L, Policy Statement, P. 2 The Total Credit Limit of a Market Participant is the sum of its unsecured credit allowance and the financial security provided. In addition to completing a credit application, each Applicant and/or Tariff Customer is subject to a complete credit evaluation that includes, but is not limited to, a review of financial statements, if available, Rating Agency reports, and other pertinent indicators of credit strength. In addition to the initial credit evaluation for all Market Participant applicants, MISO conducts ongoing credit analysis of all Market Participants who have been granted an unsecured credit allowance.

For the purposes of its credit policy MISO divides its Tariff Customers into two categories:

A. A Category A Tariff Customer is either (i) a Tariff Customer who has granted a continuing first priority security interest to the Midwest ISO in all of its accounts receivable and other rights of payment for goods and services provided for under the Tariff or (ii) a Tariff Customer which is a municipality or joint action agency qualifying for an exemption from granting a security interest in the receivables based on MISO's right to receive payment in advance of debt service on revenue bonds.

B. A Category B Tariff Customer is one who has not granted such a receivable security interest.

Tariff, Attachment L, Implementation, I.A.6.a. P. 1; Attachment L, Section II.G.

Exposure for Category A

The Midwest ISO calculates the Total Potential Exposure of a Category A Tariff Customer by netting all charges and credits for all service categories except for FTRs. FTRs must be covered by financial security so credits in other services cannot be used to offset FTR obligations.

Exposure for Category B

The Total Potential Exposure of a Category B Tariff Customer is determined service category by service category on a daily basis and if an amount within a service category is a credit amount, that credit amount is excluded from the computation of Total Potential Exposure. The service categories for purposes of calculation of the Total Potential Exposure of Category B Tariff Customers are:

1. Energy Transactions — The sum of charges and credit associated with Real-Time Energy and Operating Reserve Markets Potential Exposure, Day- Ahead Energy and Operating Reserve Markets Potential Exposure and Congestion and Losses

Potential Exposure.
2. Virtual Transactions Potential Exposure.
3. FTR Transactions — The sum of charges and credits associated with FTR Auction Settled Transactions Exposure, Auction Revenue Rights Settled Exposure, FTR and ARR Transactions Cleared But Not Yet Settled Exposure, and FTR Portfolio Potential Exposure.
4. Transmission Service Potential Exposure.
5. Module E Potential Exposure.

The effect of the Midwest ISO Credit Policy is to allow a Category B Tariff Customer to net charges and credits within an applicable service category but not across service categories for calculation of Total Potential Exposure.

Due to MISO's ability to net market obligations and to better position itself in a bankruptcy proceeding of a Market Participant in default, MISO is evaluating the possibility of becoming a central counterparty to transactions in its markets. MISO is also discussing these issues with its Market Participants. The manner in which MISO will comply with this requirement depends, in large part, on its analysis of the effect that becoming a central counterparty and taking title to market transactions would have on MISO's operations and its Market Participants.

The reference values used to set Total Potential Exposure values for Tariff Customers are reviewed and adjusted on an annual basis, or more frequently if necessary.

Section III of Attachment L to the Tariff provides specific rules for virtual transactions and FTRs. Market Participants submitting virtual transactions must submit a proposed daily virtual MWh limit ("Virtual Limit") to MISO, which is then evaluated to determine the impact of the Virtual Limit on the Market Participant's non-FTR potential exposure. If the proposed Virtual Limit will cause the Market Participant's non-FTR potential exposure to equal or exceed its non-FTR total credit limit, the Virtual Limit is rejected. In addition, MISO has the right to reject virtual bids and offers of a Market Participant if the virtual bids and/or offers exceed the Virtual Limit for the operating day.

MISO also requires Market Participants to allocate a portion of their total financial security in order to participate in FTR Auctions. In these instances, the market participant's FTR Auction Credit Exposure cannot equal or exceed the Market Participant's FTR Auction Credit Allocation.

MISO's Credit Policy and related practices are regularly reviewed and evaluated with Market Participants and interested stakeholders in various MISO stakeholder forums.

B. Events of Default - Generally

In the event that payments received from Market Participants that owe funds are less than payments due to Market Participants that are net owed funds, MISO will (a) allocate the deficit *pro rata* to Market Participants that are net owed funds; and (b) upon deeming such amounts as uncollectible, uplift the deficit to all Market Participants based on respective market activity for the applicable billing period. See MISO Tariff Section 7. Further detail regarding the process to address defaults under the MISO Tariff is provided in Attachment G hereto.

Attachment D—DCO Core Principle D: Risk Management

New York ISO

A. Measurement of Credit Exposure

As discussed in greater detail in Attachment C, *supra*, the NYISO establishes separate credit requirements for each of its product and service categories and requires each Market Participant to maintain financial security (e.g., cash, letter of credit, or surety bond) that is sufficient at all times to meet each separate credit requirement. Market Participants with strong financial health may apply for unsecured credit to satisfy this obligation. *See* Services Tariff Sections 26.3 and 26.5. However, from November 12, 2009, the NYISO has not allowed Market Participants to use unsecured credit to meet TCC credit requirements. *See* Services Tariff Section 26.5.

A Market Participant's total credit requirement to the NYISO is known as the Market Participant's "Operating Requirement" and is the sum of the separate credit requirements (e.g., TCC Component, ICAP Component) for each market in which the Market Participant participates (e.g., TCC market, ICAP market). The methodologies underlying the calculation of each separate credit requirement project, to the extent reasonably practicable, each Market Participant's actual financial obligations to the NYISO based upon that Market Participant's specific market activities. *See* Services Tariff Sections 26.4.2.1 - 26.4.2.7. The NYISO routinely reviews and refines these methodologies, as appropriate, to better align its credit requirements with market risks based on actual market results.

The NYISO adjusts each Market Participant's TCC credit requirement upwards to the extent the net mark-to-market value of all of the TCCs in the Market Participant's portfolio exceeds the Market Participant's baseline credit requirement. *See* Services Tariff Section 26.4.2.3(b). With respect to Virtual Transactions, the NYISO, through its automated credit management system, marks-to-market on a daily basis each Market Participant's Virtual Transaction credit requirement. *See* Services Tariff Section 26.4.2.5.

The NYISO will make a collateral call when a Market Participant does not have sufficient financial security (or, when applicable, unsecured credit) to cover its estimated financial obligations. *See* Services Tariff Sections 26.6 (first paragraph) and 26.11. For Virtual Transactions, however, the NYISO will make a collateral call when the Market Participant's estimated financial obligations for Virtual Transactions reaches 50% of the unsecured credit/financial security allocated to cover Virtual Transactions. *See* Services Tariff Section 26.8.2.

B. Risk Management via Financial Surveillance

The NYISO Credit Department conducts daily monitoring of Market Participant compliance with NYISO's credit policies. The NYISO also utilizes subscription tools provided by Moody's, Standard and Poor's, Fitch Ratings, and Dunn & Bradstreet to obtain and monitor information relevant to the financial health of Market Participants (e.g., research reports, analyst opinions, industry reports, new articles, press releases, investor presentations, stock prices, credit default swap spreads).

Attachment D—DCO Core Principle D: Risk Management

The NYISO also monitors the creditworthiness of Market Participants granted unsecured credit through the use of a unique credit assessment methodology developed by Oliver Wyman, a global consulting firm with expertise in financial risk management. This methodology utilizes a combination of traditional financial ratios derived from Market Participant recent financial statement data and market-based indicators of financial performance that Oliver Wyman determined, after significant research, analysis, and statistical testing of NYISO data are most predictive of NYISO Market Participant default.

Further, the NYISO reviews the "Expected Default Frequency" of Market Participants that are public companies using Moody's CreditEdge. This product provides daily updates on the changes in the probability of a company's default based on the market value of the company's assets, its volatility, and its current capital structure.

Attachment D—DCO Core Principle D: Risk Management

PJM

A. Risk Management.

PJM's risk management provisions provide PJM with appropriate tools and procedures to manage the risks associated with operating its wholesale electricity and related markets. These provisions, as set forth in the PJM Tariff and PJM's Credit Policy, specify the forms of acceptable collateral and provide the formula for determining when additional collateral is necessary.

Many of PJM's risk management procedures are tailored to the unique environment in which RTOs operate.[166] For example, margin and value at risk are tools that clearinghouses use along with *real-time* market data to actively manage risk on a daily (or more frequent) basis. In contrast, PJM relies more heavily on a *retrospective* analysis of price behavior, plus a margin of error, to manage risk. PJM does not have insurance, guarantee funds, or an intermediary default structure. However, if a PJM market participant defaults and its posted security is insufficient, the remaining deficit is mutualized to PJM's members pursuant to PJM's Tariff and the PJM OA.

In calculating credit requirements for the FTR market, PJM includes in the calculation a discounted three-year weighted average of historical values for each individual path in a participant's portfolio.[167] PJM requires significant additional collateral for counterflow portfolios. In addition, PJM has the authority (and has exercised such authority) to require additional collateral when modeling of a participant's FTR portfolio indicates an increased level of exposure.[168]

PJM has broad discretion under its tariff to demand bid, hold, and require additional collateral for FTRs.[169] Conceptually, the FTR Credit Requirement is the price of an FTR portfolio less a discounted measure of its historical value. That calculation is performed separately for each month. The months with positive credit requirements are then added together to produce the total requirement for a participant.[170]

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[166] Note that DCOs and ISOs/RTOs have different risk control objectives. DCOs are designed to save each individual participant from exposure created by another individual participant. To that end, DCOs include multiple layers of protection including collateral, daily margin calls, and more. ISOs/RTOs, on the other hand, are mutual organizations owned by their members, with a stated objective to balance the exposure created by one member to the others against the cost of protecting against that exposure. Accordingly, the risk control mechanisms of the RTO are designed to minimize, though not eliminate entirely, the risk to the members.

[167] PJM Tariff, Attachment Q, Section V.B (defining the FTR Credit Requirement); PJM Tariff, Attachment Q, Section VIII (defining "FTR Historical Value" as "for each month, this is the historical weighted average value over three years for the FTR path using the following weightings: 50% - most recent year; 30% - second year; 20% - third year.").

[168] PJM Tariff, Attachment Q, Sections I.B.3 and II.D.

[169] PJM Tariff, Attachment Q, Section II ("PJMSettlement has the right at any time to modify any Unsecured Credit Allowance and/or require additional Financial Security as may be deemed reasonably necessary to support current market activity."); *see also* PJM Tariff, Attachment Q, Section V.

[170] PJM Tariff, Attachment Q, Section V.B.

All FTR credit calculations are performed monthly. Quarterly, annual, and long-term FTRs are broken into their monthly components for the calculation (with the price divided equally among the months). For any given month, a single FTR on a given path has a historical value equal to the 50-30-20 weighted average[171] of the path congestion value during that calendar month over the past three years. That historical value is discounted 10% (if negative, it is increased by 10%), then subtracted from the price of the FTR, resulting in the credit requirement for the FTR that month.[172]

During auction bidding, the price used for bid FTRs is the bid price. After the auction, the price used for the FTRs that cleared is the cleared price. The individual FTR credit requirements are summed up across all FTRs in a participant's portfolio for each month, resulting in a subtotal for each month. In that summation, negative individual requirements from cleared FTRs are allowed to offset positive requirements within a month; however, negative requirements from FTRs that have been bid into an auction but that have not yet cleared are not allowed to offset positive requirements (since it is not known if the FTR will clear, or at what price). Once a subtotal has been calculated for each month, all of the positive monthly subtotals are added together to result in the portfolio requirement.

These calculations are performed any time the portfolio changes (*i.e.*, when an auction clears) or are proposed to be changed (*i.e.*, for a proposed trade or when bids are entered during an auction). For proposed trades and submitted bids, the calculation is performed assuming that the intended action will take place. If the resulting credit requirement exceeds the credit available, the action is rejected.[173]

The following examples are all for one-month FTRs; however, they can be extrapolated to longer-period FTRs since such FTRs are broken into their separate monthly components for credit calculation purposes. For example, in the January auction (which is conducted in December for the month of January and subsequent periods), FTRs may be purchased for that month and the two subsequent months.

Example 1: In the January FTR auction, a February FTR ("FTR1") clears for $1,500. It has a historical value in February of $1,500. Its cleared February credit requirement is $150, which is $1,500 - $1,500 * 90%.

Example 2: In the February auction, the owner of FTR1 bids $1,000 for another February FTR ("FTR2"), which has a historical value of $1000 in February. The February credit requirement associated with FTR2 during the bidding is $100 ($1,000 - $1,000 * 90%).

Example 3: Also in the February auction, the owner of FTR1 bids $600 for another FTR ("FTR3"), which also has a $1,000 historical value in February. The February credit requirement associated with FTR3 during the bidding is -$300, which is $600 - $1,000 * 90%.

171 The weighted average is 50% prior year, 30% two years prior, and 20% three years prior.

172 FTR Historical Value definition in PJM Tariff, Attachment Q.

173 PJM Tariff, Attachment Q, Sections V.C and V.F.

Example 4: The Participant's total February credit requirement during the bidding for the February auction, therefore, is $250. The total February credit requirement is the sum of FTRs 1 and 2, but not FTR3, since FTR3 is a bid (not cleared) FTR with a negative credit requirement. FTR1's individual credit requirement is based on its cleared price in the January auction, while FTR2's individual requirement is based on its bid price in the current auction.

Example 5: FTR2 eventually clears the auction at a price of $700, so its individual cleared credit requirement will be -$200, which is $700 - $1,000 * 90%.

Example 6: FTR3 does not clear the auction, so its cleared requirement is zero.

Example 7: After the February auction clears, the total portfolio credit requirement for the Participant for February will be -$50, which is the sum of the requirements of FTR1 ($150) and FTR2 (-$200). Although negative, FTR2 is included since it is a cleared FTR.

Example 8: If the Participant also owns FTRs in March and April, with aggregate total requirements for each month of $100, then the Participant's total FTR credit requirement would be $200 (the sum of the March and April requirements). It is not $150, because the negative value of February is ignored in the cross-month total calculation.

The FTR credit requirement is compared against the credit limit any time the requirement changes or is proposed to change through a trade, a bid, or an undiversified credit calculation. Credit requirements are calculated for trades and bids at the point of submission into the PJM system. If a trade or bid would put the portfolio credit requirement above its credit limit, the trade or bid is automatically rejected before it is even accepted by PJM. All of the individual bids uploaded in the same set are rejected; however, the Participant may submit a revised bid (or trade) that would not cause the credit limit to be exceeded. In certain cases where a credit requirement exceeds the credit limit as part of a tentative clearing of an auction, the company is notified and given one day to provide the required collateral; if the collateral is not received, all of the participant's bids in that auction are removed and the auction is recalculated.[174]

Furthermore, in response to FERC Order No. 741, PJM proposed that the total amount of unsecured credit allowance, whether from its own creditworthiness or from a guaranty, would be capped at $50 million. For example, a participant with $50 million unsecured credit allowance of its own, plus a guaranty for $50 million from another creditworthy entity, would be deemed to have only $50 million of total unsecured credit allowance, and a $49 million obligation would leave it with only $1 million unsecured credit allowance remaining. Seller Credit is available to participants as unsecured credit. Seller Credit is based on the current period liquid receivables that are owed by PJM to a participant, subject to additional limits based on historical

[174] PJM Tariff, Attachment Q, Section V.G.

experience.[175] On November 29, 2011, PJM proposed tariff revisions in compliance with FERC's September 15, 2011 Order on its Order No. 741 Compliance Filing to remove the possibility that Seller Credit, which is a form of unsecured credit, could be used as credit for FTRs and ensuring that Seller Credit is included as part of the $50 million unsecured credit allowance cap.[176] The level of Seller Credit is established such that it represents 60% of the thirteenth lowest net amount due to the associated member in the past 52 weeks. At this conservative level, Seller Credit is reasonably expected to be less than the net amount due to the associated member in each weekly PJM invoice for which PJM has the right to retain such funds in the event that the associated member does not fulfill all of its responsibilities. In essence, it represents cash collected by PJM that will not be remitted to the member with the Seller Credit in the event that member is not in compliance with PJM's governing documents.

Per the Credit Policy, PJM stipulates that cash or an unconditional, irrevocable standby letter of credit can be utilized to meet Financial Security requirement.[177] The form, substance, and provider of the letter of credit must all be acceptable to PJM. PJM monitors the concentration of letters of credit from all issuers providing letters of credit in support of PJM members' credit requirements.

Requirements for Issuers of Letters of Credit

PJM will only accept letters of credit from U.S.-based financial institutions or U.S. branches of foreign financial institutions ("financial institutions") that have a minimum corporate debt rating of "A" by Standard & Poor's or Fitch Ratings, or "A2" from Moody's Investors Service, or an equivalent short term rating from one of these agencies.[178] PJM will consider the lowest applicable rating to be the rating of the financial institution. If the rating of a financial institution providing the letter of credit is lowered below A/A2 by any rating agency, then PJM Settlement may require the Participant to provide a letter of credit from another financial institution that is rated A/A2 or better, or to provide a cash deposit. If a letter of credit is provided from a U.S. branch of a foreign institution, the U.S. branch must itself comply with the

[175] *See* PJM Tariff, Attachment Q, Section II.C ("A Participant's Seller Credit will be equal to sixty percent of the Participant's thirteenth smallest weekly Net Sell Position invoiced in the past 52 weeks."). Each Participant receiving Seller Credit must maintain both its Seller Credit and its Total Net Sell Position equal to or greater than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided. For every participant receiving Seller Credit, PJM will maintain a forecast of the Participant's Total Net Sell Position considering the Participant's current Total Net Sell Position, recent trends in the Participant's Total Net Sell Position, and other information available to PJM, such as, but not limited to, known generator outages, changes in load responsibility, and bilateral transactions impacting the Participant. If PJM's forecast ever indicates that the Participant's Total Net Sell Position may in the future be less than the Participant's aggregate credit requirements, less any Financial Security or other sources of credit provided, then PJM may require Financial Security as needed to cover the difference. Failure to pay the required amount of additional Financial Security within two Business Days shall be an event of default. Any Financial Security required by PJM pursuant to these provisions for Seller Credit will be returned once the requirement for such Financial Security has ended. Seller Credit may not be conveyed to another entity through use of a guaranty.

[176] FERC permitted the use of unsecured credit allowance for FTRs acquired prior to the June 2009 auction, noting that the elimination of the use of an unsecured credit allowance will be complete after May 2012. *PJM Interconnection, L.L.C.*, 136 FERC ¶ 61,190, at P 27 (2011).

[177] PJM Tariff, Attachment Q, Section VI (describing the types of financial security that participants in PJM's markets may provide); *see also* PJM Tariff, Attachment Q, Section VIII (definition of "financial security").

[178] PJM Tariff, Attachment Q, Section VI.B.

terms of PJM's Credit Policy, including having its own acceptable credit rating. PJM may accept a letter of credit from a financial institution that does not meet the credit standards, provided that the letter of credit has third-party support, in a form acceptable to PJM , from a financial institution that does meet PJM's credit standards.

Requirements for Letters of Credit

The letter of credit itself must also meet several requirements. It must clearly state the full names of the "Issuer", "Account Party" and "Beneficiary", the dollar amount available for drawings, specify that funds will be disbursed upon presentation of the drawing certificate in accordance with the instructions stated in the letter of credit, and specify any statement that is required to be on the drawing certificate and any other terms and conditions that apply to such drawings. In addition, the letter of credit must state that it shall renew automatically for successive one-year periods, until terminated upon at least ninety days prior written notice from the issuing financial institution. If PJM receives notice from the issuing financial institution that the current letter of credit is being cancelled, the participant will be required to provide evidence, acceptable to PJM, no later than thirty days before the cancellation date of the letter of credit, that such letter of credit will be replaced with appropriate Financial Security, which will be effective as of the cancellation date of the letter of credit. Failure to do so constitutes a default.

The PJM Credit Application contains an acceptable form of a letter of credit that should be utilized by a participant choosing to meet its Financial Security requirement with a letter of credit. If a participant uses a letter of credit that varies in any way from the PJM format, it must first be reviewed and approved by PJM. All costs associated with obtaining and maintaining a letter of credit and meeting the policy provisions are the responsibility of the participant.

PJM's method of risk management necessarily differs from the analogous procedures used by DCOs because PJM's markets do not function in the same manner as a futures exchange. Nevertheless, PJM believes that the material aspects of its risk management provisions are comparable to this DCO core principle.

B. Measurement of Credit Exposure.

The manner in which PJM measures credit exposure varies depending on the type of market activity and the recourse that PJM has with respect to such activity.

For the receivables portion of FTR positions and daily energy market activity, position reports are generated three times a week. Collateral calls are made if current activity exceeds 75% of available market collateral.[179] The 25% buffer is designed to mitigate exposure from delays such as collateral call cure periods and weekends.[180]

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179 PJM Tariff, Attachment Q, Section II.E.

180 PJM Interconnection, L.L.C., *Credit Overview and Supplement*, Version 2,2 (Dec. 16, 2011) page 9 "Credit Requirements," available at http://www.pjm.com/about-pjm/member-services/~/media/pjm-settlement/credit/pjm-credit-overview.ashx.

Daily measurement and intraday monitoring of credit exposure is not practical for FTRs because of the low liquidity and other unique attributes of the FTR markets. The value of exposure to FTRs is determined by the price of physical electricity during the days and hours for which the FTR is effective. No liquid market exists from which to derive a forward price curve prior to any given auction. However, the credit requirement calculation approximates an exposure calculation, and it is performed at the time of acquisition of the FTR for all but multi-year FTRs, which also are recalculated each year when a new set of historical values are available.[181] PJM monitors maturing positions as the daily matured values post to the invoices throughout the month. PJM does not monitor forward positions between auctions because no source for market prices exists. It is impossible to value the impact of an engineering change before it occurs. PJM has issued inter-auction collateral calls under the material adverse change clause of the PJM Tariff on rare occasions. Such calls, however, have been issued only when congestion becomes extreme, and not simply on the basis of engineering changes. However, if an inter-auction engineering event causes substantial congestion, PJM could utilize all provisions of the Credit Policy to issue a collateral call.

FTRs are unique to the electricity industry in that they are integrally combined with physical electricity markets and are inextricably linked with the physical capacity of the high-voltage electricity network in the PJM footprint and surrounding territories. FTRs are products with minimal liquidity, whose variability is subject to both statistical forces (*e.g.*, weather, economy) and non-statistical forces (*e.g.*, system outages). The statistical forces tend to be either modest (economy) or mean-reverting (weather). The non-statistical forces occur so sharply that their price effect is felt before a liquidation could occur. Due to these reasons, a mark-to-market forward valuation of FTR exposure based on current values is impractical. Therefore, credit requirements are made based on historical measures of value, with extra “super-requirements” for FTRs that pose the greatest risk (counterflow FTRs) from the non-statistical forces.[182]

While there are no specific restrictions in the PJM Tariff on the number of FTRs any one entity may hold, in practice, PJM’s credit policies, and the allocation process for ARRs effectively limits the ability of speculators to purchase a “large portion of available supply.” In the first stage of the FTR allocation process, ARRs are allocated to LSEs in proportion to the amount of load each LSE serves. Speculators and other market participants cannot participate in the ARR allocation process. Prior to the first FTR auction, ARRs can be converted into FTRs by LSEs seeking to hedge their congestion risk. This conversion process reduces the quantity of FTRs available for auction to other market participants, and, as a result, prevents any LSE (or speculator) from acquiring an excessive share of FTRs.[183]

The overall size of the FTR market is also, as a practical matter, limited by the physical capabilities of the transmission system. All FTRs must be “simultaneously feasible,” meaning that they correspond to the physical transmission capability of actual transmission lines.[184]

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[181] PJM Tariff, Attachment Q, Section V.I.

[182] PJM Tariff, Attachment Q, Section V.B.

[183] PJM Tariff, Attachment K Appendix, Section 7.4.

[184] PJM Tariff, Attachment K Appendix, Section 7.5.

Although counterflow FTRs could, in theory, increase the size of the FTR market by effectively increasing the transmission capabilities of the affected transmission lines, this has not happened to a significant degree. Accordingly, the method of distribution of ARRs and FTRs among market participants effectively prevents individual LSEs and speculators from obtaining excessive shares of FTRs.

Since FTRs were first implemented, on average, over two thirds of the FTR positions in PJM's markets are used to hedge physical transmission. Of the remaining one third, only a small fraction of the outstanding FTR positions are "out of the money" counterflow positions that would "expand" the size of the overall market. Given the substantial credit requirements associated with counterflow FTR positions, these percentages are not likely to change in the future.

Capacity markets do not experience fluctuating exposure, since the financial exposure is penalty-derived, and penalties are fixed.

C. Limitation of Exposure to Potential Losses From Defaults.

As noted above, PJM regularly monitors members' positions to ensure that they remain within available credit allowances, and like a DCO, effectively limits the risk that any one participant may accumulate, relative to its size in the markets. PJM uses Peak Market Activity, which means "a measure of exposure for which credit is required, involving peak exposures in rolling three-week periods over a year timeframe, with two semi-annual reset points." The normal payment cycle exposure period for PJM is three weeks. PJM's invoices cover a period Thursday through Wednesday (days 1-7). Invoices are issued the following Tuesday (day 13), and due on Friday (day 16). If unpaid, there is a two-business-day cure period that expires on Tuesday (day 20); however, by close of business Tuesday, bids could have already been placed for Wednesday (day 21). The three week peak, therefore, looks at the largest payment cycle exposure experienced in the given retrospective timeframe. A participant's Total Net Obligation is compared against its Working Credit Limit whenever new position data is available, which is three times weekly.[185]

PJM utilizes a two-tier risk control structure:

- Collateral equal to three weeks of invoiced billings (less FTR activity, since that is collateralized separately) is required of participants that do not meet PJM's creditworthiness standards. This level is sized to cover the weekly billing period itself, the payment period plus a non-payment cure period.
- Additional collateral is required for FTR positions as follows: for each month of a portfolio's FTR positions, the weighted average[186] historical value (discounted 10%) of each FTR is subtracted from the purchase cost of each FTR, and the resulting values summed. The participant's FTR credit requirement is the sum of the resulting monthly values for months where the value is positive only. In

185 PJM Tariff, Attachment Q, Section II.E.

186 The weighted average is 50% prior year, 30% two years prior, and 20% three years prior.

> addition, if, in any month, the net portfolio position is counterflow (as evidenced by a net negative purchase price for the portfolio that month), then an additional credit requirement of twice[187] that negative value is added to the credit requirement.[188]

In order to allow members to anticipate potential losses, PJM publishes and distributes to its members a monthly exposure report that shows, for each of five creditworthiness categories of its members, the overall total and the uncollateralized total peak billings of the members, along with a weighted average default rate using a posted table of historical default rates published by a major credit rating agency. Additionally, PJM members may view all positions awarded through the periodic FTR market auctions and may assess for themselves whatever risk is presented by those positions of each member, recognizing that all participants must provide collateral for all new FTR positions.

PJM began administering its FTR market in 1999. In the twelve years PJM's FTR market has been active, total member defaults on FTR positions represent 0.54% of the nearly $12 billion aggregate FTR market activity for that time period. In the twelve-year history of FTRs, the only defaults have occurred in the 2007-08 annual period when five participants experienced significantly higher than historical congestion on counterflow positions, and in the 2008-2009 annual period, when an "A"-rated participant declared bankruptcy. In each case, PJM has subsequently strengthened its credit procedures to mitigate such risks in the future. In the first case, PJM had an entirely different credit requirement for FTRs that did not measure the monthly variations as well as the current procedure, and did not include a super credit requirement for counterflow FTRs. In the second case, unsecured credit had been allowed for FTRs, whereas today, all purchased FTRs must be fully collateralized.

D. Margin Requirements.

As noted above, unlike a DCO, PJM does not allow unsecured credit for FTR positions.[189]

E. Requirements Regarding Models and Parameters.

The formulas used by PJM to set credit requirements for participating in its wholesale electricity and related markets, including the FTR markets, are part of the FERC-approved PJM Tariff. Proposed changes to the PJM Tariff are discussed with PJM's stakeholders prior to implementation. PJM does not independently change formulas, models or parameters, except as specifically authorized by the PJM Tariff. The parameters that are used in setting its credit requirements, however, are established by the markets, and are derived from historical pricing data from the past year for virtual bids and three years for FTRs. Virtual bid parameters are updated semi-monthly based on prior year data. FTR parameters are updated annually based on

[187] The credit requirement is three times the negative value, if an analysis shows that the portfolio would be negatively impacted by any one of a prior-posted set of known planned system outages.

[188] PJM Tariff, Attachment Q, Section V.G.

[189] *See* discussion above on "Product and Participant Eligibility" and "Risk Management."

data from the prior three years.[190] It is necessary to consider prior-year information in establishing current credit requirements for these activities because both virtual bids and FTRs are products derived from the physical electricity markets, and their prices reflect seasonal differences in electricity demand. Accordingly, PJM factors in prior seasons' data into its current requirements.[191]

[190] FTR Historical Value definition in PJM Tariff, Attachment Q.

[191] *See also* discussion above on "Risk Management."

Attachment E

DCO Core Principle E: Settlement Procedures

Each derivatives clearing organization shall—

(i) complete money settlements on a timely basis (but not less frequently than once each business day);

(ii) employ money settlement arrangements to eliminate or strictly limit the exposure of the derivatives clearing organization to settlement bank risks (including credit and liquidity risks from the use of banks to effect money settlements);

(iii) ensure that money settlements are final when effected;

(iv) maintain an accurate record of the flow of funds associated with each money settlement;

(v) possess the ability to comply with each term and condition of any permitted netting or offset arrangement with any other clearing organization;

(vi) regarding physical settlements, establish rules that clearly state each obligation of the derivatives clearing organization with respect to physical deliveries; and

(vii) ensure that each risk arising from an obligation described in clause (vi) is identified and managed.

Responses:

Attachment E—DCO Core Principle E: Settlement Procedures

California ISO

Consistent with FERC Order No. 741, the CAISO employs a weekly settlement cycle with subsequent incremental adjustments as meter data and other information affecting settlements becomes available.[192] Section 11 also includes rules for netting of market transactions and other settlement-related provisions.

Under Section 11.29.9.2 of the CAISO Tariff, a CAISO Clearing Account is established that is operated on trust for market participants. All payments for market transactions under the CAISO Tariff are made to the Clearing Account, which is cleared by the end of the day payment is received.[193]

The billing and payment process in Section 11.29 of the CAISO Tariff provides a timeline for raising settlement disputes and for finalizing settlements of market transactions.[194] The dispute procedures are detailed in the Business Practice Manual for Settlements and Billing.[195] Under these procedures settlements are subject to adjustment for up to three years. This is based upon practice in the cash markets and under FERC ratemaking authority.

CAISO is required to retain all settlement data records for a period which, at least, allows for the re-run of data as required by the Tariff and applicable regulators.[196] In addition, CAISO maintains records regarding the flow of funds involved in its settlements.

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[192] CAISO Tariff § 11.29.7 and 11.29.8.

[193] CAISO Tariff § 11.29.9.6.1.

[194] *Id.* § 11.29.8.4.

[195] *Available at* https://bpm.caiso.com/bpm/bpm/version/000000000000085.

[196] CAISO Tariff § 11.1(c).

Attachment E—DCO Core Principle E: Settlement Procedures

ERCOT

A. Money Settlements.

ERCOT's settlement procedures are comparable to those required by this Core principle. ERCOT completes settlements on a timely basis (but not less frequently than once each business day). PURA, the PUCT Rules and the ERCOT Protocols all require that transactions be appropriately accounted for among buyers and seller.[197] The ERCOT Protocols specify the settlement timelines, which were the result of market participant discussion and approval. In particular, Section 9 of the ERCOT Protocols requires that:

1) ERCOT perform Day-Ahead Market settlements every business day:

   a) Day-Ahead Market Invoices are posted two business days after the Operating Day (the Day-Ahead Market is executed one day before the Operating Day).[198]

   b) Payments into ERCOT are due three bank business days after Day-Ahead Market invoices are posted.[199]

   c) Pursuant to these rules, the time period from the Operating Day to payment is between five days and 13 days, with approximately 90% clearing within eight days (payment occurs in 13 days when there are the maximum amount of weekend days and holidays following the Operating Day).

   d) ERCOT rules generally settle CRRs in the Day-Ahead Market, but do allow CRRs to be moved into the Real-Time Market in which case, the CRRs are settled based on the normal Real-Time settlement cycle.[200]

2) ERCOT perform Real Time settlements every business day:

   a) Real Time settlement statements are posted nine days after the Operating Day.[201]

   b) Real Time Invoices are posted weekly.[202]

   c) Payments into ERCOT are due five bank business days after Real Time Invoices are posted.[203]

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197 PURA Section 39.151(a)(4), P.U.C. SUBST. R. 25.361(b) and ERCOT Protocol Section 1.2.

198 ERCOT Protocol Sections 9.3 and 9.4.1.

199 ERCOT Protocol Sections 9.3 and 9.4.1.

200 ERCOT Protocol Sections 7.9.1 and 7.9.2.

201 ERCOT Protocol Sections 9.5.4, 9.6, and 9.7.1.

202 ERCOT Protocol Sections 9.5.4, 9.6, and 9.7.1.

203 ERCOT Protocol Sections 9.5.4, 9.6, and 9.7.1.

d) Pursuant to these rules, the time period from the Operating Day to payment ranges from 21 days to 31 days (payment occurs in 31 days when there is the maximum number of weekends and holidays).

e) In 2011 ERCOT approved Protocol changes to tighten the Real Time settlement and payment cycle:

i) Combining Real Time settlements with DAM settlements into one "daily" invoice with both DAM and RT settlement statements on it, eliminating the delay in invoicing RT settlement statements.[204]

ii) Shortening the RT payment timeline by two bank business days since the "daily" invoice will be paid within 3 bank business days instead of five.[205]

iii) These changes should ensure that approximately 90% of Real Time days are settled and paid within 15 days, with the weighted average settlement and payment cycle being no more than 15 days. Settlement and payment timelines longer than the above are expected to be primarily due to weekend and holiday schedules.

3) Ensure that money settlements are final when effected.

a) Payment must be made no later than the due date by Electronic Funds Transfer in immediately available or good funds (*i.e.*, not subject to reversal); or on or before two Bank Business Days before the payment due date if the payment is made by Automated Clearing House funds.[206]

i) In 2011, ERCOT approved a Protocol change that will eliminate the use of Automatic Clearing House funds.

ERCOT employs money settlement arrangements to eliminate or strictly limit its exposure to settlement bank risks (including credit and liquidity risks from the use of banks to effect money settlements).

ERCOT's banking and investment activity is conducted pursuant to its Investment Corporate Standard. The Investment Corporate Standard is approved by its Board of Directors and reviewed at least annually.[207] Key aspects of this Standard include:

- Conservative Objectives–In order of priority, the objectives of ERCOT's Investment Corporate Standard are: (1) Safety of principal, (2) Liquidity and (3) Reasonable rate of return.

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204 ERCOT Protocol Section 9.6.

205 ERCOT Protocol Sections 9.7 and 9.7.1.

206 ERCOT Protocol Section 9.4.1 and 9.7.1.

207 ERCOT Corporate Standard CS3.1, *Financial Corporate Standard*, at Section 3.0

- Qualified Institutions are carefully selected and must:

  (a) Maintain a senior debt rating at least the equivalent of A- by Standard & Poor's or A3 by Moody's Investor Service;

  (b) Maintain capital of not less than $100 million;

  (c) Maintain assets of not less than $1 billion; and

  (d) Provide current audited financial statements to ERCOT treasury personnel.

- ERCOT procedures include investment of funds overnight. To the extent possible, ERCOT minimizes cash balances left in banks overnight.

B. Flow of Funds Records.

ERCOT's settlement procedures are comparable to those required by this core principle. ERCOT performs a complete shadow settlement validation of all settlements calculations and settlement statements and invoices generated by the settlements system.[208] All statements, invoices and data used in the calculations are securely posted for market participants to retrieve and review.[209]

ERCOT also maintains all payment and receipt information.

As provided in the ERCOT Protocols, these data are stored in the ERCOT Data Warehouse and Data Archive for seven years.[210] ERCOT is also subject to a SSAE16 audit and other audits conducted by the ERCOT Internal Audit Department. This helps provide assurance that controls are in place for ERCOT to accurately follow its data control objectives.[211]

C. Compliance with Netting or Offsetting Arrangements.

ERCOT is not a clearing organization and does not have the type of arrangements contemplated by this Core Principle. As a result, ERCOT does not net with third-party clearing organizations.

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208 ERCOT Protocol Section 1.2(d).

209 ERCOT Protocol Sections 9.1.2, 9.1.3, 9.2.2(1), 9.3(1), 9.5.2(1), 9.6(3), 9.15.1, 12.1(1), 11.5.1.1(2), 11.5.2.2(2), 12.2(1), 12.2(3), and 12.3(c).

210 ERCOT Protocol Section 1.4.5.

211 ERCOT Protocol Section 11.5.1.1(2).

D. Physical Settlements.

ERCOT Protocols establish rules that clearly state each entity's obligation with respect to physical deliveries. Section 9 of ERCOT Protocols describes the settlement charges, including specifics of charge types. Section 9.5.3 describes all real-time charges related to physical metered load consumed, or generation produced, and any offsetting positions to those obligations that are reflected in trades with other counterparties. Prior to real-time operations, an entity in the ERCOT market also has the capability to satisfy part or all of its energy and ancillary service obligations by buying or selling energy or services utilizing the day-ahead market.

Attachment E—DCO Core Principle E: Settlement Procedures

ISO New England

ISO-NE has adequate settlement procedures that provide for timeliness, limited exposure, finality, and accuracy in the settlement process.

ISO-NE's billing policies for its energy and other hourly markets are currently compliant with the FERC Order mandating that ISOs "have billing periods of no more than seven days and settlement periods of no more than seven days after issuance of bills." Credit Ruling ¶32. Billing is performed twice per week for Hourly Markets (generally Monday & Wednesday) with Non-Hourly Markets being included on the first Monday bill that follows the 10th of the month. *See* Section 1.3 of the Billing Policy, which is Exhibit D to Section I of the Tariff (found on the website at http://www.iso-ne.com/regulatory/tariff/sect_1/sect_i.pdf). All invoices (provided to participants that owe money) are paid to ISO-NE first (within two business days), and remittance advices (sent to participants that are owed money) are paid by ISO later (within two business days from the due date of the invoices). All payments are made by electronic funds transfer. *See* Section 3 of the Billing Policy. Section 2.5 of the Billing Policy sets out timelines for the resettlement of certain charges. Section 6 describes the timeframe (three months) for requesting a billing adjustment. Also, ISO-NE has a Record Retention Policy that stipulates that settlements data will be retained for six years.

ISO-NE also prohibits "netting" of credit requirements between FTR and non-FTR activity. *See* FERC Credit Ruling ¶78. ISO-NE has established a stand-alone FTR credit test percentage that is not influenced by credits and/or obligations accruing as a result of a participant's activity in any other market.

With regard to ISO-NE's ability to offset market obligations, ISO-NE intends to continue to utilize a net margining approach while doing so in a way that better ensures that Market Participants are protected from a substantial default should a participant file for bankruptcy protection. Specifically, ISO-NE intends to propose changes to its tariff to permit it to become a central counterparty to transactions in its markets. Before ISO-NE can make these changes, it has requested a private letter ruling from the Internal Revenue Service confirming that this change will not affect ISO-NE's status as a Section 501(c)(3) tax-exempt entity. ISO-NE must also complete its contractually-required stakeholder processes and make a filing with FERC for FERC approval.

Attachment E—DCO Core Principle E: Settlement Procedures

MISO

MISO maintains a weekly settlement cycle and clearing account for market transactions. An initial settlement statement is issued seven (7) days after the operating day and subsequent settlement statements are issued fourteen (14), fifty-five (55) and one-hundred and five (105) days after the operating day. (BPM-005-r9 Market Settlements, Section 2.1.3, p. 24. The BPM can be found on the MISO website, under the Module B tap at https://www.midwestiso.org/Library/Tariff/Pages/Tariff.aspx) This timeline allows for the submission of meter data and other information relevant to the settlement of transactions. Only incremental changes to the settlement amount are processed between day seven (7) and the final settlement at day one hundred and five (105).

Currently, MISO invoices Market Participants for market transactions concurrent with the seven (7) day settlement statement, and payment of invoices are due seven (7) days from the date of the invoice. This invoice timeline is consistent with FERC Order No. 741 directives to implement reduced timelines to minimize credit exposure and costs attributed to any default.

Tariff Section 39.3 of the MISO Tariff provides settlement rules for the Day-Ahead Energy and Operating Reserve Market, including the settlement of FTRs, and Section 40 of the Tariff provides settlement rules for the Real-Time Energy and Operating Reserve Market. Further detail and calculations related to MISO's settlement rules are provided in MISO's Business Practice Manual for Market Settlements available at: https://www.midwestiso.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx.

Attachment E—DCO Core Principle E: Settlement Procedures

New York ISO

Services Tariff Section 7.2 and OATT Section 2.7.3 established, effective October 1, 2011, a weekly settlement cycle for approximately 99% of the dollar volume of NYISO-administered market transactions, rules for netting of market transactions, and other settlement-related provisions. Under Services Tariff Section 7.2 and OATT Section 2.7.3, NYISO Market Participants make payments into and receive payments from the ISO Clearing Account. Payments are generally due to the NYISO on each Friday, and the NYISO generally makes payments on the following Monday. Payments associated with the auction of TCCs are due to the NYISO within three business days from the notification of award of TCCs, and the NYISO must make payments owed to Market Participants for TCC awards within three business days thereafter. *See* TCC Manual Section 4.7.[212]

With respect to the NYISO's ability to offset market obligations, the NYISO is currently evaluating its compliance options and examining the tax, accounting, and other implications of taking title to market transactions. The NYISO is also discussing these issues with its Market Participants. The manner in which the NYISO will comply with this requirement depends, in large part, on the effect that becoming a central counterparty and taking title to market transactions would have on NYISO's operations and its Market Participants.

In documents the NYISO previously submitted to the Internal Revenue Service ("IRS") and to the New York State Department of Taxation and Finance ("NYS Tax Department") to obtain 501(c)(3) status and exemptions from certain taxes (*e.g.*, income tax, sales tax, gross receipts tax, franchise tax), the NYISO noted that it does not take title to market transactions. On December 6, 2011, the IRS confirmed, in a Private Letter Ruling, that the NYISO's establishment of a central counterparty structure pursuant to which the NYISO would become the central counterparty to the transactions that take place in the markets administered by the NYISO would not affect the NYISO's status as a 501(c)(3) organization exempt from federal income tax. The NYISO is awaiting an Advisory Opinion from the NYS Tax Department that its existing State tax exemptions would continue to apply if the NYISO were to take title to market transactions. Upon confirmation that the state tax implications of becoming the central counterparty will not adversely affect the NYISO's state tax exemptions, the NYISO will comply with the FERC Order No. 741 related to the ability to offset market obligations by implementing tariff revisions that allow the NYISO to take title as a central counterparty.

The enforceability of both the NYISO's current netting practices and the central counterparty model has been evaluated by the NYISO's outside bankruptcy counsel. The NYISO will provide a memorandum of counsel to CFTC staff under separate cover that concludes a bankruptcy court likely would enforce the NYISO's current tariff provisions and netting practices in the event that a Market Participant files for bankruptcy protection. In this memorandum, NYISO counsel also opines that taking title to the products bought and sold within the NYISO-administered markets (under a central counterparty model) would provide additional support that mutuality exists between the NYISO and its Market Participants to support netting through setoff.

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[212] The TCC Manual is available on the NYISO's website (click on "Transmission Congestion Contracts") at: http://www.nyiso.com/public/markets_operations/documents/manuals_guides/index.jsp.

Attachment E—DCO Core Principle E: Settlement Procedures

PJM

A. Money Settlements.

PJM's settlement period is generally one week, but PJM retains monthly billing practices for about five percent of transactions for which data is not available for weekly billing. Additionally, PJM's members have access to daily online billing statements that include all amounts calculated from completed transactions. Payment on all invoices is due within three business days.[213]

Per Section 15.1.3 of the PJM OA, all billing statements are final and financially binding when issued by PJM.[214] Similarly, all cash settlements of invoices are final when completed in the time periods stipulated in the PJM OA.[215]

B. Flow of Funds Records.

PJM maintains records concerning the flow of funds involved in its settlements. All transactions, collateral and settlement activity are recorded by individual member companies. Transaction data is maintained in PJM's market settlements database from which daily, weekly and month-end online statements are available to all member companies. Collateral data are maintained in PJM's cash accounting records, and member companies can obtain read-only access to their cash collateral accounts. Settlement activity is also maintained in PJM's cash accounting records. In addition, the transaction, collateral and settlement activity are all uploaded into PJM's SAP accounting system for financial reporting purposes.[216]

C. Compliance with Netting or Offsetting Arrangements.

This is not applicable because PJM is not a clearing organization. Moreover, PJM does not have netting or offsetting arrangements with other clearing organizations or ISOs/RTOs.

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213 PJM Tariff, Section 7.1A.

214 PJM OA, Section 15.1.3 ("A Member shall make full and timely payment, in accordance with the terms specified by the Office of the Interconnection, of all bills rendered in connection with or arising under or from this Agreement, any service or rate schedule, any tariff, or any services performed by the Office of the Interconnection or transactions with PJMSettlement, notwithstanding any disputed amount, but any such payment shall not be deemed a waiver of any right with respect to such dispute. Any Member that fails to make full and timely payment to PJMSettlement (of amounts owed either directly to PJMSettlement or PJMSettlement as agent for the LLC) or otherwise fails to meet its financial or other obligations to a Member, PJMSettlement, or the LLC under this Agreement, shall, in addition to any requirement set forth in Section 15.1 and upon expiration of the 2-day period specified below be in default."); PJM OA, Section 15.6; PJM Tariff, Section 10.4.

215 PJM OA, Schedule 1, Section 3.2.7; PJM Manual 29 – Billing, Section 2, *available at* http://www.pjm.com/~/media/documents/manuals/m29.ashx ("PJM Members and Transmission Customers are obligated to pay the amounts shown as due in the monthly billing statement."); *see also* PJM OA, Section 14B.2; PJM Tariff, Section 7.1A.

216 PJM OA, Schedule 1, Section 3.2.7; PJM OA, Section 14B.1; PJM Tariff, Section 7.1; PJM Tariff, Attachment Q, Section VI.A; PJM Manual 29 – Billing, Sections 1.1, 2, and 4.1, *available at* http://www.pjm.com/~/media/documents/manuals/m29.ashx (from Section 4.1: "PJM issues numerous accounting reports electronically throughout the billing month as well as month-end reports along with the monthly billing statements. The purpose of providing the reports is to enable the PJM Members and Transmission Customers to verify the charges and credits that appear on their billing statement.").

D. Physical Settlements.

Though day-ahead and real-time energy market transactions collectively settle physically, FTR and FTR Option transactions are financial transactions employing money settlements only.

Attachment F

DCO Core Principle F: Treatment of Funds

(i) REQUIRED STANDARDS AND PROCEDURES.—Each derivatives clearing organization shall establish standards and procedures that are designed to protect and ensure the safety of member and participant funds and assets.

(ii) HOLDING OF FUNDS AND ASSETS.—Each derivatives clearing organization shall hold member and participant funds and assets in a manner by which to minimize the risk of loss or of delay in the access by the derivatives clearing organization to the assets and funds.

(iii) PERMISSIBLE INVESTMENTS.—Funds and assets invested by a derivatives clearing organization shall be held in instruments with minimal credit, market, and liquidity risks.

Responses:

Attachment F—DCO Core Principle F: Treatment of Funds

California ISO

The CAISO is required to maintain specified types of separate accounts for funds it receives or holds, including segregated and aggregated market clearing accounts that the CAISO generally clears on the day that funds are received into them.[217] The CAISO tariff requires that financial security amounts held for market participants by the CAISO can be held only in bank accounts, money market accounts, U.S. Treasury securities, or U.S. Agency securities, unless the market participant makes a specific request that their funds be placed in an alternative investment.[218] Market participants receive any interest accruing to investment of their funds deposited as financial security and bear the risk of any loss of principle or interest.[219]

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217 *See* CAISO Tariff §§ 11.2.4.5 (CRR Balancing Account); 11.13.2.1 (Facility Trust Account for RMR contracts); 11.13.2.2 (RMR Owner's Settlement Accounts); 11.17 (CAISO Operating and Capital Reserves Account); 11.18.2 (CAISO Emissions Cost Trust Account); 11.19.2 (FERC Annual Charge Trust Account); 11.20.6 (NERC/WECC Charge Trust Account); 11.29.2.1 (CAISO Clearing Account); 11.29.2.2 (CAISO Reserve Account); 11.29.2.3 (CAISO Surplus Account); 11.29.2.4 (CAISO Penalty Reserve Account); 11.29.2.5 (other accounts).

218 *Id*. § 12.1.2.4.

219 *Id*.

Attachment F—DCO Core Principle F: Treatment of Funds

ERCOT

ERCOT and ERCOT market funds are managed under an Investment Corporate Standard that is reviewed and updated annually by its Board of Directors, and under separate procedures designed to comply with the Investment Corporate Standard.[220] The Standard defines the primary objectives, in priority order, of ERCOT's investment activities as: (1) safety, (2) liquidity and (3) return on investment. ERCOT's Investment Corporate Standard also defines what kinds of instruments may be held and places limits on how much may be held in any particular instrument or fund. The Investment Corporate Standard was also discussed in Attachment E in Section A(3).

220 ERCOT Corporate Standard CS3.1, *Financial Corporate Standard*.

Attachment F—DCO Core Principle F: Treatment of Funds

ISO New England

ISO-NE has adequate standards and procedures to protect and ensure the safety of member and participant funds and assets.

ISO-NE maintains segregated accounts to hold market participants' money until the clearing of those funds is effectuated. Some accounts are specific to certain markets or rules (for example, the FTR market, congestion revenue account and the late fee accounts). Market participants' cash financial assurance is held in a bank account in the individual participant's name. The ISO has certain rights to the accounts through a Security Agreement and a Control Agreement. See Section X.A of the Financial Assurance Policy, and the Security Agreement at Attachment 1 to the Financial Assurance Policy. As set forth in Section X.A., the Control Agreement is posted on the ISO website. It is located at http://www.iso-ne.com/stlmnts/assur_crdt/coll_docs/blkrck/br_app/index.html.

The available investment accounts are comprised of a variety of investment options available to the Market Participants, which affords them the option of investing their collateral in the best choice for their business. The funds are managed by a third party financial institution selected by the ISO in consultation with the market participants. *See* Section X.A of the Financial Assurance Policy. ISO-NE also has an Investment Policy that is approved by the Audit and Finance Committee of the Board of Directors. It dictates the investment of settlement "float" in limited conservative options (e.g., CDs or government obligations maturing in three years or less).

Attachment F—DCO Core Principle F: Treatment of Funds

MISO

MISO maintains separate accounts for funds it receives or holds from market participants invoiced for market transactions. These funds are generally paid out to market participants within 24 to 48 hours after the invoice due date.

Section 7.15 of the MISO Tariff requires MISO to hold all monies deposited by a Tariff Customer as financial assurance in a separate, interest-bearing money market account with one-hundred percent (100%) of the interest earned accruing to the benefit of the Tariff Customer. Interest accrued is held as financial assurance until released from the account to the Tariff Customer or applied to satisfy past due amounts owed by the Tariff Customer pursuant to Section 7.7 of the MISO Tariff. The interest accrued on the account is paid to the Tariff Customer on a quarterly basis unless a default exists and is continuing.

Attachment F—DCO Core Principle F: Treatment of Funds

New York ISO

As described in detail in Attachment B, *supra*, NYISO Market Participants make payments into and receive payments from the ISO Clearing Account operated by the NYISO as trustee for the benefit of Market Participants. *See* Services Tariff Section 7.1; OATT Section 2.7.1. The ISO Clearing Account is maintained as a cash account at a reputable commercial bank.

Market Participants electing to post cash as a form of collateral have four different options for investing their cash collateral deposits — a taxable money market fund, a tax-exempt money market fund, a short-term bond fund, and an intermediate-term bond fund maintained through a reputable financial services firm. *See* Services Tariff Sections 26.6.1.1 and 26.6.2.

Attachment F—DCO Core Principle F: Treatment of Funds

PJM

Given the nature of PJM's markets, PJM does not accept any "customer" funds. Accordingly, no policy of protecting or segregating customer and proprietary funds is applicable.

PJM maintains its members' cash collateral deposits in PJM's name by member-specific accounts at BlackRock. They are invested in the BlackRock TempFund, a money market fund, with all interest earnings credited to the members' collateral balance. Such member cash collateral accounts have always maintained $1.00 net asset value as designed for the BlackRock TempFund. PJM may access members' cash collateral deposits on all banking days and has never experienced a delay in access from any of these accounts.

Section VI.A of the Credit Policy allows members to choose whether their cash collateral deposits are invested in a money market fund or high quality debt instruments, such as obligations issued by the federal government and/or federal government sponsored enterprises. To date, all PJM members have elected the BlackRock TempFund for their cash collateral deposits.

Attachment G

DCO Core Principle G: Default Rules and Procedures

(i) IN GENERAL.—Each derivatives clearing organization shall have rules and procedures designed to allow for the efficient, fair, and safe management of events during which members or participants—

(I) become insolvent; or

(II) otherwise default on the obligations of the members or participants to the derivatives clearing organization.

(ii) DEFAULT PROCEDURES.—Each derivatives clearing organization shall—

(I) clearly state the default procedures of the derivatives clearing organization;

(II) make publicly available the default rules of the derivatives clearing organization; and

(III) ensure that the derivatives clearing organization may take timely action—

(aa) to contain losses and liquidity pressures; and (bb) to continue meeting each obligation of the derivatives clearing organization.

Responses:

Attachment G—DCO Core Principle G: Default Rules and Procedures

California ISO

If a market participant defaults on its credit obligations by failing to support its estimated liability through a combination of unsecured credit and financial security, CAISO has authority to limit or suspend the market participant's trading and its eligibility to participate in CRR allocations or auctions.[221]

In addition, the CAISO Tariff sets forth the CAISO's procedures in the event of a market participant's payment default. Section 11.29.13 of the CAISO tariff describes the steps the CAISO will take in the event that it determines that all or part of any amount due to be paid by a scheduling coordinator or CRR holder to the CAISO clearing account has not been paid or will not be paid by 10:00 am on the date payment is due.

First, the CAISO will attempt to cover the default by accessing any financial security deposited by the defaulting participant.[222] If it is not practicable to effect payment to CAISO creditors on the same day by accessing the defaulting participant's financial security, the CAISO can access any funds that are available in its reserve account or penalty reserve account.[223] As soon as possible, the CAISO must take any action it deems appropriate to recover the default amount from the defaulting participant, including by accessing the defaulting member's financial security, exercising its right of recoupment or set-off.[224]

As discussed in Attachment B, the CAISO tariff provides that losses from defaults, due to the insolvency of a market participant or any other reason, are socialized among the other market participants.[225] If, after taking the steps discussed above, the CAISO is unable to clear its clearing account on a given day, the shortfall is allocated among the non-defaulting participants pursuant to formulas set forth in Section 11.29.17 of the CAISO tariff. The non-defaulting participants bear the responsibility of collecting from the defaulting participant.[226] If requested by non-defaulting participants to do so, the CAISO may also institute a proceeding against the defaulting participant to recover amounts due to the non-defaulting participants if it has first reached agreement with the non-defaulting participants as to indemnification and receiving any financial security it may reasonably requests against costs, claims and expenses.[227]

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[221] CAISO Tariff § 12.5.1(b).

[222] CAISO Tariff § 11.29.13.3.

[223] *Id.*, § 11.29.13.4. The CAISO penalty reserve account holds fines assessed to market participants for late payments.

[224] *Id.*, § 11.29.13.5.

[225] *See, e.g.*, CAISO Tariff § 11.29.9.6.2.1 (Replenishing the CAISO Reserve Account Following Payment Default).

[226] See CAISO Tariff § 11.29.21.2.

[227] *Id.*, §§ 11.29.13.5, 11.29.21.1.

Attachment G—DCO Core Principle G: Default Rules and Procedures

ERCOT

A. Default Rules.

Under its current procedures, if ERCOT is unable to recover from the defaulting entity all of the costs associated with a market default, the unrecovered costs are uplifted to all market participants on a *pro rata* basis based on maximum MWh activity ratio share.[228] In these situations, ERCOT first exercises all of its rights against the responsible entity. If it is unable to collect funds from the defaulting entity (through direct payment, collateral or otherwise), ERCOT short-pays the market to manage the shortfall during the settlement cycle to maintain revenue neutrality.[229] If necessary, ERCOT issues an uplift charge to all counterparties based on their maximum activity, in MWh, across all ERCOT markets. This process is detailed in Attachment D and the relevant discussion in that section is incorporated herein by reference.

ERCOT expects to adopt the central counterparty model. To that end, ERCOT has initiated due diligence actions designed to ensure the central counterparty alternative can be implemented consistent with all legal obligations and policy purposes that apply to ERCOT as the independent system operator in the ERCOT Region of Texas. These actions include, but are not limited to determining the impact on ERCOT's corporate structure, working with its regulators and market participants to develop all necessary support, and implementing the most effective means of effectuating the central counterparty approach.

B. Default Procedures.

ERCOT's Protocols include procedures that are comparable to those required by this core principle. They provide ERCOT with the ability to suspend any Counter-Party if it is in Payment Breach or default. [230] ERCOT's Protocols also provide ERCOT with the ability to subject any Counter-Party's activity in the Day Ahead Market or the CRR Auction to the Counter-Party's ACL.[231] The ACL is a function of the Counter-Party's credit limit (its unsecured credit granted and posted collateral) and outstanding exposure. When exposure exceeds the credit limit, that Counter-Party's ACL is zero and the Counter-Party is restricted from participation in the Day Ahead Market or future CRR Auctions that would result in potential liability.[232]

In addition, ERCOT has the ability within its systems to flag an entity as not creditworthy and suspend that entity's activity in the ERCOT market.[233] Accordingly, any default leading to a Mass Transition of a Load-Serving Entity's (LSE) load would result in suspension of the LSE from participation in ERCOT's Day Ahead Market and future CRR Auctions.

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228 ERCOT Protocol Section 9.19.1.

229 ERCOT Protocol Section 9.19.

230 ERCOT Protocol Section 16.11.6.

231 ERCOT Protocol Sections 16.11.4.6, 16.11.4.6.1, and 16.11.4.6.2.

232 ERCOT Protocol Section 16.11.4.

233 ERCOT Protocol Section 16.11.6.

Attachment G—DCO Core Principle G: Default Rules and Procedures

The default procedures for the CRR market are set forth in detail in the ERCOT Protocols, which are publicly available on the ERCOT website.[234] The Protocols allow ERCOT to take the sequential steps described above in Attachment D. In addition, to contain losses ERCOT may take several risk management actions, also described above in Attachment D, which, among other things, include termination of market participation, resale of CRR positions and, to the maximum extent possible, management of default risk against that participant's funds, including collateral/financial security and credits owed to the participant in other ERCOT markets.[235]

After ERCOT terminates a defaulting counterparty's contract, the counterparty must reapply with ERCOT and provide ERCOT with a new DUNS number to re-enter the market.[236] In order to execute a new Standard Form Market Participant Agreement, a counterparty re-entering the market must represent, warrant, and covenant that it has paid ERCOT all sums due to it in relation to a prior default.[237]

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[234] ERCOT Protocol Section 16.11.6.

[235] ERCOT Protocol Section 16.11.6.

[236] ERCOT Protocol Section 16.1.1.

[237] *See* Section 4.A(5) and (6) of the Standard Form Market Participant Agreement.

Attachment G—DCO Core Principle G: Default Rules and Procedures

ISO New England

ISO-NE has rules and procedures that allow for the efficient, fair, and safe management of participants' default, including insolvency. ISO-NE's default rules are set forth in the Financial Assurance and Billing Policies. *See* III.B of the Financial Assurance Policy (Credit Test Calculations and Allocation of Financial Assurance, Notice and Suspension in the New England Markets) and Section 3.3 of the Billing Policy (Payment Defaults for ISO Charges). Payment defaults are socialized after realizing any collateral specific to the defaulting participant, late payment funds, funds in the payment shortfall account and possible insurance claims paid for protracted defaults. ISO-NE also has the ability to suspend and terminate a participant in default and levy financial penalties.

ISO-NE has rules and procedures that allow for the efficient, fair, and safe management of participants' default, including insolvency. ISO-NE's payment default rules are set forth in the Billing Policy, while defaults related to collateral deficiencies are addressed in the Financial Assurance Policy. Payment Defaults are socialized after realizing any collateral specific to the defaulting participant, late payment funds, funds in the payment shortfall account and possible insurance claims paid for protracted defaults.

ISO-NE also has the ability to suspend and terminate a participant in default and levy financial penalties. See Financial Assurance Policy (Attachment IA to the Tariff) at Section III.B.2.c. Regarding payment of invoices, on the business day following the day on which a missed payment was due, the ISO must provide notice of the default to market participants and the defaulting participant. See Section 3.7 of the Billing Policy, which is attachment ID to Section I of the Tariff. On the second day after the payment default, the ISO will suspend the defaulting participant until payment is made in full. Id. Regarding maintenance of adequate financial assurance, the ISO is required to suspend participants who fail to maintain adequate financial assurance. See Financial Assurance Policy (Attachment IA to the Tariff) at Section III.B. Upon a suspension or more than five notices of financial assurance defaults in any rolling 12-month period, the defaulting participant must pay a $1,000 penalty for such suspension and for each notice. See Section III.B.4. These penalties, along with interest charged on overdue unpaid balances, fund the Late Payment Account referenced above. Id. Although, in each case, suspension effectively prohibits a participant from transacting in the markets, the ISO has the right to follow up with a filing at FERC to formally terminate the participant. See Section I.4 of the Tariff. For more information, *see* Section III.B of the Financial Assurance Policy and Section 3.7 of the Billing Policy.

Defaults and Load-Serving Entities

ISO-NE suspends defaulting Load-Serving Entities ("LSE") from participating in the ISO-NE markets by removing the defaulting party's access to the ISO-NE market systems. For a Market Participant that defaults, its load service obligation is assigned to the relevant host Market Participant (*e.g.*, distribution company or "provider of last resort"), unless the host participant has arrangements for the load to be served by another Market Participant. If the suspended Market Participant is the entity that is ultimately responsible for serving the load (*e.g.*, the defaulting party is the provider of last resort or the owner of station service load for generation feed directly from the Pool Transmission Facilities), then the suspended Market Participant will retain the obligation to serve such load. While the obligation to serve remains with such entities, their ISO market access is limited to purchasing energy in the real-time market with no ability to trade day-ahead, virtuals, FTRs, etc. If a suspended Market Participant purchased the obligation to serve such load from another Market Participant, the obligation to serve such load will revert to the Market Participant that sold such obligation.

A suspended LSE is prohibited from entering new FTR transactions and the ISO has the right to terminate and/or liquidate any FTRs that are held but that have not yet matured. Bilaterally negotiated agreements that have been submitted to the ISO for future settlement as a financial obligation to the defaulting LSE's account that have not been collateralized to their full notional value will be terminated by the ISO. Bilateral transactions that, upon maturity, will serve as a financial benefit to the defaulting LSE will not be terminated, nor will bilateral transactions that have already been fully collateralized.

A Load-Serving Entity may have its full rights and privileges restored by curing its financial assurance or payment default. Any market contracts or load obligations that were terminated may be restored as allowed for in the governing documents. Load obligations previously held by the suspended Market Participant may not be immediately recoverable based on competitive or default load serving rules of the states in which the suspended Market Participant were operating. LSEs that are not providers of last resort have no privileges while in default, while a defaulting provider of last resort's market access is limited to real-time energy purchases.

The relevant language governing how ISO-NE must treat Load-Serving Entities that default is contained in Section III.B.3(b) of ISO-NE's Financial Assurance Policy, which is Exhibit IA to Section I of the ISO-NE Tariff. Section III.B.3(b) provides:

> Any load asset registered to a suspended Market Participant shall be terminated, and the obligation to serve the load associated with such load asset shall be assigned to the relevant unmetered load asset(s) unless and until the host Market Participant for such load assigns the obligation to serve such load to another asset. If the suspended Market Participant is responsible for serving an unmetered load asset, such suspended Market Participant shall retain the obligation to serve such unmetered load asset. If a suspended Market Participant has an ownership share of a load asset, such ownership share shall revert to the Market Participant that assigned such ownership share to such suspended Market Participant. If a suspended Market Participant has the obligation under the Tariff or otherwise to offer any of its supply or to bid any pumping load to provide products or services sold through the New England Markets, that obligation shall continue, but only in Real-Time, notwithstanding the Market Participant's suspension, and such offer or bid, if cleared under the Tariff, shall be effective.

Market Participants that are not Load-Serving Entities are suspended in a similar way as Load-Serving Entities, although by definition a non-Load-Serving Entity does not have load assets registered, and therefore does not have to deal with the process of assigning such assets.

Attachment G—DCO Core Principle G: Default Rules and Procedures

Non-LSE participants do not own load assets and as such are not subject to repercussions surrounding load assets.

Attachment G—DCO Core Principle G: Default Rules and Procedures

MISO

The following provides a general overview of default procedures in the Tariff.

A. Process to Address Default and / or Insolvency – In General

In addition to the actions related to default discussed below with regard to Section 7.8 of the MISO Tariff, MISO may, subject to receipt of FERC approval, take actions to:

- Suspend any and all services a Tariff Customer in Default receives under its Service Agreement(s), Market Participant Agreement, other agreements and/or this Tariff (including such Tariff Customer's access to the Energy Markets and FTR Auction) subject to the receipt of approval from FERC, Tariff, Section 7.17(a)(1(ii);

- Terminate any and all other services and/or agreements, subject to the receipt of approval to terminate and settle any and all FTRs held by such Tariff Customer from FERC and any other approvals from FERC that may be necessary, Tariff, Section 7.17(a)(1)(iii);

- Initiate requests for any necessary FERC approvals or consents to terminate any and all services to and agreements with the Tariff Customer, Tariff, Section 7.17(a)(1)(iv);

- Terminate and settle any and all FTRs held by such Tariff Customer, subject to the receipt of approval to terminate and settle such FTRs from FERC, Tariff, Section 7.17(a)(1)(v);

- Liquidate all or a portion of the Tariff Customer's Financial Security and otherwise exercise MISO's rights under any or all of the Credit Support Documents, at MISO's discretion to satisfy total amounts due and payable by the Tariff Customer, Tariff, Section 7.17(a)(1)(vi); and,

- Proceed to exercise any and all remedies available to MISO under this Tariff and/or any applicable agreements or otherwise under applicable law. Tariff, Section 7.17(a)(1)(viii).

In addition, in the event of a Default or Potential Event of Default occurs as a result of a market participant's failure to pay amounts owed under the Tariff, MISO may suspend, without having to obtain approval from FERC, any and all services the defaulting Tariff Customer receives under its Service Agreement(s), Market Participant Agreement, other agreements and/or this Tariff (including such Tariff Customer's access to the Energy Markets and FTR Auction); provided that any such suspension is effectuated upon one (1) Business Day notice to the affected Tariff Customer and FERC. Tariff, Section 7.17(a)(2).

Due to MISO's ability to net market obligations and to better position itself in a bankruptcy proceeding of a Market Participant in default, MISO is evaluating the possibility of becoming a central counterparty to transactions in its markets. MISO is also discussing these issues with its Market Participants. The manner in which MISO will comply with this requirement depends, in large part, on its analysis of the effect that becoming a central counterparty and taking title to market transactions would have on MISO's operations and its Market Participants.

B. Default Procedures

The rules applicable to market participant default are provided in Section 7.8 of the MISO Tariff, which is publicly available on MISO's website at: https://www.midwestiso.org/LIBRARY/Pages/Library.aspx. Under these rules, monies received from Market Participants are used to pay amounts due for Tariff services and membership agreement before making any payments to any other Market Participants. This ensures that MISO will have sufficient funding to pay for its operating costs to continue to meet its obligations as the market administrator.

Pursuant to subsection (b) of Section 7.8, MISO will reduce payments to Market Participants owned monies for the billing period on a *pro rata* basis based on the net credit invoiced amounts owned to the Market Participants to the extent necessary to clear its accounts on the date such payments are due. If funds attributable to past due amounts are received prior to being declared uncollectible amounts, the funds are distributed *pro rata* to the Market Participants that did not receive the full amount of their net credit invoiced amount as a result of the past due amount not being paid.

Pursuant to Section 7.8 (d) MISO may exercise its rights of recoupment and setoff to offset the past due amount against any amounts owned to the market participant. In addition, MISO may use funds attained under credit support documents provided by a market participant to the extent necessary to pay past due amounts and any applicable interest.

Pursuant to Section 7.10 of the Tariff, if MISO concludes that payment in full of a past due amount is not reasonably expected within an acceptable timeframe, MISO may declare the amount an uncollectible obligation. Prior to declaring an uncollectible obligation, MISO will: (i) set aside all funds held by MISO relative to the defaulting market participant, pending determination by MISO's counsel and/or the appropriate bankruptcy courts as to the appropriate disposition of such funds; (ii) seek to recover the unpaid past due amount by drawing upon the entire amount of collateral provided by the defaulting market participant; (iii) seek to recover the amount of the unpaid past due amount from any guarantor of the defaulting market participant's obligations; (iv) seek to exercise other remedies under the credit support documents provided by the defaulting market participant; and (v) pursue available remedies for defaults under this Section 7, including, without limitation, initiating a filing with FERC to terminate the market participant agreement and any service agreements of the defaulting market participant.

If MISO declares an amount an uncollectible obligation it will notify market participants of such by posting a notice on MISO's Open Access Same-time Information System ("OASIS") identifying the defaulting market participant, the amount of the uncollectible obligation, the applicable weeks of service for which the defaulting market participant was initially invoiced and the future weeks in which MISO will uplift the uncollectible obligation to market participants. Uncollectible obligations are recovered from all market participants that were invoiced in the same period of time as the unpaid invoices of the market participant whose unpaid past due amount has been declared an uncollectible obligation.

Attachment G—DCO Core Principle G: Default Rules and Procedures

New York ISO

A. Default Provisions, Generally

The basis for declaring a NYISO Market Participant in default and NYISO default rules and remedies in general are set forth in Services Tariff Section 7.5 and OATT Section 2.7.5. In the event of a default and expiration of the applicable cure period, if any, the NYISO has the right to suspend and/or terminate a Market Participant. *See* Services Tariff Section 7.5 and OATT Section 2.7.5. In addition, the NYISO has the right to initiate debt collection procedures on behalf of the ISO Clearing Account.[238] *See* OATT Section 2.7.5.3(i).

Under the terms of the NYISO's published procedures, if a TCC holder fails to hold any TCC in accordance with the terms and conditions in the OATT, the NYISO will be entitled to revoke the TCC. *See* TCC Manual, Attachments A and B, Section 3(c).

The NYISO's treatment of a Market Participant in the event of a default is the same for both Load Serving Entities ("LSEs") and other Market Participants with respect to providing notice of default to the defaulting customer and to other Market Participants, the length of default cure periods, and the NYISO's collection efforts. The only unique aspect to a defaulting LSE, as discussed in more detail in Section C, *infra*, is that the NYISO would coordinate the appropriate operational communications with the distribution utility taking the load as soon as the NYISO reasonably believed that it would have to transfer the defaulting LSE's load to the Provider of Last Resort ("POLR").

A Market Participant that is terminated by the NYISO after an event of default may participate in the NYISO-administered markets in the future by re-applying to become a NYISO Market Participant and satisfying all customer registration and participation requirements. Any former Market Participant whose previous default resulted in a bad debt loss must cure that default by payment to the NYISO of all outstanding and unpaid obligations prior to being re-admitted by the NYISO to participate in the NYISO-administered markets. *See* OATT Section 27.4.

B. Default Procedures

In the event of a collateral default, the NYISO will issue notice to the defaulting Market Participant and demand additional collateral. A defaulting Market Participant is given no more than two business days to cure a collateral default. *See* Services Tariff Section 26.11. In certain situations, the tariffs permit the NYISO to suspend a Market Participant's trading activity immediately upon a collateral default. For example, the NYISO may immediately suspend the Virtual Transaction activity of a Market Participant and cancel any pending Day-Ahead Bids if at any time the amount of the Market Participant's actual losses on Virtual Transactions equals 100% of its credit support provided for Virtual Transactions. *See* Services Tariff Section 26.8.2.

[238] Upon FERC's acceptance of the NYISO's April 30, 2012 filing that establishes the NYISO as the single counterparty to Market Participant transactions, as discussed in detail in Attachment B, *supra*, the NYISO will have the sole and exclusive right to initiate debt collection procedures, on its own behalf, against defaulting Market Participants.

Attachment G—DCO Core Principle G: Default Rules and Procedures

In the event of a payment default, a Market Participant is given only one business day to cure its default. *See* Services Tariff Section 7.5.2(i); OATT Section 2.7.5.2(i). If the Market Participant does not cure its default then the NYISO, to the extent the past due amount exceeds the Market Participant's collateral and working capital contribution, will attempt to collect the shortfall amount from the defaulting Market Participant. If collection efforts are unsuccessful, and the CFO determines that further collection efforts are not likely to be successful, the NYISO will declare a bad debt loss. The NYISO will then recover the amount of the loss from Market Participants on a pro rata basis in accordance with the formula set forth in the NYISO OATT Section 27.3. Under this formula, the loss is allocated to each Market Participant that participated in the NYISO-administered markets during the period in which the defaulting Market Participant incurred the charge. The formula allocates the loss ratably based on each Market Participant's purchases and sales during the applicable period as a percentage of the total market purchases and sales.

After the NYISO declares a bad debt loss, it typically adds the appropriate charge to Market Participant invoices to recover the full amount of the bad debt loss in a single billing period. Under OATT Section 27.3, the NYISO has the right to recover the bad debt loss over multiple billing periods, and to ratably adjust Market Participant allocations of the bad debt loss as necessary to fully recover the loss. If the NYISO subsequently recovers money from the defaulting Market Participant, or otherwise, then the NYISO will distribute the recovered funds on a *pro rata* basis to the Market Participants previously charged for the loss.

Market Participant payment defaults have never resulted in the NYISO short-paying Market Participants, but as discussed in detail in Attachment B, *supra*, the NYISO's tariffs would permit short-payment.

C. Default Provisions Applied to LSEs

In the event of a default by a LSE, and expiration of the applicable cure period, the NYISO would suspend or terminate the LSE's authorization to participate in all NYISO-administered markets, including the TCC market and Virtual Transactions. *See* Services Tariff Section 7.5.3; OATT Section 2.7.5.3. The NYISO's suspension or termination of an LSE does not interrupt the flow of power to the LSE's customers. The NYISO's transfer of an LSE's load to the POLR merely shifts the billing and scheduling obligations for the load from the LSE to the POLR. For this reason, the NYISO can promptly suspend or terminate a defaulting LSE without concern that this action would disturb the reliable flow of power to the LSE's customers. Further, in order to maintain system reliability, the NYISO would continue to schedule energy to serve the LSE's load until the transfer to the POLR has been effectuated. The actual time required for the NYISO to process the transfer of an LSE's load to a POLR is a few hours.

The NYISO may suspend or terminate an LSE for, among other reasons, failure to pay invoices when due and failure to comply with the NYISO's creditworthiness requirements. *See* Services Tariff Section 7.5.3; OATT Section 2.7.5.3. A defaulting LSE has only one business day to cure a payment default and two business days to cure a creditworthiness default. *See* NYISO Services Tariff Section 7.5.2; OATT Section 2.7.5.2.

In the event the NYISO reasonably believed that it would have to suspend or terminate an LSE, the NYISO would immediately notify the POLR but, as discussed above, would not stay or otherwise delay the suspension or termination until the LSE's obligations to serve retail load have reverted to the POLR in each territory in which the LSE serves load.[239]

In terms of the potential impact of a LSE's default in light of its outstanding obligations, it is important to recognize that long-term power contracts are not traded in the NYISO-administered markets. Accordingly, NYISO Market Participants, including LSEs, would not have any long-term energy commitments that have not yet matured that the NYISO would need to address. The longest Installed Capacity commitment that a Market Participant can purchase is for six months. In the event an LSE's participation is suspended or terminated and its load shifted to the POLR, then the POLR should also assume the LSE's Installed Capacity obligations. The longest TCC commitment is for two years. While some LSEs have a right to purchase fixed-prices TCCs with durations of up to 10 years, these rights are exercised in one year increments. To the extent the NYISO is unsuccessful in its collection efforts and an LSE remains indebted to the NYISO for an Installed Capacity commitment or TCC, the NYISO would draw first upon the LSE's collateral and then its working capital contribution to cover the obligations.

[239] POLR obligations are a matter of state law. The New York State Department of Public Service oversees compliance by POLR utilities with their POLR obligations.

Attachment G—DCO Core Principle G: Default Rules and Procedures

PJM

A. Default Rules.

PJM's legal framework pertaining to its default rules include potential default allocation obligations where one member's default could be mutualized to PJM's membership as a whole. PJM's default rules and procedures do not address "cross-margin programs" or "customer priority" because these concepts are inapplicable to PJM or other ISO/RTOs.

Historically, PJM has not required collateral for default allocation charges. Because such amounts are small in relation to a participant's own activity, any default on a default allocation charge is de minimis. PJM's use of a three-week historical peak for its credit requirements also provides a credit reserve for such charges in other weeks. Furthermore, PJM's response to the FERC Order 741 includes a minimum capitalization or minimum collateral provision, which will provide additional credit reserves for such charges.

Moreover, a sound legal foundation is fundamental to an effective market structure.[240] As a result, PJM has worked with its members to obtain FERC approval to clarify title in market transactions thus establishing clear mutuality to support PJM's netting practices. Effective January 1, 2011, the PJM OA and PJM Tariff were revised to establish PJMSettlement, Inc., an affiliated company, as the counterparty to all market participant purchase and sale transactions in the organized markets administered by PJM so as to provide title clarity and clear legal standing to support PJM's netting practices.[241] Specifically, these provisions establish PJMSettlement as the counterparty to market participants and customers for transmission service, ancillary services transactions, purchases and sales in PJM's energy markets, purchases and sales of capacity in the Reliability Pricing Model ("RPM") auctions, purchases and sales of FTRs in auctions, and ARRs.[242] While numerous revisions to the PJM Tariff and OA have been necessary to effectuate this transition, most notably, Section 14B.4 of the PJM OA was added to clarify the right of PJMSettlement to net and/or set-off obligations owed to it, and PJM, by a market participant.[243]

B. Default Procedures.

Upon the occurrence of a member default, PJM has several remedial options (primarily set forth in Section 15 of the PJM OA), including:

- Termination/liquidation of member FTRs;

240 The Bank for International Settlements provides core principles to ensure safety and efficiency in systemically important payment systems. The first Core Principle states: "The system should have a well-founded legal basis under all relevant jurisdictions." Core Principles for Systemically Important Payment Systems, Bank for International Settlements (January 2001). PJMSettlement enhances PJM's adherence to that general principle.

241 The effective date of the relevant PJM OA and PJM Open Access Transmission Tariff provisions were established in FERC's September 3, 2010 order in Docket No. ER10-1196-000, *available at* http://www.pjm.com/~/media/documents/ferc/2010-orders/20100903-er10-1196-000.ashx.

242 PJM OA, Definitions C-D, Sections 1.7.01a, 3.3 (definitions of "counterparty"), and 14B.4; PJM Tariff, Definitions C-D, Sections 1.6D, 3.4, and 6A (definitions of "counterparty").

243 *See also* discussion below on "Legal Risk."

- Termination of market buyer/seller rights to make purchases/submit offers from/to the PJM markets;

- Set-off, subject to applicable law, amounts owed to defaulting member. If the default remains after set-off, PJM will draw upon the defaulting member's credit support, as provided in the Credit Policy. If a default still remains, PJM will allocate the remaining amount to other PJM members via the default allocation assessment formula;

- Close-out netting, subject to applicable law, amounts owed to a defaulting member by PJM and amounts realized by PJM in the close-out and liquidation of a member's FTRs;

- Termination of the defaulting member's participation and right to vote in relevant stakeholder meetings;

- Rules relating to reinstatement of members following multiple defaults and eventual remedies, including loss of stakeholder privileges for specified period, loss of the allowance of unsecured credit, and, ultimately, expulsion of the member from PJM membership and prohibition of future membership.

In addition, the PJM OA Section 15.1.6 and PJM Tariff Section 7.3 both speak to the possible consequences that may occur following a declaration of default. In particular, Section 15.1.6 specifies increasing restrictions on the member when a member is declared in default, ultimately resulting in member expulsion and preclusion from seeking further membership.

Except for Providers of Last Resort ("POLR")—local, regulated utilities, which are required to provide retail service to customers in the event that an alternative LSE does not provide such service, LSEs that default may not continue participating in PJM markets. Specifically, if an LSE that is not a POLR defaults, then the LSE is terminated and PJM notifies the POLR that the LSE's retail load customers should be returned to the utility that is the POLR. If the defaulting LSE's load could not be transferred to the POLR as of the default declaration, then the LSE's FTR and virtual bidding transaction rights would still be terminated as of the default declaration date. The LSE's ability to undertake future transactions through PJM's eTools are also terminated. If an LSE is a POLR, PJM is required to file with the FERC to seek termination of the LSE's service.[244] In PJM's history, there have been three instances when an LSE has defaulted and had its customers returned to the POLR: twice in 2001 and once in 2007. However, none of those defaults has ever involved an LSE that was otherwise a POLR.

At the same time when PJM terminates an LSE's ability to transact, PJM also cancels or schedules for liquidation, as applicable, the LSE's positions in the PJM system. Reported bilateral schedules are canceled, while FTR positions are liquidated. For the most part, LSEs typically buy in PJM's energy market and ancillary services markets (which are both spot markets). They usually do not enter into forward obligations with future maturity. The approach

[244] PJM Tariff, Section 7.3.

taken for defaulting LSEs is no different than the approach taken for other defaulting market participants, except that a non-LSE does not have retail load customers that must be returned to a POLR following a termination of service. An LSE that has cured its default may resume normal activity after complying with the requirements of PJM OA Section 15.1.6. In each of the three LSE default cases mentioned above, all LSE activity was terminated; however, because the 2007 LSE default did not involve a payment default, but rather a collateral default, the participant was eventually allowed to resume limited activity.

Attachment H

DCO Core Principle H: Rule Enforcement

Each derivatives clearing organization shall—

(i) maintain adequate arrangements and resources for—

> (I) the effective monitoring and enforcement of compliance with the rules of the derivatives clearing organization; and
>
> (II) the resolution of disputes;

(ii) have the authority and ability to discipline, limit, suspend, or terminate the activities of a member or participant due to a violation by the member or participant of any rule of the derivatives clearing organization; and

(iii) report to the Commission regarding rule enforcement activities and sanctions imposed against members and participants as provided in clause (ii).

Responses:

Attachment H—DCO Core Principle H: Rule Enforcement

California ISO

The CAISO tariff provides the CAISO with authority to enforce numerous provisions of the tariff. For example, the CAISO may take a range of actions against a market participant that fails to pay an invoice,[245] pays late,[246] or fails to post financial security according to the tariff deadlines.[247] These remedies include assessment of fines for repeated late payments[248] and, ultimately, suspension of the market participant's right to bid in the CAISO markets or use the CAISO grid.

In addition, Section 37 of the Tariff contains the CAISO's "Rules of Conduct" for market participants. With the exceptions of rules that require subjective judgments (which are enforced by FERC),[249] the CAISO has authority to investigate and enforce suspected violations of the Rules of Conduct.[250] In addition to the CAISO's enforcement authority, the FERC Office of Enforcement receives referrals of potentially violative conduct from the CAISO's Department of Market Monitoring ("DMM"). Appendix P of the CAISO Tariff establishes the structure, as well as the roles and responsibilities, of the DMM. The DMM must be adequately staffed with full-time CAISO personnel who have adequate experience and qualifications to fulfill the DMM's functions.[251] Among the duties of the DMM set forth in Appendix P are to "identify and notify the FERC's Office of Enforcement staff of instances in which a Market Participant's behavior or the behavior of the CAISO itself is suspected to constitute" a violation of the CAISO Tariff or of FERC regulations.[252] Potential violations for which the DMM monitors include violations of 18 C.F.R. § 35.41(b) and 18 C.F.R. 1c.2, which require the provision of accurate information to the CAISO and prohibit market manipulation, respectively. The decision to make a referral to FERC is in the sole discretion of the DMM[253] and, while the FERC is responsible for investigating any such referrals, the DMM may continue to monitor for additional instances of the referred behavior.[254]

The CAISO also offers alternative dispute resolution, so that market participants can have disputes resolved by a neutral mediator or arbitrator.[255]

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245 CAISO Tariff § 12.5.1. Note that the definition of "estimated aggregate liability includes amounts invoiced but not yet paid. See CAISO Tariff § 12.1.3.1.1(a).

246 CAISO Tariff § 11.29.14.

247 CAISO Tariff § 12.5.2.

248 CAISO Tariff § 11.29.14(c).

249 Those parts of the Rules of Conduct that are enforced by FERC are delineated in CAISO Tariff § 37.1.5.

250 Market participants have the right to appeal CAISO enforcement decisions to FERC. CAISO Tariff § 37.8.10.

251 CAISO Tariff Appendix P, § 4.1.

252 *Id.*, § 5.3.

253 *Id.*, § 11.1.1.

254 *Id.*, § 11.1.

255 CAISO Tariff § 13.2 & 13.3.

Attachment H—DCO Core Principle H: Rule Enforcement

ERCOT

ERCOT's rule enforcement resources and dispute resolution procedures are comparable to those required by this core principle. The regulatory framework that governs ERCOT provides for adequate resources to monitor and enforce compliance with all rules that govern the ERCOT markets, including the CRR market.[256] Specifically, PURA and PUCT rules authorize ERCOT to collect a reasonable fee to enable it to cover the costs necessary to perform its functions.[257]

A. Enforcement of Market Rules and Dispute Resolution

Pursuant to the ERCOT Protocols and the Market Participant Standard Form Agreement, ERCOT market participants are obligated to comply with ERCOT rules. If a market participant violates ERCOT rules, depending on the nature of the issue, ERCOT and/or the PUCT may take appropriate action against the party, including, but not necessarily limited to, terminating, expelling, suspending, or sanctioning a Member, subject to due process.[258]

The ERCOT Protocols establish comprehensive alternative dispute resolution ("ADR") procedures, and PUCT Procedural Rules require the use of these procedures prior to the filing of complaints at the PUCT.[259] If a market participant disputes an ERCOT determination, it may engage in ERCOT's ADR process, which is managed by the ERCOT Legal Department. ADR requires involvement of senior representatives of ERCOT and the disputing party, and seeks to provide a final resolution to issues arising from ERCOT financial or operational decisions.[260] The ERCOT Protocols also include formal processes for mediation and arbitration if the parties agree to participate in it.[261] If the ADR process does not succeed, the disputing party may appeal ERCOT's decision to the PUCT, where its complaint will be litigated as a contested case before the PUCT. In addition, all decisions of the ERCOT Board of Directors (including decisions adopting changes to the ERCOT market rules) are automatically appealable to the PUCT.[262]

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256 *See* discussion of ERCOT funding in Attachment B.

257 See Attachment B discussion that describes the authority of ERCOT to collect a reasonable fee to enable it to perform its functions. *See Generally* PURA § 39.151(e) and P.U.C. SUBST. R. 25.363(c).

258 P.U.C. SUBST. R. 25.503 and ERCOT Protocol Sections 16.11 and Section 8 (Section 8 also establishes performance obligations/metrics and gives ERCOT the right to take action against participants for non-performance by limiting or suspending their participation in relevant markets). ERCOT authority to suspend market participants for contravention of financial obligations was discussed in Attachments C and D.

259 ERCOT Protocol Section 20 and P.U.C. PROC. R. 22.251(c), respectively.

260 ERCOT Protocol Section 20.3.

261 ERCOT Protocol Sections 20.4 and 20.5.

262 P.U.C. PROC. R. 22.251(a). The decisions appealable to the PUCT include those reached in an arbitration proceeding conducted pursuant to the ERCOT Protocols.

B. Market Monitoring

PURA and the PUCT Substantive Rules specifically address market power/manipulation/abuse issues, and the state statute institutionalized an Independent Market Monitor ("IMM") for the ERCOT region. The IMM's purpose is to monitor market behavior and report any market compliance issues to the PUCT,[263] and to monitor and recommend changes in the ERCOT market rules.[264] The IMM reports to the PUCT and its duties are delineated in PUCT Rules.[265] ERCOT supports the IMM and the PUCT in their market oversight/monitoring roles.[266] The IMM is required to be qualified and staffed to perform its functions, and the PUCT is charged with ensuring the IMM has adequate resources to perform its functions, including being adequately funded.[267] The IMM can communicate with the PUCT on any matter, and is required to report any market issues to the PUCT.[268] ERCOT is required to cooperate with the IMM in this role, including, but not limited to, providing information and data to support the IMM activities and functions.[269] This is in addition to monitoring its own rules as the ISO responsible for administration of the ERCOT market.[270] Market participants are similarly required to provide information to the IMM.[271] The IMM role facilitates market rule enforcement in the ERCOT region by providing a focused market monitoring function that supports the PUCT enforcement role in the ERCOT region.[272]

In addition to the roles of the IMM and ERCOT, as noted above, the PUCT has an enforcement division charged with overseeing, monitoring and enforcing rules in the ERCOT market.[273] ERCOT provides support to the PUCT in this role, and is required to provide information to the PUCT as necessary, including supporting its investigatory functions.[274] The PUCT can take any action appropriate for contravention of market rules.[275] The IMM also reports to the PUCT regarding market digressions and/or violations.[276] Collectively, these

263 PURA §§ 39.157 and 39.1515 and P.U.C. SUBST. R. 25.503(g).

264 PURA § 39.1515(a) and P.U.C. SUBST. R. 25.365(c) and (d).

265 PURA § 39.1515 and P.U.C. SUBST. R. 25.365.

266 PURA § 39.1515(b), P.U.C. SUBST. R. 25.365(e) and (m) and ERCOT Protocol Section 17.

267 PURA § 39.1515(d) and P.U.C. SUBST. R. 25.365(g) and (h).

268 P.U.C. SUBST. R. 25.365(l)(1) and (2).

269 PURA § 39.1515(b) and P.U.C. SUBST. R. 25.365(e)(3) and 25.365(m).

270 P.U.C. SUBST. R. 25.503(j). This applies to operations but market obligations and performance are directly related to operations and ERCOT monitors market activity pursuant to this specific obligation and its general obligation as the market administrator charged with administering efficient markets.

271 P.U.C. SUBST. R. 25.365(e)(3).

272 Specific authority granted to ERCOT in the ERCOT Protocols also allows ERCOT to limit or suspend market participation (*e.g.* authority in Sections 8 and 16 of the ERCOT Protocols for violations of performance and credit obligations, respectively).

273 P.U.C. SUBST. R. 25.503.

274 PURA § 39.151(d) and P.U.C. SUBST. R. 25.503(f)(8) and 25.503(j)(4).

275 P.U.C. SUBST. R. 25.503(m).

276 PURA § 39.1515 and P.U.C. SUBST. R. 25.365.

authorities and the entities charged with executing the duties thereunder provide a comprehensive oversight and enforcement framework that facilitates market participant compliance with all relevant rules.

Attachment H—DCO Core Principle H: Rule Enforcement

ISO New England

ISO-NE has adequate arrangements and resources for effective monitoring and enforcement of compliance with its rules and for the resolution of disputes.

Role of Market Monitors

ISO-NE has an internal market monitor ("IMM") and external market monitor ("EMM"). *See* Appendix A to Section III of the Tariff. The IMM monitors for Market Participant violations of the ISO Tariff, violation of a Commission-approved order, rule or regulation, or inappropriate dispatch (together with market manipulation, collectively defined as "Market Violations" in the ISO Tariff). Note that a Tariff violation could also constitute market manipulation, and vice versa. Market Violations are referred to FERC for investigation.

The IMM's authority to monitor and mitigate virtual transactions is found in Section III.A.8 of the ISO Tariff. Per Section III.A.8.2.1, the IMM compares the deviations between day-ahead and real-time locational marginal prices to determine if there is a persistent difference that would not be expected in a workably competitive market, *i.e.*, that is not explained by technical constraints or supply and demand conditions. Per Section III.A.8.2.2 of the ISO Tariff, the IMM also calculates a rolling average locational marginal price deviation value. Depending on the amount of the rolling average deviation, the IMM is required to investigate whether and to what extent the actions of one or more Market Participants are contributing to the price deviation. If a Market Participant is found to have contributed, through its virtual transactions, to an unwarranted deviation in the day-ahead and real-time prices at a node, the IMM may restrict that Market Participant's ability to submit virtual bids or offers for up to six months. In addition, per Section III.A.14 of the ISO Tariff, if the Market Participant's activities constitute a "Market Violation," the IMM would refer the Market Participant to the FERC.

Beyond the specific activities outlined in the Tariff, on a weekly basis the IMM reviews the activity of Market Participants taking virtual positions. The IMM analyzes the profitability of virtual positions and the distribution of those virtual positions (nodal, zonal, hub). It also analyzes the other market positions taken by those Market Participants in order to ascertain, for example, whether their virtual transactions are used principally to hedge physical positions or are arbitrage/speculative in nature. The IMM also relies on information from the ISO's system operators and market operations and settlements departments regarding perceived anomalous behavior. The purpose of this analysis is to monitor the marketplace for trends and "outliers." Should the IMM identify a trend (*e.g.*, a Market Participant taking consistently unprofitable positions) or an outlier (*e.g.*, a sudden change in a Market Participant's bidding behavior), the IMM contacts the Market Participant to discuss the identified behavior. Absent a satisfactory explanation, the IMM will open an investigation and may refer the Market Participant to the FERC for consideration of whether a violation has occurred. The IMM may also notify the ISO if any changes to market rules, models or procedures are needed or advisable to prevent manipulative conduct. The IMM also computes the degree of price convergence daily, and provides monthly reports on price convergence to the Markets Committee of the ISO-NE Board of Directors. The IMM investigates persistent price differences that are not explained by transaction costs.

Attachment H—DCO Core Principle H: Rule Enforcement

The IMM has a weekly call with FERC's Office of Enforcement and also makes formal written reports to the Office of Enforcement on a monthly, quarterly and annual basis. Moreover, as discussed above, the IMM discusses with and makes referrals to FERC regarding any potential Market Violation. FERC has the legal authority to investigate and take action on Market Violations separately from the actions that an ISO's/RTO's IMM is empowered to take under its Tariff.

Both the IMM and EMM report directly to the Markets Committee of ISO-NE's independent Board of Directors. In the event that either market monitor uncovers problems with the markets, it is required to promptly inform FERC, FERC's Office of Energy Market Regulation staff, the ISO Board, the public utility commissions for each of the six New England states, and the market participants of its findings in accordance with the procedures outlined in Sections III.A of ISO-NE's Tariff, subject to redaction pursuant to the ISO's Information Policy, if necessary.

Both market monitors produce annual reports detailing the operation and competitiveness of the markets; their reports can be found at http://www.iso-ne.com/markets/mktmonmit/rpts/index.html.

One of the main functions of the IMM is to evaluate all behavior in the ISO markets for consistency with profit maximizing behavior based on our model of how an actor facing a competitive market would behave, viewing the action in isolation. This standard for judging behavior mitigates the need for knowledge of bilateral market positions in many cases. (Note that this is probably easier to do in electricity markets than other commodities markets because of the greater level of information the IMM has regarding electricity markets.) If an action does not appear to be profit maximizing, then further investigation occurs. If it appears to be profit maximizing but only when other (known) positions are taken into account, then further investigation occurs (e.g., if a series of virtual trades make no sense unless the affect on FTRs is considered). If it is profit maximizing in isolation, then that is at least consistent with good behavior and knowledge about additional positions is not generally needed. In the cases where investigation is required, and the results are suspicious, then the matter must be referred to FERC.

Under the FERC's market-based rate making policy, electricity prices are deemed just and reasonable if they are the result of a competitive process. As implemented in the ISO tariff, a price is competitive if the marginal resource in any pricing interval is not pivotal; that is, absent the resource, demand can still be satisfied. If a resource is pivotal it has market power in the pricing interval. A resource can be said to have "undue market power" if it exercises that power and raises prices above an allowed threshold. According to the Tariff, a pivotal resource is not allowed to mark up its offer above its reference price by more than a specified amount. The reference price is either cost-based or a function of the offers accepted from the resource over a historical period in which it was not pivotal. If the offer from a pivotal resource exceeds the allowed mark-up, a test is run to determine to what extent the resource impacts price. If the price impact exceeds a tariff specified threshold, the resource has improperly exercised its market power and its offers are mitigated to the reference level ensuring that the resulting prices are just and reasonable. For more detail on this discussion, see the IMM's annual report at the link above.

Among other matters, the IMM has observed or investigated:

(i) Economic withholding -- where a unit does not offer into the energy markets in a potential effort to raise prices for other resources.

(ii) Physical withholding -- where a resource erroneously claims that it is not available for physical reasons in an attempt to raise prices for other resources.

(iii) Improperly claiming a resource available when, in fact, it is physically incapable of operation -- this might be done to collect capacity payments when a resource should not receive such payments due to unavailability.

(iv) Attempts to manipulate reference prices -- use of offer strategies to raise reference prices which, in turn, can be used to increase offers and, particularly in constrained areas where a resource is needed for reliability, increase revenues.

(v) Use of interrelated virtual bids and FTRs -- to increase the value of products in these markets.

Dispute Resolution

Section III.A.11 of the ISO-NE's Tariff is entitled "ADR Review of Internal Market Monitor Mitigation Actions." It provides that a Market Participant may obtain prompt Alternative Dispute Resolution review of Internal Market Monitor mitigation imposed on it. The procedure for review is set forth in *Appendix D* to Market Rule 1. The standard of review is that the ADR Neutral shall remove the Internal Market Monitor's mitigation only if it concludes that the Internal Market Monitor's application of the Internal Market Monitor mitigation policy was clearly erroneous. In addition, participants have also used the process for "Requested Billing Adjustments" in Section 6 of ISO-NE's Billing Policy, which is located at Exhibit ID to Section I of the ISO-NE Tariff.

Attachment H—DCO Core Principle H: Rule Enforcement

MISO

As discussed in its response to Attachments D and G above, MISO actively monitors and enforces its Credit Policy and default procedures in an effort to protect Market Participants from financial losses.

MISO also employs internal and external resources to monitor market activity for actions that are inconsistent with market rules.

MISO relies on an independent market monitor ("IMM") to review market activity for manipulation and anti-competitive behavior. In addition, MISO staff reviews market participant activities and behavior and reports identified issues to the IMM or FERC, as appropriate. To the extent necessary, MISO may suspend or terminate a market participant's participation in market activities for failure to comply with the Tariff.

Module D of the MISO Tariff provides market monitoring and mitigation measures related to MISO's markets. Module D provides for the reporting of the IMM's findings to FERC, MISO, its board of directors and state regulatory commissions. In addition, Attachment S-1 to the MISO Tariff provides the retention agreement between MISO and its IMM.

Attachment HH to the MISO Tariff provides dispute resolution procedures. These procedures begin with informal dispute resolution between the parties to a dispute under the Tariff and other FERC filed rate schedules and progress to mediation and arbitration. The informal dispute resolution process is intended to provide an opportunity to resolve disputes on an expedited timeline when necessary or possible. The dispute resolution process is overseen by MISO's ADR Committee, which is established under the MISO Agreement for this purpose and made up of MISO stakeholder representatives.

Attachment H—DCO Core Principle H: Rule Enforcement

New York ISO

A. Monitoring and Compliance with NYISO Tariffs and Policies, Generally

1. Internal Monitoring and Compliance Efforts

The NYISO has established numerous internal procedures to ensure that NYISO personnel and systems operate in accordance with the NYISO tariffs and other applicable rules. These include the following:

- The NYISO utilizes a well established and long running Enterprise Risk Management process to identify potential areas for improvement of NYISO markets and operations. These processes examine potential risks or areas of concern associated with FERC rules enforcement, NERC Reliability Standards, and other rules applicable to the NYISO. This process is conducted on a monthly basis and includes participation by senior level NYISO executives and subject matter experts, which regularly report to the NYISO Board. The NYISO's Enterprise Risk Management process has been identified as an industry leader.

- The NYISO's Compliance Program also ensures that NYISO personnel act in compliance with the NYISO Code of Conduct and related requirements. All NYISO staff receive annual training on the NYISO's Code of Conduct and compliance obligations. In addition to compliance training, all staff are provided with a listing of NYISO Market Participants, Parents, and Affiliates in which they may not hold securities. This list is maintained by the NYISO Compliance Office in conjunction with the Prohibited Investment Committee.

- The NYISO has established specific reporting requirements and specific reporting processes in the event of any non-compliance with NYISO tariffs and policies. In the event of an alleged or confirmed reliability or business practice non-compliance by either the NYISO or a Market Participant, it is the responsibility of the Compliance Responsible Managers to provide immediate notification to the applicable Senior Management. Within 24 hours the result of the initial evaluation will be reported to the Chief Compliance Officer. This accelerated reporting requirement will ensure that the appropriate evaluation, documentation, mitigation, and notification actions are taken.

- To support the NYISO's internal efforts to maintain a robust compliance program, the NYISO regularly engages independent third party consultants to assess the program, to advise the NYISO on industry "best practices" and to provide recommendations for enhancing the program. Since 2007, outside independent consultants have performed annual certifications of the NYISO's dispatch and pricing, market monitoring, and settlement software systems.

2. Monitoring and Enforcement of Market Participants

In addition to the NYISO's efforts to ensure internal compliance by NYISO personnel, all markets administered by the NYISO are monitored in accordance with the requirements of Services Tariff, Attachment H – ISO Market Power Mitigation Measures ("Services Tariff Section 23"), as well as Services Tariff, Attachment O – Market Monitoring Plan ("Services Tariff Section 30"). Services Tariff Section 23 sets forth the NYISO's market power mitigation measures, including measures for Virtual Transactions, and sanctions for violations of bidding requirements. *See* Services Tariff Section 23.4.6.

Services Tariff Section 30 sets forth the NYISO's Market Monitoring Plan ("Plan"). The Plan delineates the duties and responsibilities of the NYISO's internal Market Mitigation and Analysis Department, and of its external Market Monitoring Unit. Both the Market Mitigation and Analysis Department and Market Monitoring Unit have extensive market monitoring functions. The Market Monitoring Unit reports to the NYISO Board and is responsible for certain core market monitoring functions, as specified in Services Tariff Section 30.4.5. The responsibilities of the Market Mitigation and Analysis Department and Market Monitoring Unit include monitoring all markets administered by the NYISO, including the TCC market, Virtual Transactions, Capacity and Day-Ahead and Real-Time energy markets. *See, e.g.,* Market Monitoring Unit Sections 30.5.1.2 and 30.10.3. Under Services Tariff Section 30.6.2, the Market Mitigation and Analysis Department and Market Monitoring Unit can obtain data necessary for their functions from the participants in the NYISO markets, and under Services Tariff Section 30.4.7 the NYISO is required to ensure that the Market Monitoring Unit has sufficient access to NYISO resources, personnel, and market data to enable the Market Monitoring Unit to carry out its functions.

The NYISO's internal Market Mitigation and Analysis Department is required to bring "to the Market Monitoring Unit's attention market-related concerns (including, but not limited to, possible Market Violations) it identifies while carrying out its responsibilities …" *Id.* at Section 30.3.3. Among the Market Monitoring Unit's core functions set forth in Services Tariff Section 30 is the obligation to identify and notify FERC staff of instances in which a Market Party's or the ISO's behavior may require investigation, including, but not limited to, suspected Market Violations. *See* Services Tariff Sections 30.4.5.2.1 and 30.4.5.3. The definition of "Market Violations" in Services Tariff Section 30.2 is broad, including any of the following:

(i) a tariff violation;

(ii) a violation of a FERC accepted or approved order, rule or regulation including, but not limited to, violations of FERC's Market Behavior Rules, 18 C.F.R. § 35.41, or any successor provisions thereto;

(iii) market manipulation (referencing 18 C.F.R. § 1c.2, or any successor provision thereto);

(iv) inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Likewise, the Market Monitoring Unit has broad authority under Service Tariff Section 30 to investigate any and all conduct that may constitute a market power abuse, market manipulation, fraud, Tariff violations, or otherwise contribute to inefficient market outcomes.

Both the internal Market Mitigation and Analysis Department and the Market Monitoring Unit apply substantial resources in exercising the tariff authority described above.

The Market Monitoring Unit issues regular reports on the competitiveness of the NYISO markets, including in relation to TCCs and Virtual Transactions. The NYISO meets frequently with its Market Participants and other stakeholders to discuss any concerns raised by the Market Monitoring Unit in such reports related to market structures and additional mechanisms to promote competition in the NYISO markets. This allows for the identification of any perceived flaws in the market or modeling inconsistencies between the Day-Ahead and Real-Time Markets in order to prevent Market Participants from engaging in Virtual Transaction in order to take advantage of such inconsistencies. If the Market Monitoring Unit determines that such a flaw in the market exists, it will notify the NYISO and FERC and may recommend a specific remedy.

In addition to active enforcement efforts by the NYISO, some NYISO rules are self-enforcing as a result of bidding protocol and other automated limits. For example, TCC bids may not be entered by a Market Participant beyond credit obligations required by the applicable credit rules have been satisfied.

B. Market Monitoring Metrics to Enforce Compliance with Rules Requiring Competitive Bidding and Preventing Market Manipulation

The Market Mitigation and Analysis Department devotes significant resources to ensuring that Market Participants' activities are consistent with NYISO rules designed to prevent the exercise of market power and other forms of market manipulation. The NYISO's Market Mitigation and Analysis Department's market monitoring metrics used to perform market surveillance to detect potential market distorting behavior are the mitigation thresholds specified in Services Tariff Section 23. In addition, the Market Monitoring Unit reviews market outcomes for systematically poor convergence between forward prices and spot prices, and between spot prices in adjacent ISOs, particularly at locations where non-physical transactions can have a significant effect on prices.

1. <u>Preventing the Exercise of Undue Market Power in the Energy Markets (Including Virtual Transactions) and the Installed Capacity Market</u>

Consistent with standard economic theories, the NYISO defines market power as the ability profitably to engage in physical or economic withholding. "Physical withholding" refers to a practice of not offering a product or service into a market when it would be in the entity's economic interest, in the absence of market power, to offer the product or service. In the presence of market power, such a strategy will be profitable for the seller if it sufficiently increases the price on its transactions that remain in the market. "Economic withholding" refers to a practice of offering a product or service at prices above competitive levels when doing so would not be profit maximizing in the absence of market power. In the presence of market power, such a strategy can cause the market clearing price to increase rather than causing the seller to lose sales by bidding itself out of the market, or if sales are lost can have the same effects as physical withholding.

The NYISO's approach to preventing undue exercises of market power in relation to its Energy markets (which include Virtual Transactions) takes into account the distinguishing characteristics of electricity as a commercial commodity, and takes advantage of the operation of the NYISO markets as single clearing price auctions.

Electricity has three features that must be accommodated by any market design:

1) Demand in wholesale electricity markets, such as those administered by the NYISO, is almost totally inelastic, because virtually all retail end-users do not see hour-to-hour prices reflecting wholesale prices. Thus, end-users cannot discipline sellers by reducing consumption in response to wholesale price increases.

2) Storage is not feasible, so production must continuously satisfy demand. This can result in a supplier being "pivotal," meaning that demand in a given region cannot be met without using that supplier's production facilities. Such a supplier would have a significant unilateral ability to control market prices.

3) Transmission constraints (limitations on the ability of the transmission system to move electricity from supply to load) can give rise to geographic areas in which meeting demand requires using resources inside the constraint. If there are only a few suppliers offering such resources, those suppliers may be able to exercise market power.

Experience in electricity markets around the world and across much of the U.S. has shown that single clearing price auctions, such as those administered by the NYISO, are well-suited to the distinctive characteristics of electricity described above. In such auctions, offers are ranked by price, and accepted from lowest to highest up to the quantity needed to meet demand in a given interval, subject to complying with reliability requirements. The price paid to the last, or marginal, supplier needed to meet demand for the interval is paid to all suppliers offering at or below that price, and clears the market by matching supply to demand for the interval. Because limitations of the transmission system may occur, this process is conducted by the NYISO on a regional basis. If transmitted energy cannot fully satisfy regional demand, the use of additional generation in that region would be required, and would clear the regional market, even though less expensive resources are available outside the region. Thus, prices may differ, sometimes significantly, from area to area across the New York market. The intended result of this market design is that demand is met from interval to interval at the locational marginal cost of the marginal supplier, the economically efficient outcome, with a difference in locational prices between two points corresponding to the value of transmission between those points.

Another consequence of this market design is that, in competitive conditions, the profit-maximizing strategy for suppliers is to bid at their marginal cost. A supplier will not know the clearing price until after bids have been submitted and the market software has been run, but by definition (i) a supplier will not lose money if it operates when prices are equal to its marginal cost because it will cover its operating costs, and (ii) it will cover its operating costs and earn a contribution to its fixed costs whenever prices exceed its marginal cost. Correspondingly, a supplier risks foregoing economically beneficial sales if it bids above its marginal cost and its offers are not accepted when the market clears below such offers but above the supplier's marginal cost. Thus, to ensure that it will operate whenever it is profitable to do so, a supplier should bid at its marginal cost.

This auction design puts market administrators, such as the NYISO, in a strong position to monitor markets for and control abuses of market power. As the market administrator, the NYISO receives all of the supplier bids, and determines the market clearing price in its Energy markets. The NYISO can also determine a supplier's bidding level during periods when markets are competitive. As explained above, such bids would reflect a supplier's marginal costs. Alternatively, the NYISO has authority under its tariff to require cost information from the supplier, or to use proxy methods to determine those costs. The NYISO also monitors fuel price indices and other input costs. The end result is a set of benchmarks, or reference levels, adjusted for current fuel prices and other market conditions as appropriate, against which to compare a supplier's bids.

Armed with this information, the NYISO can monitor its Energy markets (a) for offering conduct that is not consistent with the conduct that would be expected under competitive conditions as indicated by a comparison of a supplier's offers to its reference levels, and (b) to determine whether such offers would have a significant effect on prices. When such bidding behavior and price effects are detected, the NYISO can restore its markets to competitive outcomes by capping the offers of the offending supplier at the resource's reference level, which is designed to reflect the unit's marginal cost (or the best available proxy for that cost). This is done automatically for areas with persistent transmission constraints, such as New York City, or in the case of a unit needed for the reliability of the electric system, and can be done on a case-by-case basis for other areas as conditions warrant. This basic methodology applies across all electricity products produced from physical assets, including Energy, Ancillary Services and Installed Capacity.

The thresholds for comparing offers to reference levels, and for determining whether offers exceeding those thresholds would cause a significant increase in prices, are specified in the NYISO's Market Power Mitigation Measures in the NYISO's Services Tariff Section 23. The thresholds are significantly tighter for New York City, as an area subject to persistent transmission constraints, than they are for the rest of the state. Thresholds are also tighter for units that are needed for the reliability of the power system. Conduct that exceeds the applicable offering and price effects thresholds is deemed to constitute an undue exercise of market power. The Market Power Mitigation Measures also specify a hierarchy of methods for determining a supplier's reference levels, in accordance with the principles described above. The resulting reference levels may be relatively high for some units, or for the uppermost output levels on some units (since units may be significantly less efficient, and subject to wear and tear and outages, at high output levels). As a result, market clearing prices can rise to relatively high levels when meeting demand requires using high-priced units or output levels, and such legitimately high prices are not subject to mitigation.

In addition to monitoring bids, reference levels and market prices, the NYISO is aware of the general configuration of the electric system in New York and is alert for areas or situations that may be vulnerable to potential exercises of market power in relation to the NYISO Energy markets. The clearest example of this is New York City, which as discussed above is subject to significant transmission constraints. That is, there is not enough transmission capacity into New York City to serve its local load in many hours, so that resources within the City must be used even if less expensive resources are available outside the City. In addition, generation resources within New York City resources are controlled by only a few suppliers. Thus, the markets in New York City are subject to mitigation measures that are tailored to keep Energy prices at competitive levels notwithstanding their frequent exposure to conditions of market power.

Transmission constraints can also arise from sustained facility outages, or changes in the topography of generation and load over time. Energy markets are also monitored for results that do not appear consistent with competitive outcomes but fall below the thresholds specified in the Market Power Mitigation Measures set forth in Services Tariff Section 23. In those situations the NYISO can seek authorization from FERC to impose mitigation at appropriate levels, if warranted.

The Market Power Mitigation Measures also include mitigation measures applicable to the Capacity market.[277] These provisions include mitigation measures for pivotal suppliers, and "buyer side mitigation measures" to guard against the exercise of market power by those who buy Installed Capacity and who thus benefit from a low price.

2. <u>Absence of Market Power in the TCC Market and Virtual Transactions</u>

With respect to TCCs and Virtual Transactions, there are unique aspects that make these markets and transactions less susceptible to manipulation and which prevent the exercise of undue market power. The distinctive characteristics of TCCs and Virtual Transactions are discussed in greater depth in Attachment U, *infra.*

The following is a summary of the manner in which the TCC market design prevents the abuse of market power:

1) The quantity of TCCs held by a Market Participant does not impact the value of the congestion "rents" that will flow to the holder. A strong position in TCCs therefore will not enable the holder to manipulate the market.

2) A TCC purchaser has no incentive to pay more than the expected congestion "rents" that will accrue from holding the TCC.

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277 *Id.,* Section 23.4.5.

3) A substantial number of TCCs are allocated outside of the auction process and are not available for purchase by speculators. Rather, there has historically been substantial diversity of ownership of TCCs in New York.

4) TCCs are sold by auction, the design of which includes multiple auction rounds with a fixed amount of transmission capacity being offered for sale in each round. The multi-round process minimizes the opportunity for one party to buy a large quantity of TCCs all at one time.

With respect to Virtual Transactions – arbitrage trades between the Day-Ahead and Real-Time energy markets – such transactions factor into the competitive price discovery provided by Day-Ahead Markets in the same way as physical bids.[278] In Real Time, virtual sales are treated as injecting zero MW into the grid, and virtual purchases are treated as taking zero MW from the grid. A virtual sale in the Day-Ahead Market at the Day-Ahead price thus carries with it a corresponding obligation to purchase the same number of MW in Real Time at the Real-Time price and vice versa for Day-Ahead offers to buy. In both cases, the transaction is settled in the NYISO energy markets as if it were a physical transaction – as if it was a generator that was scheduled Day Ahead but did not perform in Real Time, or a load that was scheduled Day Ahead but did not materialize in Real Time. There are no non-performance penalties incorporated into the financial settlement in either case – physical transactions or Virtual Transactions. Actual deliveries to or receipts from the grid that differ from an entity's Day-Ahead position are settled (*i.e.,* balanced) at the applicable Real-Time Locational Based Marginal Prices ("LBMPs").

Virtual Transactions that are ultimately scheduled in the Day-Ahead Markets receive settlements at the Day-Ahead LBMPs for the locations applicable to the virtual bids and offers; however, system constraints can and do limit the amount of Virtual Transactions scheduled in the Day-Ahead Market. As discussed in more detail in Attachment V, *infra,* the Day-Ahead Market software simultaneously evaluates physical bids and offers along with virtual bids and offers to develop a feasible solution through the commitment and dispatch process. In order to ensure that sufficient resources are available to meet reliability, virtual bids and offers are excluded from the commitment and dispatch passes that evaluate the need for additional resources needed to meet NYISO forecasted load. This necessarily limits the amount of Virtual Transactions scheduled in the Day-Ahead Market and thereby inhibits the ability of a Market Participant to exercise undue market power with respect to Virtual Transactions.

3. Preventing Other Forms of Market Manipulation

By and large, manipulation in the markets for products from physical assets would be problematic mainly to the extent it results in prices that diverge from competitive outcomes. Any such outcomes would be evident to the NYISO through the continuous market monitoring described above. Transmission constraints or reliability requirements have resulted in relatively

[278] Since Virtual Transactions are not accepted in the Real-Time Markets, they do not play any direct role in the formation of Real-Time prices. Day-Ahead Virtual Transactions could in theory have an indirect role from time to time in the formation of Real-Time prices, to the extent that the unit commitment produced by the SCUC and carried forward into Real-Time might have been different at the margin had virtual transactions not been considered.

frequent mitigation of certain suppliers in the Day-Ahead and Real-Time Energy markets. The Installed Capacity market also has active mitigation measures, discussed above.

As discussed in more detail in Section B.2, *supra*, purchases and sales of TCCs and Virtual Transactions tend to help arbitrage differences between forward prices and spot prices. Thus, the Market Monitoring Unit reviews patterns of unprofitable transactions, which tend to worsen the consistency between these prices. Likewise, unprofitable inter-ISO transactions in the Real-Time market tend to worsen the consistency between spot prices in adjacent ISOs and are therefore similarly reviewed by the Market Monitoring Unit. The Market Monitoring Unit focuses on unprofitable transactions scheduled at locations where clearing prices are more sensitive to the effects of transmission bottlenecks.

Since Potomac Economics became the independent Market Monitoring Unit in November 2009, the Market Monitoring Unit has investigated market outcomes to identify transactions that might be manipulative and has investigated patterns of poor price convergence between forward markets and spot markets. It has not attributed any such patterns to manipulative transactions.

With respect to TCCs and Virtual Transactions, there are inherent limits in the design of the TCC market that restrict the scope for manipulation, as discussed in Section B.2, *supra,* and as discussed in greater depth in Attachment U, *infra*. As a result of these features, the TCC markets are not susceptible to market manipulation in the way that traditional commodity markets might be.

Financial markets that include Virtual Transactions and TCCs are also protected against manipulation by low barriers to entry. As a result, efforts to drive prices to artificially high or low levels through the use of Virtual Transactions or TCCs can be readily offset by other Market Participants making offers in the opposite direction.

Nonetheless, the NYISO and its Market Monitoring Unit monitor a number of market conditions in order to detect possible instances of market manipulation in Virtual Transactions and the TCC market. While cost-based reference levels are generally not meaningful for financial products, such as TCCs or Virtual Transactions, manipulation is more likely to be attempted in geographic markets with relatively few competitors, and in which a large position in the relevant product can be obtained. The NYISO and the Market Monitoring Unit are thus alert to identify situations that meet these conditions, and carefully scrutinize the resulting market outcomes. The Market Monitoring Unit reviews patterns of unprofitable purchases and sales of TCCs and Virtual Transactions, with particular focus on unprofitable transactions scheduled at locations where clearing prices are more sensitive to the effects of transmission bottlenecks.

This scrutiny starts from the proposition that profitable TCC and Virtual Transactions contribute to market efficiency. Correspondingly, positions in those markets that appear unprofitable do not contribute to price convergence and market efficiency. Such unprofitable positions may indicate manipulation intended to benefit the settlement of other positions, and would trigger further scrutiny. Likewise, a lack of consistency in the spot prices in adjacent markets coinciding with significant transactions between those markets would be carefully scrutinized to determine the cause for the poor convergence, including possible manipulation. Such scrutiny would be particularly warranted in locations where non-physical transactions can have a significant effect on prices. The Market Power Mitigation Measures include specific charges to monitor the impact of LSEs (purchasers) and virtual bidding on Day Ahead and Real time market convergence, as well as corresponding mitigation measures.

Virtual Transactions have the effect of bringing Day-Ahead and Real-Time prices closer to convergence by increasing liquidity and the efficient commitment of resources in the energy markets. The Market Monitoring Unit continually evaluates Virtual Transactions' success in improving certainty and stability in energy prices by increasing convergence between Day-Ahead and Real-Time prices. As discussed in more detail in Section B.3, *infra*, the Market Monitoring Unit tracks the profitability of virtual trading patterns in aggregate, and by individual Market Participant. Profitable virtual trading increases price convergence, while unprofitable trading usually decreases price convergence. While Virtual Transactions may be unprofitable on a particular day due to unexpected Real-Time price fluctuations, they should be profitable over the longer term. The Market Monitoring Unit has generally found that this is the case.

The Market Monitoring Unit's surveillance of Virtual Transactions is focused on screening market results for intentional losses incurred by virtual traders. Since such losses result in price divergence between the Day-Ahead Market and the Real-Time Market and may benefit other market positions, such as TCCs, Virtual Transactions resulting in substantial losses would be irrational absent such a secondary benefit. Therefore, the Market Monitoring Unit screens for transactions that produce substantial or sustained losses.[279] The Market Monitoring Unit then evaluates whether these losses are likely caused by unpredictable fluctuations in the Real-Time prices, or by bids and offers that do not reflect a reasonable expectation of Real-Time price levels. In the latter case, the conduct is referred to the office of enforcement at the FERC for investigation and may be subject to penalties under FERC's enforcement authority.

While the Market Monitoring Unit's surveillance of Virtual Transactions seeks to identify losses that are largely attributable to bids and offers that do not reflect a reasonable expectation of Real-Time energy prices (*i.e.*, irrational bids or offers), the Market Monitoring Unit also tracks the price-responsiveness in the Day-Ahead Market in each geographic area of bids and offers from virtual buyers and sellers as well as from generation suppliers, load serving entities, importers, etc. While the Market Monitoring Unit typically relies on estimates of the price responsiveness of the Day-Ahead Market to identify potentially manipulative virtual bids and offers, it can also request for the NYISO to run simulations of the Day-Ahead and Real-Time Markets to determine the effect of virtual trading strategies or other conduct by Market Participants. In this evaluation, greater scrutiny is applied to geographic areas that are less-price-responsive and where relatively few firms are active. Two locations are considered to be in the same geographic area if there are no significant transmission bottlenecks between them. In evaluating questionable Virtual Transactions, the Market Monitoring Unit may consider their effects on TCC transactions and other transactions settling at the Day-Ahead Market price

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[279] These screens will also detect manipulation of the Day-Ahead prices which could affect the value of forward contracts that reference the Day-Ahead price.

C. Dispute Resolution

Services Tariff Section 11, OATT Section 2.16, and Article 10 of the NYISO Independent System Operator Agreement ("ISO Agreement") establish the NYISO's dispute resolution procedures that apply generally to disputes concerning the application of existing rates, terms, and conditions of service that arise in connection with the NYISO tariffs and ISO Agreement ("General Dispute Resolution Procedures").[280] Disputes regarding proposed changes to the rates, terms and conditions of service that arise in connection with the NYISO tariffs, procedures, and agreements are addressed through the NYISO governance process or before FERC.

In addition to the General Dispute Resolution Procedures, the NYISO tariffs contain several subject matter specific dispute resolution procedures that apply in limited circumstances in place of the General Dispute Resolution Procedures ("Subject Matter Specific Dispute Resolution Procedures").

1. Overview of General Dispute Resolution Procedures

The application of the General Dispute Resolution Procedures is voluntary. Parties to disputes concerning the NYISO's existing rates, terms, and conditions of service, unless otherwise addressed by the Subject Matter Specific Dispute Resolution Procedures, may agree to apply the General Dispute Resolution Procedures or instead rely on their rights to file a complaint or seek any other remedy from FERC under the Federal Power Act. Under the General Dispute Resolution Procedures, senior representatives of the affected parties attempt to resolve the matter on an informal basis. If they are unable to do so, the parties may agree to take part in mediation or arbitration. Parties to a mediation or arbitration must mutually agree on the terms and procedures of the mediation or arbitration, including whether the finding of an arbitration will be binding. .

2. Overview of Subject Matter Specific Dispute Resolution Procedures

The Subject Matter Specific Dispute Resolution Procedures address the resolution of disputes concerning: (i) the finalization of customer settlements (*see* Services Tariff Section 7.4.3; OATT Section 2.7.4.4), (ii) certain limited Installed Capacity related issues (*see* Services Tariff Section 5.16), (iii) TCC auction related issues (*see* OATT Section 19.9.6; TCC Manual), and (iv) interconnection and planning related issues (*see* OATT Sections 25, 30, 31, and 32).

The dispute resolution provisions for customer settlements establish a non-binding expedited proceeding to address a dispute between the NYISO and a customer regarding a customer settlement that was not resolved through the NYISO's ordinary settlement review, challenge, and correction process. The expedited process enables the NYISO to attempt, with the aid of a neutral party, to resolve a dispute within the existing timeframes for finalizing

[280] OATT Section 2.16 applies the dispute resolution procedures under the NYISO Services Tariff to disputes arising under the OATT.

customer settlements when the NYISO believes that such a proceeding will aid in the resolution of the dispute.

The Installed Capacity dispute resolution provisions provide for an expedited arbitration proceeding to address certain Installed Capacity-related disputes. If the parties cannot resolve the dispute on an informal basis, the disputing parties will enter into an expedited arbitration proceeding, and the results of the arbitration will be binding.

The TCC dispute resolution provisions provide for a separate dispute resolution proceeding for challenges to awards in TCC auctions and the calculation of related prices. If the parties cannot resolve the dispute on an informal basis, the disputing parties will enter into an expedited arbitration proceeding, and the results of the arbitration will be binding.

In addition, the NYISO's interconnection and planning requirements set forth in OATT Sections 25, 30, 31, and 32 contain separate dispute resolution provisions that are specific to the planning and interconnection processes. For example, dispute resolution provisions in OATT Section 30 applicable to large generating facility interconnection disputes requires that the parties attempt to resolve a dispute on an informal basis. If they are not able to resolve the dispute, the parties may enter into a binding arbitration to resolve the dispute. Otherwise, the parties may rely on their rights to file a complaint or seek any other remedy from FERC under the relevant provisions of the Federal Power Act.

D. Authority to Discipline, Limit, Suspend, or Terminate a Market Participant

The NYISO has the authority and ability to sanction, limit, suspend and terminate the activities of a Market Participant due to a violation of NYISO tariff provisions.

First, the NYISO has the right to suspend and/or terminate a Market Participant in the event of a Market Participant default. The basis for declaring a Market Participant in default (as discussed in detail in Attachment G, *supra*) and the NYISO's default rules and remedy provisions that apply generally to Market Participants are set forth in Services Tariff Section 7.5 and OATT Section 2.7.5. The NYISO's tariff requires the NYISO to notify FERC in the event the NYISO suspends or terminates a Market Participant for a default. *See* Services Tariff Section 7.5.3; OATT Section 2.7.5.3.

Second, in addition to the NYISO's authority under its general default and remedy tariff provisions discussed above, the NYISO tariffs contain some subject matter specific remedy provisions that apply in limited circumstances. For example, the NYISO may immediately suspend the Virtual Transaction activity of a Market Participant and cancel any pending Day-Ahead Bids if at any time the amount of the Market Participant's actual losses on Virtual Transactions equals 100% of its credit support provided for Virtual Transactions. *See* Services Tariff Section 26.2.2. A Market Participant's ability to engage in Virtual Transactions can also be limited or suspended by the NYISO if the NYISO determines that the Market Participant's Virtual Transaction practices contributed to an unwarranted divergence of market prices between the Day-Ahead and Real-Time Markets. See Services Tariff Section 23.4.6. In such event, the conduct of the Market Participant is referred to the FERC Office of Enforcement for potential sanction.

Third, a Market Participant that violates a NYISO tariff provision may be subject to a penalty or sanction that is authorized under the NYISO tariffs. The NYISO's Penalty Review Committee evaluates requests by NYISO departments for the issuance of penalties or sanctions as a result of a tariff violation. The Penalty Review Committee includes, at a minimum, a corporate officer, members of the Legal Department, and members of the Market Mitigation & Analysis Department. The Penalty Review Committee meets monthly to review requests for penalties or sanctions and to determine whether such penalties or sanctions should be assessed and in what amount. In making its determination, the Penalty Review Committee will confirm whether there has been a tariff violation, consider a waiver of the penalty or sanction where the tariff violation resulted from factors outside of the Market Participant's control, determine the range of penalties authorized by the applicable tariff revisions, and determine the appropriate penalty or sanction if the tariffs provide the NYISO with discretion. Upon a unanimous vote by the Penalty Review Committee, a penalty or sanction recommendation will be forwarded to the NYISO CEO for consideration. If approved by the CEO, the NYISO will impose the penalty or sanction. When the NYISO's Penalty Review Committee assesses a penalty, it advises the Market Monitoring Unit, which may refer the matter to FERC.

Finally, the NYISO may impose Market Mitigation Measures consistent with the Services Tariff as set forth in Section 23.4.6. The criteria for mitigation under the Services Tariff are embodied in two tests that are consistent with the logic of the criteria outlined above. The first test measures the 4-week rolling average of the difference in prices between the Day-Ahead and Real-Time market as follows: [(Zone Price Real-Time / Zone Price Day-Ahead) - 1].[281] If the difference is larger than would be expected under workable competition and the difference is caused in part or in whole by one or more virtual traders, mitigation may be imposed. *See* Section 23.4.6.3. The mitigation measure is a restriction on the participant that prevents it from engaging in Virtual Transactions at one or more locations.

E. Reporting Sanctions and Tariff Violations to FERC

The Market Monitoring Unit is required to inform FERC of behavior that may require investigation, including efforts to manipulate markets. *See* Services Tariff Section 30.4.5.3. As required by 18 C.F.R. § 35.28(g)(3)(iv), the Market Monitoring Unit must submit to FERC a non-public referral "in all instances where the Market Monitoring Unit has reason to believe that a Market Violation has occurred." Services Tariff Section 30 similarly requires the Market Monitoring Unit to submit a non-public referral to FERC "in all instances where it has obtained sufficient credible information to believe a Market Violation has occurred."[282] This referral process is mandatory except for limited circumstances (*e.g.*, if the Market Violation has already been reported by the NYISO as a Market Problem).[283] The Market Monitoring Unit for the NYISO makes such referrals to FERC where appropriate and as required by NYISO tariff and 18 C.F.R. § 35.28(g)(3)(iv).

281 However, this formula may be modified in a pending docket (FERC Docket ER11-2544).

282 *Id.* at Section 30.4.5.3.1.

283 *Id.* at Section 30.4.5.3.2.

Attachment H—DCO Core Principle H: Rule Enforcement

Among other matters, the NYISO's Market Mitigation and Analysis Department and Market Monitoring Unit have observed, investigated and/or referred to FERC Office of Enforcement the following types of conduct:

- Economic withholding – where a unit offers into the Energy markets at prices significantly above competitive levels in a potential effort to raise prices for other resources;
- Physical withholding – where a resource erroneously claims that it is not available for physical reasons, or otherwise does not offer the unit when it would be economic to do so, in an attempt to raise prices for other resources;
- Improperly claiming a resource available when, in fact, it is physically incapable of operation (*e.g.*, to collect capacity payments when a resource should not receive such payments due to unavailability);
- Competitiveness of Market Participants' behavior in and potential barriers to entry into a TCC Auction; and
- Virtual bidding practices that contributed to an unwarranted divergence of LBMPs between the Day-Ahead and Real-Time Markets.

The Market Monitoring Unit is in regular contact (typically multiple times per week) with FERC's Division of Energy Market Oversight to discuss observations from the Market Monitoring Unit's daily monitoring regarding significant market events and to answer any questions from FERC staff. In these regular communications with FERC staff, the Market Monitoring Unit conveys the results of its screening and investigations. This allows the FERC to be aware of potential issues prior to the submission of a formal referral on manipulative conduct. The Market Monitoring Unit is obligated under Services Tariff to convey such information to FERC and to make referrals to the Office of Enforcement when it has credible evidence that manipulation has occurred. *See* Services Tariff Section 30.4.5.3.1 and 18 C.F.R. § 35.28.

After a referral is submitted, the Market Monitoring Unit continues to update FERC staff on its findings and any continuing conduct by the participant. FERC staff frequently requests data or additional analyses related to the subject of the referral.

FERC may also initiate its own market monitoring. It is the NYISO's and the Market Monitoring Unit's understanding that FERC staff have market information tools that allow it to monitor market activity and trends in market behavior. In addition, subscription-based market information tools and access to publicly available data on the NYISO web site regarding prices and market activity also allow FERC to engage in real-time monitoring of the NYISO markets. FERC staff also regularly request specific data from the NYISO. Nothing prevents the FERC from separately detecting or taking action on manipulative conduct, however, it is not the practice of FERC staff to inform the NYISO or the Market Monitoring Unit of the details regarding or status of non-public investigations.

Attachment H—DCO Core Principle H: Rule Enforcement

PJM

PJM runs the "Three-Pivotal Supplier Test" during the clearing of the energy, ancillary service and capacity markets.[284] This test guards against the exercise of market power. Additionally, behavior that could be regarded as manipulation is evaluated by both PJM and Market Monitoring Unit ("MMU") who conducts market structure screens and after-the-fact checks for manipulative behavior in all markets.

Immediately upon determining that it has identified a significant market problem or a potential market violation by a market participant or PJM that may require (a) further inquiry by the MMU, (b) referral to FERC for investigation and/or (c) FERC action, the MMU must notify the FERC's Office of Enforcement.[285] In addition to the notification requirement, where the MMU has reason to believe, based on sufficient credible information, that the behavior of a market participant or PJM may require investigation, including suspected market violations, the MMU must refer the matter to the FERC's Office of Enforcement. The MMU may also provide FERC with oral notice of the alleged market violation in advance of the submission of a written, non-public referral. The MMU is not precluded from continuing to monitor for any repeated instances of the activity in question by the same or other market participants, which activity would constitute new market violations.[286]

Market participants and PJM, alike, are required to refer suspected market problems or market violations to the MMU for investigation and, where warranted, to FERC enforcement staff. In addition, Section 15 of PJM OA sets forth PJM's rights and obligations with respect to members that have breached any of its obligations under the PJM agreements and, ultimately, with respect to members in default. These include, but are not limited to, termination of the market participants' access to PJM markets (including transmission service), close-out and liquidation of member positions, and rules relating to the reinstatement of members following default and remedy. Repeated breaches of the PJM Credit Policy may lead to escalated penalties and/or cancellation of transactions. Moreover, various portions of the PJM agreements provide for the assessment of "traffic ticket" penalties for failure to adhere to the rights and obligations contained therein. For example, members may be assessed interest on all late payments.

Market participants may be assessed reasonable charges, remedies or sanctions for non-compliance with operations requirements of PJM, the PJM Tariff and schedules and associated PJM manuals. In addition, PJM or market participants may report suspected market violations to the independent PJM MMU or directly to FERC.

Attachment M of the PJM Tariff establishes a PJM Market Monitoring Plan ("Plan"), which sets forth the maintenance of an independent MMU that will objectively monitor, investigate, evaluate and report on the PJM markets, including, but not limited to, structural, design or operational flaws in the PJM markets or the exercise of market power or manipulation

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[284] PJM Tariff, Attachment K Appendix, Sections 3.2.2A.1, 6.4, and 6.6, and Attachment M Appendix and PJM OA, Schedule 1, Section 6.4.

[285] PJM Tariff, Attachment M, Section IV.I.1.

[286] PJM Tariff, Attachment M Appendix.

in the PJM markets. The MMU relies primarily upon data and information that are customarily gathered in the normal course of business of PJM and such publicly available data and information that may be helpful to accomplish the objectives of the Plan, including, but not limited to, (1) information gathered or generated by PJM in connection with its scheduling and dispatch functions, its operation of the transmission grid in the PJM region or its determination of LMP, (2) information required to be provided to PJM in accordance with the PJM market rules and (3) any other information that is generated by, provided to, or in the possession of PJM.

Although PJM is responsible for proposing PJM market rules, PJM Tariff and design of the PJM markets, and any subsequent revisions (all subject to FERC approval), the MMU evaluates and monitors such rules and market designs. If the MMU detects a design flaw or other problem with the PJM markets, it may initiate and propose, through the appropriate stakeholder processes, changes to the design of such markets, as well as changes to the PJM market rules and PJM Tariff. In support of this function, the MMU may engage in discussions with stakeholders, State Commissions, PJM Management, or the PJM Board; participate in PJM stakeholder meetings or working groups regarding market design matters; publish proposals, reports or studies on such market design issues; and make filings with FERC on market design issues. The MMU may also recommend changes to the PJM market rules and PJM Tariff provisions to FERC's Office of Energy Market Regulation, State Commissions, and the PJM Board. In all instances where the MMU has reason to believe market design flaws exist that it believes could effectively be remedied by rule or PJM Tariff changes, the MMU must make a written referral to FERC.

The MMU may recommend to PJM that it take specific mitigation action that PJM is authorized to take under the PJM market rules to address market behavior or conditions. The MMU does not, however, have authority to require modification of PJM operational decisions, including dispatch instructions. If PJM does not accept the MMU's recommendations regarding mitigation actions, the MMU may report its mitigation recommendation to the Authorized Government Agencies, FERC staff, State Commissions or the PJM members, as the MMU deems appropriate. If during the ordinary course of its activities the MMU discovers evidence of wrongdoing (other than minor misconduct) that the MMU reasonably believes to be within a State Commission's jurisdiction, the MMU will report such information to the State Commission(s).

Attachment I

DCO Core Principle I: System Safeguards

Each derivatives clearing organization shall—

(i) establish and maintain a program of risk analysis and oversight to identify and minimize sources of operational risk through the development of appropriate controls and procedures, and automated systems, that are reliable, secure, and have adequate scalable capacity;

(ii) establish and maintain emergency procedures, backup facilities, and a plan for disaster recovery that allows for—

> (I) the timely recovery and resumption of operations of the derivatives clearing organization; and
>
> (II) the fulfillment of each obligation and responsibility of the derivatives clearing organization; and

(iii) periodically conduct tests to verify that the backup resources of the derivatives clearing organization are sufficient to ensure daily processing, clearing, and settlement.

Responses:

Attachment I—DCO Core Principle I: System Safeguards

California ISO

The CAISO maintains installed redundant control centers, communication systems, and computer systems.[287] The CAISO tariff nonetheless provides policies detailing what market participants should do in the event of the failure of various CAISO systems.[288]

The CAISO is also required to maintain computer back-up systems, including off-site storage of all necessary computer hardware, software, records and data at an alternative location, in the event of a settlement system breakdown.[289] The CAISO maintains emergency and disaster recovery plans designed to address operational, physical and cyber security events, and performs testing of the plans pursuant to the requirements of NERC.

The CAISO utilizes Incident Command System as its incident management and response process, and the incident management team includes appropriate market, settlements, real time operations, compliance and information technology groups, as well as others. The incident management team exercises annually. All employees are trained on the CAISO Corporate Preparedness Program, which includes the corporate incident management and response process, emergency response (life/safety) and the business continuity program.

Section 22.1 or the CAISO tariff requires the CAISO to perform specified audits and authorizes the CAISO to perform any other audits as needed.[290] Pursuant to that authority, and in order to identify any areas of operational risk, the CAISO performs an annual SAS 70 audit of its operational controls.

The CAISO tariff requires that the CAISO declare a system emergency in the event that the CAISO controlled grid is in danger of a failure due to a system operational issue.[291] In the event of a system emergency, the CAISO is directed to take any action that it deems necessary to preserve or restore the stable operation of the CAISO controlled grid.[292] The CAISO is required to develop and administer periodic unannounced tests to determine that CAISO market participants are capable of promptly and efficiently responding to imminent or actual system emergencies.[293] After major outages, the CAISO performs a review to determine the cause of the outage and whether the practices of the CAISO or relevant market participants enhanced or undermined the CAISO's ability to maintain or restore service.[294]

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[287] CAISO Tariff § 7.7.14.1.

[288] *Id.*, § 7.7.14.

[289] *Id.*, § 11.1(b).

[290] *Id.*, § 22.1.2.4

[291] *Id.*, § 7.7.1.

[292] *Id.*, § 7.7.2.

[293] *Id.*, § 7.7.6.

[294] *Id.*, § 7.7.13.1.

Attachment I—DCO Core Principle I: System Safeguards

ERCOT

ERCOT's system safeguards are comparable to those required by this core principle. As described above at Attachment D, ERCOT has established and maintains controls and procedures to identify and minimize sources of operational risk. With respect to development, testing and implementation of systems, ERCOT minimizes operational risks by utilizing rigorous methodologies to govern these processes. ERCOT has defined methodologies, processes and controls in place covering the Systems Development Life Cycle, addressing methodologies, development, testing and release management.[295]

ERCOT has a comprehensive plan to mitigate the risk of interruption or disruption to its operations.[296] ERCOT's recovery strategy and plan is to operate two Control Centers and two data centers. Each Control Center and each data center is functionally capable of operating as the primary center. ERCOT's recovery plan takes advantage of its Energy and Market Management System infrastructure ("EMMS"), which has been carefully designed to maintain a high degree of redundancy and availability. As a result, there is no "primary" or "backup" site; rather there is an "acting primary" site and a "hot stand-by" site. ERCOT switches between data centers on a set schedule and as necessary in response to conditions that warrant such action (*e.g.*, system failures or maintenance procedures that may raise the risk profile for systems operating in the data center to be maintained).[297]

Recovery plans, service levels, recovery time and point objectives are defined for all systems and the systems are engineered to meet those objectives. The recovery plans ensure the continuation of market operations in five minutes, which means that the potential loss of data is less than five minutes. Recovery of settlement functions occurs on the next business day. This lag is allowed because the critical function in terms of recovery is the market function: settlements will be based on that data.[298]

In addition, ERCOT has a business continuity plan developed to recover all operations. The plan is revised annually or as necessary based on changed circumstances (*e.g.*, in response to the deployment of new systems or business functions within the organization). To ensure that the plan can be effectively implemented, ERCOT staff is trained on an annual basis and a drill is conducted annually to train staff in actual deployment of the plan.

During normal operations, data are protected using real-time redundancy between data centers. In addition, as an additional precaution, ERCOT utilizes near-term data backup systems

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295 ERCOT Corporate Standard ("CS") 6.4, CS 6.5. ERCOT Operating Procedures OP 6.4.1, OP 6.5.1, OP 6.5.2.

296 ERCOT's Business Continuity Plan is is highly confidential. ERCOT will make the plan available to CFTC Staff for inspection upon request and at a mutually agreeable time in ERCOT's Offices in Austin, TX. In addition, ERCOT has provided the affidavit of ERCOT's CEO filed with the Public Utility Commission of Texas attesting to, *inter alia,* the existence of the Business Continuity Plan and a presentation (with redacted confidential information) describing the process for testing and updating the Business Continuity Plan.

297 ERCOT EMMS Desk Procedures, Section 9: Disaster Recovery Plan. *ERCOT Network Standard*, section 19.4. Database Team Desk Procedures, section 2.6.

298 ERCOT Protocols Sections 1.2, 9.2.4, 9.3, 9.5.2, 9.6, 9.8, 9.10, and 9.12.

on site and an offsite retention facility.[299] These actions mitigate risk in the event that both ERCOT facilities are simultaneously impacted by an event. Backup media are tested in accordance with NERC Critical Infrastructure Protection requirements to ensure that systems can be recovered from backup media.[300]

[299] ERCOT CS 6.2 *Records and Information Management Corporate Standard*. ERCOT Operating Procedure OP6.2.3 Off-Site Storage Operating Procedure.

[300] ERCOT Corporate Standard CS 7.4 *Information Technology Corporate Standard*, CS 7.5 *Application and Database Security Corporate Standard*. ERCOT Operating Procedure OP6.5.3 Data Backup and Recovery Operating Procedure, page 4.

Attachment I—DCO Core Principle I: System Safeguards

ISO New England

ISO-NE has an adequate program of risk analysis and oversight to identify and minimize sources of operational risk through the development of appropriate controls and procedures; reliable automated systems; and emergency procedures.

Resources Deployed for Safeguards

ISO-NE dedicates a number of resources to credit and risk management. These resources include an internal audit department (five full-time employees), internal market monitoring department (twenty full-time employees), a cyber security team (six full-time employees), a reliability and operations compliance group (six full-time employees), market and credit risk group (three full-time employees), and a risk management group (five full-time employees). All of these resources are supplemented by external consultants, auditors and monitors, as applicable. The internal audit department is headed by a director-level employee who reports to the Board's Audit and Finance Committee. The internal market monitoring department is headed by a Vice President who reports to the Board's Markets Committee. The cyber security team is led by a manager-level employee who reports to the Vice President in charge of Information Services. Last, the reliability and operations compliance group, market and credit risk group and risk management group are led by manager- or director-level employees who all report to the Vice President/Chief Financial and Compliance Officer.

ISO-NE's Board of Directors undertakes regular risk analyses. The various standing committees of the Board are responsible for identifying risks within their scopes of authority and reporting on them to the full Board. At least annually, the Board takes a comprehensive look at the risks facing the Company and the means of mitigating those risks.

Automated Systems

The ISO-NE maintains offsite computer backup systems fully able to operate in the event that the primary system fails. Related requirements are in Operating Procedure No. 2 (Maintenance of Communications, Computers, Metering and Computer Support Equipment). ISO-NE has a back-up control center that will soon be fully redundant, a Facilities Emergency Action Plan, and a comprehensive compliance management system pursuant to which the ISO has catalogued each of its responsibilities, along with the relevant governing document and responsible employee.

Emergency Procedures

ISO-NE's emergency authority is outlined in its operating procedures (*see, e.g.*, Operating Procedure No. 7 (Action in an Emergency)).

Attachment I—DCO Core Principle I: System Safeguards

MISO

MISO maintains a corporate compliance program designed to promote the assessment and minimization of operational risk through the documentation of controls, processes and procedures both manually and through software, where possible. In addition, MISO conducts internal audits of its operations and is subject to an annual SSAE 16 (formerly SAS 70) audit of its operations by an external auditor. MISO is also subject to regular audits and spot checks by the North-American Electric Reliability Corporation ("NERC"), NERC's Regional Entities and FERC.

As discussed in Attachment B, MISO maintains two operational control centers used in daily operations, as well as a fully operational, off-site back-up control center. Mock emergency and disaster scenarios are tested on a regular basis to ensure the readiness of back-up facilities and personnel. In addition, MISO maintains emergency and disaster recovery plans pursuant to the requirements of NERC.

Attachment I—DCO Core Principle I: System Safeguards

New York ISO

The NYISO is subject to reliability rules established by the New York State Reliability Council, Northeast Power Coordinating Council, and the North American Electric Reliability Corporation. *See, e.g.,* Services Tariff Section 5.1.1. In compliance with these requirements, the NYISO has procedures in place to address emergency situations and maintains an alternate control center and back-up computer systems and data centers at a separate location. *See* OATT Section 2.12 ("Back-Up Operation"); Services Tariff Sections 5.3.1 ("Back-Up Operation"), 5.4 ("Operation Under Adverse Conditions"), 5.5 ("Major Emergency State").

The NYISO also is required to take action to address market problems and market disruptions and has the authority to file unilaterally for changes to its tariff rules under exigent circumstances. *See* ISO Agreement Section 19.1; Services Tariff Sections 3.5.1 ("Market Problem Reporting Procedure"), 5.2.1 ("Suspension of Virtual Transactions") and 20 ("Procedures for Reserving and Correcting Erroneous Energy and Ancillary Service Prices").

The NYISO performs internal and external audits, including a SSAE 16 audit, to ensure its internal controls, procedures, and business processes comply with accepted standards. *See* ISO Agreement Section 5.08 and 12.03; Services Tariff Section 10.

Attachment I—DCO Core Principle I: System Safeguards

PJM

PJM currently has a robust information technology infrastructure and sound emergency management plan. In addition, PJM has been subject to annual SAS-70 Type-2 audits for over ten years, and has received an unqualified opinion in all such audits.[301]

PJM manages a vigorous Business Continuity Planning ("BCP") program to maintain continuity of operations and organizational services in the event of an emergency and to assure the safety, reliability, and security of the bulk electric power system.

PJM's incident response and disaster recovery plans are designed to address operational, physical and cyber security events within a comprehensive risk management program. These BCP plans are based upon strategies approved by PJM management and compliant with all applicable regulatory requirements.

PJM's Corporate Incident Response Team ("IRT") leads PJM emergency response activities, working closely with executive management, shift operations and local emergency officials. Incident response exercises are conducted quarterly. Security and BCP awareness programs are continuous with an annual security training program required of all employees and contractors.

PJM's primary and secondary control centers and data centers are hardened facilities with redundant and diverse electric power, telecommunications and security services. All operational and business data is saved and stored on a secure and separate storage device from the primary operational storage device. Data from critical cyber assets are saved and stored in a separate local storage device and at a remote offsite facility. Data may be retrieved from both on-site and off-site facilities for recovery and restoration purposes.

All disaster recovery plans are reviewed at least annually, and recovery exercises of system components are conducted monthly to ensure that mission critical processes and vital records are recoverable within predetermined recovery time and point objectives.

[301] *See* PJM Passes Stringent Audit for 10th Consecutive Year, PJM New Releases (Dec. 15, 2010) *available* at http://www.pjm.com/~/media/about-pjm/newsroom/2010-releases/20101215-PJM-Passes-Stringent-Audit-for-10th-Consecutive-Year.ashx.

Attachment J

DCO Core Principle J: Reporting

Each derivatives clearing organization shall provide to the Commission all information that the Commission determines to be necessary to conduct oversight of the derivatives clearing organization.

Responses:

Attachment J—DCO Core Principle J: Reporting

California ISO

CAISO is subject to extensive reporting requirements. In this regard, CAISO must provide FERC with information as requested.[302] CAISO continually provides information on a range of specific issues that FERC has requested,[303] and on general issues of market performance. Finally, as noted above, CAISO must inform FERC of, and seek its approval for, all amendments and modifications to the CAISO Tariff.

CAISO's Department of Market Monitoring reports to the FERC Office of Enforcement all instances of potentially violative conduct.

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302 See 16 U.S.C. § 825(b).

303 *See, e.g.*, CAISO reports to FERC in Docket Nos. ER08-1178, EL08-88 (Exceptional dispatch report (Chart 1 data), due the 15th of every month and exceptional dispatch report (Chart 2 data), due the 30th of every month, ER06-615-000, ER07-1257-000 (Market disruption report, due the 15th of every month, and ER06-615-000 (Negotiated Default Energy Bids informational filing, due the 7th of every month.

Attachment J—DCO Core Principle J: Reporting

ERCOT

ERCOT's reporting and information-sharing procedures are comparable to this core principle. PURA provides that ERCOT is directly responsible and accountable to the PUCT and that the PUCT has complete authority to oversee ERCOT's operations to ensure it adequately performs its duties and functions.[304] PURA requires ERCOT to fully cooperate with the PUCT in performing its functions.[305] This grants broad authority to the PUCT in terms of requiring ERCOT to report on all necessary information, whether on an *ad hoc* basis or via specific, scheduled periodic reports. This reporting obligation ensures that the regulatory body charged with oversight of ERCOT and the ERCOT market receives all necessary information and reports to perform its regulatory duties. The PUCT also oversees the behavior of the ERCOT market participants.[306] ERCOT and IMM reporting obligations described herein and in Attachment H support the PUCT in performing this function.

PURA and PUCT Substantive Rules require ERCOT to provide information to the PUCT on request.[307] In addition, ERCOT is charged with the general obligation to disseminate information on the ERCOT market.[308] ERCOT is also required to file specific reports as well as *ad hoc* reports as deemed necessary by the PUCT, including reports related to all instances where ERCOT is unable to comply with rules applicable to its obligations as the ISO.[309] Among the established reports, ERCOT is required to provide several reports that reflect the performance of its functions, which include administration of the ERCOT markets.[310] ERCOT is also required to comply with any PUCT order.[311] PUCT rules also require market participants to comply with requests for data from ERCOT.[312] The PUCT can then access this information via its right to request information from ERCOT.

The ERCOT Bylaws require ERCOT Corporate Members to provide information to ERCOT.[313] The PUCT can then access such information via its broad authority, subject to confidentiality protections. In addition, ERCOT market participants are required to provide information directly to ERCOT and/or the PUCT.[314] They are also required to establish clear lines of accountability for their market activity/participation.[315]

304 PURA § 39.151(d).

305 PURA § 39.151(d).

306 P.U.C. SUBST. R. 25.503.

307 PURA § 39.151(d), P.U.C. SUBST. R. 25.362(e)(1)(B) and 25.503(f)(8).

308 P.U.C. SUBST. R. 25.361(b)(14).

309 P.U.C. SUBST. R. 25.362(i).

310 P.U.C. SUBST. R. 25.362(i)(1)(B)(5) and 25.362(i)(2)(B).

311 PURA § 39.151(d), P.U.C. SUBST. R. 25.361(b)(16) and 25.362(j).

312 P.U.C. SUBST. R. 25.503(f)(10).

313 ERCOT Bylaws Section 3.3.

314 P.U.C. SUBST. R. 25.503(f)(8), (9) and (10).

315 P.U.C. SUBST. R. 25.503(f)(13).

Attachment J—DCO Core Principle J: Reporting

The ERCOT Protocols require ERCOT to manage confidential information accordingly, but enable ERCOT to release confidential information to government officials if required by law, regulation or order.[316]

The IMM also plays a role in reporting on market matters. The IMM reports to the PUCT, which establishes the IMM reporting requirements.[317] The IMM has the authority to investigate and report on any relevant matter, to communicate with the PUCT as it deems necessary, and is required to report on any market issue/violation it identifies.[318] ERCOT is required to provide technical assistance to the IMM, and to provide any information requested by the IMM to support its functions.[319] The IMM is subject to appropriate confidentiality rules in the exercise of its duties and the management of information used in performing its function.[320]

Collectively, the rules that apply to ERCOT and the ERCOT market participants facilitate effective reporting of information necessary for the PUCT to perform its general and market specific oversight duties.

316 ERCOT Protocol Section 1.3.

317 PURA § 39.1515(d)(1) and P.U.C. SUBST. R. 25.365(d)(11) and (k).

318 P.U.C. SUBST. R. 25.365(e)(1) and (l)(1) and (2)(A).

319 PURA § 39.1515(b) and P.U.C. SUBST. R. 25.365(e)(3) and (m).

320 P.U.C. SUBST. R. 25.365(j).

Attachment J—DCO Core Principle J: Reporting

ISO New England

ISO-NE has an adequate system of reporting that allows it to provide the information necessary for regulatory oversight. In addition to ISO-NE's required reporting to FERC, as established in the Tariff and on an ad hoc basis in various FERC Orders, Section 3.2 of ISO-NE's Information Policy, which is Attachment D to the Tariff, explicitly states that ISO-NE will provide FERC with any requested confidential information

Attachment J—DCO Core Principle J: Reporting

MISO

MISO maintains a data request process through which it responds to requests for information related to MISO's operations and market data. In addition, Section 38.9 of the MISO Tariff contains provisions related to confidential information and MISO's disclosure of such information to regulatory bodies, courts, the Federal Energy Regulatory Commission and other requestors of information. Under these provisions MISO may provide confidential or commercially sensitive information to a regulatory body, court or the Federal Energy Regulatory Commission provided that it satisfies the notice requirements to the owner of the information. Section 38.9.3 specifically addresses requests by the Commission. Appendix A to the Transmission Owners Agreement also contains confidentiality obligations with regard to transmission/reliability data.

Attachment J—DCO Core Principle J: Reporting

New York ISO

The NYISO maintains business records in accordance with a number of applicable requirements, including FERC's Uniform System of Accounts and the provisions set forth in Services Tariff Section 10. In addition, the NYISO and its Market Monitoring Unit are required to inform FERC of Market Violations and Market Problems. *See, e.g.,* the NYISO's response in Attachment H, *supra*, and Services Tariff Section 3.5.1.

The NYISO proposes a continuation of current reporting practices. Specifically, in carrying out its statutory and tariff obligations, the NYISO will continue close monitoring of its markets and relevant market conditions in cooperation with the Market Monitoring Unit, coupled with the tariff-mandated obligation of the NYISO and the Market Monitoring Unit to report possible instances of market manipulation to FERC. In addition, the NYISO will continue its cooperation with and assistance to the FERC in any investigations it may conduct. The NYISO anticipates that to the extent cross market manipulation or other anti-competitive behavior is discovered, FERC will share such information with other agencies, including the CFTC where appropriate, in order to foster cross market monitoring. To the extent any of the above requires disclosure of confidential information, there are extensive provisions on the protection of confidential information set forth in the NYISO OATT Section 12.

With respect to the public interest that would be served by a Section 4(c) exemption, the NYISO notes that one of the primary concerns of the Dodd–Frank Wall Street Reform and Consumer Protection Act (Pub.L. 111-203, H.R. 4173) ("Dodd-Frank") appears to be the "information deficits" that result from unregulated over-the-counter derivative transaction.[321] Of particular concern appears to be information deficits for regulators who cannot see and police the markets. There is no such information deficit in FERC-regulated markets. In addition, the NYISO provides extensive data on its website that is available to the public.

[321] *Impacts of H.R. 3795, the Over-The-Counter Derivatives markets Act of 2009, on Energy Markets*, Before the Subcomm. on Energy and the Environment of the H. Comm. on Energy and Commerce, 111th Congress (Dec. 2, 2009) (statement of Jon Wellinghoff, Chairman of FERC).

Attachment J—DCO Core Principle J: Reporting

PJM

A substantial amount of information regarding PJM, including market data, PJM's Tariff and PJM OA, and many details of PJM's stakeholder process, is publicly available on PJM's web site. FERC has access to this information through a user ID and password provided by PJM. In addition, PJM provides FERC with comprehensive information regarding its operations on a routine and non-routine basis.

PJM also publishes a quarterly state of the market report that includes an overview of its FTR markets. The state of the market report is available on PJM's web site.

Attachment K

DCO Core Principle K: Recordkeeping

Each derivatives clearing organization shall maintain records of all activities related to the business of the derivatives clearing organization as a derivatives clearing organization—

(i) in a form and manner that is acceptable to the Commission; and

(ii) for a period of not less than 5 years.

Responses:

Attachment K—DCO Core Principle K: Recordkeeping

California ISO

FERC has comprehensive regulations that govern recordkeeping by public utilities, including all ISOs and RTOs.[322]

In addition, the CAISO tariff includes numerous provisions addressing recordkeeping. These include:

- Section 6.3.2, requiring the CAISO to maintain records of all communications related to dispatch instructions;
- Section 9.5.1, requiring the CAISO to create records of approved maintenance outages;
- Section 11.1(c), requiring the CAISO to retain settlement records sufficient, at a minimum, to allow for the re-run of settlement data, as required by the CAISO Tariff, the rules of local regulatory authorities, and FERC; and
- Section 11.22.1.1, requiring the CAISO to maintain a set of financial statements and records in accordance with the FERC's Uniform System of Accounts.

[322] See 18 C.F.R. § 125.

Attachment K—DCO Core Principle K: Recordkeeping

ERCOT

ERCOT's recordkeeping requirements are comparable to those required by this core principle. ERCOT has specific record retention rules established in the ERCOT Protocols and ERCOT Records and Information Management Corporate Standard.[323] The ERCOT Records Retention Schedule specifies the required retention for all ERCOT records. With respect to market accounting information, ERCOT is required to retain such information for a period of seven years. This information includes records related to tracking and allocation of electrical usage for the billing and settlement process and records related to CRRs.[324] Credit records related to tracking and allocation of electrical usage for the settlement process where there is a continuing interest or liability are required to be retained for 25 years.[325] In addition, see ERCOT's response to core principle E in Attachment E.

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323 ERCOT Protocol Section 17.3.5; *ERCOT Records and Information Management Corporate Standard* CS6.2

324 ERCOT Records Retention Schedule (ACC5000, ACC5010).

325 ERCOT Records Retention Schedule (ACC5020).

Attachment K—DCO Core Principle K: Recordkeeping

ISO New England

ISO-NE has an adequate system of recordkeeping that allows it to provide the information necessary for regulatory oversight. ISO-NE has a records retention policy that is based on legal obligations to maintain records as well as obligations established in ISO-NE's Tariff. For example, the policy states that settlements information must be maintained for six years.

Attachment K—DCO Core Principle K: Recordkeeping

MISO

MISO maintains a records management program applicable to corporate records and data. The retention requirements provided as part of MISO's records management program are consistent with FERC's Uniform System of Accounts and the retention requirements specified in 18 C.F.R. 125.

Attachment K—DCO Core Principle K: Recordkeeping

New York ISO

The NYISO maintains business records in accordance with a number of applicable requirements, including FERC's Uniform System of Accounts, OATT Section 12.6, and the provisions set forth in Services Tariff Section 10.

Attachment K—DCO Core Principle K: Recordkeeping

PJM

Pursuant to FERC regulations, PJM currently maintains all relevant records for at least five years. Such records are maintained in a combination of archived electronic media and paper copies in both on-site and off-site storage.

Attachment L

DCO Core Principle L: Public Information

(i) IN GENERAL.—Each derivatives clearing organization shall provide to market participants sufficient information to enable the market participants to identify and evaluate accurately the risks and costs associated with using the services of the derivatives clearing organization.

(ii) AVAILABILITY OF INFORMATION.—Each derivatives clearing organization shall make information concerning the rules and operating and default procedures governing the clearing and settlement systems of the derivatives clearing organization available to market participants.

(iii) PUBLIC DISCLOSURE.—Each derivatives clearing organization shall disclose publicly and to the Commission information concerning—

> (I) the terms and conditions of each contract, agreement, and transaction cleared and settled by the derivatives clearing organization;
>
> (II) each clearing and other fee that the derivatives clearing organization charges the members and participants of the derivatives clearing organization;
>
> (III) the margin-setting methodology, and the size and composition, of the financial resource package of the derivatives clearing organization;
>
> (IV) daily settlement prices, volume, and open interest for each contract settled or cleared by the derivatives clearing organization; and
>
> (V) any other matter relevant to participation in the settlement and clearing activities of the derivatives clearing organization.

Responses:

Attachment L—DCO Core Principle L: Public Information

California ISO

As required by the CAISO tariff, the CAISO provides a variety of information to the public and market participants using its Open Access Same-Time Information System ("OASIS").[326] This information includes real-time updates of system demand forecasts, transmission outage and capacity status, and market result data, including prices. The CAISO is also required to provide non-discriminatory access to information concerning the status of the CAISO controlled grid or facilities affecting the CAISO controlled grid by posting the information on its website.[327]

The CAISO tariff, which is posted to the CAISO website, provides an array of information about the operations of the CAISO, including the following:

(i) Terms and conditions of pro forma contracts with market participants;[328]

(ii) Credit requirements for market participants;[329]

(iii) CAISO charges;[330] and

(iv) Default procedures.[331]

A wealth of additional information on these and other subjects is provided in business practice manuals published on the CAISO website. The business practice manuals discuss, among other things, the process for registration as a CRR holder; the operations of the CRR market; the processes and procedures used to monitor market participant operation to ensure grid reliability; the CAISO's credit management policies; and the various market instruments traded in the CAISO markets.[332]

The CAISO also has an Information Availability Policy designed to afford the public with the greatest possible access to the CAISO's corporate records, consistent with the CAISO's other duties.[333] The Information Availability Policy provides for the designation of a Records Coordinator to whom requests for information can be made and sets the procedure for making and responding to such requests. The Policy also lists certain categories of documents that the CAISO Board has determined should generally be kept confidential.

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326 CAISO Tariff § 6.2.2.2.

327 *Id.*, § 6.2.2.1.

328 *Id.*, Appendix B.

329 *Id.*, § 12.

330 *Id.*, § 11.

331 *Id.*, § 11.29.

332 The CAISO Business Practice Manual Library is *available at* http://www.caiso.com/235f/235f939f8dc0.html.

333 The CAISO Information Availability Policy is *available at* http://www.caiso.com/275e/275eed0c218e0.pdf.

Attachment L—DCO Core Principle L: Public Information

ERCOT

A. In General.

ERCOT's procedures for making information related to all aspects of its markets and operations available to the public are comparable to those required by this core principle.

The ERCOT Protocols and other supporting documents (*e.g.*, the Operating Guides) that prescribe the rules governing ERCOT markets, including all operational and market obligations, are developed in concert with ERCOT market participants and other interested parties (*e.g.*, the IMM),[334] and submitted to the PUCT. These documents are public, and are posted on the ERCOT website to facilitate access and transparency.[335] Thus, the rules that govern ERCOT's functions, including all market rules, are fully transparent and available to all interested parties.

The information made publicly available includes, but is not limited to, ERCOT fees, default, market clearing and settlement rules. In addition, all credit obligations for market participation are transparent in the public ERCOT Protocols and supporting documents.[336] The public rules establish the terms and conditions for transactions in the ERCOT markets. Thus, all obligations and costs associated with ERCOT market participation are public and readily available to interested parties.

In addition, market information is made public subject only to the application of appropriate confidentiality provisions and timing requirements established to protect proprietary information, which supports market efficiency.[337]

The PUCT rules establish a general obligation to disseminate market information in accordance with relevant authorities.[338] PUCT rules also specifically address public access to information. The rules require ERCOT to have procedures for making information available to the public.[339] The rules establish that information is public unless specifically designated as Protected Information pursuant to ERCOT Protocols, or as otherwise provided for in PUCT rules.[340]

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334 P.U.C. SUBST. R. 25.501(m) and 25.362(c) generally, and, specifically, paragraphs (1) and (2).

335 *See* http://www.ercot.com/mktrules/nprotocols/current.

336 ERCOT's credit mathematical formulas are in the ERCOT Protocol Section 16.11, which includes many pages of detailed calculations for exposure and credit limit determinations. .

337 ERCOT Protocol Section 1.3 addresses information confidentiality rules, and specific sections of the ERCOT Protocols address information release rules that establish delayed public release timing requirements, which are designed to protect information that is proprietary on a temporary basis, but loses its need for confidential treatment over time.

338 P.U.C. SUBST. R. 25.361(14).

339 P.U.C. SUBST. R. 25.362(e)(1).

340 P.U.C. SUBST. R. 25.362(e)(1)(A). ERCOT Protocol Section 1.3 governs the management of Protected Information.

In addition to specific market information, the system models used to auction CRRs are available to Market Participants to provide them with appropriate information for participation in that market.[341] These system models and the information reflected therein support informed participation in the energy and ancillary service markets as well. ERCOT uses the most recent, and therefore the most accurate, system model to enable Market Participants to assess the value and risk associated with certain positions based on the best information. ERCOT also publishes all material operating results, which, due to the relationship between system operations and markets, facilitates Market Participants' ability to manage their market positions. Specific market information posting rules are described below.

C. Public Disclosure.

As discussed above, the PUCT Substantive Rules require ERCOT to generally disseminate information relating to market operations, prices and availability of services. In addition, they also establish specific mandates that require the public release of specific market data/information.[342] The ERCOT Protocols also contain specific data release obligations. With respect to CRR information, the following rules apply:

1) Following each CRR Auction, ERCOT shall post to the MIS Public Area the following information for all outstanding CRRs following the auction:
   a) Point-To-Point (PTP) Options and PTP Options with Refund – the source and sink, and total MWs;
   b) PTP Obligations and PTP Obligations with Refund – the source and sink and total MWs;
   c) Flowgate Rights (FGRs) – the identity of each directional flowgate, and the magnitude of positive flow (in MW) on each directional network element represented by each flowgate;
   d) The identities of the CRRAHs that were awarded or allocated CRRs in or before the CRR Auction;
   e) The clearing prices for each strip of CRR blocks awarded in the CRR Auction;
   f) The identity and post-contingency flow of each binding directional element based on the CRR Network Model used in the CRR Auction; and
   g) All CRR Auction Bids and CRR Auction Offers, without identifying the name of the CRRAH that submitted the bid or offer.[343]

This information reflects the terms and conditions of the CRRs awarded in the auctions. All other bid information is posted six months after the relevant auction. At present, there are no

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[341] ERCOT Protocol Section 7.5.3(i).

[342] P.U.C. SUBST. R. 25.505(f).

[343] ERCOT Protocol Section 7.5.3.1(2); *see also* links to public data for monthly and annual auctions available at http://mis.ercot.com/misapp/GetReports.do?reportTypeId=11201&reportTitle=Monthly%20CRR%20Auction%20Results&showHTMLView=&mimicKey and http://mis.ercot.com/misapp/GetReports.do?reportTypeId=11203&reportTitle=CRR%20Annual%20Auction%20Results&showHTMLView=&mimicKey.

special fees to participate in the CRR market. The ERCOT membership fees are prescribed in the ERCOT Protocols and are approved by the PUCT.

ERCOT additionally provides public notice of CRR auctions, which includes pertinent auction participation information.[344]

ERCOT's credit rules are described in the ERCOT Protocols in Section 16.11 (general), Section 4.4.10 (DAM) and Section 7.5.5 (CRR Auction).

ERCOT publicly posts the prices of all nodes and load zones in the ERCOT region on a daily basis.[345] These are the sources and sinks for CRRs. As noted above, the CRRs awarded in monthly auctions are public.[346]

ERCOT disclosure rules also are established for the energy and ancillary services bought and sold in both the Day-Ahead and Real-Time markets in Protocol Section 3.2.5, Publication of Resource and Loan Information. ERCOT posts this data to the public in accordance with PUCT Rule 25.505 (f), Publication of resource and load information in ERCOT markets, in the following sequence:

- Immediately upon completion and publishing of the Day-Ahead or Real-Time market, all pricing is available to the public.
- 48 hours after the Operating Day, ERCOT posts the aggregate offer curves and bid curves from the market to the public.
- 60 days following the Operating Day, ERCOT posts all entity-specific offer curves and bid curves to the public.

[344] ERCOT Protocol Section 7.5.3.2.

[345] ERCOT Protocol Section 4.5.3(2)(b) ("As soon as practicable, but no later than 1330, ERCOT shall post on the Market Information System (MIS) Public Area the hourly. . . Day-Ahead Settlement Point Prices (DASPPs) for each Settlement Point for each hour of the Operating Day."); *see also* links to public data available at http://mis.ercot.com/misapp/GetReports.do?reportTypeId=12328&reportTitle=DAM%20Hourly%20LMPs&showHTMLView=&mimicKey.

[346] ERCOT Protocol Section 7.5.5.2 ("ERCOT shall post monthly, by the fifth Business Day of the month, on the MIS Public Area CRR ownership of record for each source and sink pair and each flowgate: the identities of the CRR Account Holders, type of CRR held by that account holder, and total MWs held by that account holder."); *see also* links to public datda available at http://mis.ercot.com/misapp/GetReports.do?reportTypeId=11206&reportTitle=CRR%20Ownership%20of%20Record&showHTMLView=&mimicKey.

Attachment L—DCO Core Principle L: Public Information

ISO New England

ISO-NE provides sufficient information to enable its market participants to identify and evaluate accurately the risks and costs associated with using its services. ISO-NE has a large amount of information, including information and data on the various markets it operates publicly available on its website. For example:

- Bid data is released after 90 days. *See* Section 3.0(a) of the Information Policy;
- ISO-NE also publishes all FTRs, including the FTR path, MW amount, and recipient, that clear in an FTR auction shortly after the auction closes. FTR bids are published with a masked participant ID three months after the auction. *See* Section 3.0(a) of the Information Policy and III.7 of the ISO-NE Tariff;
- Real-time locational marginal prices are posted on the home page of the ISO's website; and
- The Tariff, which sets forth all rules regarding market participation, operating and default procedures, and margin-setting methodology, as well as all ISO-NE fees, is located on the website at http://www.iso-ne.com/regulatory/tariff/index.html.

Attachment L—DCO Core Principle L: Public Information

MISO

MISO's Tariff and Business Practices Manuals containing rules, operating and default procedures and the credit policy governing the clearing and settlement systems of MISO are provided publicly on MISO's website at: https://www.midwestiso.org/Library/Pages/Library.aspx.

MISO posts Locational Marginal Prices for energy and Market Clearing Prices for operating reserves on its website and provides monthly market reports with information related to market demand and supply conditions, market prices and fuel costs, virtual supply and demand volumes and FTR funding levels. In addition, MISO provides Electronic Quarterly Reports ("EQR") to the Federal Energy Regulatory Commission providing required contract information.

Attachment L—DCO Core Principle L: Public Information

New York ISO

The NYISO maintains on its public website copies of its tariffs, manuals, and technical bulletins describing all rules and procedures applicable to NYISO Market Participants, including those engaged in TCC transactions and Virtual Transactions. These materials specifically include detailed information regarding the methodologies for setting market clearing prices and other information that may impact clearing prices, such as transmission system models, reserved transmission capacity, and similar information. *See, e.g.,* OATT Section 19.9.8; Services Tariff Section 17.1.

The NYISO routinely and promptly makes available on its public website market clearing prices related to all NYISO-administered markets. *See, e.g.,* OATT Section 19.9.8. In addition, the NYISO publishes on its public website information on bids submitted in the NYISO-administered markets three months after the relevant market clears. *See* Services Tariff Section 6; OATT Section 19.9.2. The bids are available at the following location: http://mis.nyiso.com/public/P-27list.htm.

Attachment L—DCO Core Principle L: Public Information

PJM

PJM currently makes all of its rules and operating procedures available to market participants and the general public. Moreover, PJM's rules are established through an open and interactive process that allows all stakeholders to comment and participate. All PJM rules must be reviewed and accepted by FERC.

The PJM Tariff lists all applicable costs for participation in the PJM markets, and the PJM OA describes capital requirements and default allocations. All socialized defaults are posted on PJM's website.

Furthermore, in response to FERC Order No. 741, PJM requires annual certification from each PJM member that such member has established adequate and appropriate risk management, operating, and training measures as applicable to each member's participation in the PJM markets.[347]

B. Availability of Information.

All such rules are available on PJM's website via the PJM OA and the PJM Tariff.

C. Public Disclosure.

The terms and conditions of all transactions are delineated in the PJM OA, PJM Tariff, and manuals, which are posted publicly on PJM's website.

The fees PJM charges its members are specified in Schedule 9 of the PJM Tariff, which is posted publicly on PJM's website.

PJM's methodology for establishing credit requirements and issuing collateral calls is detailed in the Credit Policy and the PJM Credit Overview, both of which are posted publicly on PJM's website.

PJM posts energy market prices every five minutes, and transaction volumes are posted daily. There is no daily market for FTRs or FTR options. Thus, settlement prices and volumes of FTRs and FTR options are posted as each monthly auction clears. FTR and FTR option open positions are maintained on PJM's website for market participant access and updated as each monthly auction clears. Further, promptly after the close of each auction, PJM posts capacity auction clearing prices.[348]

PJM's billing and settlement cycles and billing dispute procedures are included in the PJM Tariff and OA, which is posted publicly on PJM's website.

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[347] *See* discussion above on "Product and Participant Eligibility."

[348] PJM Tariff, Attachment DD, Section 3.3.

Attachment M

DCO Core Principle M: Information-Sharing

Each derivatives clearing organization shall—

(i) enter into, and abide by the terms of, each appropriate and applicable domestic and international information-sharing agreement; and

(ii) use relevant information obtained from each agreement described in clause (i) in carrying out the risk management program of the derivatives clearing organization.

Responses:

Attachment M—DCO Core Principle M: Information-Sharing

California ISO

The ISOs and RTOs are able to coordinate with respect to market participant defaults, and have done so regularly. In the event that the CAISO determined that a market participant was facing financial difficulties that could potentially result in default, the CAISO would be able to share that information with the other ISOs and RTOs. As discussed in Attachment L, the CAISO Information Availability Policy sets forth CAISO's policy on responding to requests for information.

Attachment M—DCO Core Principle M: Information-Sharing

ERCOT

PURA, PUCT Rules and the ERCOT Protocols establish a comprehensive set of rules that address information exchange obligations between ERCOT, the ERCOT IMM, ERCOT Market Participants and the PUCT. Collectively, the rules provide for an effective exchange of information that facilitates efficient operation and oversight of the ERCOT markets. These rules, and the ways they are used to advance ERCOT's risk management program, are described in more detail in Attachments H, J and L hereto.

Attachment M—DCO Core Principle M: Information-Sharing

ISO New England

ISO-NE's Information Policy, Attachment D to the ISO-NE Tariff, sets out rules for sharing information with participants, FERC, and other requestors. The Policy allows stakeholder committees, the ISO, and participants to share information with the benefit of a common understanding regarding how that information will be used and how appropriate confidentiality will be maintained. The Policy consists of three sections. Section 1 highlights the Policy's intent and objectives. Section 2 discusses confidentiality issues and defines "Confidential Information." Finally, Section 3 gives specific guidance as to the categorization of a variety of commonly-used types of information, and also sets out processes for responding to information requests from FERC, state public utilities commissions, academic institutions and the public.

Attachment M—DCO Core Principle M: Information-Sharing

MISO

The MISO Tariff, Transmission Owners Agreement, and various Rate Schedules filed with and accepted by FERC contain provisions facilitating the sharing of information and requiring the use of confidentiality agreements for the sharing of confidential information.

Attachment M—DCO Core Principle M: Information-Sharing

New York ISO

The NYISO maintains interconnection agreements with each of the control areas with which it is interconnected. These agreements provide for sharing of operations information and for other sharing of information where appropriate. Copies are available on the NYISO public website. In addition, the NYISO tariffs provide for the sharing of information by the NYISO with PJM Interconnection, L.L.C. ("PJM") and ISO New England Inc. ("ISO-NE"); see Services Tariff Sections 30.4.6.5.2 and 30.6.7.

The NYISO does not believe there are areas of concern beyond the NYISO's or the Market Monitoring Unit's visibility that are not addressed by the market monitoring processes and remedies discussed in this submission. With respect to conduct in other non-NYISO markets, in general, trades or other bilateral transactions outside of the NYISO markets would not be subject to monitoring by the NYISO or the Market Monitoring Unit. To the extent transactions occurring outside the NYISO markets are part of a scheme to manipulate NYISO markets, the bids, reference levels and prices would still be apparent to the NYISO and relevant to assessing the competitiveness of market outcomes. Thus, the fact that an entity may have an incentive to manipulate a NYISO market because of a position in some other market does not mean that such an entity has an ability to manipulate the NYISO Energy market without detection of the effects of that manipulation in the NYISO market.

Participants in non-NYISO markets seeking to affect prices in price discovery markets would, however, be subject to detection and mitigation on the same basis as any other entity seeking to do so. The Market Monitoring Unit's access to data outside the NYISO markets is limited, but it has full visibility to identify potentially manipulative virtual trading patterns. The Market Monitoring unit has access to public information for certain non-NYISO markets that provide an indication of the potential open interest of individual firms in contracts that settle at the Day-Ahead price. In addition, the Market Monitoring Unit has been working with the Intercontinental Exchange to acquire data via an automated data feed on individual Over-the-Counter transactions in order to improve its ability to evaluate these market interactions.

The independent Market Monitoring Unit's initial screening for manipulation is designed to identify manipulative transactions rather than other positions from which the manipulating firm might benefit. Such screening methods are designed around the information that is available to the Market Monitoring Unit. If the Market Monitoring Unit were investigating the conduct of a particular firm, it could ask the firm for information about its futures, over-the-counter contracts, and any other positions that are not visible in the NYISO data but that might shed additional light on the overall position of an individual firm. Services Tariff Section 30 specifically provides for such data requests. Specifically, Section 30.6.2.1 provides:

> If the Market Monitoring Unit or [Market Mitigation and Analysis Department] determines that additional data or other information is required to accomplish the objectives of Attachment O [Services Tariff Section 30] or of the Market Mitigation Measures, the ISO may request the persons or entities possessing, having access to, or having the ability to generate or produce such data or other

> information to furnish it to the ISO or to its Market Monitoring Unit.

Any party who receives such a request is obliged to furnish the requested information as long as the requested information is (i) within the categories of data or information that Services Tariff Section 30 allows the ISO to routinely request from a Market Party; or (ii) is reasonably necessary to achieve the purposes or objectives of Services Tariff Section 30, not readily available from some other source that is more convenient, less burdensome and less expensive, and not subject to an attorney-client or other generally recognized evidentiary doctrine of confidentiality or privilege. *Id.*

Attachment M—DCO Core Principle M: Information-Sharing

PJM

Only the domestic information-sharing aspect of this core principle is relevant to PJM. PJM already shares market and member information with various regulatory entities, including FERC. PJM's risk management programs are largely retrospective and based on positions and transactions within PJM's own markets. As a result, PJM does not utilize information-sharing agreements to manage risk or assess the continuing eligibility of its members.

Attachment N

DCO Core Principle N: Antitrust Considerations

Unless necessary or appropriate to achieve the purposes of this Act, a derivatives clearing organization shall not—

(i) adopt any rule or take any action that results in any unreasonable restraint of trade; or

(ii) impose any material anticompetitive burden.

Responses:

Attachment N—DCO Core Principle N: Antitrust Considerations

California ISO

ISOs and RTOs were created in order to foster competition in the generation sector by allowing open access to transmission lines, as detailed in FERC Orders 888 and 2000. Fostering competition is part of the culture of the CAISO.

CAISO's market rules are subject to advance review by stakeholders and must be approved by FERC. In addition, those rules are subject to review by CAISO's Department of Market Monitoring ("DMM"). DMM is charged with providing independent oversight of the CAISO markets to detect market power abuses,[349] with responsibilities that include reviewing existing and proposed CAISO rules to identify flaws in the structure of the CAISO markets that reveal undue concentrations or market power.[350] The DMM also provides quarterly and annual reports on trends in, and the performance of, the CAISO markets to the CAISO Governing Board, FERC staff, the California Public Utilities Commission, market participants, and other interested parties.[351]

In addition, the CAISO has a panel of experts, the Market Surveillance Committee (Tariff, Appendix O), to provide it with expert, outside advice with respect to its operations, including advice on any anti-competitive burden that may be associated with CAISO's requirements. The MSC serves as an external advisor, providing independent expertise and recommendations to the CEO and the Governing Board. Members are required to be experts with professional experience in areas that include economics, with an emphasis on antitrust, competition, and market power issues in the electricity industry.

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[349] CAISO Tariff, Appendix P, § 1.2.

[350] *Id.*, §§ 5.1, 5.1.1.

[351] *Id.*, § 5.2.

Attachment N—DCO Core Principle N: Antitrust Considerations

ERCOT

ERCOT complies with this core principle. The PUCT rules setting forth ERCOT's mandates states that the existence of ERCOT does not affect the application of state or federal antitrust laws.[352] To facilitate compliance with the PUCT rules, ERCOT established a Corporate Standard that addresses antitrust issues.[353] In essence, it requires ERCOT employees to comply with antitrust laws in all their activities related to the market and market participants. To facilitate compliance, the Corporate Standard lists specific prohibited and permitted activities that are consistent with antitrust compliance. ERCOT also has a Corporate Standard that addresses ethics obligations, and requires that all employees annually review and sign the agreement. Among other requirements, the ethics agreement mandates that ERCOT employees comply with all antitrust laws. ERCOT also conducts antitrust training for its employees annually.

PURA and PUCT rules require that ERCOT meetings be open.[354] This facilitates activity consistent with antitrust considerations by supporting transparent development of market rules and ERCOT actions in forums open to all interested parties, which enables consideration of all relevant interests such that ERCOT actions and rules are objective and do not favor any particular market participant or market segment, which, in turn, supports competitive and efficient markets.[355] ERCOT has a standard antitrust admonition that is presented at the opening of all meetings.

ERCOT's conflict of interest policies, principles and standards also support consistency with this core principle by ensuring ERCOT employees do not have conflicts that could inequitably favor particular market participants in a manner that could run afoul of the antitrust considerations presented herein. ERCOT's conflict policies/rules are discussed in Attachment P.

In addition to the above specific authorities that are directly related to this DCO core principle, there are several aspects of ERCOT's functions that indirectly facilitate compliance with the antitrust considerations reflected in this core principle. Most notably, ERCOT is the independent organization under PURA, which is defined as:

> "Independent organization" means an independent system operator or other person that is sufficiently independent of any producer or seller of electricity that its decisions will not be unduly influenced by any producer or seller.[356]

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[352] P.U.C. SUBST. R. 25.361(i).

[353] ERCOT Corporate Standard CS1.10, *Antitrust Compliance Corporate Standard*.

[354] PURA § 39.1511(a)-(c) and P.U.C. SUBST. R. 25.362(d).

[355] P.U.C. SUBST. R. 25.362(c) requires that interested parties have an opportunity to comment and participate in the development or revision of rules.

[356] PURA § 39.151(b).

Attachment N—DCO Core Principle N: Antitrust Considerations

ERCOT's independent status requires it to administer its duties in a manner that facilitates the adoption of rules and/or actions that do not result in unreasonable restraints of trade or impose any material anticompetitive burden.

PURA, PUCT Substantive Rules and ERCOT Protocols also require that ERCOT allow access to the transmission system for all buyers and sellers of electricity on a nondiscriminatory basis, which facilitates actions consistent with the antitrust considerations reflected in this DCO Core Principle.

PUCT rules addressing the wholesale market design in the ERCOT state that the wholesale market design be consistent with economic efficiency principles and support competition.[357] Executing its duties consistent with these principles requires ERCOT to perform its functions consistent with the antitrust considerations reflected in this DCO core principle.

[357] P.U.C. SUBST. R. 25.501(a).

Attachment N—DCO Core Principle N: Antitrust Considerations

ISO New England

ISO-NE has not adopted any rule or taken any action that results in an unreasonable restraint of trade or imposes a material competitive burden. In this regard, it notes that the very reason for the existence of ISOs and RTOs, such as ISO-NE, is to bring greater competition to the electricity markets. Moreover, FERC and ISO-NE's two market monitors screen the markets for any anticompetitive behavior and rules that inhibit competition. (*See, e.g.*, Appendix A to Section III of the Tariff, § III.A.)

Attachment N—DCO Core Principle N: Antitrust Considerations

MISO

The rates, terms and conditions of the services provided by MISO are included in the MISO Tariff, Transmission Owners Agreement or related Rate Schedules. All of these documents are subject to the oversight, review and acceptance of FERC. As such, any proposed rule or revision to an existing rule is subject to FERC's review pursuant to the Federal Power Act and other applicable precedent.

Attachment N—DCO Core Principle N: Antitrust Considerations

New York ISO

NYISO rules and actions are subject to oversight by FERC. It is well-established that FERC's responsibilities include consideration of possible restraints of trade or other burdens on competition. In furtherance of FERC's responsibilities, the Market Monitoring Unit's responsibilities include evaluating existing and proposed market rules, tariff provisions and market design elements and recommending proposed rule and tariff changes and monitoring NYISO actions. *See* Services Tariff Sections 30.4.5, 30.4.5.3.

Attachment N—DCO Core Principle N: Antitrust Considerations

PJM

PJM does not anticipate that its current or future products or services will result in any unreasonable restraints of trade or anticompetitive burdens on contract markets. PJM and other RTOs promote competition in the wholesale energy markets.[358] PJM's market monitor also monitors all PJM rule changes for such impacts and informs the FERC regarding any such perceived effects.

[358] *Regional Transmission Organizations,* Order No. 2000, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,089 (1999), *order on reh'g,* Order No. 2000-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,092 (2000), *petitions for review dismissed sub nom. Pub. Util. Dist. No. 1 v. FERC,* 272 F.3d 607 (D.C. Cir. 2001).

Attachment O

DCO Core Principle O: Governance Fitness Standards

(i) GOVERNANCE ARRANGEMENTS.—Each derivatives clearing organization shall establish governance arrangements that are transparent—

(I) to fulfill public interest requirements; and

(II) to permit the consideration of the views of owners and participants.

(ii) FITNESS STANDARDS.—Each derivatives clearing organization shall establish and enforce appropriate fitness standards for—

(I) directors;

(II) members of any disciplinary committee;

(III) members of the derivatives clearing organization;

(IV) any other individual or entity with direct access to the settlement or clearing activities of the derivatives clearing organization; and

(V) any party affiliated with any individual or entity described in this clause.

Responses:

Attachment O—DCO Core Principle O: Governance Fitness Standards

California ISO

FERC imposes governance standards on ISOs through Order No.888, which requires that:

- an ISO's governance should be structured in a fair and non-discriminatory manner;
- an ISO and its employees should have no financial interest in the economic performance of any power market participant; and
- an ISO should adopt and enforce strict conflict of interest standards.[359]

FERC Order No.719 sets minimum standards for governance in relation to required responsiveness to stakeholders.[360] Order No.719 requires ISOs to establish a means to give customers and other shareholders direct access to the board of directors and increase the board's willingness to respond directly to their concerns.[361]

California statutory law also regulates governance at the CAISO. Members of the CAISO Board of Governors ("Board") are appointed by the Governor of California, subject to confirmation by the California senate. Both by statute and under the CAISO's code of conduct, members of the Board may not be affiliated with market participants.

The Board has adopted a policy, available on the CAISO website, detailing the CAISO's corporate governance principles (the "Principles").[362] The Principles describe the duties and responsibilities of the Board and set forth expectations for Board members. These include approving the management's strategic plans and the CAISO's operating and capital budgets; approving material transactions; setting and monitoring compliance with policies and procedures; selecting and reviewing management; overseeing the Department of Market Monitoring; and managing the CAISO's corporate governance.

The CAISO has an Open Meeting Policy requiring that, with the exception of executive sessions, meetings of the Board must be open to the public, except for a limited set of subjects that are appropriate for discussion in an executive session.[363] The Open Meeting Policy requires all formal actions taken by the Board to be taken at a properly noticed open meeting or a properly noticed executive session.

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[359] FERC Order No. 888 (Apr. 24, 1996), *available at* http://www.ferc.gov/legal/maj-ord-reg/land-docs/rm95-8-00w.txt.

[360] FERC Order No. 719 (Oct. 17, 2008), *available at* http://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf.

[361] *Id*. at ¶ 477.

[362] California ISO Corporate Governance Principles, *available at* http://www.caiso.com/1b7e/1b7e7a3b6b5d0.pdf.

[363] California ISO Open Meeting Policy, *available at*, http://www.caiso.com/docs/1998/11/06/1998110614130047l5.pdf.

Attachment O—DCO Core Principle O: Governance Fitness Standards

Board committees are designated pursuant to the CAISO Bylaws.[364] The Board is permitted to designate committees and appoint members to such committees annually, by vote of two-thirds of the Board then in office. An Audit Committee is tasked with, *inter alia*, monitoring compliance with the CAISO's Codes of Conduct and Ethical Principles for employees and members of the Board.

As discussed in Attachment C, the CAISO Tariff sets forth the conditions for the participation in CAISO markets.

The rule enforcement discussed in Attachment H does not involve discretion on the CAISO's part. The fines are set at specific levels in the CAISO Tariff,[365] with any waiver or variation requiring permission from FERC.[366]

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[364] CAISO Bylaws, § IV.

[365] E.g., CAISO Tariff §§ 37.2.1.1, 37.2.2.2, 37.2.3.2, 37.2.4.2, 37.4.1.2 (specifying the dollar amount of any fines).

[366] *Id*. § 37.9.1.

Attachment O—DCO Core Principle O: Governance Fitness Standards

ERCOT

A. Governance Arrangements.

ERCOT's governance structure is mandated by PURA to include both independent directors unaffiliated with any market segment and market segment representation.[367] In addition, PURA requires that all meetings be open and broadcasted to the public on the internet.[368] These requirements do not apply to executive session matters, which are limited to personnel, legal, and risk management matters.

Consistent with this theme of transparency and inclusion, PURA requires that Board materials be posted in advance, which provides notice and adequate opportunity to review, and that interested parties be afforded the right to comment on agenda items for the relevant meeting.[369] These policies of transparency and inclusion are also reflected in PUCT Substantive Rules, which require access and ability to participate in rule development/revision and ERCOT meetings generally, and the ERCOT Bylaws, which require open Board meetings.[370]

These policies are further supported by the substantive involvement of market participants in facilitating the purposes of ERCOT via the Technical Advisory Committee ("TAC").[371] TAC is a market participant body that acts to facilitate the purposes of ERCOT and the policies of the ERCOT Board.[372] Similar to the ERCOT Board, TAC is comprised of diverse market participant groups to facilitate consideration of the views of all interested parties.[373] TAC reports to the Board at each meeting.

B. Fitness Standards.

ERCOT's fitness standards for directors and other key entities are comparable to this core principle. The following fitness standards apply to each of the relevant categories:

1) Directors

PURA establishes the Board construct to include market participant and unaffiliated representation (discussed in greater detail below) and requires the ERCOT Bylaws to establish a selection process that provides for input from its regulatory body (*i.e.*, the PUCT).[374] The PUCT

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367 PURA § 39.151(g).

368 PURA § 39.1511.

369 PURA § 39.1511.

370 P.U.C. SUBST. R. 25.362 generally, and, specifically, 25.362(c) and (d) and ERCOT Bylaws Sections 4.2 and 4.6(e).

371 ERCOT Bylaws, Article 5 generally, and, specifically, Section 5.2.

372 ERCOT Bylaws, Article 5 generally, and, specifically, Section 5.2

373 ERCOT Bylaws, Article 5 generally, and, specifically, Section 5.1.

374 PURA § 39.151(g).

Attachment O—DCO Core Principle O: Governance Fitness Standards

Substantive Rules require ERCOT to establish criteria for Board positions and for removal of Board members if they cease to meet the requisite criteria.[375] ERCOT Bylaws establish the relevant criteria for unaffiliated directors, including, but not limited to, subject matter expertise and independence.[376]

2) Members of Disciplinary Committee

There is no formally established disciplinary committee in ERCOT. Effectively, the Board acts as the "disciplinary" committee in ERCOT in terms of revocation of sanction, expulsion, termination or suspension of membership.[377] Moreover, unaffiliated Board members may be removed by the PUCT.

In addition, the PUCT enforcement division may be viewed as a disciplinary entity in terms of market participant and ERCOT behavior (*e.g.*, Protocol compliance and market abuse).[378]

3) Member of the DCO

The fitness criteria for ERCOT Corporate Members is generally established in the ERCOT Bylaws. [379] In essence, membership requires a nexus between an entity's business and ERCOT's functions (*e.g.*, operations and markets) and, specifically, a financial interest.[380] It also requires the ability to participate in ERCOT's markets.[381]

With respect to specific markets, the ERCOT Protocols establish specific registration and qualification requirements for the relevant types of market participants,[382] which ensure an entity participating in the ERCOT markets meets a minimum level of eligibility standards and capabilities.[383]

As discussed above, through its stakeholder process ERCOT is in the process of developing new market participation eligibility requirements in the Protocols that are comparable to those required by FERC Order No. 741. Proposed eligibility requirements specify that Counter-Parties must:

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375 P.U.C. SUBST. R. 25.362(g).

376 ERCOT Bylaws, Article 4 generally, and, specifically, Sections 4.2 and 4.3.

377 ERCOT Bylaws, Article 3, Section 3.8.

378 The PUCT role in enforcement is discussed in Attachment H.

379 ERCOT Bylaws, Article 3, Section 3.1.

380 *See* ERCOT Bylaws Section 3.1 (Membership).

381 *See* ERCOT Bylaws Section 3.1 (Membership).

382 There is a distinction between Corporate Members under the bylaws and market participants under the Protocols. While Corporate Members may be, and often are, market participants under the Protocols, market participants are not necessarily Corporate Members of ERCOT.

383 ERCOT Protocol Section 16.

- Have appropriate expertise in markets;
- Have appropriate operational capabilities to respond to ERCOT directions;
- Meet minimum capitalization requirements; and
- Maintain a risk management framework appropriate to the ERCOT markets in which it transacts or wishes to transact.

Counter-Parties will be required to provide an annual certification that they have met these requirements, attested by an officer of the company.

Proposed capitalization requirements are higher for Counter-Parties transacting or wishing to transact in CRR markets. Counter-Parties who fail to meet the capitalization requirements would be required to post an "Independent Amount" in addition to any collateral posted with respect to market positions.

Within the scope of the proposed eligibility requirements, Counter-Parties would be subject to periodic verification of their risk management framework to be performed either by ERCOT or an agent acting on ERCOT's behalf.

4) Any other individual or entity with direct access to the settlement or clearing activities of the derivatives clearing organization

This category would only apply to settlement activities, because ERCOT does not engage in clearing activity. With respect to settlement, this category would be limited to ERCOT employees. All ERCOT positions are staffed based on the needs relative to the experience of the individuals. Each position must meet minimum requirements as established by positions descriptions. Accordingly, each relevant ERCOT employee meets minimum fitness standards relative to the position.

5) Any party affiliated with any individual or entity described in this clause.

The rules governing the standards applicable to the above categories circumscribe the standards applicable to those persons/entities. To the extent any affiliated person or organization falls within those categories, the relevant fitness standards would be addressed in the relevant rules.

Attachment O—DCO Core Principle O: Governance Fitness Standards

ISO New England

ISO-NE has governance and fitness standards that apply to its officers and members which are transparent, which fulfill public interest requirements, and which permit the consideration of the views of owners and participants.

Governance and Fitness Standards

ISO-NE has a FERC-approved Code of Conduct that establishes obligations for members of the Board and all employees. These obligations include foregoing investment in and other relationships with market participants. *See* Section 2.1 of the Code of Conduct, available at http://www.iso-ne.com/aboutiso/corp_gov/bylaws/code_of_conduct.pdf. Moreover, ISO-NE's officers and directors are bound to FERC's regulations, including its interlock rules. In addition, the charter of the ISO-NE Audit and Finance Committee of the Board of Directors requires that its members be financially literate and that at least one of them be an audit committee financial expert within the meaning of Item 401(h) of Securities and Exchange Commission Regulation S-K. *See* Audit and Finance Committee Charter at http://www.iso-ne.com/aboutiso/corp_gov/charters/audit_charter_may_2011.pdf.

Market Participants' Input

ISO-NE has a Participants Agreement ("PA") with its stakeholders that sets out the processes for receiving mandatory stakeholder feedback on any changes to Tariff provisions, operating procedures, and other rules. The PA also establishes a Nominating Committee of stakeholders and members of the Board. The Committee selects an annual slate of directors for election and re-election to the Board. The PA also includes provisions about stakeholder interaction with the Board (*e.g.*, meetings, posting of Board agendas).

Attachment O—DCO Core Principle O: Governance Fitness Standards

MISO

A. MISO Independence

The MISO Agreement establishes MISO as non-for-profit corporation independent of its member and market participants. The governance of MISO is accomplished through the election of an independent board of directors from a slate of qualified candidates provided by MISO's Nominating Committee relying on an independent search firm. MISO's Board of Directors is comprised of individuals independent of any affiliation with MISO's members or market participants. MISO Transmission Owner Agreement, Article IV, Section 4.2 Qualifications, Section 4.3 Elections. See Rate Schedule 01 at https://www.midwestiso.org/Library/Tariff/Pages/RateSchedules.aspx.

Appendix A to the MISO Agreement provides Standards of Conduct applicable to all directors, officers and employees of MISO. In addition, all directors and employees of MISO are required to annually certify their compliance with MISO's Standards of Conduct and Code of Business Ethics, which includes restrictions on holding securities of MISO's members and market participants. MISO Transmission Owner Agreement , Appendix A, Section II. E. See Rate Schedule 01 at https://www.midwestiso.org/Library/Tariff/Pages/RateSchedules.aspx.

B. Stakeholder Process

MISO hosts a number of stakeholder committee, sub-committee and task force meetings to provide members and market participants an opportunity to review and discuss various MISO policies and market rules. Proposed revisions to the Tariff or Rate Schedules, including revisions to market rules, are generally vetted through the stakeholder process with a summary of each new filing being provided to market participants on a bi-monthly basis. In addition, Revisions to MISO's Tariff and rate schedules must be filed with the FERC, generally under Section 205 of the Federal Power Act, which provides stakeholders additional notice and opportunity to review and comment on MISO's proposed policies and market rules.

Attachment O—DCO Core Principle O: Governance Fitness Standards

New York ISO

The NYISO is a not-for-profit corporation independent of all of its Stakeholders and Market Participants. The NYISO is governed by an independent 10 member Board. The Board includes nine outside directors as well as the CEO. The Board has the ultimate responsibility for the operation of the NYISO and the effective implementation of the NYISO's responsibilities. None of the Board members are affiliated with any of the NYISO Market Participants, ensuring the NYISO's independence and ability to administer a fair and efficient marketplace. The Board is comprised of individuals with a variety of backgrounds and expertise including that of utility operations, financial markets, law, education, information technology, and the environment. *See* ISO Agreement Sections 5.01, 5.02, 5.03, 5.07 and 5.08.

NYISO Market Participants provide their advice and recommendations to the NYISO and develop certain operating procedures and standards through their representation on Market Participant committees, various subcommittees, and working groups. *See* ISO Agreement Sections 7.02, 8.01, and 9.01. Thus stakeholders are generally involved in establishing the rules that apply to the NYISO's markets. In fact, the Market Participant Management Committee must jointly approve with the Board any proposed changes to the NYISO tariffs submitted for FERC approval under Section 205 (but not Section 206) of the Federal Power Act. *See* ISO Agreement, Section 19. The Management Committee also develops recommendations regarding the NYISO's annual operating and capital budgets and the candidates for Board vacancies. *See* ISO Agreement, Sections 5.04 and 7.02. Market Participants also meet directly with directors after monthly Board meetings and at an annual joint Board/Management Committee meeting.

Directors, as well as all NYISO employees, are subject to the NYISO Code of Conduct, which imposes obligations in relation to conflicts of interest, confidentiality, insider trading, non-discrimination, and related policies, discussed in greater detail in Attachment P, *infra*.

Attachment O—DCO Core Principle O: Governance Fitness Standards

PJM

A. Governance Arrangements.

FERC Order No. 2000 identified four minimum characteristics that RTOs, such as PJM, must exhibit to be qualified as such:

- Independence from all market participants;
- Appropriate scope and regional configuration;
- Operational authority for all transmission facilities under the RTO's control; and
- Exclusive authority for short-term reliability of the transmission system.

In 2001, FERC determined that PJM met these requirements and designated PJM as a RTO.

PJM's governance structure is set forth in the PJM OA and includes the establishment of the independent PJM Board of Managers ("PJM Board"), which is comprised of individuals elected by the PJM members.[384] The PJM members also belong to the PJM Members Committee. The Members Committee is authorized to take actions as specified in the PJM OA, including the election of the PJM Board, filing any amendments or new schedules of the PJM agreements with FERC or any regulatory body of competent jurisdiction, adopting bylaws that are consistent with the PJM OA, termination of the PJM OA, and to provide advice and recommendations to the PJM Board.[385]

B. Fitness Standards.

PJM has established, and enforces, appropriate fitness standards for its Board members as set forth in Section 7 of the PJM OA. For example, PJM Board members are not allowed to be, nor shall they have been within five years of election to the PJM Board, a director, officer of employee of a member or of an affiliate or related party of a member.

All PJM Board members, officers, directors and employees are bound to strictly adhere to PJM's published Code of Conduct.[386]

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384 PJM OA, Sections 7.1 and 7.2.

385 PJM OA, Section 8.8.

386 *See* PJM Interconnection, L.L.C. PJM Board of Mangers Code of Conduct (December, 2008), *available at* http://www.pjm.com/about-pjm/who-we-are/~/media/about-pjm/who-we-are/bom-code.ashx.

Attachment P

DCO Core Principle P: Conflicts of Interest

Each derivatives clearing organization shall—

(i) establish and enforce rules to minimize conflicts of interest in the decision-making process of the derivatives clearing organization; and

(ii) establish a process for resolving conflicts of interest described in clause (i).

Responses:

Attachment P—DCO Core Principle P: Conflicts of Interest

California ISO

As discussed in Attachment O, FERC Order No.888 requires ISOs to implement strict conflict of interest policies. Accordingly, the CAISO has adopted separate but similar codes of conduct for employees and Board members ("Codes").[387] Each of the Codes includes specific conflict of interest rules. Employees and Board members are required to avoid any activity, investment, or interest that might reflect unfavorably on the integrity and reputation of the Board member or the CAISO, even if only in appearance.[388] Employees and Board members must perform their duties in the best interests of the CAISO, avoid relationships and situations that compete with their loyalty to the CAISO, and avoid any activity that is contrary to the best interests of the CAISO.[389] The Codes forbid employees and Board members from acting as a broker in connection with the sale of electricity.[390] Employees and Board members may not serve as employees, directors, or consultants for entities engaged in the generation, transmission, marketing or distribution of power, without the prior written approval of the Board.[391] The Codes also impose rules regarding the political activities of Board members, gifts and gratuities, and the unauthorized use of CAISO assets.[392]

In addition to these Codes, Board members are subject to a California law that prohibits them from being affiliated with any actual or potential market participant.[393]

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387 CAISO Employees Code of Conduct and Ethical Principles ("Employee Code"), *available at* http://www.caiso.com/Documents/EmployeesCodeConduct.pdf; CAISO Governors Code of Conduct and Ethical Principles ("Governors Code"), *available at* http://www.caiso.com/Documents/GovernorsCode-Conduct.pdf.

388 Employee Code § 3; Governors Code § 3.

389 *Id*.

390 Employee Code § 3.1; Governors Code § 3.1.

391 *Id*.

392 Employee Code § 3.5; Governors Code § 3.4.

393 California Pub. Utils. Code § 337.

Attachment P—DCO Core Principle P: Conflicts of Interest

ERCOT

ERCOT's general structure and conflict of interest policies are comparable to this core principle. ERCOT is required by PURA to be independent,[394] and is a non-profit corporation.[395] As such, ERCOT has no financial interest in market outcomes, which mitigates the potential for conflicts of interest to arise in the execution of its duties.

In addition, the PUCT Substantive Rules expressly require ERCOT to adopt policies to mitigate conflicts of interest.[396] In terms of its staff, ERCOT mitigates potential conflicts of interest by employing a specific Corporate Standard to address this concern.[397] The Corporate Standard requires that all employees avoid conflict and appearance of conflict. It also provides a non-exclusive list of situations that create potential actual or perceived conflict and impose an obligation on the employee to determine the existence, if any, of any conflict. If an employee believes a situation may present conflict, but is not sure, he/she is required to exercise one of the following three options:

- Eliminate the conflict of interest;
- Submit a written statement of the possible conflict to the Vice President & Chief Administrative Officer, Director of Audit or the Vice President, General Counsel & Corporate Secretary of ERCOT who will review and provide a written response to the employee as to the action required, if any, or
- Leave the Company.

In addition, each employee is required to submit an Employee Ethics Agreement annually that, among other issues, addresses conflicts of interest. The agreement requires the disclosure of any potential conflicts.[398] If a conflict exists, the employee will be notified by ERCOT's human resources or legal department. The conflict must be resolved promptly or the employee will be terminated.

Potential conflicts of interest are further mitigated by PURA and the ERCOT Bylaws, which impose appropriate restrictions on ERCOT Board members and relevant committee

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394 PURA §§ 39.151(a) and (b). ERCOT is the independent organization under (a), which, pursuant to the requirements in the definition under (b), must be independent of relevant market participants to mitigate undue influence from such entities.

395 ERCOT is a non-profit Texas corporation, and is a tax-exempt 501(c)(4) organization.

396 P.U.C. SUBST. R. 25.362(f).

397 ERCOT Corporate Standard 5.18 ("CS 5.18").

398 The Employee Ethics Agreement is an attachment to CS1.7, *Code of Conduct and Ethics Corporate Standard*.

members to ensure actions taken in their respective roles do not present potential conflicts of interests.[399]

The authorities described above provide structural and behavioral protections that prevent conflicts of interest in the first instance, and, to the extent a conflict arises, a process for resolving such conflict to respect and preserve ERCOT's integrity in performing its independent functions, including the objective administration of the markets.

[399] PURA § 39.1512 and ERCOT Bylaws, Article 9, Sections 9.2 and 9.3.

Attachment P—DCO Core Principle P: Conflicts of Interest

ISO New England

ISO-NE has appropriate rules for minimizing conflicts of interest in the decision-making process and resolving those conflicts. ISO-NE has a FERC-approved Code of Conduct, available at http://www.iso-ne.com/aboutiso/corp_gov/bylaws/code_of_conduct.pdf, that establishes obligations for members of the Board and all employees. These obligations include foregoing investment in and other relationships with market participants. See the Code of Conduct at Section 2.1, which prohibits stock ownership; and Section 2.2, which prohibits other relationships, including spousal employment, receipt of continuing benefits, and business relationships with market participants, and imposes a two-year blackout period on former directors and officers of market participants. The Audit and Finance Committee of the Board is the entity responsible for enforcing compliance, except in matters related to directors, in which case the entire Board (minus the conflicted director) is the arbiter. Each employee and director is required to annually certify his or her compliance with the Code. In addition, ISO-NE maintains an anonymous, web-based portal at ethicspoint.com for making reports. *See* the discussion regarding DCO Core Principle O.

Attachment P—DCO Core Principle P: Conflicts of Interest

MISO

Appendix A to the MISO Agreement provides Standards of Conduct applicable to all directors, officers and employees of MISO. Each new employee, officer and director of MISO receives training on the Standards of Conduct and MISO Code of Business Ethics. In addition, all directors, officers and employees of MISO are required to annually certify their compliance with MISO's Standards of Conduct and Code of Business Ethics, which includes restrictions on holding securities of MISO's members and market participants. MISO Transmission Owner Agreement , Appendix A, Section II. O. See Rate Schedule 01 at https://www.midwestiso.org/Library/Tariff/Pages/RateSchedules.aspx.

MISO also maintains a compliance hotline to facilitate the reporting of actions perceived to be unlawful, unethical or inappropriate relative to MISO's Standards of Conduct, company policies or applicable laws and regulations.

Attachment P—DCO Core Principle P: Conflicts of Interest

New York ISO

The NYISO's Code of Conduct applies to all NYISO directors, officers, and employees and establishes policies, rules and procedures to follow in carrying out the NYISO's responsibilities. *See* OATT Section 12. NYISO directors, officers and employees, their spouses, and their minor children are required to be independent of any Market Participant and are not permitted to own the securities of any Market Participant or its affiliates. *See* ISO Agreement, Section 5.01; OATT Section 12.7. The NYISO's Code of Conduct also prohibits directors, officers and employees from engaging in lobbying activities on behalf of a Market Participant, taking secondary employment with a Market Participant, and accepting gifts, in excess of a nominal value, from Market Participants. *See* OATT Sections 12.7.3 - 12.7.5.

The NYISO's Code of Conduct specifically prohibits NYISO employees and contractors from holding a financial interest in a Market Participant or its Parent/Affiliate. The Code defines a Financial Interest as the ownership of securities in a Market Participant or Parent/Affiliate whose primary business purpose is to buy, sell or schedule Energy, Capacity, Ancillary Services or Transmission Services (also referred to as "Energy Market Activities").

To assist its Employees and Contractors in fulfilling this obligation, the NYISO Compliance Office, in conjunction with the NYISO Prohibited Investment Committee, maintains a listing (i.e., the Prohibited Investment List) of NYISO Market Participants, Parents and Affiliates, in which the ownership of securities is prohibited. Upon notification from the NYISO Customer Relations Department of a new Market Participant, the Market Participant and its Parent/Affiliate(s) will be placed on the Prohibited Investment List. Similarly, upon notification from the NYISO Customer Relations Department of the withdrawal of a Market Participant, the Market Participant (to the extent that it is not a Parent/Affiliate of an active Market Participant) and its Parent/Affiliate(s) (to the extent that the Parent/Affiliate is not associated with an active Market Participant) are removed from the Prohibited Investment List. The NYISO Compliance Office incorporates any changes from the NYISO Customer Relations Department and distributes an updated Prohibited Investment List to employees and contractors on a quarterly basis.

Additionally, the NYISO does not permit any adverse personnel decisions to be taken against the Supervisor of Reliability, Compliance & Assessment by the Vice President of Operations without the concurrence of the Chief Compliance Officer. Further, the Chief Compliance Officer has unfettered access to the NYISO Board, including the Chair of the Audit and Compliance Committee as well as the Board Chair.

Attachment P—DCO Core Principle P: Conflicts of Interest

PJM

Except as provided for in PJM's Standards of Conduct, a PJM Board member is prohibited from having any direct business relationship or other affiliation with any member (or its affiliate or related parties) at any time while serving on the PJM Board.[400]

400 PJM OA, Section 7.2.

Attachment Q

DCO Core Principle Q: Composition of Governing Boards

Each derivatives clearing organization shall ensure that the composition of the governing board or committee of the derivatives clearing organization includes market participants.

Responses:

Attachment Q—DCO Core Principle Q: Composition of Governing Boards

California ISO

As discussed in Attachment O, the CAISO's Board composition is mandated by California statute. Members of the Board are appointed by the Governor of California and subject to confirmation by the California senate.

Attachment Q—DCO Core Principle Q: Composition of Governing Boards

ERCOT

The composition of ERCOT's Board of Directors reflects the spectrum of market participant interests in the ERCOT market and is comparable to this core principle.[401] The Board includes the ERCOT Chief Executive Officer ("CEO") as an *ex officio* voting member and PUCT Chairman as an *ex-officio* non-voting member (the other PUCT Commissioners also participate in the Board meetings). The former ensures the Board decisions consider the interests of the organization and the latter facilitates effective regulation of ERCOT and the market.

The ERCOT Board composition is as follows:

- One Independent Retail Electric Provider and one (1) Segment Alternate;
- One Independent Generator and one (1) Segment Alternate;
- One Independent Power Marketer and one (1) Segment Alternate;
- One Investor Owned Utility (IOU) and one (1) Segment Alternate;
- One Municipal electric utility and one (1) Segment Alternate;
- One Cooperative electric utility and one (1) Segment Alternate;
- Three (3) Consumers: the Public Counsel,[402] representing Residential Consumers and Small Commercial Consumers, as an *ex officio* voting member, one Large Commercial Consumer, and one Industrial Consumer;
- Five (5) Unaffiliated Directors;
- The CEO as an *ex officio* voting member; and
- The Chair of the PUCT as an *ex officio* non-voting member.

This composition is mandated by PURA, and is implemented by the ERCOT Bylaws.[403] It is set by statute it cannot be changed absent specific action by the Texas legislature.

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[401] PURA § 39.151(g), ERCOT Bylaws, Article 4, Section 4.2 and P.U.C. SUBST. R. 25.362(g).

[402] The Public Counsel is appointed by the Governor of Texas to represent the interests of residential and small commercial ratepayers in utility regulatory matters.

[403] ERCOT Bylaws Sections 4.2 and 4.3.

Attachment Q—DCO Core Principle Q: Composition of Governing Boards

ISO New England

The composition of ISO-NE's Board is influenced by market participants, as stakeholders participate in the nomination of members of the Board through a joint Nominating Committee established pursuant to the Participants Agreement. That said, independence from participants is a crucial criteria for Board membership and is measured against ISO-NE's Code of Conduct and FERC's interlock rules.

Attachment Q—DCO Core Principle Q: Composition of Governing Boards

MISO

MISO has an active and engaged stakeholder process. MISO holds regular, noticed meetings of its Board of Directors that are open to stakeholder participation. In addition, the governing committee of the MISO stakeholder process is the Advisory Committee, which provides voting positions for the various stakeholder groups within MISO. The Advisory Committee provides recommendations to the MISO Board of Directors via statements in open meetings or votes based upon advice and reports from numerous subcommittees and task-forces charged with reviewing and developing operational and market policies.

Attachment Q—DCO Core Principle Q: Composition of Governing Boards

New York ISO

See the description of governance arrangements set forth in Attachment O, *supra*.

Attachment Q—DCO Core Principle Q: Composition of Governing Boards

PJM

PJM employs a two-tiered governance structure which is comprised of the independent PJM Board, made-up of nine voting members and the PJM President, as a non-voting member, and the Members Committee, which is comprised of PJM member representatives.[404] The Members Committee is authorized to take actions as specified in the PJM OA, including the election of the members of the PJM Board, filing any amendments or new schedules of the PJM agreements with FERC or any regulatory body of competent jurisdiction, adopting bylaws that are consistent with the PJM OA, termination of the PJM OA, and to provide advice and recommendations to the PJM Board.[405]

The PJM Board operates independently of the PJM Members Committee and is charged with the supervision of all matters pertaining to the PJM Region and PJM, including, but not limited, to the following:

- Ensuring that the Officers of PJM perform the duties and responsibilities set forth in the PJM OA in a manner consistent with the safe and reliable operation of the PJM Region, the creation and operation of a robust, competitive and non-discriminatory electric power market in the PJM Region and the principle that a Member or group of Members shall not have undue influence of the operation of the PJM Region.
- Select the Officers of PJM;
- Adopt budgets for PJM;
- Petition FERC to modify any provision of the PJM OA or any Schedule or PJM practice that the PJM Board believes to be unjust unreasonable or unduly discriminatory under Section 206 of the Federal Power Act.
- Review, in accordance with the terms of the PJM OA, determinations of PJM with respect to events of default;
- Assess against the other Members in proportion to their Default Allocation Assessment an amount equal to any payment to PJM, including interest, as to which a Member is in default;
- Establish reasonable sanctions for failure of a Member to comply with obligations;
- Terminate a Member as may be appropriate under the terms of the PJM OA.[406]

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404 PJM OA, Sections 7 and 8.

405 PJM OA, Section 8.8.

406 PJM OA, Section 7.7.

Attachment R

DCO Core Principle R: Legal Risk

Each derivatives clearing organization shall have a well-founded, transparent, and enforceable legal framework for each aspect of the activities of the derivatives clearing organization.

Responses:

Attachment R—DCO Core Principle R: Legal Risk

California ISO

CAISO operates under a transparent and well-established statutory and regulatory framework, which is grounded in the Federal Power Act and administered by an independent regulatory commission of the United States—the FERC. As discussed above, CAISO is subject to FERC Orders and rules, and operates pursuant to tariffs that have been approved by FERC. CAISO market participants are bound to the tariffs through pro forma contractual agreements approved by FERC that they enter with CAISO.[407]

CAISO's netting arrangements as they are currently structured have withstood market participant insolvencies. Since 2000, seven CAISO market participants have filed for bankruptcy protection. Only one of those participants challenged the CAISO's netting arrangements, and this challenge was later withdrawn.

[407] CAISO's pro forma agreements are available at http://www.caiso.com/docs/2005/10/28/2005102815281216540.html.

Attachment R—DCO Core Principle R: Legal Risk

ERCOT

ERCOT's legal framework is comparable to the core principle. The ERCOT Bylaws establish obligations for ERCOT Corporate Members.[408] The specific rules governing the operation of and participation in ERCOT markets are established in the ERCOT Protocols. As described above, the Protocols are developed in concert with market participants and other interested parties and are public documents that are available on the ERCOT website. The Protocols implement the statutory and regulatory requirements of PURA and the PUCT Substantive Rules, and, therefore, are legally enforceable against all ERCOT market participants. Accordingly, consistent with DCO Core Principle R, the Protocols are a "well-founded, transparent, and enforceable legal framework for each aspect of the activities of the derivatives clearing organization."

ERCOT is subject to a comprehensive legal framework, including governing rules prescribed by statute and regulations that were developed and implemented by the Texas legislature and PUCT, respectively. The rights, obligations and policies embodied in this overarching framework are implemented pursuant to detailed rules – the ERCOT Protocols – that, among other things, govern the markets for the products that are the subject of this exemption request. Because they are the product of collaborative efforts (*i.e.*, legislation, rulemakings and committee based rule development) they are well founded such that the final product is not the result of a narrow viewpoint, but rather represents consideration of the views of a wide variety of interested parties. All of these authorities are public documents, and, therefore, are transparent and available to all current and prospective market participants. The fact that the legal framework emanates from statute and regulation ensures that the rules are enforceable. In addition, to ensure the rules are followed there are several layers of oversight.

With respect to ERCOT's activities, participants can raise issues with ERCOT and escalate them to the PUCT if satisfaction is not achieved via such discussions. In addition, the PUCT has an enforcement division that oversees the market, including ERCOT, to ensure all rules are respected. PURA established the IMM, which monitors ERCOT and market participant behavior for compliance with the market rules. The IMM can raise issues related to ERCOT with the PUCT.

This legislative, regulatory and organizational rule paradigm facilitates effective regulatory oversight of ERCOT and mitigates legal risk because all rules applicable to the design, operation and participation in the ERCOT markets is prescribed in the first instance by legislation, which is then implemented by regulation of the PUCT that is further defined and effectuated by ERCOT Protocols. All of these authorities are public, which results in transparency that ensures all relevant entities are aware of their rights and obligations, thereby mitigating legal risk.

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408 ERCOT Bylaws, Article 3.

Attachment R—DCO Core Principle R: Legal Risk

ERCOT's existing legal framework also protects its rights and those of market participants and the public in the event of market participant bankruptcy. To provide further assurance that set-off will be effective in future bankruptcy proceedings ERCOT expects to adopt the central counterparty model, which would make ERCOT the counter-party to all transactions in the ERCOT market.

Attachment R—DCO Core Principle R: Legal Risk

ISO New England

ISO-NE has a well-founded, transparent, and enforceable legal framework for each aspect of its business, which operates in a comprehensively regulated environment. It is based on its Tariff, which is approved by FERC. FERC, in turn, derives its authority from the Federal Power Act.

Attachment R—DCO Core Principle R: Legal Risk

MISO

MISO's Tariff and Rate Schedules are filed with the Federal Energy Regulatory Commission, which provides the basis for the well-founded, transparent and enforceable legal framework surrounding the activities of MISO. To provide additional transparency, MISO provides stakeholders with a bi-monthly update of upcoming regulatory filings and review of orders issued by FERC.

Attachment R—DCO Core Principle R: Legal Risk

New York ISO

The NYISO administers the wholesale electricity markets in New York State pursuant to a well-founded, transparent, and enforceable legal framework. *See*, generally, Services Tariff and OATT, *passim*.

A. Well-Founded Legal Framework

The NYISO's tariffs and agreements establish the NYISO's and Market Participants' rights and obligations in connection with NYISO activities. The NYISO's tariffs and agreements are consistent with the principles and requirements for just and reasonable rates for Independent System Operators that have been developed by FERC through its rulemakings and orders in accordance with the Federal Power Act. The NYISO's tariffs and agreements have been submitted to and accepted by FERC and are effective pursuant to the Federal Power Act and related FERC regulations.

As a general matter, the NYISO may only modify its tariffs and agreements filed through its shared governance process and with approval of FERC. Under its shared governance process, NYISO Market Participants, which represent various stakeholder interests throughout the electric industry, develop and review proposed modifications in coordination with the NYISO and are responsible for voting on proposed modifications to the NYISO tariffs and agreements. If 58% or more of Market Participants participating in the NYISO Management Committee and the NYISO Board approve a modification to a tariff or agreement, the NYISO will file the proposed modifications with FERC. FERC evaluates whether a proposed change is just and reasonable and may accept or deny the proposed modifications following a period in which Market Participants and other interested parties are permitted to submit comments on the proposed modification.

This multi-step process ensures that the binding rules establishing the basis on which the NYISO operates are just and reasonable, reflect broad stakeholder input, and reflect sound policy consistent with federal law and FERC's express requirements and guiding principles.

The individual services furnished by the NYISO pursuant to its tariffs and agreements are in accordance with such express requirements and guiding principles. As detailed below, the NYISO is required to administer a Day-Ahead and Real-Time energy market, an Installed Capacity market and a TCC market. The NYISO is also required to provide Ancillary Services, schedule Bilateral Contracts for energy, and offer Virtual Transactions.

- Energy Markets and Bilateral Energy Contracts. The NYISO-administered Energy markets and the NYISO's scheduling of bilateral energy contracts are a fundamental component of the NYISO structure initially approved by FERC in authorizing the establishment of the NYISO. Accordingly, the NYISO is required under its tariffs to administer the energy markets and to schedule bilateral energy contracts. FERC expressed its intent to require transmission providers to schedule bilateral energy contracts, in addition to operating energy markets, in a 2002 notice of proposed rulemaking.[409]

- Installed Capacity Market. Under the NYISO Services Tariff, all LSEs serving load in the New York Control Area must provide capacity in accordance with NYISO requirements. This requirement is necessary to ensure long-term reliability of the NYS power system. To facilitate compliance with this requirement, the initial filing establishing the NYISO provided for the creation and operation of an Installed Capacity Market. This Installed Capacity Market is a fundamental feature of the initial structure as approved by FERC in its orders authorizing the establishment of the NYISO. Accordingly, the NYISO is required to administer the ICAP Market in accordance with its tariffs.

- TCC Market. In FERC Order No. 888, FERC required that all ISOs provide transmission service under standard terms and conditions. FERC included open access transmission requirements in the pro forma tariff that all ISOs were required to adopt. As part of the proceeding establishing the NYISO, the NYISO proposed to establish the NYISO-administered TCC market as a mechanism for providing the financial equivalent of transmission service. Accordingly, the NYISO is required to operate the TCC Market in compliance with the NYISO tariffs.

- Ancillary Services. The provision of ancillary services is required under the pro forma Open Access Transmission Tariff that all ISOs, including the NYISO, were required to adopt by FERC Order No. 888. The NYISO substantially adopted the *pro forma* Open Access Transmission Tariff as the OATT, which FERC approved prior to NYISO start-up. Accordingly, the NYISO is required to provide ancillary services (such as black start, voltage control, etc.) to its customers in accordance with the NYISO tariffs.

- Virtual Transaction. Virtual Transactions were not part of the NYISO market structure upon NYISO start-up and were not initially required by FERC. However, soon thereafter, the NYISO and its Market Participants began a process to implement Virtual Transactions because they serve to improve the liquidity and efficiency of the NYISO-administered energy markets. In an order issued by FERC in 2000, FERC placed a high priority on the NYISO's development of Virtual Transactions.[410] The NYISO introduced Virtual Transactions in 2001. The NYISO is now required to make Virtual Transactions available to its customers in accordance with the NYISO tariffs.

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[409] *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Docket No. RM01-12-000 (2002), at P 225.

[410] *Morgan Stanley Capital Group, Inc. v. New York Independent System Operator, Inc.*, 93 FERC ¶ 61,107 (2000).

Attachment R—DCO Core Principle R: Legal Risk

B. Transparent Legal Framework

The NYISO must act in accordance with its tariffs and agreements, which the NYISO is required to make publicly available and which are on file with FERC. The NYISO also publicly posts its manuals, technical bulletins, and other written procedures that provide additional details in connection with NYISO activities. As described above, the NYISO modifies its tariffs and agreements through a public process in which Market Participants develop, review, and vote on proposed modifications. The NYISO publicly posts the materials being developed and discussed by Market Participants as part of the shared governance process. In addition, any proposed modifications to the NYISO's tariffs and agreements submitted to FERC become part of a public proceeding in which Market Participants and other interested parties can intervene and submit comments regarding the proposed modifications. Finally, transparency is facilitated through efforts to make available to Market Participants substantial information about operations and settlements and through Code of Conduct provisions requiring all employees to administer the tariffs in a fair, non-discriminatory manner.

These procedures ensure that the NYISO's rules are established and applied in a transparent manner.

C. Enforceable Legal Framework

NYISO Market Participants must register with the NYISO and enter into a service agreement with the NYISO to participate in the NYISO administered markets and to utilize the New York State power system in accordance with the requirements set forth in the NYISO tariffs and agreements. Prior to becoming a NYISO Market Participant, each applicant must satisfy all of the NYISO's registration requirements. As part of the registration process, each applicant is required to submit to the NYISO a copy of its formation documents, a recent certificate of good standing, and a resolution of the applicant's governing body. In the resolution, the applicant's governing body authorizes the applicant to enter into the service agreements with the NYISO and specifies the individual that is permitted to sign the service agreements on behalf of the applicant. These procedures help ensure the applicant is legally able to enter into the service agreements and that the applicant is legally bound by the terms of the service agreements. Each executed service agreement is catalogued with the Commission.

As described in detail in Attachment H of the NYISO's responses, the NYISO monitors Market Participant's participation in its markets and may take action to penalize a Market Participant or suspend or terminate its participation in the NYISO markets if the Market Participant is not acting in accordance with the NYISO's tariffs and agreements. In addition, Market Participants receive substantial information regarding NYISO operations and settlements and may identify any non-compliance with NYISO rules. The NYISO and Market Participants may at any time request that FERC direct a Market Participant, and the NYISO, to perform the obligations set forth in the NYISO tariffs and agreements if the party is not performing such obligation. In addition, FERC conducts audits and investigations of Independent System Operators and Market Participants to ensure that they are acting in accordance with the filed tariffs and agreements. Also, many rules are self-enforcing, as the NYISO information systems will not accept bids that are not consistent with certain automated NYISO rules.

These mechanisms ensure that the NYISO's rules are enforced in accordance with the NYISO tariffs and agreements.

Attachment R—DCO Core Principle R: Legal Risk

PJM

PJM's legal framework to enforce its market rules is constituted in the PJM OA, PJM Tariff and related documents filed with the FERC. These rules are enforceable, not merely as matters of contract, but additionally as regulatory directives with attendant enforcement and penalty programs administered by the FERC. In limited instances where PJM needs to enforce legal rights, including its rights to set off positions, outside the FERC regulatory context, it has taken recent steps to clarify its legal capacity and privity with market participants involving transactions undertaken in its markets. These steps afford PJM a strong basis to enforce tariff-based rights in contexts outside the FERC, such as in bankruptcy proceedings or in civil litigation.

As noted above, effective January 1, 2011, the PJM OA and PJM Tariff were revised to establish PJMSettlement Inc., an affiliated company, as the central counterparty to transactions in the PJM markets. According to the PJMSettlement filing, "[t]he purpose of the filed revisions is to clarify that there is a single, specified counterparty to market participants with respect to all 'pool' transactions in the markets operated by PJM and for transmission service."[411]

Under the new PJM regime:

- PJMSettlement takes "title to all power that is purchased and sold in the 'pool transactions' in the [PJM-administered] markets"[412];
- the revisions to PJM's structure establish that "PJMSettlement will be a buyer to each market seller and a seller to each market buyer, *taking title to electricity and other products and assuming liability for payables, in its own name and right*"[413]; and
- the interposition of PJMSettlement as a counterparty in PJM-administered markets does not extend to certain bilateral contracts and self-supply transactions (which PJM considers to be non-pool transactions, which is to say, outside of the organized markets it administers).[414]

Designation of a central counterparty for pool transactions in PJM markets satisfies the mutuality requirement to ensure contractual setoff rights will be enforced in the event of a bankruptcy of a PJM member. Under U.S. bankruptcy laws, generally, a creditor may assert a right of setoff with respect to otherwise enforceable pre-petition claims against a debtor if the claim and the pre-petition debt against which it is sought to be set off are "mutual." Mutual means the debts to be set off are between the same parties, standing in the same right and in the same capacity. By

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411 PJM Filing with FERC, *PJM Interconnection, L.L.C., and PJM Settlement, Inc.*, Docket No. ER10-1196-000, at 1 (May 5, 2010).

412 *Id.* at 9.

413 *Id.* (emphasis added).

414 *Id*.

interposing PJMSettlement as a formal contract party, taking title to assets and incurring obligations in its own name, PJM can satisfy this standard.

Attachment S

SEF Core Principle 1: Compliance With Core Principles

(A) IN GENERAL.—To be registered, and maintain registration, as a swap execution facility, the swap execution facility shall comply with—

(i) the core principles described in this subsection; and

(ii) any requirement that the Commission may impose by rule or regulation pursuant to section 8a(5).

(B) REASONABLE DISCRETION OF SWAP EXECUTION FACILITY.—Unless otherwise determined by the Commission by rule or regulation, a swap execution facility described in subparagraph (A) shall have reasonable discretion in establishing the manner in which the swap execution facility complies with the core principles described in this subsection.

Responses:

Many of the Requestors' practices that are generally comparable to this SEF core principle and the SEF core principles addressed below are the same as those discussed in responses to the DCO core principles above, and are therefore incorporated by reference herein.

Attachment T

SEF Core Principle 2: Compliance With Rules

A swap execution facility shall—

(A) establish and enforce compliance with any rule of the swap execution facility, including—

> (i) the terms and conditions of the swaps traded or processed on or through the swap execution facility; and
>
> (ii) any limitation on access to the swap execution facility;

(B) establish and enforce trading, trade processing, and participation rules that will deter abuses and have the capacity to detect, investigate, and enforce those rules, including means—

> (i) to provide market participants with impartial access to the market; and
>
> (ii) to capture information that may be used in establishing whether rule violations have occurred;

(C) establish rules governing the operation of the facility, including rules specifying trading procedures to be used in entering and executing orders traded or posted on the facility, including block trades; and

(D) provide by its rules that when a swap dealer or major swap participant enters into or facilitates a swap that is subject to the mandatory clearing requirement of section 2(h), the swap dealer or major swap participant shall be responsible for compliance with the mandatory trading requirement under section 2(h)(8).

Responses:

Attachment T—SEF Core Principle 2: Compliance With Rules

California ISO

The CAISO Tariff sets forth transparent rules for all of the CAISO markets, including rules to deter abuses. Please see Attachment H for a discussion of the CAISO's enforcement program, as well as the Department of Market Monitoring.

Attachment T—SEF Core Principle 2: Compliance With Rules

ERCOT

The responses provided in Attachments H and R of the DCO Core Principle discussion are responsive to this SEF Core Principle, and those responses are incorporated herein by reference. An overview of the aspects of the ERCOT market construct that demonstrate comparability to SEF Core Principle 2 is provided below to complement the Attachment H and R responses.

The ERCOT markets are governed by a comprehensive set of authorities. The market construct is established in the first instance by state law, which is then implemented by regulation.[415] The detailed rules that govern the functions of ERCOT, including the markets administered by ERCOT, are established in the ERCOT Protocols. This comprehensive legal framework ensures the rules that apply to the operation of and participation in the ERCOT markets are enforceable.

The oversight and enforcement mechanisms are administered through the interaction of ERCOT, the ERCOT IMM, and the PUCT. As discussed in Attachment H, all market participants sign agreements obligating them to comply with all ERCOT market rules. ERCOT, the IMM, and the PUCT all play active roles in monitoring compliance with ERCOT market rules, and the PUCT has ultimate enforcement authority. ERCOT and the IMM support the PUCT in performing that role. Each of these entities is adequately staffed and funded to perform its functions, including enforcement of ERCOT rules.

Enforcement and compliance are supported from a structural perspective as well. ERCOT markets are administered on a non-discriminatory basis, which facilitates impartial access to the ERCOT markets and transmission system. ERCOT systems capture all relevant market data and information, which supports compliance and enforcement efforts by providing the oversight and enforcement entities with the information required to assess compliance and determine if violations have occurred. ERCOT, the IMM, and the PUCT have access to all relevant information, either from the ERCOT systems, or directly from market participants.

In summary, ERCOT is subject to a comprehensive legal framework, including governing rules prescribed by both statute and regulations that were developed and implemented by the Texas legislature and PUCT, respectively. The rights, obligations and policies embodied in this overarching framework are implemented pursuant to detailed rules – the ERCOT Protocols – that, among other things, establish and enforce trading, trade processing, and participation rules. In addition, the PUCT rules establish market participant behavioral rules that, among other things, list specific prohibited activities. All of these authorities are public documents, and, therefore, are transparent and available to all current and prospective market participants. The fact that the legal framework emanates from statute and regulation ensures that the rules are enforceable. In addition, to ensure that the rules are followed there are several layers of oversight. ERCOT market participants are required by regulation to comply with

[415] *See generally* PURA § 39.151 and P.U.C. SUBST. R., Subchapters O, Division 2 and Subchapter S.

ERCOT rules and are prohibited from engaging in market abuses. In addition, all market participants sign agreements that obligate them to comply with ERCOT market rules.

Attachment T—SEF Core Principle 2: Compliance With Rules

ISO New England

ISO-NE has rules governing all of its markets, including rules to deter abuses, and an enforcement program. For FTRs, these rules are in Section III.7 of the ISO-NE Tariff, and require impartial access to the market, fair eligibility standards, and limitations on access for non-participants. In addition, Appendix A to Section III of the ISO-NE Tariff sets out the structure and rules related to the internal and external market monitors.

As noted above in the discussion of DCO Core Principle H, internal and external market monitors ("IMM" and "EMM") play an essential role in ensuring compliance with the rules of the wholesale electricity market. IMM monitors compare the deviations between day-ahead and real-time locational marginal prices to determine if there is a persistent difference that would not be expected in a workably competitive market and calculate a rolling average locational marginal price deviation value. *See* Section III.A.8 of the ISO Tariff. Depending on the amount of the rolling average deviation, the IMM is required to investigate whether and to what extent the actions of one or more Market Participants are contributing to the price deviation. If a Market Participant is found to have contributed, through its virtual transactions, to an unwarranted deviation in the day-ahead and real-time prices at a node, the IMM may restrict that Market Participant's ability to submit virtual bids or offers for up to six months. In addition, per Section III.A.14 of the ISO Tariff, if the Market Participant's activities constitute a "Market Violation," the IMM would refer the Market Participant to the FERC.

Also, the IMM reviews the activity of Market Participants taking virtual positions weekly, analyzing the profitability of virtual positions and the distribution of those virtual positions as well as other market positions taken by those Market Participants in order to ascertain, for example, whether their virtual transactions are used principally to hedge physical positions or are arbitrage/speculative in nature. The IMM also relies on information from the ISO's system operators and market operations and settlements departments regarding perceived anomalous behavior in order to monitor the marketplace for trends and "outliers." The IMM may also notify the ISO if any changes to market rules, models or procedures are needed or advisable to prevent manipulative conduct as well as computes the degree of price convergence daily, and provides monthly reports on price convergence to the Markets Committee of the ISO-NE Board of Directors.

The IMM has a weekly call with FERC's Office of Enforcement and also makes formal written reports to the Office of Enforcement on a monthly, quarterly and annual basis; and discusses with and makes referrals to FERC regarding any potential Market Violation. Both the IMM and EMM report directly to the Markets Committee of ISO-NE's independent Board of Directors. In the event that either market monitor uncovers problems with the markets, it is required to promptly inform FERC, FERC's Office of Energy Market Regulation staff, the ISO Board, the public utility commissions for each of the six New England states, and the market participants of its findings in accordance with the procedures outlined in Sections lILA.14 and lILA.15 of Appendix A of the Market Rules, subject to redaction pursuant to the ISO's Information Policy, if necessary.

Among other matters, the IMM has observed or investigated:

(i) Economic withholding – where a unit does not offer into the energy markets in a potential effort to raise prices for other resources.

(ii) Physical withholding – where a resource erroneously claims that it is not available for physical reasons in an attempt to raise prices for other resources.

(iii) Improperly claiming a resource available when, in fact, it is physically incapable of operation – this might be done to collect capacity payments when a resource should not receive such payments due to unavailability.

(iv) Attempts to manipulate reference prices – use of offer strategies to raise reference prices which, in turn, can be used to increase offers and, particularly in constrained areas where a resource is needed for reliability, increase revenues.

(v) Use of interrelated virtual bids and FTRs – to increase the value of products in these markets.

Attachment T—SEF Core Principle 2: Compliance With Rules

MISO

MISO has transparent rules for all of its markets that have been filed with and accepted by FERC. These include rules to deter market abuses, prevent manipulation and enforce compliance with its Tariff and Rate Schedules. See generally Module D and Attachment S of the MISO Tariff.

Attachment T—SEF Core Principle 2: Compliance With Rules

New York ISO

The NYISO has transparent rules for all of its markets, including rules to deter market abuses, prevent manipulation and enforce compliance with its tariffs. *See* Attachment H, *supra,* and Attachment U, *infra.*

Attachment T—SEF Core Principle 2: Compliance With Rules

PJM

The PJM tariff has transparent rules for all of its markets, including rules to deter abuses, and an enforcement program, comparable to the requirements SEF Core Principle 2. In addition, Attachment M of the PJM tariff provides for an independent Market Monitoring Unit ("MMU"), which sets forth the maintenance of an independent MMU that will objectively monitor, investigate, evaluate and report on the PJM markets, including, but not limited to, structural, design or operational flaws in the PJM markets or the exercise of market power or manipulation in the PJM markets.

Attachment U

SEF Core Principle 3: Swaps Not Readily Susceptible to Manipulation

The swap execution facility shall permit trading only in swaps that are not readily susceptible to manipulation.

Responses:

Attachment U—SEF Core Principle 3: Swaps Not Readily Susceptible to Manipulation

California ISO

Section 36 of the CAISO Tariff sets out detailed rules for issuing, allocating, and auctioning CRRs. These market rules were developed for the CAISO by experts, thoroughly vetted with stakeholders before implementation, and then approved by FERC. In addition, the CAISO tariff forbids holders of CRRs from using virtual bidding to enhance their CRR revenues.[416] As discussed in Attachment H, CAISO's Department of Market Monitoring ("DMM") watches the CAISO's markets for potential manipulation and refers any suspected manipulative activity to FERC, including manipulation that could affect the value of CRRs. In addition, DMM reviews existing CAISO rules to identify any flaws and recommend improvements.

[416] See CAISO Tariff section 11.2.4.6.

Attachment U—SEF Core Principle 3: Swaps Not Readily Susceptible to Manipulation

ERCOT

ERCOT market transactions are not readily susceptible to manipulation for several reasons. The rules are transparent to all interested parties and cannot be manipulated by entities due to opaqueness. Market Participants are required by regulation and agreement to comply with these rules, including the regulatory prohibitions on inappropriate market behavior. The market rules themselves effectively operate in a manner that creates structural safeguards that incent efficient market behavior, and, therefore, mitigate the potential for market manipulation. In addition, ERCOT publicly posts extensive market information, which further enhances transparency and mitigates the ability for market manipulation. The reporting obligations of ERCOT and the IMM also mitigate the potential for market manipulation because they ensure that market performance is evaluated on a constant basis.

PURA also gives the PUCT express authority to address market power through a variety of means including actions against individual entities for market abuse.[417] In addition, PURA establishes the IMM, whose primary functions are detecting and preventing market manipulation and market design assessment with the goal of enhancing market efficiency,[418] while PUCT rules implement the IMM's functions.[419] The PUCT has full authority to take action to address market power and has an internal enforcement division that detects and addresses market power.[420]

Further, ERCOT is proactive in this regard in administration of its markets. For example, when ERCOT observes CRR trading and positions that purposefully take advantage of discrepancies in the network model or software, and potentially create payouts on artificial congestion, the ERCOT Board has the opportunity and discretion to approve price corrections due to any significant errors in the software or data.[421]

The principles and rules discussed above are also described in the DCO Core Principle responses. Collectively, Attachments C, H, J, L, M and R support the response to this SEF Core Principle and the relevant discussions in those responses are incorporated herein by reference.

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417 PURA § 39.157 provides that "for purposes of this subchapter, market power abuses are practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition, including practices that tie unregulated products or services to regulated products or services or unreasonably discriminate in the provision of regulated services. For purposes of this section, "market power abuses" include predatory pricing, withholding of production, precluding entry, and collusion. A violation of the code of conduct provided by Subsection (d) that materially impairs the ability of a person to compete in a competitive market shall be deemed to be an abuse of market power. The possession of a high market share in a market open to competition may not, of itself, be deemed to be an abuse of market power; however, this sentence shall not affect the application of state and federal antitrust laws."

418 PURA § 39.1515.

419 P.U.C. SUBST. R. 25.365.

420 P.U.C. SUBST. R. 25.503.

421 ERCOT Protocols Section 4.5.3 for DAM and Section 6.3 for Real-Time market prices.

Attachment U—SEF Core Principle 3: Swaps Not Readily Susceptible to Manipulation

ISO New England

ISO-NE permits trading only in instruments that are not readily susceptible to manipulation. For example, rules for issuing, allocating, settling and auctioning FTRs are in Sections III.5.2 and III.7 of the ISO-NE Tariff. The Markets Committee of the Board and the Markets Committee of NEPOOL (ISO-NE's stakeholder body) advise on market rules, all of which are approved by FERC. Further, the internal and external market monitors review transactions for evidence of manipulation. *See* Section III.A.2.1(c) of the ISO-NE Tariff. As noted above in DCO Core Principle H and SEF Core Principle 2, the, IMM monitors compare the deviations between day-ahead and real-time locational marginal prices to (i) determine if there is a persistent difference that would not be expected in a workably competitive market and (ii) calculate a rolling average locational marginal price deviation value. *See* Section III.A.8 of the ISO Tariff. Depending on the amount of the rolling average deviation, the IMM is required to investigate whether and to what extent the actions of one or more Market Participants are contributing to the price deviation. If a Market Participant is found to have contributed, through its virtual transactions, to an unwarranted deviation in the day-ahead and real-time prices at a node, the IMM may restrict that Market Participant's ability to submit virtual bids or offers for up to six months. In addition, per Section III.A.14 of the ISO Tariff, if the Market Participant's activities constitute a "Market Violation," the IMM would refer the Market Participant to the FERC.

Also, the IMM reviews the activity of Market Participants taking virtual positions weekly, analyzing the profitability of virtual positions and the distribution of those virtual positions as well as other market positions taken by those Market Participants in order to ascertain, for example, whether their virtual transactions are used principally to hedge physical positions or are arbitrage/speculative in nature. The IMM also relies on information from the ISO's system operators and market operations and settlements departments regarding perceived anomalous behavior in order to monitor the marketplace for trends and "outliers." The IMM may also notify the ISO if any changes to market rules, models or procedures are needed or advisable to prevent manipulative conduct as well as computes the degree of price convergence daily, and provides monthly reports on price convergence to the Markets Committee of the ISO-NE Board of Directors. Among other matters, the IMM has observed or investigated attempts to manipulate reference prices, including use of offer strategies to raise reference prices which, in turn, can be used to increase offers.

Attachment U—SEF Core Principle 3: Swaps Not Readily Susceptible to Manipulation

MISO

MISO has detailed rules for Financial Transmission Rights (FTRs) in its Tariff FTR and ARR Business Practices Manual (BPM No. 004). Also, MISO's Independent Market Monitor is responsible for monitoring and enforcement actions associated with virtual transactions and FTRs.

Attachment U—SEF Core Principle 3: Swaps Not Readily Susceptible to Manipulation

New York ISO

There are several aspects of the NYISO-administered markets that make transactions in those markets less susceptible to manipulation: (1) financial surveillance and risk management which serve to prevent unusually large positions in any one product; (2) price discovery – the use of competitive auction markets that result in public market-clearing prices; and (3) market monitoring. In addition, as discussed in greater detail in Attachment H, *supra*, the NYISO's Market Mitigation and Analysis Department and the Market Monitoring Unit devote significant resources to the detection and prevention of market manipulation.

With respect to TCCs and Virtual Transactions, there are additional unique aspects that make these transactions less susceptible to manipulation:

1) The quantity of TCCs held by a Market Participant does not impact the value of the congestion "rents" that will flow to the holder. A strong position in TCCs therefore will not enable the holder to manipulate the market.

2) A TCC purchaser has no incentive to pay more than the expected congestion "rents" that will accrue from holding the TCC.

3) A substantial number of TCCs are allocated outside of the auction process and are not available for purchase by speculators. Rather, there has historically been substantial diversity of ownership of TCCs in New York.

4) TCCs are sold by auction, the design of which includes multiple auction rounds with a fixed amount of transmission capacity being offered for sale in each round. The multi-round process minimizes the opportunity for one party to buy a large quantity of TCCs all at one time.

5) With respect to Virtual Transactions, system constraints can and do limit the amount of Virtual Transactions scheduled in the Day-Ahead Market.

As a result, NYISO-administered markets generally, and particularly the TCC markets and Virtual Transactions are not "readily susceptible to manipulation" in the way that traditional commodity markets might be. Each of these limitations on manipulation is described in greater detail below.

A. <u>Credit Requirements</u>

The NYISO's risk management and financial surveillance processes prevent a Market Participant from assuming significant risks in NYISO-administered markets without providing corresponding financial security. The processes are discussed in detail in Attachment C, *supra*. By requiring Market Participants to meet stringent operating and bidding requirements, such processes discourage high-risk speculative trading and are one of several ways in which the NYISO makes products and transactions in its markets less susceptible to manipulation.

B. Price Discovery

The NYISO-administered markets for TCCs, Installed Capacity, Day-Ahead Energy (including Virtual Transactions), Real-Time Energy, and Ancillary Services all perform this "price discovery" function. In addition to clearing the market for the relevant product, the NYISO understands that these prices can be and are used by NYISO Market Participants and others as reference points for bilateral contracts or other transactions outside of the NYISO markets. In addition, within the NYISO markets, prices determined in certain markets are relevant to assessing price expectations in a related market, and thus provide a further form of "price discovery."

1. Price Discovery in the Energy Markets, including Virtual Transactions

Bids and offers made in the NYISO-administered Energy markets are settled through the NYISO at prices set based on a locational market clearing price. This price, referred to in the NYISO as the LBMP is made up of three components: (1) the marginal Energy price component; (2) the marginal Losses Component; and (3) the marginal Congestion component. The Day-Ahead Market for Energy, in which Virtual Transactions occur, provides LBMP information for Real-Time Market price expectations. Bids in the Day-Ahead Market are due by 5:00 a.m. the day ahead of the scheduled transaction. By 11:00 a.m., the NYISO posts the Day-Ahead prices for the next day. Since the Day-Ahead Market prices are for delivery in Real-Time the next day, the Day Ahead prices include expectations about likely Real-Time prices the next day.

Virtual Transactions are arbitrage trades between the Day-Ahead and Real-Time energy markets. A Virtual Transaction is either (i) a sale in the day-ahead market and a corresponding purchase in the real-time market or (ii) a purchase in the day-ahead market and a corresponding sale in the real-time market. Virtual Transactions factor into the competitive price discovery provided by Day-Ahead Markets in the same way as physical bids.[422] Virtual Transactions that are ultimately scheduled in the Day-Ahead Markets receive settlements at the Day-Ahead LBMPs for the locations applicable to the virtual bids and offers. There are no non-performance penalties incorporated into their financial settlement. The system must balance physical resources and loads in Real Time. Thus, actual deliveries to or receipts from the grid that differ from an entity's Day-Ahead position are settled at the applicable Real-Time LBMPs.

In Real Time, virtual sales are treated as injecting zero MW into the grid, and virtual purchases are treated as taking zero MW from the grid. A virtual sale in the Day-Ahead Market at the Day-Ahead price thus carries with it a corresponding obligation to purchase the same number of MWs in Real Time at the Real-Time price and vice versa for Day-Ahead offers to buy. In both cases, the transaction nets to zero in terms of physical energy production or consumption. The same results would apply to a generator that was scheduled Day Ahead but did not perform in Real Time, or a load that was scheduled Day Ahead but did not materialize in

[422] Since Virtual Transactions are not accepted in the Real-Time Markets, they do not play any direct role in the formation of Real-Time prices. Day-Ahead Virtual Transactions could in theory have an indirect role from time to time in the formation of Real-Time prices, to the extent that the unit commitment produced by the SCUC and carried forward into Real-Time might have been different at the margin had virtual transactions not been considered.

Real Time. The NYISO views these results as balancing out of Day-Ahead positions at the applicable Real Time LBMPs[423].

The benefit to the marketplace provided by these transactions is increased liquidity in the energy markets and more efficient commitment of resources than would otherwise occur if participation were limited to physical resources. This has the effect of bringing Day-Ahead and Real-Time prices closer to convergence, which provides improved certainty and stability in energy prices.

2. Price Discovery in the TCC Market

The outcome of the TCC market, by producing market prices for congestion between specified points, provides an opportunity for the discovery of prices relevant to the anticipated average Congestion component of Day-Ahead LBMPs, and by extension of Real-Time LBMPs. Within the TCC market itself, the TCC auction includes multiple auction rounds with a fixed amount of transmission capacity being offered for sale in each round. Each of the multiple TCC auction rounds can provide price information for subsequent rounds.

3. Price Discovery in the Installed Capacity Market

Similarly, in the Installed Capacity Market, prior auctions provide price discovery information for the Spot Auction. In the NYISO Installed Capacity Market, Load Serving Entities ("LSEs") may procure adequate Unforced Capacity from Installed Capacity Suppliers, either bilaterally or through NYISO-administered auctions. The NYISO conducts three types of Installed Capacity auctions: the Capability Period Auction, the Monthly Auction, and the Installed Capacity Spot Market Auction. The Capability Period Auction and the Monthly Auction provide price information for expected Installed Capacity Spot Market Auction Capacity prices.

C. Market Monitoring

Efforts to monitor market manipulation and market power, as described in more detail in Attachment H, *supra,* serve to protect the validity of the price discovery functions of the markets. All NYISO markets, including in relation to TCCs and Virtual Transactions, are subject to surveillance by the NYISO and its Market Monitoring Unit. The NYISO's internal Market Mitigation and Analysis Department and external Market Monitoring Unit monitoring and enforcement prevent market manipulation and disruptive trading practices, as discussed *supra* in Attachment H.

[423] Virtual Transactions affect the bid-based Day-Ahead price determination the same way as physical bids and, at best, have only an indirect effect on Real-Time prices. Offers for physical resources but not virtual resources may be accepted in SCUC reliability runs subsequent to the initial price determination for a given day, but any commitments from those runs are limited to ensuring that reliability requirements are met.

D. Unique Aspects of TCCs and Virtual Transactions that Make Them Less Susceptible to Manipulation

1. Background on TCCs

In New York, energy transactions are frequently impacted by congestion. Congestion occurs when transmission capacity between two points is exhausted, and more expensive power must be dispatched nearer to the location of the demand for the power. The additional energy costs are the result of transmission congestion, and these congestion costs are factored into both NYISO-administered energy market transactions, as a component of energy prices, and bilateral contracts, through a separate transmission usage charge. Congestion costs are factored into each energy transaction in New York.

Market Participants with long-term bilateral energy contracts[424] frequently use TCCs to "lock in" congestion costs. By way of background, bilateral energy contracts can be for any term established by the parties, though these contracts are not traded through NYISO-administered markets. However, bilateral energy contracts are all registered with the NYISO in hourly blocks. In the case of NYISO-administered Day-Ahead and Real-Time energy sales and purchases, as well as Installed Capacity transactions, the NYISO deals directly with sellers and buyers, and those buyers and sellers do not deal directly with each other. By contrast, in the case of bilateral energy contracts, buyers and sellers deal directly with each other with regard to the commercial terms of the transaction, but the energy schedules are registered with the NYISO to be included into the centralized scheduling, commitment, dispatch and settlement of the transmission usage charge.[425]

The NYISO schedules supply-side resources to meet the requirements of bilateral energy transactions simultaneously with energy market demand obligations. Bilateral energy transactions establish a demand side obligation within the markets, but not a supply-side obligation. All supply-side resources are selected within the Security Constrained Unit Commitment total production cost minimization process based upon the offers of those resources. As such, no conflict can emerge between energy transactions scheduled commitments and energy market scheduled commitment.

Long-term power contracts are effectuated in New York through either a scheduled bilateral energy transaction between the seller and the buyer or through an energy transaction in the NYISO market coupled with a Contract-for-Differences. In scheduled bilateral energy transactions, the NYISO is not involved in the energy payment but charges for use of the

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[424] Bilateral energy contracts are contracts for delivery of power under which delivery has been deferred to a future date for commercial convenience. As such they are excluded from the definition of "contract for future delivery" under section 1a(27) of the Commodity Exchange Act, 7 U.S.C. §1 et seq. (the "Act") and from the definition of "swap" under section 1a(47)(B)(ii) of the Act.

[425] In Capacity market transactions, buyers and sellers may deal directly with each other through bilateral transactions, but these must be registered with the NYISO for the LSE to receive credit for procuring Capacity toward fulfillment of its assigned capacity requirement.

transmission system through a Transmission Usage Charge.[426] More specifically, when scheduling an energy bilateral, the Transmission Usage Charge imposes the cost of congestion (if any) on the scheduling entity.

Under a Contract-For-Differences, the energy transaction is in the NYISO-administered energy market with that price "balanced" against the agreed-upon price, outside the NYISO market, by the buyer and the seller. When using a Contract-For-Differences, congestion costs are factored into the energy price set by the NYISO. The use of a TCC enables the holder to "lock in" congestion costs because, after absorbing the initial cost of the TCC, the holder will receive congestion payments to offset the congestion costs that the TCC holder will have to pay in its Transmission Usage Charge (for a bilaterally scheduled energy transaction) or its energy charge (for an energy transaction in the NYISO-administered market). Thus, the TCC holder will in effect substitute a fixed cost for a variable cost.

2. TCCs Are Not Readily Susceptible to Manipulation

As noted in Attachment H, *supra,* the NYISO defines market power, consistent with standard economic theories, as the ability profitably to engage in physical or economic withholding. Unlike the Energy market (including Ancillary Services) and Installed Capacity market in which physical or economic withholding is possible, the TCC market is not susceptible to abuses of market power. The fact that a TCC holder collects Congestion "rent" does not give it the ability to increase or decrease the cost of Congestion. Congestion "rents" are determined based on Energy transactions and the existence of congestion on the New York State power system and are not impacted by any Market Participant's TCC holdings, and the rents provide a reference point for whether TCCs are mispriced. For the same reasons, the value of a TCC is inherently limited by the expected cost of the related congestion.

A unique aspect to TCCs is that they are used primarily to "lock in" congestion costs and thereby hedge against congestion cost variability by purchasing TCCs. This unique congestion cost hedging mechanism served by TCC trading makes the TCC unique from many other commodities and less susceptible to manipulation.

Empirical evidence indicates that the hedging aspect of TCCs, particularly in light of the unique congestion issues in the wholesale electricity markets, makes TCCs less susceptible to manipulation. For example, there is substantial diversity of ownership of TCCs in New York. The following information breaks down the percentage of TCCs allocated to LSEs, Generators and Transmission Owners versus the percentage auctioned to other entities. This information is based on TCCs in effect during June 2011,[427] including grandfathered rights.

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[426] Bilateral energy contracts can be for any term established by the parties, though these contracts are not traded through NYISO-administered markets. However, bilateral energy contracts are all registered with the NYISO in hourly blocks.

[427] The NYISO also examined data for May and November 2010 and January, February and May 2011. The data was comparable to that provided for June 2011.

- Approximately 34% of the TCCs in effect in June 2011 were allocated[428] by the NYISO to Market Participants (primarily, LSEs, Generators, and Transmission Owners) outside of the auction process in accordance with standard NYISO rules. Most of those Market Participants (approximately 61%) were LSEs.[429] This allocation prior to the TCC auction process is part of the standard NYISO rules, and is intended to honor historic transmission agreements.

- Of the remaining TCCs in effect during this period (*i.e.*, obtained through a TCC auction), approximately 46% were held by LSEs, Generators or Transmission Owners in a position to use the TCCs as a hedge against congestion costs, rather than for speculation.

- Notably, in the time period described above, more than forty-five separate entities held TCCs, most of which were traditional "utilities" (*i.e.,* LSEs, Generators or Transmission Owners).

In addition, the TCC auction design prevents any one Market Participant from obtaining large TCC positions at one time. TCCs are sold by auction, the design of which includes multiple auction rounds with a fixed amount of transmission capacity being offered for sale in each round. The multi-round process minimizes the opportunity for one party to buy a large quantity of TCCs all at one time.

3. <u>Virtual Transactions Are Not Readily Susceptible to Manipulation</u>

Virtual Transactions are not readily susceptible to being used as a means of manipulating the price in the physical spot market because Virtual Transactions only indirectly affect the Real-Time market via potential changes in the commitment patterns of physical supply.

Moreover, unlike traditional derivatives,[430] Virtual Transactions are not mechanisms for transferring risk from one party to another, but rather involve corresponding transactions in the Day-Ahead and Real-Time Markets. These transactions are determined separately from each other, and one is not a derivative of the other. The price at which a Virtual Transaction is settled is therefore not a derivative of the value of an underlying commodity; it *is* the value of the underlying commodity – Energy in the NYISO Real-Time Market. In that sense, a Virtual Transaction is no different than a physical spot market transaction and is substantially different from traditional derivatives, including futures, option and swaps.

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[428] As used herein, the NYISO term "allocation" in the TCC context includes rights obtained by conversion of rights associated with existing transmission agreements.

[429] Participation in TCC auctions is not restricted to LSEs. Any entity that satisfies the NYISO's registration and eligibility requirements can participate in the TCC auctions.

[430] As the NYISO understands the definition of "derivative," it is primarily a financial instrument that serves as a risk transfer agreement, the value of which is derived from the value of an underlying commodity or index or tradable instrument. As such, derivatives minimize risk for one party while offering the potential for a high return (at increased risk) to another. Among the specific types of derivatives are futures, options and swaps.

Attachment U—SEF Core Principle 3: Swaps Not Readily Susceptible to Manipulation

Unlike futures contracts, Virtual Transactions are, in effect, offers to buy or sell a one-day forward physical contract that is financially settled in the Real-Time Market.[431] Day-Ahead LBMPs set the market prices for an obligation to deliver or receive electric energy the next day. That obligation cannot be satisfied prior to maturity, or re-traded. In addition, as far as the NYISO markets are concerned, these Virtual Transactions are not exchange-traded, and are not used for assumption or shifting price risk between parties.

Similarly, Virtual Transactions are not options. Virtual Transactions do not give the buyer or the seller an option as to the Day-Ahead and Real-Time settlements and obligations described above. Once a Virtual Transaction is scheduled in the Day-Ahead Market, neither the seller nor the buyer has any option to exercise or not exercise their buy/sell obligation. Rather, virtual traders receive settlements for their Day-Ahead positions at the applicable Day-Ahead prices, and are obligated to settle any deviations in Real-Time from their Day-Ahead positions at the applicable Real-Time prices. There is no option as to whether to balance a Day-Ahead position out in Real-Time.

Finally, unlike swaps, Virtual Transactions do not involve separate parties exchanging payment streams, assets or liabilities. Rather, each trader is in effect taking a position in the Day-Ahead Market based on its anticipation of changes in the market prices applicable to its own corresponding position as a buyer or seller the next day in the Real-Time Market.

[431] Physical forward contracts are not traded in the Day-Ahead and Real-Time Markets. Schedules in the Day-Ahead Market are financially binding whether from Virtual Transactions or from transactions associated with physical resources and loads.

Attachment U—SEF Core Principle 3: Swaps Not Readily Susceptible to Manipulation

PJM

PJM's trading rules are comparable to the requirements of SEF Core Principle 3. The PJM OA Schedule 1 Section 7 contains detailed rules for issuing, allocating, and auctioning FTRs. PJM further defines the rules for FTRs in its Financial Transmission Rights Business Practice Manual (PJM Manual 6). Additionally, as set forth in Attachment M of the PJM Tariff, PJM's independent MMU evaluates, monitors and advices PJM on issues of market structure and design. See discussion below, PJM's response to SEF Core Principle 4. The PJM Market Implementation Committee also advises PJM on issues related to competition in the PJM markets.

Attachment V

SEF Core Principle 4: Monitoring of Trading and Trade Processing

The swap execution facility shall—

(A) establish and enforce rules or terms and conditions defining, or specifications detailing—

(i) trading procedures to be used in entering and executing orders traded on or through the facilities of the swap execution facility; and

(ii) procedures for trade processing of swaps on or through the facilities of the swap execution facility; and

(B) monitor trading in swaps to prevent manipulation, price distortion, and disruptions of the delivery or cash settlement process through surveillance, compliance, and disciplinary practices and procedures, including methods for conducting real-time monitoring of trading and comprehensive and accurate trade reconstructions.

Responses:

Attachment V—SEF Core Principle 4: Monitoring of Trading and Trade Processing

California ISO

Section 27 of the CAISO Tariff describes the procedures and markets that are collectively referred to as CAISO Markets Processes. This tariff section, among other things, describes the pricing of transactions and the CAISO market model. Rules governing the various transactions that occur on the CAISO markets are detailed in the CAISO Tariff in sections 28 (Inter-SC Trades), 30 (Bid And Self-Schedule Submissions For All CAISO Markets), 31 (Day-Ahead Market), 33 (Hour-Ahead Scheduling Process (HASP)), 34 (Real-Time Market), 35 (Market Validation and Price Correction), and 36 (Congestion Revenue Rights). The CAISO has also implemented a Business Practice Manual for Market Operations and a Business Practice Manual for Market Instruments. Together, these two manuals describe the rules, design, and operational elements of the CAISO markets.[432] These manuals detail the processing of transactions in the day-ahead and real-time markets.[433] The CAISO also provides market participants with documentation for using the CAISO market systems.[434]

As discussed in Attachment H, the Department of Market Monitoring monitors the CAISO markets to identify any manipulative behavior and any flaws in the design or operation of the markets. DMM has a variety of metrics that it reviews to detect potential manipulative conduct. These include:

- Excessive or sustained virtual bidding losses by an individual participant not consistent with more general market trends;
- Excessive or sustained virtual bidding profits by an individual participant not consistent with more general market trends;
- Accepted virtual bids by a participant that have a significant impact on an individual transmission constraint (*e.g.*, greater than 10% of total flow);
- Accepted virtual bids by a participant that have a significant impact on individual transmission constraints that would increase the participant's revenues from CRRs; and
- Accepted virtual demand bids by a participant that may have the effect of decreasing the effectiveness of the ISO's automated local market power mitigation mechanism in the day-ahead market.

Any anomalous behavior detected by these metrics is reviewed in more detail by an analyst. DMM may contact a market participant for an explanation of any behavior that appears anomalous or manipulative. If, based on this investigation, DMM believes a participant may have violated rules prohibiting false or misleading information and market manipulation, the matter is referred to the FERC.

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[432] CAISO Business Practice Manuals *available at* https://bpm.caiso.com/bpm/bpm/list.

[433] *Id*. at pp. 19-25.

[434] Information about system access and documentation is *available at* http://www.caiso.com/271f/271fcbd45ca60.html.

DMM also monitors overall market results and behavior that may not violate these market rules, but may be detrimental to market efficiency or may indicate flaws in market rules or processes. This type of behavior is not specifically identified in advance but a recent example of such behavior was detected by monitoring the virtual bidding of a market participant that consistently submitted offsetting virtual supply and demand bids up to position limits at a large number of nodes in a specific area of the grid. These bids earned a small profit due to systematic differences in the transmission loss component of prices at these nodes. DMM referred this issue to market operations staff, who determined that these price differences were due to a modeling error in the market software.

DMM has the ability to re-run the day-ahead and real-time market software using modified bidding inputs. DMM has used this capability in a variety of investigations, but has not yet used it to analyze the impact of an individual participant's virtual bids. The software cannot re-run the market and accurately replicate market results for all days because the market software is continually modified over time. These modifications can sometimes prevent DMM from being able to re-run the software using market inputs for a day in the past and accurately replicate market results. In addition, re-running the software is relatively labor and time intensive.

For these reasons, the metrics described above are designed to identify bidding by individual participants that may have a significant impact on day-ahead price (*e.g.*, by first calculating the impact of the participant's portfolio of accepted virtual bids on the flows on individual constraints, and then calculating the impact of congestion these constraints on overall prices). If this analysis indicates that an individual participant's bids had a significant impact on prices, further analysis would be done by re-running the market software to quantify the impact of bidding on prices.

DMM employs a set of metrics to monitor the interaction of virtual bids with CRRs. The basic approach is based on a settlement rule developed to automatically rescind CRR payments (or create additional charges) if a participant's virtual bids are determined to have increased price divergence in a way that increases the participant's profits from CRRs.[435]

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[435] A description of this approach can be found in a whitepaper prepared by DMM and *available at* http://www.caiso.com/2429/24291027c1fb50.pdf.

Attachment V—SEF Core Principle 4: Monitoring of Trading and Trade Processing

ERCOT

The ERCOT Protocols provides extensive rules regarding transactions in the ERCOT markets, consistent with Core Principle 4. ERCOT monitors compliance with its rules in its day-to-day function as the market administrator. Further, the IMM monitors market behavior in the ERCOT markets. By law, the IMM has complete access to ERCOT systems, data and information to enable it to perform market monitoring functions consistent with SEF Core Principle 4. The IMM has complete visibility into all ERCOT market activity. ERCOT is obligated by law to support and cooperate with the IMM, including providing access to all ERCOT systems, data and information. In addition to the annual and other standard periodic reports and analysis conducted by the IMM, the IMM monitors continuously based on standard review of data and any *ad hoc* scenarios that arise, whether identification of such is by the IMM on its own, or is brought to the attention of the IMM by ERCOT or any other entity. As the ISO, ERCOT looks at market activity in the course of performing its market, operational, and planning activities. Any potentially suspicious market activity identified by ERCOT would be brought to the attention of the IMM and the PUCT as necessary. The PUCT is the enforcement authority in the ERCOT regions, and also performs the oversight function in concert with ERCOT and the IMM.

The monitoring and enforcement roles of ERCOT, the IMM and the PUCT are discussed in Attachment H, and the response to that attachment is incorporated herein by reference. In addition, the ERCOT and IMM reports, public information rules and posting of public information rules also provide transparency to market outcomes that facilitate monitoring the efficiency and behavior in the markets. These matters are discussed in response to DCO Core principles J, L and M.

Attachment V—SEF Core Principle 4: Monitoring of Trading and Trade Processing

ISO New England

ISO-NE has established adequate trading procedures and monitors trades to prevent manipulation, price distortion, and disruptions of the delivery or cash settlement process through surveillance, compliance, and disciplinary practices and procedures, including methods for conducting real-time monitoring of trading and comprehensive and accurate trade reconstructions.

For instance, rules for issuing, allocating, settling and auctioning FTRs are set forth in Sections III.5.2 and III.7 of the ISO-NE Tariff. FTR collateral requirements are based upon the 75% (annual FTRs) and 95% (monthly FTRs) confidence interval of observed monthly results. Requirements are calculated on a path by path basis with no accounting for correlations or portfolio benefits. This approach produces margin requirements that are even more conservative then the confidence intervals may initially suggest. Examples of the calculation methodology can be found in the PowerPoint presentation available at http://www.isone.com/stlmnts/assur_crdt/misc/ftr_%20fa_calc_examples.ppt.

While not necessarily constituting market manipulation, Market Participants have sometimes utilized virtual transactions to take advantage of modeling differences between the Day-Ahead and Real-Time Energy Markets. That is, in a few instances, Market Participants obtained financial benefit by submitting virtual transactions at locations with predictable day-ahead to real-time price differences caused by differences in the way physical transmission network constraints were modeled in the two markets. The ISO's Internal Market Monitor ("IMM") investigated the behavior and recommended that the ISO remedy this issue by aligning the physical transmission network model used to clear each market.

As noted above, IMM monitors compare the deviations between day-ahead and real-time locational marginal prices to determine if there is a persistent difference that would not be expected in a workably competitive market and calculate a rolling average locational marginal price deviation value. *See* Section III.A.8 of the ISO Tariff. Depending on the amount of the rolling average deviation, the IMM is required to investigate whether and to what extent the actions of one or more Market Participants are contributing to the price deviation. If a Market Participant is found to have contributed, through its virtual transactions, to an unwarranted deviation in the day-ahead and real-time prices at a node, the IMM may restrict that Market Participant's ability to submit virtual bids or offers for up to six months. In addition, per Section III.A.14 of the ISO Tariff, if the Market Participant's activities constitute a "Market Violation," the IMM would refer the Market Participant to the FERC.

Also, the IMM reviews the activity of Market Participants taking virtual positions weekly, analyzing the profitability of virtual positions and the distribution of those virtual positions as well as other market positions taken by those Market Participants in order to ascertain, for example, whether their virtual transactions are used principally to hedge physical positions or are arbitrage/speculative in nature. The IMM also relies on information from the ISO's system operators and market operations and settlements departments regarding perceived anomalous behavior in order to monitor the marketplace for trends and "outliers." The IMM may also notify the ISO if any changes to market rules, models or procedures are needed or advisable to prevent manipulative conduct as well as computes the degree of price convergence daily, and provides monthly reports on price convergence to the Markets Committee of the ISO-NE Board of Directors.

Also see the discussions of ISO-NE's compliance with DCO Core Principle H and SEF Core Principle 2.

Attachment V—SEF Core Principle 4: Monitoring of Trading and Trade Processing

MISO

Part IV of Module C of the MISO Tariff, Sections 42 – 46 provide detailed rules for FTRs and ARRs. In addition, MISO's Independent Market Monitor is responsible for reviewing market participant behavior with respect to FTRs, the ARR auction and related transactions.

Attachment V—SEF Core Principle 4: Monitoring of Trading and Trade Processing

New York ISO

A. Establishment and Maintenance of Trading Procedures

The NYISO establishes the rules and procedures for the trading procedures for Energy, Virtual Transactions, Capacity, and TCCs through its governance process, as described in the NYISO's responses in Attachments O and R. The NYISO maintains on its public website copies of its tariffs, manuals, and technical bulletins describing all rules and procedures applicable to NYISO Market Participants, including those engaged in TCC transactions and Virtual Transactions. These documents specifically include detailed procedures for trading in the NYISO's TCC markets and engaging in Virtual Transactions.

B. Procedures for Energy and Virtual Transactions

In New York, energy is bought and sold through both the NYISO-administered energy markets and outside the NYISO markets through bilateral energy contracts. However, all energy, regardless of how it is bought and sold, is scheduled through the NYISO-administered energy markets. Bids and offers made in the NYISO-administered markets are settled through the NYISO at prices set based on a locational market clearing price. In contrast, energy prices for bilateral energy contracts are set on a negotiated basis by the buyer and seller and financial settlement is made outside the NYISO, though the bilateral transactions must be registered with the NYISO for purposes of physical scheduling, commitment, dispatch, settlement and related operational activities.

Physical bids and offers and virtual bids and offers both occur within the NYISO-administered markets. Bids in the Day-Ahead Market are due by 5:00 a.m. the day ahead of the scheduled transaction. Bilateral energy contracts must also be registered with the NYISO by 5:00 a.m. the day ahead of the scheduled transaction. Once received, the physical bids, virtual bids, and bilateral energy contracts are processed (together with other types of bids, such as for reserves, regulation, and demand response) using the NYISO's Security Constrained Unit Commitment ("SCUC") process.

SCUC is the Day-Ahead Market software through which the NYISO evaluates load forecasts, considers offers to supply energy (including offers to supply energy in Virtual Transactions), offers to supply Ancillary Services, requests for bilateral transaction schedules, bids to purchase energy (including bids to purchase energy in Virtual Transactions) and Demand Reduction bids. SCUC prepares a generation schedule for the following day through the operation of a computer algorithm that minimizes the total bid production cost of energy while observing various operational parameters. Through the SCUC system, the NYISO arrives at the lowest-cost solution for scheduling all bilateral energy contracts, supplying sufficient power to satisfy purchasers' bids in the Day-Ahead Market, and meeting other requirements necessary to reliably operate the power system. The SCUC works through a number of "passes" to arrive at the optimal solution for each hour of the Day-Ahead Market.

In the initial SCUC computer pass, which determines the least-cost economic dispatch and the resulting locational marginal prices ("LBMPs"), the dispatch simulation evaluates

Virtual Transactions on the same basis as physical bids and offers. This initial pass commits and schedules generation, transactions with neighboring Control Areas, Physical Bids, and Virtual Bids simultaneously in the Unit Commitment (linear program) module. This pass also evaluates for potential application of market mitigation measures and commits resources required to meet local system reliability.[436]

Subsequent SCUC passes evaluate whether additional physical resources need to be committed (*i.e.,* whether the NYISO needs to direct such resources to be ready to operate or to operate at minimum output) to reliably meet NYISO forecasted load conditions. As SCUC determines the need to commit additional generators to meet NYISO forecasted load, it performs redispatches as necessary to produce the final Day-Ahead Market prices and schedules. Because Virtual Transactions are not backed by physical resources, they are not considered in these subsequent passes to determine unit commitments needed for reliability.[437]

The NYISO uses a similar process for the Real-Time Market, which operates as a balancing market to meet real-time demand for energy, to dispatch generators, and to set real-time prices based on the optimal real-time solution. Virtual bids and offers are entered only in the Day-Ahead Market, not in the Real-Time Market.

C. Procedures for Installed Capacity

Capacity contracts administered through the separate NYISO Installed Capacity Market relate to the *capability* of an electrical generating facility to produce power. Capacity contracts are not considered at the same time as, or through the same systems used for, physical bids, virtual bids, and bilateral energy contracts. All Installed Capacity Suppliers are obligated to provide “physical” bids into the Day-Ahead market and to provide notice of all planned, maintenance, and forced outages that limit their ability to submit bids. LSEs may procure adequate Unforced Capacity from Installed Capacity Suppliers, either bilaterally or through NYISO-administered auctions, to meet their requirements.

The NYISO conducts three types of Installed Capacity auctions: the Capability Period Auction, the Monthly Auction, and the Installed Capacity Spot Market Auction. LSEs may use Unforced Capacity procured in the Installed Capacity auctions to meet their respective LSE Unforced Capacity Obligations for the applicable Obligation Procurement Period. Participation in the Monthly Auction and the Capability Period Auction consists of the following parties: (i) LSEs seeking to purchase Unforced Capacity; (ii) any other entity seeking to purchase Unforced Capacity; (iii) qualified Installed Capacity Suppliers; and (iv) any other entity that owns excess Unforced Capacity. Participation in the Installed Capacity Spot Market Auction consists of all LSEs and any other entity that has an Unforced Capacity shortfall.

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[436] Unlike in the TCC markets, unit capacity does not act as a constraint with regard to Virtual Transactions. Day-Ahead Market software simultaneously evaluates physical bids and offers along with virtual bids and offers to develop a feasible solution through the SCUC and dispatch process.

[437] Even if the Day-Ahead Market were limited to physical bids and offers, the resulting commitment might not meet all reliability requirements experienced in real-time operation.

D. Procedures for Transmission Congestion Contracts

A Transmission Congestion Contract represents the right to collect, or the obligation to pay, the Day-Ahead Market congestion rents associated with 1-Megawatt of transmission between a specified Point of Injection and specified Point of Withdrawal. The Day-Ahead Market congestion rents are determined by the difference in the congestion component of the Day-Ahead Market LBMP at the Point of Withdrawal of the TCC and the congestion component of the Day-Ahead Market LBMP at the Point of Injection of the TCC, for each hour of the effective period. Payments to Primary Holders of TCCs are primarily funded through congestion rents collected in the Day-Ahead Market. Congestion rents are collected by the NYISO from energy buyers and transmissions system users when the congestion components of LBMPs differ between locations where energy is purchased versus locations where energy is supplied.

Auctions are the NYISO's primary means of allocating and pricing TCCs. Normally, the NYISO conducts two Centralized TCC Auctions, one in the Spring and one in the Fall, prior to the beginning of the Summer and Winter Capability periods. The NYISO also conducts monthly Reconfiguration Auctions in which TCCs with a duration of one month are sold. Each Centralized TCC Auction consists of a series of sub-auctions in which TCCs of a single duration are sold. Each sub-auction may have multiple rounds. Each round takes one week to complete. Auction participants submit their bids/offers on the first day of the auction period (typically a Friday). The results are posted to a secure location on the NYISO's website that is accessible to the auction participant on the last day of the auction period (typically the following Thursday). Each monthly Reconfiguration Auction consists of a single round that requires approximately one week to complete.

E. Market Monitoring

The NYISO's significant measures to monitor its markets and promote competition, as described in Attachments H and U, *supra*, provide for monitoring of TCC transactions and Virtual Transactions.

Attachment V—SEF Core Principle 4: Monitoring of Trading and Trade Processing

PJM

PJM's tariff and other governing documents provide rules and procedures comparable to the requirements of SEF Core Principle 7. The PJM OA Schedule 1 Section 7 contains detailed rules for issuing, allocating, and auctioning FTRs. PJM further defines the rules for FTRs in its Financial Transmission Rights Business Practice Manual (PJM Manual 6).

As described above, Attachment M of the PJM Tariff grants the MMU broad authority to screen and monitor the conduct of all Market Participants under the MMU's purview to monitor, investigate, evaluate and report on the PJM Markets. The MMU has direct, confidential access to the FERC. The MMU may also refer matters to the attention of State commissions.

When the MMU detects market activity that is inconsistent with market rules or may constitute the actual or potential exercise of market power, the MMU performs targeted analysis including counter factual simulation. Where there is indication of a potential issue, the participant is contacted to discuss their view of the activity. Where this does not resolve the issue, the MMU can propose rule changes to address the issue, refer design flaws to the FERC on a confidential basis, file for a rule change with FERC, inform FERC staff and discuss next steps and/or refer the participant to FERC.

Attachment W

SEF Core Principle 5: Ability to Obtain Information

The swap execution facility shall—

(A) establish and enforce rules that will allow the facility to obtain any necessary information to perform any of the functions described in this section;

(B) provide the information to the Commission on request; and

(C) have the capacity to carry out such international information-sharing agreements as the Commission may require.

Responses:

Attachment W—SEF Core Principle 5: Ability to Obtain Information

California ISO

As provided by the CAISO "Rules of Conduct," market participants are required to submit information requested by the CAISO that is reasonably necessary for the CAISO's conduct of an investigation.[438] Market participants must also comply with the CAISO's audit and testing procedures.[439]

[438] CAISO Tariff, § 37.6.2.1.

[439] *Id.*, § 37.6.3.1.

Attachment W—SEF Core Principle 5: Ability to Obtain Information

ERCOT

ERCOT's reporting and information-sharing procedures are consistent with SEF Core Principle 5. The ERCOT market construct has comprehensive rules that give ERCOT, the IMM and the PUCT the ability to access all information/data necessary to perform their respective roles in the operation, oversight and enforcement of the ERCOT market. This information can be accessed on an *ad hoc* basis as necessary, via the information made public pursuant to the relevant public disclosure rules and reports and/or through oversight and enforcement activities. These issues were discussed in response to DCO Core Principles M, L, J and H. Accordingly, the responses to those Attachments are incorporated herein by reference.

Attachment W—SEF Core Principle 5: Ability to Obtain Information

ISO New England

ISO-NE establishes and enforces rules to allow it to obtain any necessary information to perform any of its functions and provide that information, when necessary, to the appropriate regulatory authorities. *See* Section I.3.5 of the ISO-NE Tariff, which requires participants to share information deemed necessary by ISO-NE. The Information Policy, which is Attachment D to the ISO-NE Tariff, explicitly states that ISO-NE will provide FERC with any requested confidential information.[440] *See also* the discussion of DCO Core Principle M.

440 *See* ISO-NE Tariff, Attachment D, § 3.2, *available at* http://www.iso-ne.com/regulatory/tariff/attach_d/attachment-d.pdf.

Attachment W—SEF Core Principle 5: Ability to Obtain Information

MISO

See response to Attachments J and M above.

Attachment W—SEF Core Principle 5: Ability to Obtain Information

New York ISO

The NYISO has the authority under Services Tariff Section 10 to verify settlements and compliance with the terms of the NYISO's tariffs. In addition, Services Tariff Section 30.6 gives the NYISO and its Market Monitoring Unit broad authority to obtain from Market Participants information necessary for market monitoring and evaluation. Additional details regarding the NYISO's ability to obtain information and information sharing procedures is discussed in *Attachments* H and M, *supra.*

Attachment W—SEF Core Principle 5: Ability to Obtain Information

PJM

PJM's reporting and information-sharing rules are comparable to the requirements of SEF Core Principle 5. The PJM Tariff and Operating Agreement contain provisions requiring market participants to provide information to PJM.[441] In turn, PJM provides the MMU with information to facilitate effective market oversight.[442] Furthermore, as noted above, PJM shares market and member information with various regulatory entities, including FERC.[443]

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441 *See, e.g.*, PJM OA, Sections 11.3.1 and 11.3.4 ("Each Member shall report as promptly as possible to the Office of the Interconnection any changes in its operating practices and procedures relating to the reliability of the bulk power supply facilities of the PJM Region."); Schedule 1, Section 1.5 ("The applicant shall furnish all information reasonably requested by the Office of the Interconnection in order to determine the applicant's qualification to be a Market Buyer."); Schedule 1, Section 1.7.4 ("All Market Participants shall provide to the Office of the Interconnection the scheduling and other information specified in the Schedules to this Agreement, and such other information as the Office of the Interconnection may reasonably require for the reliable and efficient operation of the PJM Region and PJM Interchange Energy Market, and for compliance with applicable regulatory requirements for posting market and related information. Such information shall be provided as much in advance as possible, but in no event later than the deadlines established by the Schedules to this Agreement, or by the Office of the Interconnection in conformance with such Schedules. Such information shall include, but not be limited to, maintenance and other anticipated outages of generation or transmission facilities, scheduling and related information on bilateral transactions and self-scheduled resources, and implementation of active load management, interruption of load, and other load reduction measures."); Schedule 1, Section 1.9.5 ("Each Market Participant making a bilateral sale covering a period greater than the following Operating Day from a generating resource located within the PJM Region for delivery outside the PJM Region shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered."); Schedule 1, Section 1.9.6 ("Each Internal Market Buyer making a bilateral purchase covering a period greater than the following Operating Day shall furnish to the Office of the Interconnection, in the form and manner specified in the PJM Manuals, information regarding the source of the energy, the load sink, the energy schedule, and the amount of energy being delivered. Each Internal Market Buyer shall provide the Office of the Interconnection with details of any load management agreements with customers that allow the Office of the Interconnection to reduce load under specified circumstances."); Schedule 1, Section 1.9.7 ("Not less than 30 days before a Market Seller's initial offer to sell energy from a given generation resource on the PJM Interchange Energy Market, the Market Seller shall furnish to the Office of the Interconnection the information specified in the Offer Data for new generation resources."); PJM Tariff, Attachment Q ("Each Participant must submit with its application audited financial statements for the most recent fiscal quarter, as well as the most recent three fiscal years, or the period of existence of the Participant, if shorter.").

442 PJM OA, Section 18.17.5; *see also* PJM Tariff, Attachment M, Sections V.A, V.B, and V.D.

443 PJM OA, Section 18.17.3; *see also* PJM OA, Section 18.17.4

Attachment X

SEF Core Principle 6: Position Limits or Accountability

(A) IN GENERAL.—To reduce the potential threat of market manipulation or congestion, especially during trading in the delivery month, a swap execution facility that is a trading facility shall adopt for each of the contracts of the facility, as is necessary and appropriate, position limitations or position accountability for speculators.

(B) POSITION LIMITS.—For any contract that is subject to a position limitation established by the Commission pursuant to section 4a(a), the swap execution facility shall—

(i) set its position limitation at a level no higher than the Commission limitation; and

(ii) monitor positions established on or through the swap execution facility for compliance with the limit set by the Commission and the limit, if any, set by the swap execution facility.

Responses:

Attachment X—SEF Core Principle 6: Position Limits or Accountability

California ISO

The provisions in Section 30.7 of the CAISO Tariff that govern CAISO's convergence bidding include temporary position limits.[444] For example, the position limit on a node associated with a generator is a percentage of the maximum output capability of the generator and, for a node associated with demand, a percentage of the maximum flow over that node.

The CAISO does not impose position limits for CRRs but has implemented alternative means to prevent undue concentration of large positions with one or a few market participants. First, a simultaneous feasibility requirement limits the overall amount of CRRs that can be created.[445] CRRs function as intended only if there is enough congestion revenue to pay the holders of transmission rights. This will be the case during a given time period only if the total amount of CRRs is limited to corresponding energy schedules that are "simultaneously feasible" on the transmission system; *i.e.*, energy schedules that can physically flow on the grid without violating any transmission constraints. The CAISO tariff limits the issuance of CRRs accordingly. Second, the allocation process for CRRs provides that they will be allocated to numerous market participants that are load serving entities resulting in dispersed ownership among market participants that are not strictly financial market participants.[446]

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[444] CAISO Tariff, §§ 30.7.3.6.3.

[445] *Id*., § 36.4.2.

[446] *Id*, §§ 36.8 – 36.11.

Attachment X—SEF Core Principle 6: Position Limits or Accountability

ERCOT

Generally speaking, ERCOT does not set explicit position limits with respect to the market products that are subject to this exemption request. However, practically speaking, ERCOT's rules and market structure are comparable to the requirements of SEF Core Principle 6. For the DAM and CRR markets, market participation is limited relative to a Market Participant's credit limits, such that an entity is only allowed to take positions it can cover from a credit perspective, which, as discussed in detail in the context of the DCO Core Principles, require credit equal to 100% of market exposure.[447]

In addition, CRRs are also subject to a maximum of 10,000 CRR positions; in other words, a market participant cannot have more than 10,000 CRRs despite its ability to post credit to cover more than that amount.[448]

Market participants are required by Protocols to operate within their credit limits, and these limits are systematically enforced by both the DAM and CRR systems. DAM credit is allocated and enforced from the entity's existing Available Credit Limit and cannot be exceeded.[449] Similarly the CRR Credit is allocated and potentially reduced by the entity and enforced in the CRR systems.[450] Additionally, ERCOT monitors market positions and related exposure daily, including calculating mark-to-market values on all CRR positions held, and sends collateral requests as needed to ensure that all positions are adequately collateralized.

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[447] Please refer to DCO Core Principle discussion above for detailed discussion of ERCOT credit requirements and how those rules limit market participation and associated risk.

[448] ERCOT Protocol Section 7.5.2(2)(b).

[449] ERCOT Protocol Section 4.4.10.

[450] ERCOT Protocol Section 7.5.5.1.

Attachment X—SEF Core Principle 6: Position Limits or Accountability

ISO New England

ISO-NE does not set explicit position limits per se, but does establish financial assurance requirements based on a participant's position and bids.

To create accountability, the IMM relies on information from the ISO's system operators and market operations and settlements departments regarding perceived anomalous behavior. The purpose of this analysis is to monitor the marketplace for trends and "outliers." Should the IMM identify a trend (*e.g*., a Market Participant taking consistently unprofitable positions) or an outlier (*e.g.,* a sudden change in a Market Participant's bidding behavior), the IMM contacts the Market Participant to discuss the identified behavior. Absent a satisfactory explanation, the IMM will open an investigation and may refer the Market Participant to the FERC for consideration of whether a violation has occurred. The IMM may also notify the ISO if any changes to market rules, models or procedures are needed or advisable to prevent manipulative conduct.

With specific reference to FTRs, see Section III.7 of the ISO-NE Tariff, which sets forth FTR Auction rules regarding power flow models and simultaneous feasibility that in effect limit the FTRs available for purchase and/or sale in the FTR Auction. As set forth in Section III.A.8.4 of the Tariff, the internal market monitor may mitigate FTR positions if participants take virtual positions that inappropriately influence their FTR returns.

Regarding virtuals, the IMM analyzes the profitability of virtual positions and the distribution of those virtual positions (nodal, zonal, hub). It also analyzes the other market positions taken by those Market Participants in order to ascertain, for example, whether their virtual transactions are used principally to hedge physical positions or are arbitrage/speculative in nature.

Please also review, in this document, the discussions of DCO Core Principle H and SEF Core Principle 2, among others, for a description of the role that market monitors play in ensuring compliance with the rules of the wholesale electricity market.

Attachment X—SEF Core Principle 6: Position Limits or Accountability

MISO

Section III of Attachment L to the Tariff provides specific rules for virtual transactions and FTRs. Market participants submitting virtual transactions must submit a proposed virtual MWh limit ("Virtual Limit") to MISO, which is then evaluated to determine the impact of the Virtual Limit on the market participant's non-FTR potential exposure. If the proposed Virtual Limit will cause the market participant's non-FTR potential exposure to equal or exceed its non-FTR total credit limit, the Virtual Limit is rejected. In addition, MISO has the right to reject virtual bids and offers of a market participant if the virtual bids and/or offers exceed the Virtual Limit for the operating day.

ARRs have position limit rules based on historical rights and peak load. FTRs do not have position limit rules but are positions are limited based on the level of financial security allocated to the FTR Auction Credit Allocation. If bid exposure exceeds the FTR Auction Credit Allocation then the set of bids will be rejected. MISO limits ARRs to a Load Serving Entity's peak load, simultaneous feasibility test (SFT) and available system capability in the annual ARR Allocation process. FTRs are limited by the available system capability and SFT in the FTR Auctions. The allocation and auction process provides that a number of entities will be holders of the instruments; thus have alternative protections against large concentrations by one or a few holders. See Sections 43, 44 and 45 of the MISO Tariff.

Attachment X—SEF Core Principle 6: Position Limits or Accountability

New York ISO

In general, the NYISO relies upon credit requirements and both internal and external monitoring and enforcement (discussed in Attachment U, *supra*) to prevent market manipulation and disruptive trading practices.

NYISO rules do not set explicit position limits, however, with regard to TCCs there are several unique aspects to this market that make it less susceptible to manipulation, discussed in Attachment U, *supra*. One of those characteristics is the inherent market design limitations that the TCC market that prevent a single Market Participant from holding all or substantially all of the TCCs available for a given period. A substantial number of TCCs are allocated outside of the auction process and are not available for purchase by speculators. Auction results over the history of the NYISO have indicated that these features of the TCC auction process prevents a single buyer or a small number of buyers from holding all or substantially all of the TCCs available for a given period. The TCC auction design minimizes any one Market Participant from obtaining large TCC positions at one time. TCCs are sold by auction, the design of which includes multiple auction rounds with a fixed amount of transmission capacity being offered for sale in each round. The multi-round process minimizes the opportunity for one party to buy a large quantity of TCCs all at one time.

Attachment X—SEF Core Principle 6: Position Limits or Accountability

PJM

PJM's ARR rules do not impose expressly enumerated position limits on market participants. Instead, PJM uses a simultaneous feasibility test to limit the total number of ARRs available for allocation in an individual auction. Additionally, PJM grants ARRs to many different entities through its allocation process. In the first stage of the FTR allocation process, ARRs are allocated to LSEs in proportion to the amount of load each LSE serves. Speculators and other market participants cannot participate in the ARR allocation process. Prior to the first FTR auction, ARRs can be converted into FTRs by LSEs seeking to hedge their congestion risk. This conversion process reduces the quantity of FTRs available for auction to other market participants, and, as a result, prevents any LSE (or speculator) from acquiring an excessive share of FTRs. PJM's allocation rules sufficiently protect against one or a few holders gaining large concentrations of ARRs. Finally, the MMU monitors the PJM markets to ensure market participants do not engage in manipulative conduct.

Attachment Y

SEF Core Principle 7: Financial Integrity of Transactions

The swap execution facility shall establish and enforce rules and procedures for ensuring the financial integrity of swaps entered on or through the facilities of the swap execution facility, including the clearance and settlement of the swaps pursuant to section 2(h)(1).

Responses:

Attachment Y—SEF Core Principle 7: Financial Integrity of Transactions

California ISO

See Attachment D (Risk Management).

Attachment Y—SEF Core Principle 7: Financial Integrity of Transactions

ERCOT

ERCOT's minimum financial requirements are comparable to the requirements of SEF Core Principle 7.

ERCOT rules impose stringent credit obligations and appropriate settlement procedures for transactions in the ERCOT markets. These rules were discussed in response to DCO Core Principles D and E, and those responses are incorporated herein by reference.

Additionally, through its stakeholder process, ERCOT is in the process of developing new market participant eligibility requirements that are comparable to those required by FERC Order 741. Proposed eligibility requirements specify that Counter-Parties must meet minimum capitalization requirements.

Counter-Parties will be required to provide an annual certification that they have met these requirements, attested by an officer of the company.

Proposed capitalization requirements are higher for Counter-Parties transacting or wishing to transact in CRR markets. Counter-Parties who fail to meet the capitalization requirements would be required to post an "Independent Amount" in addition to any collateral posted with respect to market positions.[451]

In addition to the proposed capitalization requirements, an entity's participation in the ERCOT market is effectively limited under the current rules by:

- Requiring collateral for 100% of estimated exposure subject to any approved unsecured credit.[452] Exposure is updated daily.
- Enforcing a credit limit within the CRR Auction and for Day Ahead Market transactions based on unsecured credit allowed or collateral posted in excess of what is required per the daily exposure requirement.[453]

In addition, Retail Electric Providers ("REPs") must demonstrate and maintain certain financial requirements, including an investment-grade credit rating, a tangible net worth greater than or equal to $100 million, and shareholders' equity of not less than one million dollars.[454]

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451 Nodal Protocol Revision Request 438, which will add a Protocol Section 16.16.

452 ERCOT Protocol Section 16.11.1.

453 ERCOT Protocol Sections 16.11.4.6, 16.11.4.6.1, and 16.11.4.6.2.

454 *See also* Attachment D—DCO Core Principle D: Risk Management, above.

Attachment Y—SEF Core Principle 7: Financial Integrity of Transactions

ISO New England

ISO-NE has established and enforces rules and procedures for ensuring the financial integrity of transactions entered on or through its markets.

A participant's exposure is calculated throughout the day. Collateral updates are made continuously throughout the business day. New settlements are factored in twice a day, allowing actual results to replace the forecast of forward risk. A customer's financial assurance requirements are monitored in-between auctions. As auction awards are settled, these new settlements are factored into the customer's financial assurance position.

For instance, ISO-NE does not use engineering or similar events to evaluate the impact on the value of open FTR positions. ISO-NE does not use mark-to-market or mark-to-model to account for changes arising from engineering events on the future value of open FTR positions. In the FTR market, bids are not rejected on an individual basis. If a customer does not have sufficient collateral (inclusive of credit limits) to cover the incremental margin requirements attributable to *all* such bids, *all* FTR bids are rejected shortly after the auction bidding window closes. No cure period is afforded. Rejection occurs within minutes of the closing of the auction bidding window.

As noted in the discussion of DCO Core Principle C (Participant and Product Eligibility), ISO-NE also operates a physical Forward Capacity Market that has financial assurance requirements. *See* Section VII of the Financial Assurance Policy. To participate in this market, resources must be approved through a rigorous qualification process to ensure that they can deliver energy to the electric system during the Capacity Commitment Period. When a resource receives a Capacity Obligation through these Forward Capacity Auctions, it is obligated to offer its energy into the day-ahead and real-time energy markets. Calculations of potential future exposure are based on at least the 50% expected outcome (in New England it can range as high as 95% for short-term FTRs and virtual transactions). Also, as part of the Market Participant Service Agreement, members must also register each asset that seeks eligibility to sell or purchase services in the New England Markets and comply with ISO-NE's operating documents, including registration information, approval of interconnection application, compliance with metering requirements, and providing electrical operating information. *See* Market Participant Services Agreement (Attachment A to the ISO-NE Tariff), Section 3.3. ISO-NE prepares a report or causes a report to be prepared regarding the financial viability of every applicant and submits the report to its Participants Committee within three weeks of submission of an application. Further, as noted above in the discussion of DCO Core Principle H (Rule Enforcement), IMM monitors compare the deviations between day-ahead and real-time locational marginal prices to determine if there is a persistent difference that would not be expected in a workably competitive market and calculate a rolling average locational marginal price deviation value. *See* Section III.A.8 of the ISO Tariff. Depending on the amount of the rolling average deviation, the IMM is required to investigate whether and to what extent the actions of one or more Market Participants are contributing to the price deviation. Also, the IMM reviews the activity of Market Participants taking virtual positions weekly, analyzing the profitability of virtual positions and the distribution of those virtual positions as well as other market positions taken by those Market Participants in order to ascertain, for example, whether their virtual transactions are used principally to hedge physical positions or are arbitrage/speculative in nature. The IMM also relies on information from the ISO's system operators and market operations and settlements departments regarding perceived anomalous behavior in order to monitor the marketplace for trends and "outliers." The IMM may also notify the ISO if any changes to market rules, models or procedures are needed or advisable to prevent manipulative conduct as well as computes the degree of price convergence daily, and provides monthly reports on price convergence to the Markets Committee of the ISO-NE Board of Directors.

See also the discussion of DCO Core Principle C, regarding ISO-NE's requirements for market participation, and DCO Core Principle D, regarding ISO-NE's financial assurance requirements and default protections.

Attachment Y—SEF Core Principle 7: Financial Integrity of Transactions

MISO

See Section IV(Risk Management), above. FERC Order 741.

Attachment Y—SEF Core Principle 7: Financial Integrity of Transactions

New York ISO

See the description of NYISO Risk Management procedures set forth in Attachment D, *supra*.

Attachment Y—SEF Core Principle 7: Financial Integrity of Transactions

PJM

See Attachment D (Risk Management), above.

Attachment Z

SEF Core Principle 8: Emergency Authority

The swap execution facility shall adopt rules to provide for the exercise of emergency authority, in consultation or cooperation with the Commission, as is necessary and appropriate, including the authority to liquidate or transfer open positions in any swap or to suspend or curtail trading in a swap.

Responses:

Attachment Z—SEF Core Principle 8: Emergency Authority

California ISO

See Attachment I (System Safeguards). Additionally, Section 7 of the CAISO Tariff provides the ISO a range of authorities to address emergency conditions. The CAISO has the authority to close out and liquidate all of a market participant's current and forward CRR positions if the market participant (i) no longer meets the CAISO's creditworthiness requirements, or (ii) fails to make timely payment when due, in each case following any opportunity given to cure the deficiency.[455] The CAISO may postpone the closure of the affected market, remove bids that have previously resulted in a market disruption, set an administrative price to settle metered supply and demand, or suspend or limit the ability of scheduling coordinators to submit virtual bids.[456] The CAISO is also authorized to suspend convergence bidding in the event that the virtual bidding activities of a scheduling coordinator have a detrimental effect on the reliability or operation of the CAISO system.[457]

[455] CAISO Tariff, § 12.5.1(e).

[456] *Id.*, § 7.7.15.1.

[457] *Id.*, § 7.9.2.

Attachment Z—SEF Core Principle 8: Emergency Authority

ERCOT

Section 16.11.6 of the ERCOT Protocols provides ERCOT a range of authorities to address emergency conditions including liquidating open positions of CRRs. Other actions may include:

- holding payments of defaulting participants;
- drawing on, holding or distributing funds of the participant;
- aggregating amounts owed by breaching participant and immediately due;
- restricting or eliminating the defaulting entity's ability to participate in the Day Ahead Market; and
- revoking the participant's rights and terminating its outstanding agreements(the market participant remains liable for all debt and consequences for termination/revocation).

Section 7.5.5.3 of the ERCOT Protocols also allows for the specific circumstance where an entity with high costs in terms of future credit exposure is awarded CRRs, prior to finalizing the auction results and awarding the CRRs, ERCOT can issue a collateral call to the entity. If the collateral call is not satisfied, the CRR Auction can be re-executed absent such entity's bids. ERCOT's authority to address market defaults is also addressed in response to DCO Core Principle D, and that response is incorporated herein by reference.

Attachment Z—SEF Core Principle 8: Emergency Authority

ISO New England

ISO-NE has adopted rules that provide for the exercise of emergency authority as needed. ISO-NE's emergency authority is outlined in its operating procedures (*see, e.g.*, Operating Procedure No. 7 (Action in an Emergency), *available at*, http://www.iso-ne.com/rules_proceds/operating/isone/op7/op7_rto_final.pdf.). Also, Section XI.H of the Financial Assurance Policy notes the ISO's right to liquidate open positions of defaulting FTR holders under the Financial Assurance Policy.

Attachment Z—SEF Core Principle 8: Emergency Authority

MISO

With regard to default or insolvency, see Attachment G *supra*. In addition, the MISO Tariff and Transmission Owners Agreement provide a range of authorities to address emergency conditions. The emergency authority and conditions discussed in MISO's Tariff relate to the operation of the electrical system, not to trading. MISO's Tariff does provide actions to be taken in the event of a defaulting or a potential defaulting customer. Under these circumstances, MISO may suspend the services the defaulting customer receives, including access to the Energy Markets and FTR Auction. Section 7.17(a)(2). If the defaulting customer is in bankruptcy, all FTRs held by the defaulting customer are terminated immediately. Section 7.19. Otherwise, under defaulting conditions, MISO must provide at least ten (10) days notice before terminating the defaulting customer's FTRs. Section 7.19.

Attachment Z—SEF Core Principle 8: Emergency Authority

New York ISO

The NYISO has the authority to file for an emergency change to its tariff rules under "exigent circumstances" as set forth in Section 19.1 of the ISO Agreement, available at: http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/nyiso_agreement/iso_agreement.pdf.

Under Services Tariff Section 23.4.6.4, the NYISO can limit the quantities of Virtual Transactions if necessary to prevent market distortions. Under Services Tariff Section 5.2.1, the NYISO can suspend Virtual Transactions if necessary to prevent distorted market outcomes.

The NYISO has the authority to suspend trading in the energy markets (passing control for continued operation of the power grid to the Transmission Owners) when required, such as when computer or communications systems are not functioning. *See* Services Tariff Section 5.3.1.

In the event the NYISO's price calculation software is not functioning, the NYISO has a process for notifying FERC and Market Participants of the issue and a mechanism for reconstructing affected prices. *See* Services Tariff Section 20.2.

In addition, the NYISO, in its discretion, can increase the amount of a Market Participant's credit requirement and reduce, or eliminate, the amount of unsecured credit granted to a Market Participant in the event of a material adverse change in the Market Participant's financial position. *See* Services Tariff Section 26.13.

Attachment Z—SEF Core Principle 8: Emergency Authority

PJM

PJM's rules regarding close out and liquidation of positions are comparable to the requirements of SEF Core Principle 8. Under Section 7 of the PJM Tariff and Section 15 of the PJM Operating Agreement, PJM has the authority to close out and liquidate all of a market participant's current and forward FTR positions if the market participant (i) no longer meets PJM's creditworthiness requirements, or (ii) fails to make timely payment when due under the PJM Operating Agreement or PJM Tariff, in each case following any opportunity given to cure the deficiency.[458]

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[458] *See also* PJM OA, Section 15.1 (providing PJM with the ability to terminate the rights of market buyers and sellers under certain circumstances).

Attachment AA

SEF Core Principle 9: Timely Publication of Trading Information

(A) IN GENERAL.—The swap execution facility shall make public timely information on price, trading volume, and other trading data on swaps to the extent prescribed by the Commission.

(B) CAPACITY OF SWAP EXECUTION FACILITY.—The swap execution facility shall be required to have the capacity to electronically capture and transmit trade information with respect to transactions executed on the facility.

Responses:

Attachment AA—SEF Core Principle 9: Timely Publication of Trading Information

California ISO

The CAISO releases market operations and grid management information publicly using its Open Access Same-Time Information System ("OASIS").[459] This information includes market prices, and market result data, including the market-clearing price. From this information, the value of CRRs can be calculated by subtracting the price at one point from the other. The CAISO publishes volume information including the net cleared quantities of virtual awards at the close of each trading day.[460] CAISO is required to retain all settlement data records for a period which, at least, allows for the re-run of data as required by the Tariff and applicable regulators.[461]

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459 CAISO Tariff § 6.2.2.2.

460 *Id.*, § 6.5.

461 *Id.*, § 11.1

Attachment AA—SEF Core Principle 9: Timely Publication of Trading Information

ERCOT

ERCOT rules governing publication of market information are described in response to DCO Core Principle L, and that response is incorporated herein by reference.

Attachment AA—SEF Core Principle 9: Timely Publication of Trading Information

ISO New England

ISO-NE makes public timely information on price, trading volume, and other trading data. For example, ISO-NE publishes all FTRs, including the FTR path, MW amount, and recipient, that clear in an FTR auction shortly after the auction closes. FTR bids are published with a masked participant ID three months after the auction. *See* Section 3.0(a) of the Information Policy. ISO-NE also has public information policies that are generally comparable to those of the other ISOs/RTOs. Bid data is released after 90 days. *See* Section 3.0(a) of the Information Policy. Real-time locational marginal prices are posted on the home page of the ISO's website.

Attachment AA—SEF Core Principle 9: Timely Publication of Trading Information

MISO

MISO's annual and monthly FTR auctions and ARR allocations are administered electronically. The results of these processes and related details are made available on the MISO website. See, https://www.midwestiso.org/MarketsOperations/MarketInformation/Pages/FTRMarket.aspx.

Attachment AA—SEF Core Principle 9: Timely Publication of Trading Information

New York ISO

TCC auctions and Virtual Transactions are administered electronically, and all data is managed electronically. The NYISO releases a variety of market information through its public website, including market clearing prices. The NYISO releases market operations and grid management information publicly using its Open Access Same-Time Information System. *See, e.g.,* OATT Section 2.04.

As described in Attachment L, *supra,* the NYISO regularly makes available on its public website market clearing prices and bid prices, as well as other information that may be relevant to Market Participants' bidding strategies. *See, e.g.*, NYISO Services Tariff Sections 4.1.3, 4.4.2.3, 4.4.2.8 and 19.9.2.

Attachment AA—SEF Core Principle 9: Timely Publication of Trading Information

PJM

PJM's practices on providing trading information is comparable to the requirements of SEF Core Principle 9. The terms and conditions of all transactions are delineated in the PJM OA, PJM Tariff, and manuals, which are posted publicly on PJM's website. The fees PJM charges its members are specified in Schedule 9 of the PJM Tariff, which is posted publicly on PJM's website.

PJM posts energy market prices every five minutes, and transaction volumes are posted daily. There is no daily market for FTRs or FTR options. Thus, settlement prices and volumes of FTRs and FTR options are posted as each monthly auction clears. FTR and FTR option open positions are maintained on PJM's website for market participant access and updated as each monthly auction clears. Further, promptly after the close of each auction, PJM posts capacity auction clearing prices.[462]

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[462] PJM OA, Schedule 1, Section 1.10.8; *see also* PJM OA, Sections 7.1A.2 (frequency and timing of FTR auctions), 7.3.7 (announcement of winners and prices of FTR auctions), and 7.4.2 (allocation of auction revenue rights).

Attachment BB

SEF Core Principle 10: Recordkeeping and Reporting

(A) IN GENERAL.—A swap execution facility shall—

(i) maintain records of all activities relating to the business of the facility, including a complete audit trail, in a form and manner acceptable to the Commission for a period of 5 years;

(ii) report to the Commission, in a form and manner acceptable to the Commission, such information as the Commission determines to be necessary or appropriate for the Commission to perform the duties of the Commission under this Act; and

(iii) shall keep any such records relating to swaps defined in section 1a(47)(A)(v) open to inspection and examination by the Securities and Exchange Commission.

(B) REQUIREMENTS.—The Commission shall adopt data collection and reporting requirements for swap execution facilities that are comparable to corresponding requirements for derivatives clearing organizations and swap data repositories.

Responses:

Attachment BB—SEF Core Principle 10: Recordkeeping and Reporting

California ISO

See Attachment J (Reporting) and Attachment K (Recordkeeping).

Attachment BB—SEF Core Principle 10: Recordkeeping and Reporting

ERCOT

ERCOT recordkeeping and reporting rules were discussed in response to DCO Core Principles K and J, respectively, and those responses are incorporated herein by reference. In addition, market information is reported pursuant to publication requirements, which were discussed in response to DCO Core Principle L. ERCOT also provides information and reports in support of market monitoring functions generally, and in the context of specific monitoring activities conducted by the IMM and PUCT. These roles were discussed in the response to DCO Core Principles M and H. Accordingly, the responses in Attachments L, H and M are also incorporated by reference in response to this SEF Core Principle.

Attachment BB—SEF Core Principle 10: Recordkeeping and Reporting

ISO New England

ISO-NE has an adequate system of reporting and recordkeeping that allows it to provide the information necessary for regulatory oversight. Section 3.2 of ISO-NE's Information Policy, which is Attachment D to the Tariff, explicitly states that ISO-NE will provide FERC with any requested confidential information. ISO-NE also has a records retention policy pursuant to which, for example, settlements information is maintained for six years. See also the relevant discussions of DCO Core Principles J and K, above.

Attachment BB—SEF Core Principle 10: Recordkeeping and Reporting

MISO

See the description of reporting and recordkeeping procedures set forth in Attachment H (Rule Enforcement), Attachment J (Reporting) and Attachment K (Recordkeeping), *supra*.

Attachment BB—SEF Core Principle 10: Recordkeeping and Reporting

New York ISO

See the description of reporting and recordkeeping procedures set forth in Attachment H (Rule Enforcement), Attachment J (Reporting) and Attachment K (Recordkeeping), *supra*.

Attachment BB—SEF Core Principle 10: Recordkeeping and Reporting

PJM

See Attachment J (Recordkeeping and Reporting), above.

Attachment CC

SEF Core Principle 11: Antitrust Considerations

Unless necessary or appropriate to achieve the purposes of this Act, the swap execution facility shall not—

(A) adopt any rules or taking any actions that result in any unreasonable restraint of trade; or

(B) impose any material anticompetitive burden on trading or clearing.

Responses:

Attachment CC—SEF Core Principle 11: Antitrust Considerations

California ISO

See Attachment N (Antitrust Considerations).

Attachment CC—SEF Core Principle 11: Antitrust Considerations

ERCOT

ERCOT antitrust related rules are discussed in response to DCO Core Principle N. Accordingly, the response to Attachment N is incorporated herein by reference.

Attachment CC—SEF Core Principle 11: Antitrust Considerations

ISO New England

ISO-NE has not adopted any rule or taken any action that results in an unreasonable restraint of trade or imposes a material competitive burden. As explained above, the reason that the ISOs/RTOs were created was to enhance competition in the electricity markets. See the discussion of DCO Core Principle N, above.

Attachment CC—SEF Core Principle 11: Antitrust Considerations

MISO

See the description of antitrust considerations set forth in Attachment N, *supra*.

Attachment CC—SEF Core Principle 11: Antitrust Considerations

New York ISO

See the description of antitrust considerations set forth in Attachment N, *supra*.

Attachment CC—SEF Core Principle 11: Antitrust Considerations

PJM

See Attachment N (Antitrust Considerations), above.

Attachment DD

SEF Core Principle 12: Conflicts of Interest

The swap execution facility shall—

(A) establish and enforce rules to minimize conflicts of interest in its decision-making process; and

(B) establish a process for resolving the conflicts of interest.

Responses:

Attachment DD— SEF Core Principle 12: Conflicts of Interest

California ISO

See Attachment D (Conflicts of Interest).

Attachment DD— SEF Core Principle 12: Conflicts of Interest

ERCOT

ERCOT conflict of interest related rules are discussed in response to DCO Core Principle P. Accordingly, the response to Attachment P is incorporated herein by reference.

Attachment DD— SEF Core Principle 12: Conflicts of Interest

ISO New England

ISO-NE has appropriate rules for minimizing conflicts of interest in the decision-making process and resolving those conflicts. ISO-NE has a FERC-approved Code of Conduct that establishes obligations for members of the Board and all employees. These obligations include foregoing investment in and other relationships with market participants. The Audit and Finance Committee of the Board is the entity responsible for enforcing compliance, except in matters related to directors, in which case the entire Board (minus the conflicted director) is the arbiter. See the discussion of DCO Core Principle P.

Attachment DD— SEF Core Principle 12: Conflicts of Interest

MISO

See Attachment P (Conflicts of Interest), above.

Attachment DD— SEF Core Principle 12: Conflicts of Interest

New York ISO

See the description of NYISO conflicts of interest rules and procedures set forth in Attachment P, *supra*.

Attachment DD— SEF Core Principle 12: Conflicts of Interest

PJM

See Attachment P (Conflicts of Interest), above.

Attachment EE

SEF Core Principle 13: Financial Resources

(A) IN GENERAL.—The swap execution facility shall have adequate financial, operational, and managerial resources to discharge each responsibility of the swap execution facility.

(B) DETERMINATION OF RESOURCE ADEQUACY.—The financial resources of a swap execution facility shall be considered to be adequate if the value of the financial resources exceeds the total amount that would enable the swap execution facility to cover the operating costs of the swap execution facility for a 1-year period, as calculated on a rolling basis.

Responses:

Attachment EE—SEF Core Principle 13: Financial Resources

California ISO

See Attachment B (Financial Resources) and Attachment D (Risk Management).

Attachment EE—SEF Core Principle 13: Financial Resources

ERCOT

ERCOT financial resource/funding related rules are discussed in response to DCO Core Principle B. Accordingly, the response to Attachment B is incorporated herein by reference.

Attachment EE—SEF Core Principle 13: Financial Resources

ISO New England

As noted above in Attachment B (Financial Resources), ISO-NE possesses financial resources to meet its financial obligations to its members. The ISO's obligations are set out in its contracts with its participants, including the Market Participant Service Agreement, Participants Agreement and Transmission Operating Agreement. In turn, Section IV.A of the Transmission, Markets and Services Tariff establishes a mechanism through which the ISO recovers its expenses to fulfill these obligations.

Each year, ISO-NE establishes a budget necessary to fulfill its obligations for the subsequent year. This budget is approved by ISO-NE's independent Board of Directors after review with stakeholders, and is ultimately filed with FERC, which approves the justness and reasonableness of the budget. Once established, the amount of this budget is recovered through the rates set forth in Section IV.A of the Tariff.

ISO-NE also files annually, in advance of the operating year, revised tariff rates to enable ISO-NE to collect its revenue requirement from participants. *See* Tariff Section IV.A.2.1. The annual revenue requirement includes significant contingency funds. Thus, ISO-NE's Tariff includes provisions that ensure that ISO-NE will recover its expenses, even, as discussed above in "Default Resources," in the event of a significant participant default.

Defaults are socialized after realizing any collateral specific to the defaulting participant, late payment funds, funds in the payment shortfall account and possible insurance claims paid for protracted defaults. *See* Billing Policy, Exhibit ID of the Tariff. Further, a default by an ISO-NE market participant is shared by like market participants. *See* Billing Policy, Exhibit ID of the Tariff, Section 3. Thus, the risk to ISO-NE is minimal.

ISO-NE also maintains third-party credit protection, in the form of credit insurance coverage, a performance or surety bond, or a combination thereof, on terms acceptable to the ISO in order to collectively cover the Qualifying Rated Market Participants. Further, ISO-NE maintains a Late Payment Account as a cushion. It is funded with penalty fees paid by participants that make late payments, and accrued interest. *See* Section 4 of the Billing Policy. Last, ISO-NE has third party financing to fund a Payment Default Shortfall Fund. *See* Section 5 of the Billing Policy.

Attachment EE—SEF Core Principle 13: Financial Resources

MISO

See response to Attachment B (Financial Resources) above.

Attachment EE—SEF Core Principle 13: Financial Resources

New York ISO

See the description of NYISO financial resources set forth in Attachment B, *supra.*

Attachment EE—SEF Core Principle 13: Financial Resources

PJM

PJM's financial, operational, and managerial resources are comparable to SEF Core Principle 13. See PJM's response to the DCO Core Principle on Financial Resources.

Attachment FF

SEF Core Principle 14: System Safeguards

The swap execution facility shall—

(A) establish and maintain a program of risk analysis and oversight to identify and minimize sources of operational risk, through the development of appropriate controls and procedures, and automated systems, that—

(i) are reliable and secure; and

(ii) have adequate scalable capacity;

(B) establish and maintain emergency procedures, backup facilities, and a plan for disaster recovery that allow for—

(i) the timely recovery and resumption of operations; and

(ii) the fulfillment of the responsibilities and obligations of the swap execution facility; and

(C) periodically conduct tests to verify that the backup resources of the swap execution facility are sufficient to ensure continued—

(i) order processing and trade matching;

(ii) price reporting;

(iii) market surveillance and

(iv) maintenance of a comprehensive and accurate audit trail.

Responses:

Attachment FF—SEF Core Principle 14: System Safeguards

California ISO

See Attachment I (System Safeguards).

Attachment FF—SEF Core Principle 14: System Safeguards

ERCOT

ERCOT system safeguard related rules are discussed in response to DCO Core Principle I. Accordingly, the response to Attachment I is incorporated herein by reference.

Attachment FF—SEF Core Principle 14: System Safeguards

ISO New England

See discussion of DCO Core Principle I (System Safeguards).

Attachment FF—SEF Core Principle 14: System Safeguards

MISO

See Attachment I (System Safeguards), above.

Attachment FF—SEF Core Principle 14: System Safeguards

New York ISO

See the description of NYISO's system safeguards set forth in Attachment I, *supra*.

Attachment FF—SEF Core Principle 14: System Safeguards

PJM

See Attachment I (System Safeguards), above.

Attachment GG

SEF Core Principle 15: Designation of Chief Compliance Officer

(A) IN GENERAL.—Each swap execution facility shall designate an individual to serve as a chief compliance officer.

(B) DUTIES.—The chief compliance officer shall—

(i) report directly to the board or to the senior officer of the facility;

(ii) review compliance with the core principles in this subsection;

(iii) in consultation with the board of the facility, a body performing a function similar to that of a board, or the senior officer of the facility, resolve any conflicts of interest that may arise;

(iv) be responsible for establishing and administering the policies and procedures required to be established pursuant to this section;

(v) ensure compliance with this Act and the rules and regulations issued under this Act, including rules prescribed by the Commission pursuant to this section; and

(vi) establish procedures for the remediation of noncompliance issues found during compliance office reviews, look backs, internal or external audit findings, self-reported errors, or through validated complaints.

Responses:

California ISO

The CAISO has a Compliance and Ethics Program Policy,[463] which focuses on compliance with all laws that govern the CAISO. The policy establishes the position of Chief Compliance Officer, who is responsible for compliance activities. The CAISO's Chief Compliance Officer is Nancy Saracino.

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[463] The CAISO's Compliance and Ethics Program Policy is *available at* http://www.caiso.com/275e/275eecd2195a0.pdf.

Attachment GG—SEF Core Principle 15: Designation of Chief Compliance Officer

ERCOT

ERCOT has a Chief Compliance Officer who reports directly to the Chief Executive Officer. The responsibilities of this position include compliance oversight with Protocols and other applicable standards, including NERC standards. In addition, this position also serves as the head of Human Resources. In the latter role, the position supports the ERCOT General Counsel in administering the ERCOT Code of Conduct and Ethics Compliance Standard and reporting of any exceptions and validated complaints to the Board; the ERCOT General Counsel has direct responsibility for compliance with this standard.

In addition, ERCOT's Vice President of Credit and Enterprise Risk Management ("VP of CERM") is responsible for managing compliance with control standards associated with SSAE16 and controls around ERCOT financial functions and monitoring resolution of compliance issues identified in Internal Audits. In addition, the VP of CERM is responsible for overseeing issues related to corporate risk generally, including market rules associated with market credit risk. The VP of CERM reports directly to the ERCOT Chief Executive Officer.

The ERCOT Chief Compliance Officer, VP of CERM, and General Counsel are responsible for managing the development and implementation of relevant internal ERCOT procedures, and for ERCOT participation in the development of market rules associated with the pertinent functions.

Compliance monitoring and any related remediation activity is accomplished pursuant to a collaborative, multi-pronged approach that includes ERCOT, the ERCOT IMM, and the PUCT. The specific roles and authority of each of these entities was described more fully in the context of the DCO Core Principles, and those detailed descriptions are incorporated herein.

Attachment GG—SEF Core Principle 15: Designation of Chief Compliance Officer

ISO New England

ISO-NE has a Chief Compliance Officer, who is also the Chief Financial Officer of the Company and who reports directly to the Chief Executive Officer. The Chief Compliance Officer's responsibilities include strategic planning, risk management and compliance management (including compliance with Tariff obligations). ISO-NE has voluntarily adopted Sarbanes-Oxley 302 practices (in addition to 404 "lite"), such that the Chief Compliance Officer gives quarterly reports to the Audit and Finance Committee of the Board of Directors regarding disclosures made pursuant thereto.

For purposes of the Code of Conduct, which establishes conflicts of interest, the compliance officer is the Vice President/Human Resources. This officer reports annually to the Audit and Finance Committee of the Board regarding Code of Conduct compliance and brings all conflicts to the Committee (or the full Board in the case of a conflict involving a member of the Board).

Attachment GG—SEF Core Principle 15: Designation of Chief Compliance Officer

MISO

MISO has established an executive committee comprised of the General Counsel, Chief Financial Officer and Vice President, Standards and Compliance to serve as the Corporate Compliance Oversight Committee. This committee is responsible for developing compliance related policies and reviewing compliance matters. This committee is also responsible for reporting to the MISO Board of Directors on compliance mattes. In addition, MISO has designated its Deputy General Counsel as its Chief Compliance Officer responsible for all FERC and tariff compliance matters.

Attachment GG—SEF Core Principle 15: Designation of Chief Compliance Officer

New York ISO

The NYISO Code of Conduct, as codified in OATT Section 12.10, requires the NYISO to designate an individual as a compliance officer, and the NYISO has done so. *See* OATT Section 12.10. The NYISO compliance officer is responsible for overseeing the NYISO's compliance program, which includes interpreting the NYISO Code of Conduct; responding to questions regarding the NYISO Code of Conduct; advising NYISO directors, officers, and employees regarding potential conflicts of interest; overseeing the auditing process; and following-up on all suspected violations. The NYISO compliance officer may designate one or more individuals to assist in carrying out his responsibilities. To further assist the compliance officer and any assistant compliance officers with their responsibilities, the NYISO (1) operates a "hotline" that provides a means to anonymously and confidentially report suspected violations of the NYISO Code of Conduct over the telephone; (2) engages in a well established and long running Enterprise Risk Management process to identify potential compliance risks and areas for improvement; (3) maintains a number of policies that form the structure of the compliance program, including the Code of Conduct , business ethics policy, records retention policy, and whistleblower policy; and (4) requires compliance training for all managers and compliance attestations by NYISO officers.

Attachment GG—SEF Core Principle 15: Designation of Chief Compliance Officer

PJM

PJM's compliance measures are comparable to the requirements of SEF Core Principle 15. PJM has two compliance heads who coordinate closely but are separately responsible for compliance in the following two distinct areas: (1) compliance with regulatory and legal obligations; and (2) compliance with reliability standards as promulgated by the regional reliability counsels, NERC and FERC.

Regulatory and legal compliance addresses legal obligations, including compliance with the PJM Tariff, FERC regulations and laws, and regulations governing other corporate matters, such as antitrust, human resources and procurement. Regulatory and legal compliance is handled in the Office of General Counsel, by an Assistant General Counsel and Director of Regulatory Oversight and Compliance.

Reliability compliance addresses the security of the grid, both operationally and from any cyber threat. This function is handled in the area of operations and the Executive Director of Reliability and Compliance reports directly to the senior vice president for operations.

All compliance functions (both reliability and regulatory) are coordinated through PJM's Regulatory Oversight & Compliance Committee ("ROCC"). The ROCC is chaired by the Assistant General Counsel who has reporting obligations to the CEO and a direct line to the Board's Governance Committee and Audit Committee. The Assistant General Counsel provides quarterly presentations on enterprise compliance matters at the Board's Governance Committee and quarterly reports on the Code of Conduct matters to the Board's Audit Committee. Additionally, the Assistant General Counsel is authorized to report matters to the Board at anytime as circumstances may warrant. Finally, the independent Market Monitor plays a unique role in compliance by overseeing and investigating PJM's compliance with its own rules.

FERC ORDER NO. 741 IMPLEMENTATION

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
						PJM has submitted tariff revisions to FERC, as required under Order No. 741. The last of these revisions were approved by FERC on March 15, 2012 and became effective retroactively on December 13, 2011. PJM is in full compliance with Order No. 741. *See PJM Interconnection, L.L.C.*, Order on Compliance Filing, Docket No. ER11-3972,000, 136 FERC ¶ 61,190 (2011) (order on compliance filing finding that PJM's compliance filing complies with the requirements set forth in Order No. 741 and that PJM's proposed minimum participation criteria are just and reasonable, and, therefore, conditionally accepting PJM's proposed tariff revisions effective October 1, 2011);[2] *PJM Interconnection, L.L.C.*, Order Accepting Compliance Filing, Docket No. ER11-3972-002, 138 FERC ¶ 61,183 (2012) (order accepting PJM's November 29, 2011 compliance filing and granting a December 13, 2011, effective date);[3] *PJM Interconnection, L.L.C.*, Order Denying Rehearing, Docket Nos.

[1] ERCOT is not subject to FERC regulation or the requirements of FERC Order No. 741. Nevertheless, the ERCOT Protocols and proposed revisions are comparable to the credit reform requirements of FERC Order No. 741.

[2] Available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12766169. FERC ordered PJM to submit a compliance filing within 90 days of the date of the order to clarify a provision of PJM's proposed officer certification form, amend its tariff provisions regarding the cap on unsecured credit and elimination of unsecured credit in the FTR markets, and provide for compliance verification concerning minimum criteria for market participation).

[3] Available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12915576. FERC found that PJM's proposed compliance verification process complied with the FERC's directives, and is just and reasonable and not unduly discriminatory or preferential. FERC rejected requests for an exemption for market participants that are regulated by banking regulators from PJM's compliance verification policies and procedures. FERC also declined to require PJM to adopt indicated Participants' proposal regarding when and how frequently PJM would verify a market participant's compliance with risk management practices and policies. FERC found that PJM's proposal that includes selecting participants for review on a random basis and/or based on identified risk factors strikes the appropriate balance between periodically verifying that participants are complying without unduly burdening participants. FERC declined to require PJM to revise its proposal to include an additional 14 days from the date the cure period expires to appeal a negative determination. FERC also stated that it expects PJM to explain any deficiencies in a market participant's risk management policies when it notifies the participant that PJMSettlement is unable to complete its verification. FERC noted that PJM stated this in its answer. While FERC did not require tariff revisions to clarify this, they directed PJM to address this explanation in its business rules.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
						ER11-3972-001, et al., 138 FERC ¶ 61,182 (2012) (rejecting a request by the Electric Power Supply Association for rehearing of its FERC's orders on all six RTOs' filings to comply compliance with Order No. 741, as well as requests for rehearing of PJM's Order No. 741 compliance filing submitted by several parties).[4]
Limit the amount of unsecured credit extended to any market participant or aggregate corporate family to no more than $50 million.	The maximum amount of unsecured credit available to any market participant or group of market participant affiliates is $50 million.[5] The CAISO submitted tariff revisions to satisfy this Order No. 741 mandate on June 30, 2011.[6] FERC accepted the tariff revisions on September 15, 2011, effective as of October 1, 2011.[7] Thus, the CAISO is in full compliance with this Order No. 741 mandate.	Unsecured credit is subject to a $50 million limit and is granted solely within ERCOT's discretion. The $50 million cap also is applied at the "corporate family" level and became effective December 1, 2011.[8]	Effective October 1, 2011, ISO NE lowered to $50 million the limits of certain types of unsecured credit that it previously extended above $50 million.[9]	MISO is in full compliance and does not extend Unsecured Credit exceeding $50 million to any market participant or aggregate corporate family.[10] Filing date: 6/30/11[11] FERC approval date: 9/15/11[12] Effective date: 10/1/11	The maximum amount of unsecured credit available to any one Market Participant, or group of affiliated Market Participants is $50 million.[13] The NYISO submitted this tariff revision as required by Order No. 741. FERC approved this revision on September 15, 2011, 136 FERC ¶ 61,193 (the "September 15 Order"), at P 20.[14] This revision became effective on October 18, 2011 and thus, the NYISO is in full compliance with this Order No. 741 mandate.	The total amount of unsecured credit allowance, whether from a market participant's own creditworthiness or from a guaranty, is capped at $50 million.[15] On March 15, 2012, FERC accepted PJM's proposed tariff revisions filed in compliance with FERC's September 15, 2011 Order on PJM's Order No. 741 Compliance Filing to ensure that Seller Credit, which is a form of unsecured credit, is included as part of the $50 million unsecured credit allowance cap.[16] *See PJM Interconnection, L.L.C.*, Order Accepting Compliance Filing,

4 Available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12915575.

5 *See* CAISO Tariff § 12.1.1.

6 *See* filing letter at page 10, section entitled "Limit on Unsecured Credit." Link to filing: http://www.caiso.com/Documents/2011-06-30_CredReforms_CompFiling_ER11-3973.pdf.

7 *California Independent System Operator Corporation*, 136 FERC ¶ 61,194, at Paragraph 16 (2011), available at: http://www.caiso.com/Documents/ER11-3973_Credit%20Policy%20Order_2011-09-15.pdf.

8 ERCOT Creditworthiness Standards.

9 *ISO New England and New England Power Pool*, 136 FERC ¶ 61,191 (2011), available at http://www.iso-ne.com/regulatory/ferc/orders/2011/sep/er11-3953-000_9-15-11_credit_order.pdf.

10 Link to MISO Tariff: https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx.

11 Link to 6/30/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-06-30%20Docket%20No.%20ER11-3970-000.pdf.

12 Link to 9/15/11 FERC order: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2011-09-15%20136%20FERC%2061,188%20Docket%20No.%20ER11-3970.pdf

13 *See* NYISO Services Tariff Section 26.5.2.

14 A copy of the September 15 Order is available on the NYISO's website at http://www.nyiso.com/public/webdocs/documents/regulatory/orders/2011/09/FERC_Ordr_Ordr_No_741_Crdt_Rfrms_9_15_11.pdf.

15 PJM Tariff, Attachment Q, Section II.F.

16 PJM Interconnection, L.L.C., November 29, 2011 Filing, Docket No. ER11-3972, at 13.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
						Docket No. ER11-3972-002, 138 FERC ¶ 61,183 (2012).
Adopt a settlement period of no more than seven days with an additional seven days to receive payment.	The CAISO has a weekly settlement cycle, issuing invoices every Wednesday, with payment due four business days later.[17] The CAISO submitted tariff revisions to satisfy this Order No. 741 mandate on June 30, 2011.[18] FERC accepted the tariff revisions on September 15, 2011, effective as of October 1, 2011.[19] Thus, the CAISO is in full compliance with this Order No. 741 mandate.	On August 16, 2011 and October 18, 2011, the ERCOT Board of Directors approved Protocol changes to tighten the Real Time settlement and payment cycle: (i) Combining Real Time settlements with DAM settlements into one "daily" invoice with both DAM and RT settlement statements on it; and (ii) Shortening the RT payment timeline by two bank business days. The "daily" invoice will be paid within 3 bank business days instead of five. These changes should ensure that approximately 90% of Real Time days are settled and paid within 15 days with the weighted average settlement and payment cycle being no more than 15 days. Settlement and payment timelines longer than the above are expected to be primarily due to weekend and holiday schedules. ERCOT is in the process of implementing these Protocol changes and expects completion by December 2012.[20]	Effective January 26, 2011, ISO NE has implemented twice-weekly billing for hourly charges.[21]	MISO is in full compliance and invoices on the seven-day settlement of charges and credits (S7). MISO requires payment within seven days. MISO reflected this change in a Business Practice Manual and FERC requested that MISO update its Tariff to include the settlement changes. MISO added the applicable language to Section 7 of its Tariff.[22] Initial filing date: 6/30/11[23] FERC response date: 9/15/11[24] Amended filing date: 12/14/11[25] FERC approval date: 3/15/12[26] Effective date: 10/1/11	NYISO Services Tariff Section 7.2 and OATT Section 2.7.3 established, effective October 1, 2011, a weekly settlement cycle for approximately 99% of the dollar volume of NYISO-administered market transactions. The NYISO submitted this tariff revision as required by Order No. 741. FERC approved this revision on September 15, 2011. This revision became effective on October 1, 2011 and thus, the NYISO is in full compliance with this Order No. 741 mandate.[27]	PJM's settlement period for most products and services is one week. Payment on all invoices is due within three business days.[28]

17 *See* CAISO Tariff § 11.29.2 & 11.29.10.

18 *See* filing letter at pages 4-10, section entitled "Shortening the Settlement Cycle." Link to filing: http://www.caiso.com/Documents/2011-06-30_CredReforms_CompFiling_ER11-3973.pdf

19 *California Independent System Operator Corporation*, 136 FERC ¶ 61,194, at Paragraph 12 (2011), available at: http://www.caiso.com/Documents/ER11-3973_Credit%20Policy%20Order_2011-09-15.pdf.

20 ERCOT Protocol, Sections 9.5.4, 9.6, and 9.7 as modified by NPRR 347 and NPRR391 (which currently are being implemented).

21 *ISO New England and New England Power Pool*, 132 FERC ¶ 61,046 (2010), available at http://www.iso-ne.com/regulatory/ferc/orders/2010/jul/er10-942-000_7-16-10_order_unsecured_credit.pdf. Notice of effective date available at http://www.iso-ne.com/regulatory/ferc/filings/2010/nov/er10-2933-001_11-18-10_unsecured_credit.pdf.

22 Link to MISO Tariff: https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx.

23 Link to 2/3/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-02-03%20Docket%20No.%20ER11-2831-000.pdf.

24 Link to 9/15/11 FERC order: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2011-09-15%20136%20FERC%2061,188%20Docket%20No.%20ER11-3970.pdf

25 Links to 12/14/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-12-14%20Docket%20No.%20ER11-3970-000.pdf.

26 Link to 3/15/12 FERC order: http://www.ferc.gov/whats-new/comm-meet/2012/031512/E-22.pdf

27 *See* September 15 Order at P 25.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
Eliminate unsecured credit in the financial transmission rights market.	Market participants are required to post secured collateral for bidding or holding CRRs.[29] The CAISO submitted tariff revisions to satisfy this Order No. 741 mandate on June 30, 2011.[30] FERC accepted the tariff revisions on September 15, 2011, effective as of October 1, 2011 subject to certain compliance requirements related to the treatment of federal agencies.[31] In all other respects, the CAISO is in compliance with this Order No. 741 mandate. In its September 15, 2011, order FERC directed the CAISO to submit a compliance filing that contained tariff revisions stating that a federal agency is deemed to provide secured collateral if it provides an executed letter setting forth the information described above.[32] On December 14, 2011, the CAISO submitted a compliance filing that contained the tariff revisions required by FERC.[33] A federal agency is deemed to have provided secured collateral if it provides a letter executed by an officer that: (1) attests that the	On October 18, 2011, the ERCOT Board of Directors approved Protocol changes that will ensure that the CRR Auction and CRR forward mark–to–market values are fully collateralized rather than being subject to unsecured credit. ERCOT is in the process of implementing these changes and expects completion by December 2012.[36]	Effective January 26, 2011, ISO NE has eliminated the use of unsecured credit for all FTRs for all ISO NE market participants.[37]	MISO is in full compliance and has eliminated the use of Unsecured Credit to support financial transmission rights (FTR) allocations and exposure. MISO later amended the initial filing to exclude auction revenue rights exposure from the financial transmission rights exposure calculation where market participants were allocated auction revenue rights and do not own any financial transmission rights.[38] Filing date: 2/3/11[39] FERC approval date: 4/6/11[40] Effective date: 4/5/11 Amended filing date: 6/30/11[41] FERC approval date: 9/15/11[42] Amendment effective date: 10/1/11	Market Participants are required to post collateral, and are not permitted to use unsecured credit, to satisfy credit requirements for bidding on or holding TCCs.[43] With the exception of credit requirements related to Fixed Price TCCs, the NYISO eliminated the use of unsecured credit in the TCC market effective November 12, 2009.[44] The NYISO submitted tariff revisions to eliminate the use of unsecured credit to meet credit requirements related to Fixed Price TCCs as required by Order No. 741. FERC approved these revisions on September 15, 2011. These revisions became effective on October 1, 2011 and thus, the NYISO is in full compliance with this Order No. 741 mandate.[45]	In the FTR market, unsecured credit is not allowed, and collateral, which is required on a portfolio basis based upon path-specific historical values, must be established prior to bidding into the auction.[46] On March 15, 2012, FERC accepted PJM's proposed tariff revisions filed in compliance with FERC's September 15, 2011 Order on its Order No. 741 Compliance Filing to remove the possibility that Seller Credit, which is a form of unsecured credit, could be used as credit for FTRs.[47] *PJM Interconnection, L.L.C.*, Order Accepting Compliance Filing, Docket No. ER11-3972-002, 138 FERC ¶ 61,183 (2012) (accepting PJM's November 29, 2011 compliance filing and granting a December 13, 2011, effective date).

28 PJM Tariff, Section 7.1A.

29 *See* CAISO Tariff § 12.6.2.

30 *See* filing letter at pages 10-11, section entitled "Elimination of Unsecured Credit for Financial Transmission Rights Markets." Link to filing: http://www.caiso.com/Documents/2011-06-30_CredReforms_CompFiling_ER11-3973.pdf

31 *California Independent System Operator Corporation*, 136 FERC ¶ 61,194, at Paragraph 24 (2011), available at: http://www.caiso.com/Documents/ER11-3973_Credit%20Policy%20Order_2011-09-15.pdf.

32 *California Independent System Operator Corporation*, 136 FERC ¶ 61,194, at Paragraphs 26-27 (2011), available at: http://www.caiso.com/Documents/ER11-3973_Credit%20Policy%20Order_2011-09-15.pdf.

33 *See* filing letter at pages 3-4, section entitled "Elimination of Unsecured Credit in CRR Markets – Demonstration of Financial Security by Federal Agencies." Link to filing: http://www.caiso.com/Documents/2011-12-14_ER11-3973_CredRefComp.pdf

34 *See* Tariff § 12.6.2.2.

35 *California Independent System Operator Corporation*, 138 FERC ¶ 61,181, at Paragraph 28 (2012), available at http://www.caiso.com/Documents/2012-03-15_ER11-3973_order.pdf.

36 ERCOT Protocol, Sections 16.11.4.1 and 16.11.4.6 as modified by NPRR 400 (which currently is being implemented).

37 *ISO New England and New England Power Pool*, 132 FERC ¶ 61,046 (2010), available at http://www.iso-ne.com/regulatory/ferc/orders/2010/jul/er10-942-000_7-16-10_order_unsecured_credit.pdf. Notice of effective date available at http://www.iso-ne.com/regulatory/ferc/filings/2010/nov/er10-2933-001_11-18-10_unsecured_credit.pdf.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
	federal agency is lawfully authorized to participate in the CRR Auction and that any debt the federal agency incurs due its participation in the CRR Auction is a debt of the United States; (2) identifies the current year's appropriations for the federal agency from the United States Congress; and (3) verifies that the amount of the current year's appropriations for the federal agency from the United States Congress meets or exceeds the amount required to satisfy the credit requirements set forth in Section 12.1.[34] On March 15, 2012, FERC issued an order that accepted the tariff revisions submitted in the December 14, 2011, filing, effective as of April 30, 2012.[35] Thus, as of April 30, 2012, the CAISO will be in full compliance with the directive in FERC's September 15, 2011 order.					
Reinforce the ability of the ISO/RTO to offset market obligations owed to market participants against market	The CAISO expects to file tariff revisions to become a central counterparty to all market	ERCOT has submitted Nodal Protocol Revision Request (NPRR) 458, Establishment of ERCOT's	On April 30, 2012, ISO NE filed a package of tariff changes to establish itself as the central counterparty for	FERC granted MISO an extension of time to meet this requirement, allowing MISO to more fully	On April 30, 2012, the NYISO submitted tariff revisions, to comply with this Order No. 741 mandate,	Effective January 1, 2011, PJM revised its OA and Tariff to establish PJMSettlement Inc. as the

38 Link to 3/15/12 FERC order: http://www.ferc.gov/whats-new/comm-meet/2012/031512/E-22.pdf.

39 Link to 2/3/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-02-03%20Docket%20No.%20ER11-2831-000.pdf

40 Link to 4/6/11 FERC order: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2011-04-06%20Letter%20Order%20Docket%20No.%20ER11-2831-000.pdf

41 Link to 6/30/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-06-30%20Docket%20No.%20ER11-3970-000.pdf.

42 to 9/15/11 FERC order: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2011-09-15%20136%20FERC%2061,188%20Docket%20No.%20ER11-3970.pdf

43 *See* NYISO Services Tariff Sections 26.5 and 26.6.

44 A copy of FERC's order approving these tariff revisions is available at: http://elibrary.ferc.gov/idmws/common/downloadOpen.asp?downloadfile=20091104%2D3029%2822820035%29%2Epdf&folder=689105&fileid=12190941&trial=1

45 *See* September 15 Order at P 15.

46 PJM Tariff, Attachment Q, Section V.A.

47 FERC permitted the use of unsecured credit allowance for FTRs acquired prior to the June 2009 auction, noting that the elimination of the use of an unsecured credit allowance will be complete after May 2012. *PJM Interconnection, L.L.C.*, 136 FERC ¶ 61,190, at P 27 (2011).

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
obligations owed by market participants.	transactions by April 30, 2012. On January 24, 2012, FERC issued a notice that granted all ISOs and RTOs an extension of time to April 30, 2012, to comply with this Order No. 741 mandate.[48] On April 30, 2012, FERC issued a notice grating CAISO an extension of time to May 25, 2012, to comply with this Order No. 741 mandate.[49] On May 25, 2012, CAISO filed with FERC proposed tariff revisions establishing it as central counterparty to all transactions settled by CAISO and requesting an effective date of September 1, 2012.[50]	Central Counterparty Role, revising the Protocols in order to reflect the new central counterparty status of the ISO. ERCOT anticipates that the NPRR will be approved by the ERCOT Board of Directors on September 18, 2012. ERCOT expects to implement these revisions by the end of 2012.	market participant transactions. The filing was made with a requested effective date of January 1, 2013 and is currently pending at FERC.[51] Comments and a limited protest were filed on May 14 and May 21. The ISO filed an answer and also joined NYISO and MISO in an answer to Exelon's comments on May 29, 2012.	explore the central counterparty approach. MISO initially pursued the security interest option to address this requirement but received overwhelming stakeholder support for a central counterparty approach. MISO filed Tariff revisions on 4/30/12 to become the central counterparty with a requested 1/1/13 effective date. Motion date: 1/17/12[52] FERC motion granted date: 1/24/12[53] Filing extension date: 4/30/12	that clarify the NYISO's role as the single counterparty to Market Participant transactions and establish that the NYISO, as the counterparty, will take title to the products that are the subject of the transactions it administers.[54] The NYISO requested a July 1, 2012 effective date for these tariff revisions. Upon FERC's approval of this filing, the NYISO will be in full compliance with this minimum participation criteria mandate. The NYISO will provide CFTC staff with copies of any future filings made with FERC with respect to this Order No. 741 mandate on the same day that the filings are made with FERC.	central counterparty to transactions in the PJM markets. According to the FERC filing, "[t]he purpose of the filed revisions is to clarify that there is a single, specified counterparty to market participants with respect to all 'pool' transactions in the markets operated by PJM and for transmission service."[55] Under the new PJM regime: - PJMSettlement takes "title to all power that is purchased and sold in the 'pool transactions' in the [PJM-administered] markets"[56]; - the revisions to PJM's structure establish that "PJMSettlement will be a buyer to each market seller and a seller to each market buyer, *taking title to electricity and other products and assuming liability for payables, in its own name and right*"[57]; and - the interposition of PJMSettlement

[48] Notice of Extension of Time, Docket No. RM10-13-000 (Jan. 24, 2012), available at: http://dialog.newsedge.com/portal.asp?site=20071008144431055932258&searchfolderid=pg20071008145222097593338&block=default&portlet=ep&nzesm=on&syntax=advanced&display=Electric+Utilities+Brokering&action=sitetopics&mode=realtime&nzenb=left&criteria=%5Btopic%3Delbroker%5D&searchID=730071&datetime=%5Bt-minus%3D7%5D&hdlaction=story&storyid=%5Bstoryid=ooEaXZ2MBrUNQ63d41jeGO2ijxtURgwxvwYf2m9hYBwfOLkbtN9EFu9LIdUPFcWn%5D&rtcrdata=on&epname=USDOLLAR&.

[49] Notice of Extension of Time, Docket No. RM10-13-000 (Apr. 30, 2012), available at: http://dialog.newsedge.com/portal.asp?site=20071008144431055932258&searchfolderid=pg20071008145222097593338&block=default&portlet=ep&nzesm=on&display=Internet+Regulatory&Nextseq=15-next&action=sitetopics&mode=realtime&nzenb=left&criteria=%5Btopic%3Dinetreg%5D&datetime=%5Bt-minus%3D7%5D&searchID=19014&hdlaction=story&storyid=%5Bstoryid=lnkasqygPNMKCaubRFZfiJ4-5NmxoxdlKeey7XxWAGR0aDpodEq1wL9d-d4bmVXY%5D&rtcrdata=on&epname=TRADENUZ&.

[50] Link to filing: http://www.caiso.com/Documents/May252012Order741CentralCounterpartyCompFiling.pdf.

[51] ISO-NE's central counterparty filing is available at http://www.iso-ne.com/regulatory/ferc/filings/2012/apr/er12-1651-000_4-30-12_ccp_filing.pdf

[52] Link to 1/17/12 MISO motion: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2012-01-17%20Docket%20No.%20RM10-13-000.pdf.

[53] Link to 1/24/12 FERC extension notice: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12873786

[54] A copy of this filing is available at: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2012/04/NYISO_Order_741_Tariff_Filing_all_docs_4-30-12.pdf.

[55] PJM Filing with FERC, *PJM Interconnection, L.L.C., and PJM Settlement, Inc.*, Docket No. ER10-1196-000, at 1 (May 5, 2010).

[56] *Id.* at 9.

[57] *Id.* (emphasis added).

[58] *Id*.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
						as a counterparty in PJM-administered markets does not extend to certain bilateral contracts and self-supply transactions (which PJM considers to be non-pool transactions, which is to say, outside of the organized markets it administers).[58]
Limit the time period by which a market participant must cure a collateral call to no more than two days.	A market participant has two business days to resolve a request from CAISO for additional collateral, either by posting the collateral or by demonstrating to the CAISO's satisfaction that it is not necessary.[59] The CAISO submitted tariff revisions to satisfy this Order No. 741 mandate on June 30, 2011.[60] FERC accepted the tariff revisions on September 15, 2011, effective as of October 1, 2011.[61] Thus, the CAISO is in full compliance with this Order No. 741 mandate.	If an entity's Total Potential Exposure, as defined in the Protocols, equals or exceeds its credit limit (*i.e.*, its financial security plus its unsecured credit, if applicable), ERCOT requires the entity to post additional collateral within two bank business days.[62]	Effective October 1, 2011, ISO NE has reduced the permissible time in which to cure a collateral call to two days.[63]	MISO is in full compliance and requires all market participants to cure collateral calls within 2 Business Days.[64] Filing date: 6/30/11[65] FERC approval date: 9/15/11[66] Effective date: 10/1/11	Market Participants must cure collateral calls within two business days from the date of the NYISO's request, or any shorter time period specified by the NYISO.[67] The NYISO submitted this tariff revision as required by Order No. 741. FERC approved this revision on September 15, 2011. This revision became effective on October 1, 2011 and thus, the NYISO is in full compliance with this Order No. 741 mandate.[68]	The PJM Tariff provides that a participant has two business days from notification of a breach or a collateral call to remedy the breach or satisfy the collateral call.[69]
Provide minimum participation criteria. that applies equally to all market participants	Market participants must attest annually (subject to CAISO verification) that they satisfy minimum participation requirements related to capitalization, risk	ERCOT has submitted Nodal Protocol Revision Request (NPRR) 438, Additional Minimum Counter-Party Qualification Requirements, Including Risk Management	Effective October 1, 2011, new Section II.A in the Financial Assurance Policy establishes minimum criteria for participation in ISO NE's markets. The criteria	MISO is in full compliance and requires market participants to meet the minimum participation criteria, including capitalization requirements, in order to remain	NYISO Services Tariff Section 26.1 sets forth minimum participation criteria related to capitalization, risk management, training, and operational capabilities that each	The PJM Tariff currently includes a two-pronged set of minimum participation requirements. The first prong requires market participants to provide an annual certification by a

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59 *See* CAISO Tariff § 12.4.1.

60 *See* filing letter at page 16, section entitled "Grace Period to 'Cure' Collateral Posting." Link to filing: http://www.caiso.com/Documents/2011-06-30_CredReforms_CompFiling_ER11-3973.pdf.

61 *California Independent System Operator Corporation*, 136 FERC ¶ 61,194, at Paragraph 62 (2011), available at http://www.caiso.com/Documents/ER11-3973_Credit%20Policy%20Order_2011-09-15.pdf.

62 ERCOT Protocol, Section 16.11.5 (3).

63 *ISO New England and New England Power Pool*, 136 FERC ¶ 61,191 (2011), available at http://www.iso-ne.com/regulatory/ferc/orders/2011/sep/er11-3953-000_9-15-11_credit_order.pdf.

64 Link to 3/15/12 FERC order: http://www.ferc.gov/whats-new/comm-meet/2012/031512/E-22.pdf.

65 Link to 6/30/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-06-30%20Docket%20No.%20ER11-3970-000.pdf.

66 to 9/15/11 FERC order: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2011-09-15%20136%20FERC%2061,188%20Docket%20No.%20ER11-3970.pdf.

67 *See* NYISO Services Tariff Section 26.11.

68 *See* September 15 Order at P 58.

69 PJM Tariff, Attachment Q, Section VII.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
	management, training and operational capabilities to comply with CAISO directions.[70] The CAISO submitted tariff revisions to satisfy this Order No. 741 mandate on June 30, 2011.[71] FERC accepted the tariff revisions on September 15, 2011, effective as of October 1, 2011.[72] Thus, the CAISO is in full compliance with this Order No. 741 mandate.	Capability Requirements, to establish minimum requirements for Counter-Parties to participate in the ERCOT markets. In addition, the NPRR will require ERCOT to verify the risk management framework for specified Counter-Parties. ERCOT anticipates that the NPRR will be approved by the ERCOT Board of Directors on September 18, 2012. In essence, the new eligibility requirements will specify that relevant market participants must: - have appropriate expertise in markets; - have appropriate operational capabilities to respond to ERCOT directions; - meet minimum capitalization requirements; and - maintain a risk management framework appropriate to the ERCOT markets in which it	require that market participants annually submit a list of principals and a description of, *inter alia* any material litigation, sanctions imposed by the FERC, SEC, or CFTC, any bankruptcies, mergers or acquisitions, and any operations in wholesale electricity markets other than ISO NE's markets. These criteria apply to all types of participants except those with less than $100,000 in financial assurance requirements. In addition, ISO NE has established capitalization requirements for customers and applicants. ISO NE also requires that each market participant annually submit certificates that attest that the participant has: risk management procedures and internal controls appropriate to the risks that it enters in the market; trained personnel related to its participation in New	certified and transact in the market. MISO's minimum participation criteria apply to all market participants. Initial filing date: 6/30/11[78] FERC approval date: 9/15/11[79] Effective date: 10/1/11	Market Participant must satisfy, and at all times remain in compliance with, to participate in the NYISO-administered markets. The NYISO submitted these tariff revisions as required by Order No. 741. FERC conditionally approved these revisions on September 15, 2011, subject to the NYISO further revising its tariffs to establish a periodic compliance verification process as part of its minimum participation criteria. These revisions became effective on October 1, 2011. As discussed in more detail below, on April 5, 2012, the NYISO submitted tariff revisions to establish a periodic compliance verification process. FERC approved these revisions on May 9, 2012. These revisions become effective on June 30, 2012 and thus, the NYISO is in	senior officer during a period beginning January 1 and ending April 30. For market participants applying to become new PJM members, such certification must be provided together with the prospective member's credit application. Appendix 1 to Attachment Q of the PJM Tariff sets forth the certification form, which requires certain representations regarding the participant's risk management policies and transaction activities. If the participant fails to comply with these provisions, or the certification itself, the participant will be ineligible to transact in the PJM markets. Furthermore, certain FTR Participants must provide PJM with a copy of their current governing risk control policies, procedures and controls. The second prong addresses participant capitalization requirements. A participant establishes full

70 *See* CAISO Tariff § 12.1.

71 *See* filing letter at pages 11-13, section entitled "Minimum Criteria for Market Participation." Link to filing: http://www.caiso.com/Documents/2011-06-30_CredReforms_CompFiling_ER11-3973.pdf.

72 *California Independent System Operator Corporation*, 136 FERC ¶ 61,194, at Paragraphs 41-48 (2011), available at http://www.caiso.com/Documents/ER11-3973_Credit%20Policy%20Order_2011-09-15.pdf.

73 ERCOT Protocol, Section 16.2.1, 16.8.1, 16.11.5(c), 16.11.4.1, 16.16 (the changes to these sections that effectuate this aspect of Order 741 are pending approval of NPRR 438 by the ERCOT Board of Directors and subsequent implementation).

74 ERCOT Protocol, Section 16.11.1.

75 *ISO New England and New England Power Pool,* 136 FERC ¶ 61,191 (2011), available at http://www.iso-ne.com/regulatory/ferc/orders/2011/sep/er11-3953-000_9-15-11_credit_order.pdf.

76 http://www.iso-ne.com/regulatory/ferc/filings/2011/dec/er11_3953_002_12-8-11_risk_assessment.pdf.

77 77 *ISO New England and New England Power Pool*, 138 FERC ¶ 61,185 (2012), available at http://www.iso-ne.com/regulatory/ferc/orders/2012/mar/er11-3953-002_3-15-12_order_accept_fap_compliance.pdf.

78 Link to 6/30/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-06-30%20Docket%20No.%20ER11-3970-000.pdf.

79 Link to 9/15/11 FERC order: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2011-09-15%20136%20FERC%2061,188%20Docket%20No.%20ER11-3970.pdf

80 A copy of the May 9, 2012 FERC order is available on the NYISO's website at http://www.nyiso.com/public/webdocs/documents/regulatory/orders/2012/05/2012_05_09_FERC_Ltr_Ordr_Accpt_Flng_MP_Rsk_Mngmnt_Plcs_Prcdrs.pdf.

81 PJM Tariff, Attachment Q, Section Ia.

82 *Id.*, Attachment Q.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
		transacts or wishes to transact. Counterparties will be required to provide an annual certification that they have met these requirements, attested by an officer of the company. ERCOT also is proposing minimum capitalization requirements. Proposed capitalization requirements are higher for counterparties transacting or wishing to transact in the CRR markets. Counterparties who fail to meet the capitalization requirements would be required to post an "Independent Amount" in addition to any collateral posted with respect to market positions.[73] Each Counter-Party must meet ERCOT's creditworthiness standards.[74] ERCOT expects to implement these new participation and verification requirements by the end of 2012.	England Markets; and procedures in place to effectively communicate with ISO-NE.[75] ISO-NE has also filed with FERC, in December 2011, a proposal to include an additional step involving the submission by FTR market participants of those entities' risk management procedures.[76] The proposal was accepted by FERC on March 15, 2012, with an effective date of May 1, 2012. [The changes to the certification were accepted with an effective date of February 6, 2012].[77]		full compliance with this Order No. 741 mandate.[80]	compliance with the minimum capitalization requirements through audited financials showing either tangible net worth in excess of $1 million or tangible assets in excess of $10 million if the participant is active in the FTR market, and half of either amount if the participant is not active in the FTR market. Compliance could be established either by the participant itself or through a guaranty from a compliant guarantor. Participants that are not fully compliant would be allowed to transact through a third party who meets the eligibility standards, or through the provision of collateral (only cash or a letter of credit held by PJM). The "collateral option" requires a minimum $500,000 of collateral for participants that are active in the FTR market and $200,000 of collateral for participants that are active in virtual bidding but not FTRs. A 10% reduction would be assessed on all collateral beyond those minimums and the remaining collateral value would then be available to satisfy PJM's normal credit requirements.[81] PJM's credit policy applies to all Participants.[82]
Provide examples of when a market administrator may invoke the "material adverse change" to justify requiring additional collateral.	Section 12.1.1.5 of the CAISO Tariff lists examples of circumstances constituting a "material change in financial condition" that would permit the CAISO to reduce any unsecured credit available to the affected entity and, as a result, require it to post additional collateral. Examples include a credit agency downgrade, certain financial restatements, and a default in another market. The CAISO submitted tariff	ERCOT may request additional collateral if ERCOT determines that the calculated exposure does not adequately match the financial risk created by a Counter-Party's activities under the Protocols.[85]	Effective October 1, 2011, ISO NE has added two examples of what may constitute a "material adverse change" ((1) the sanctioning of the market participant or non-market participant transmission customer or any of its principals by the Commission, the Securities and Exchange Commission, the CFTC, any exchange monitored by the National Futures Association, or any entity responsible for regulating activity in energy markets; and (2) a significant change in the market	MISO is in full compliance and updated its Tariff by supplementing pre-FERC Order 741 material adverse change measures to add a significant increase in credit default spreads and a significant decrease in market capitalization to material adverse change measures.[87] Filing date: 6/30/11[88] FERC approval date: 9/15/11[89] Effective date: 10/1/11	NYISO Services Tariff Section 26.13 sets forth examples of circumstances when the NYISO may declare a material adverse change as justification for requiring additional collateral (e.g., a significant decline in a Market Participant's market capitalization, a significant increase in a Market Participant's credit default swap spreads). The NYISO submitted this tariff revision as required by Order No. 741. FERC approved this revision on	PJM may independently determine that there is a material change in the financial condition of a participant from available information regardless of whether the participant has informed PJM of the change. In its FERC Order No. 741 compliance filing, PJM added three additional illustrative examples to the list of what constitutes a material change in financial condition: (i) a financial default in another organized wholesale electric market, futures exchange, or clearing house; (ii)

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
	revisions to satisfy this Order No. 741 mandate on June 30, 2011.[83] FERC accepted the tariff revisions on September 15, 2011, effective as of October 1, 2011.[84] Thus, the CAISO is in full compliance with this Order No. 741 mandate.		participant's or non-market participant transmission customer's market capitalization) and revised the Financial Assurance Policy to provide that, in the event of a material adverse change, the ISO may require additional financial assurance or a different form of financial assurance.[86]		September 15, 2011. This revision became effective on October 1, 2011 and thus, the NYISO is in full compliance with this Order No. 741 mandate.[90]	revocation of a license or other authority by any Federal or State regulatory agency, where the license or authority is required or important to the participant's continued business, such as a market-based rate authorization or a State license to serve retail load;[91] and (iii) a significant change in credit default spreads, market capitalization, or other market-based risk measurement criteria, such as a recent increase in Moody's KMV Expected Default Frequency that is noticeably greater than the increase in its peers rates, or a collateral default swap premium normally associated with an entity rated lower than investment grade. This third addition specifically provides illustration of possible forward-looking metrics which PJM may utilize in determining whether a material adverse change has

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83 *See* filing letter at pages 13-16, section entitled "Meaning of a 'Material Adverse Change.'" Link to filing: http://www.caiso.com/Documents/2011-06-30_CredReforms_CompFiling_ER11-3973.pdf.

84 *California Independent System Operator Corporation*, 136 FERC ¶ 61,194, at Paragraph 55-59 (2011), available at: http://www.caiso.com/Documents/ER11-3973_Credit%20Policy%20Order_2011-09-15.pdf.

85 ERCOT Protocol, Section 16.11.4.1 (3).

86 *ISO New England and New England Power Pool*, 136 FERC ¶ 61,191 (2011), available at http://www.iso-ne.com/regulatory/ferc/orders/2011/sep/er11-3953-000_9-15-11_credit_order.pdf.

87 Link to 3/15/12 FERC order: http://www.ferc.gov/whats-new/comm-meet/2012/031512/E-22.pdf .

88 Link to 6/30/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-06-30%20Docket%20No.%20ER11-3970-000.pdf.

89 Link to 9/15/11 FERC order: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2011-09-15%20136%20FERC%2061,188%20Docket%20No.%20ER11-3970.pdf.

90 *See* September 15 Order at P 53.

91 PJM also revised Sections I.A.5 and I.B.5 of Attachment Q of the PJM Tariff to add that the existence of ongoing investigations of the participant by the CFTC are required to be disclosed.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
						occurred. If PJM determines that a participant is required to provide financial security because of a material change in financial condition, PJM will provide the participant with a written explanation of why such determination was made.[92]
Engage in periodic verification of market participant risk management policies and procedures.	On September 15, 2011, FERC's order on the CAISO's June 30, 2011, Order No. 741 compliance filing directed the CAISO to submit a compliance filing that contained tariff revisions to establish periodic verification of market participant risk management policies and procedures.[93] On December 14, 2011, the CAISO filed proposed tariff revisions with FERC to establish a periodic process for verification of risk management policies and procedures of market participants that hold CRR portfolios that meet certain risk criteria.[94] On March 15, 2012, FERC issued an order that accepted the tariff revisions, effective April 30, 2012, subject to a compliance filing due by May 14, 2012, to clarify when and how often the CAISO will conduct verification of all market participants and to revise the CAISO tariff by incorporating the risk management criteria set forth in the CAISO's Business Practice Manual for Credit Management.[95] Thus, as of April 30, 2012, the CAISO will be in compliance with the March 15, 2012 FERC order, to the extent it accepted the CAISO's tariff revisions	Within the scope of the proposed eligibility requirements, which is expected to be approved by the ERCOT Board of Directors on September 18, 2012 (see above summary on minimum participation requirements), market participants would be subject to periodic verification of their risk management framework to be performed either by ERCOT or an agent acting on ERCOT's behalf.[97]	As discussed above, the annual certification requirement became effective on October 1, 2011.[98] The additional risk management assessment process was accepted by FERC on March 15, 2012, with an effective date of May 1, 2012. [The changes to the certification were accepted with an effective date of February 6, 2012].[99]	MISO is in full compliance and requires all market participants to certify the implementation of risk policies and procedures. FERC requested that MISO establish risk verification as part of its minimum participation criteria. MISO established and utilizes defined, monthly risk-based criteria and random-selection criteria for risk policy verification.[100] Initial filing date: 6/30/11[101] FERC response date: 9/15/11[102] Effective date: 10/1/11 Amended filing date: 12/14/11[103] FERC approval date: 3/15/12[104] Amendment effective date: 2/13/12	Pursuant to Services Tariff Section 26.1.3, the NYISO may require any Market Participant, at any time, to submit its risk management policies and description of internal controls to the NYISO for review. In addition to this existing discretion to request risk management policies and procedures from any Market Participant, on April 5, 2012, the NYISO filed proposed tariff revisions with FERC to establish a periodic process for verification of risk management policies and procedures with respect to two categories of Market Participants.[105] First, all Market Participants that pose significant risk in the TCC market will be subject to annual verification and all new applicants to the TCC market will be subject to verification prior to commencing any activity in the TCC market. Second, the NYISO will annually select for verification, on a random basis, 10-20% of Market Participants that are not already subject to verification. In addition, when reviewing a Market Participant's risk management policies and procedures, the NYISO will verify	PJM verifies officer certifications, described above, for all participants speculating in PJM's FTR markets by requiring such participants to submit applicable risk control policies for review. Additionally, PJM applies this same verification requirement periodically as a spot check, either randomly or based on identified risk factors, on other market participants to reinforce the importance of the annual officer certification. [107] Such review includes verification that: (1) the risk management framework is documented in a risk policy addressing market, credit and liquidity risks; (2) the Participant maintains an organizational structure with clearly defined roles and responsibility that clearly segregates trading and risk management functions; (3) there is clarity of authority specifying the types of transactions into which traders are allowed to enter; (4) the Participant has requirements that traders have adequate training relative to their authority in the systems and PJM markets in which they transact; (5) as appropriate, risk limits are in place to control risk exposures; (6)

92 PJM Tariff, Attachment Q, Section I.B.3.

93 *California Independent System Operator Corporation*, 136 FERC ¶ 61,194, at Paragraph 49 (2011), available at http://www.caiso.com/Documents/ER11-3973_Credit%20Policy%20Order_2011-09-15.pdf.

94 *See* filing letter at pages 4-5, section entitled "Minimum Participation Criteria – Officer-Certified Statements and Verification Process." Link to filing: http://www.caiso.com/Documents/2011-12-14_ER11-3973_CredRefComp.pdf.

95 *California Independent System Operator Corporation*, 138 FERC ¶ 61,181, at Paragraphs 18-19 (2012), available at http://www.caiso.com/Documents/2012-03-15_ER11-3973_order.pdf.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
	The CAISO filed the clarifying tariff revisions to comply with the March 15, 2012 order on May 14, 2012.[96]				compliance with the following eight criteria: (1) the risk management framework is documented in a risk policy addressing market, credit and liquidity risks; (2) the Market Participant maintains an organizational structure with clearly defined roles and responsibilities that appropriately segregates trading and risk management functions; (3) there is clarity of authority specifying the types of transactions into which traders are allowed to enter; (4) the Market Participant has requirements	reporting is in place to ensure that risks and exceptions are adequately communicated throughout the organization; (7) processes are in place for qualified independent review of trading activities; and (8) as appropriate, there is periodic valuation or mark-to-market of risk positions. If principles or best practices relating to risk management in PJM-type markets are published by a third-party industry association, PJM, following stakeholder discussion and notice,

96 Filing available at http://www.caiso.com/Documents/May142012CredRefCompFilingER12-1785.pdf.

97 ERCOT NPRR 438 (pending stakeholder process).

98 *ISO New England and New England Power Pool*, 136 FERC ¶ 61,191 (2011), available at http://www.iso-ne.com/regulatory/ferc/orders/2011/sep/er11-3953-000_9-15-11_credit_order.pdf;

99 *ISO New England and New England Power Pool*, 138 FERC ¶ 61,185 (2012), available at http://www.iso-ne.com/regulatory/ferc/orders/2012/mar/er11-3953-002_3-15-12_order_accept_fap_compliance.pdf.

100 Link to 3/15/12 FERC order: http://www.ferc.gov/whats-new/comm-meet/2012/031512/E-22.pdf

101 Link to 6/30/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-06-30%20Docket%20No.%20ER11-3970-000.pdf.

102 Link to 9/15/11 FERC order: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Orders/2011-09-15%20136%20FERC%2061,188%20Docket%20No.%20ER11-3970.pdf

103 Links to 12/14/11 MISO filing: https://www.misoenergy.org/Library/Repository/Tariff/FERC%20Filings/2011-12-14%20Docket%20No.%20ER11-3970-000.pdf.

104 Link to 3/15/12 FERC order: http://www.ferc.gov/whats-new/comm-meet/2012/031512/E-22.pdf

105 As background, the NYISO submitted a filing, on December 14, 2011, to comply with FERC's September 15 Order directing the NYISO to revise its tariffs to establish a periodic compliance verification process as part of its minimum participation criteria. *See* September 15 Order at P 47. A copy of the NYISO's December 14 filing is available at: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2011/12/NYISO_Cmplnc_Order_741_all_docs_12-14-11.pdf. On March 15, 2012, FERC issued an order, 138 FERC ¶ 61,186 (the "March 15 Order"), rejecting the NYISO's December 14 filing and its proposed risk management verification compliance process and directing the NYISO to submit a filing proposing a new compliance process within 60 days. A copy of the March 15 Order is available at: http://www.nyiso.com/public/webdocs/documents/regulatory/orders/2012/03/2012_03_Ordr_Rjct_Ord_741_Crdt_Vrfctn_Cmplnc_Prcss_Drct_Nw_Flng_ER11_3949_003.pdf. In the March 15 Order, FERC concluded that the NYISO's proposed exclusion from the NYISO's verification process of Market Participants that had both three years of experience in the TCC market and adequate capitalization was inconsistent with the September 15 Order. FERC found that the group of Market Participants selected by the NYISO for verification was inadequate and the NYISO's proposed process was not periodic. *See* March 15 Order a P 17. To address FERC's concerns, the NYISO proposed, in its April 5, 2012 filing, a revised risk management verification process to eliminate this exclusion, require annual verification of Market Participants that pose significant risk in the TCC market, and broaden the range of Market Participants potentially subject to review to include annual verification of 10-25% of Market Participants selected on a random basis. A copy of this April 5, 2012 filing is available at: http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2012/04/NYISO_Cmplnc_Flng_Ordr_741.pdf.

106 A copy of the May 9, 2012 FERC order is available on the NYISO's website at http://www.nyiso.com/public/webdocs/documents/regulatory/orders/2012/05/2012_05_09_FERC_Ltr_Ordr_Accpt_Flng_MP_Rsk_Mngmnt_Plcs_Prcdrs.pdf.

107 PJM Tariff, Attachment Q, Section Ia.A (as revised by PJM's further compliance filing submitted to FERC on November 29, 2011 in Docket No. ER11-3972-002).

108 Available at: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=12915576. FERC found that PJM's proposed compliance verification process complied with the FERC's directives, and is just and reasonable and not unduly discriminatory or preferential. FERC rejected requests for an exemption for market participants that are regulated by banking regulators from PJM's compliance verification policies and procedures. FERC also declined to require PJM to adopt indicated Participants' proposal regarding when and how frequently PJM would verify a market participant's compliance with risk management practices and policies. FERC found that PJM's proposal that includes selecting participants for review on a random basis and/or based on identified risk factors strikes the appropriate balance between periodically verifying that participants are complying without unduly burdening participants. FERC declined to require PJM to revise its proposal to include an additional 14 days from the date the cure period expires to appeal a negative determination. FERC also stated that it expects PJM to explain any deficiencies in a market participant's risk management policies when it notifies the participant that PJMSettlement is unable to complete its verification. FERC noted that PJM stated this in its answer. While FERC did not require tariff revisions to clarify this, they directed PJM to address this explanation in its business rules.

FERC ORDER NO. 741 MANDATES	CAISO	ERCOT[1]	ISO NEW ENGLAND	MISO	NYISO	PJM
					that traders have adequate training and/or experience relative to their authority in the systems and markets in which they transact; (5) as appropriate, risk limits are in place to control risk exposures; (6) reporting is in place to ensure that risks are adequately communicated throughout the organization; (7) processes are in place for qualified independent review of trading activities; and (8) as appropriate, there is periodic valuation or mark-to-market of risk positions. FERC approved these revisions on May 9, 2012. These revisions become effective on June 30, 2012 and thus, the NYISO is in full compliance with this Order No. 741 mandate.[106]	may apply such principles or best practices in determining the sufficiency of the Participant's risk controls. PJM may retain outside expertise to perform this review and verification. A Participant's continued eligibility to participate in the PJM markets is conditioned upon PJM notifying the Participant of successful completion of PJM's verification. If within 14 days of notification of unsuccessful completion of the verification process, the Participant demonstrates to PJM that it has filed with FERC an appeal of PJM's risk management verification determination, then the Participant will retain its transaction rights pending FERC's determination on the appeal. *See PJM Interconnection, L.L.C.*, Order Accepting Compliance Filing, Docket No. ER11-3972-002, 138 FERC ¶ 61,183 (2012). In this order, the Commission accepted PJM's November 29, 2011 filing submitted to comply with the September 15, 2011 order on its Order No. 741 compliance filing. The Commission granted a December 13, 2011, effective date, as requested.[108]