Bluffton, OH, Bluffton, VOR RWY 23, Amdt 7A
Baker City, OR, Baker City Muni, Takeoff Minimums and Obstacle DP, Amdt 2
Medford, OR, Rogue Valley Intl-Medford, RNAV (RNP) RWY 32, Orig
Portland, OR, Portland Intl, ILS OR LOC RWY 10R, ILS RWY 10R (SA CAT I), ILS RWY 10R (CAT II), ILS RWY 10R (CAT III), Amdt 33A
Hondo, TX, Hondo Muni, Takeoff Minimums and Obstacle DP, Orig
Lancaster, TX, Lancaster Rgnl, NDB RWY 31, Amdt 3
Lancaster, TX, Lancaster Rgnl, RNAV (GPS) RWY 31, Amdt 1
Victoria, TX, Victoria Rgnl, ILS OR LOC/DME RWY 12L, Amdt 11
Fillmore, UT, Fillmore Muni, RNAV (GPS) RWY 4, Orig
Fillmore, UT, Fillmore Muni, RNAV (GPS) RWY 22, Orig
Fillmore, UT, Fillmore Muni, Takeoff Minimums and Obstacle DP, Orig
Price, UT, Carbon County Rgnl/Buck Davis Field, ILS OR LOC/DME RWY 36, Orig-A
Pasco, WA, Tri-Cities, ILS OR LOC/DME RWY 21R, Amdt 12
Pasco, WA, Tri-Cities, RNAV (GPS) RWY 3L, Amdt 1
Pasco, WA, Tri-Cities, RNAV (GPS) RWY 12, Amdt 1
Pasco, WA, Tri-Cities, RNAV (GPS) RWY 21R, Amdt 1
Pasco, WA, Tri-Cities, RNAV (GPS) RWY 30, Amdt 2
Pasco, WA, Tri-Cities, VOR/DME RWY 21R, Amdt 6
Pasco, WA, Tri-Cities, VOR/DME RWY 30, Amdt 4
Richland, WA, Richland, RNAV (GPS) RWY 26, Amdt 1
Seattle, WA, Boeing Field/King County Intl, ILS RWY 13R, Amdt 30
Spokane, WA, Spokane Intl, ILS OR LOC RWY 3, ILS RWY 3 (SA CAT I), ILS RWY 3 (CAT II), ILS RWY 3 (CAT III), Amdt 6
Spokane, WA, Spokane Intl, RNAV (GPS) Y RWY 3, Amdt 2
Spokane, WA, Spokane Intl, RNAV (GPS) Y RWY 7, Amdt 2
Spokane, WA, Spokane Intl, RNAV (GPS) Y RWY 21, Amdt 1
Spokane, WA, Spokane Intl, RNAV (GPS) Y RWY 25, Amdt 3
Spokane, WA, Spokane Intl, VOR RWY 3, Amdt 13

On September 15, 2010 (75 FR 178) the FAA published an Amendment in Docket No. 30743, Amdt 3390 to Part 97 of the Federal Aviation Regulations under section 97.23 and 97.33. The following entries that were effective November 18, 2010, are changed to effective December 16, 2010:

Fort Lauderdale, FL, Fort Lauderdale/Hollywood Intl, ILS OR LOC RWY 9L, Amdt 21
Fort Lauderdale, FL, Fort Lauderdale/Hollywood Intl, ILS OR LOC RWY 27R, Amdt 9
Fort Lauderdale, FL, Fort Lauderdale/Hollywood Intl, LOC RWY 9R, Amdt 5
Fort Lauderdale, FL, Fort Lauderdale/Hollywood Intl, LOC/DME RWY 13, Amdt 1

[FR Doc. 2010–26949 Filed 10–26–10; 8:45 am]

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–13–000; Order No. 741]

Credit Reforms in Organized Wholesale Electric Markets

Issued October 21, 2010.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Pursuant to section 206 of the Federal Power Act, the Federal Energy Regulatory Commission amends its regulations to improve the management of risk and the subsequent use of credit in the organized wholesale electric markets. Each Regional Transmission Organization (RTO) and Independent System Operator (ISO) will be required to submit a compliance filing including tariff revisions to comply with the amended regulations or to demonstrate that its existing tariff already satisfies the regulations.

DATES: *Effective Date:* This Final Rule will become effective on November 26, 2010.

FOR FURTHER INFORMATION CONTACT:

Christina Hayes (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6194.

Lawrence Greenfield (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6415.

Scott Miller (Technical Information), Office of Energy Policy and Innovation, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8456.

SUPPLEMENTARY INFORMATION:

Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur.

I. Introduction

1. This Final Rule adopts reforms to credit policies used in organized wholesale electric power markets.[1]

2. The Commission has a statutory mandate 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;[2] clear and consistent credit practices are an important element of those rates. The management of risk and credit necessarily involves balance. If access to credit is too restrictive, competition suffers because fewer entities are eligible to participate, which can potentially reduce competition. Conversely, if more risk is tolerated and access to credit is too easy to obtain, then the market is more susceptible to defaults and customers bear the burden of the costs that flow from such defaults. In organized wholesale electric markets, defaults not supported by collateral are socialized among all other market participants.

3. The organized wholesale electric markets have developed their own individual credit practices through their own tariff revisions crafted through their stakeholder processes. This evolutionary process has led to varying credit practices among the organized markets. Because the activity of market participants is not confined to any one region/market and because the credit rules differ, a default in one market could weaken that participant and have ripple effects in another market. In this way, the credit practices in all ISOs and RTOs may be only as strong as the weakest credit practice. Moreover, rapid market changes can quickly escalate the costs of the transmission and sale of electric energy.

4. For these reasons, and in light of recent experiences in both the broader economy and the organized wholesale electric markets, the Commission has revisited the risk and credit procedures pertaining to the organized wholesale

[1] For purposes of this Final Rule, organized wholesale electric markets include energy, transmission and ancillary service markets operated by independent system operators (ISO) and regional transmission organizations (RTO). These entities are responsible for administering electric energy and financial transmission rights markets. As public utilities, they have on file as jurisdictional tariffs the rules governing such markets. The organized wholesale electric markets currently include the markets administered by the following RTOs and ISOs: PJM Interconnection, L.L.C. (PJM), New York Independent System Operator, Inc. (NYISO), Midwest Independent Transmission System Operator, Inc. (Midwest ISO), ISO New England Inc. (ISO–NE), California Independent Service Operator Corporation (CAISO), and Southwest Power Pool, Inc. (SPP).

[2] 16 U.S.C. 824d, 824e (2006).

markets under its jurisdiction. The Commission is thus issuing this Final Rule, requiring shortened settlement timeframes, restrictions on the use of unsecured credit, elimination of unsecured credit in all financial transmission rights (FTR) or equivalent markets,[3] steps to address the risk that RTOs and ISOs may not be allowed to use netting and set-offs, the establishment of minimum criteria for market participation, clarification regarding the organized market administrators' ability to invoke "material adverse change" to demand additional collateral from participants, adopting a standardized grace period for "curing" collateral calls, and establishing a general policy with regard to the differentiation in the applicability of these standards and reforms.

II. Background

A. Development of Credit Practices in Organized Wholesale Electric Markets

5. The Commission has long been actively interested in the credit practices of the wholesale electric markets. In crafting the *pro forma* Open Access Transmission Tariff (OATT) in Order No. 888, the Commission directed that each transmission provider's tariff include reasonable creditworthiness standards.[4] However, in response to the credit downgrades in the energy industry of 2001–2002,[5] and the resulting severe contraction in the credit markets, the Commission held a technical conference in which it received significant testimony that it should take action regarding credit practices in the organized electricity markets.[6]

6. This led the Commission to issue a Policy Statement on Electric Creditworthiness,[7] which provided market participants and market administrators with guidance to develop more robust credit practices.

7. Since it was issued, the ISOs and RTOs have made incremental progress in implementing the suggestions contained in the Policy Statement. However, the results of these efforts have been varied, leading to a wide range of risk management and creditworthiness practices among ISOs and RTOs. Because currently a default by one market participant is routinely socialized among all of the others in an ISO or RTO, this variable development of risk management practices has left many utilities at risk for a disruption in the market.

B. Credit Crunch of 2008 and Subsequent Events

8. During the autumn of 2008, large disruptions in the financial markets affected the credit markets and reduced the availability of credit. The electricity markets were vulnerable to the effects of this broader financial crisis as concern grew that default in the organized markets could lead to a damaging drop in market liquidity placing the markets themselves in jeopardy.[8] And one of the other effects of the crisis in the financial markets at that time was that credit went from being relatively plentiful and inexpensive to relatively scarce and expensive.[9]

9. The Commission held a technical conference in January of 2009 to investigate the role of credit in light of the recent financial crisis.[10] While the organized wholesale electric markets had generally functioned well overall, there were representations that improvements could be made based on the recent experience. Mr. Philip Leiber of CAISO stated that defaults in the PJM FTR markets spurred credit reforms at CAISO, but the threat of problems from larger market participants, especially related to a Bear Stearns subsidiary, also "tested our concerns." [11] Others testified about "recent near-misses" in the organized wholesale markets and suggested that the Commission should consider improvements in credit practices.[12]

10. In light of these events, the Commission proposed that the different credit practices among the organized wholesale electric markets must be strengthened.

C. Notice of Proposed Rulemaking on Credit Reforms in Organized Wholesale Electric Markets

11. On January 21, 2010, the Commission issued a NOPR pursuant to the Commission's responsibility under section 206 of the Federal Power Act (FPA).[13] The Commission proposed the following reforms related to the administration of credit in the organized markets: (1) Implementation of a billing period of no more than seven days and a settlement period of no more than seven days; (2) reduction in the allocation of unsecured credit to no more than $50 million per market participant and a further aggregate cap per corporate family; (3) elimination of unsecured credit for FTR markets, (4) clarification of the ISOs/RTOs' status as a party to each transaction so as to eliminate any ambiguity or question as to their ability to net and manage defaults through the offset of market obligations; (5) establishment of minimum criteria for market participation; (6) clarification of when

[3] References to FTR markets in this rule also include the Transmission Congestion Contracts (TCC) markets in NYISO and the Congestion Revenue Rights (CRR) markets in CAISO.

[4] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,937 (1996) (*pro forma* OATT, section 11 (Creditworthiness)), *order on reh'g,* Order No. 888–A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248, *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. *Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York* v. *FERC,* 535 U.S. 1 (2002).

[5] *See Electric Creditworthiness Standards,* Notice of Technical Conference, Docket No. AD04–8–000 (issued May 28, 2004).

[6] *See* Testimony in Technical Conference on *Electric Creditworthiness Standards,* Docket No. AD04–8–000, Tr. 120:2–6 (Mr. Alan Yoho, CAISO) (stating that CAISO was in favor of the Commission standardizing a number of credit practices among ISOs and RTOs); *Id.* at Tr. 128:22–129:11 (Mr. Dan Doyle, Vice President and CFO, American Transmission Company) (stating that the Commission should initiate a generic rulemaking proceeding to standardize credit practices among ISOs and RTOs).

[7] *Policy Statement* on Electric Creditworthiness, 109 FERC ¶ 61,186 (2004) (*Policy Statement*).

[8] In the technical conference hosted by Commission staff in May 2010, Mr. Vincent Duane of PJM stated that PJM feared it was within 24 hours of default that would cost $100 million or more. Testimony at Technical Conference on *Credit Reforms in Organized Wholesale Electric Markets,* Tr. 32 (May 11, 2010) (Mr. Vince Duane, General Counsel and Vice President, PJM). Additional testimony was submitted at the Commission's technical conference in January 2009. Testimony at Technical Conference on Credit and Capital Issues Affecting the Electric Power Industry, Docket No. AD09–2–000, presentation of Robert Ludlow, Vice President and CFO, ISO–NE at 3 ("Several recent 'near misses' with one of the largest investment grade players in the region publicly announcing that without financial relief bankruptcy was imminent."); *Id.* at 9 ("we believe concerns of a damaging drop of market liquidity are much more likely to occur given a major uncovered default"); *Id.* at Tr. 93:24–25; 94:1–2 (Jan. 13, 2009) (Mr. Robert Ludlow, CFO ISO–NE) ("we believe further damage from drops in liquidity and therefore people not clearing their transactions could exacerbate the problems and put the markets themselves in jeopardy.").

[9] A review of commercial bond spreads for creditworthy entities versus three-month Treasury bill (T–Bill) yields indicates the ability to obtain commercial credit: the wider the spread, the harder it is to obtain commercial credit. According to Bloomberg, the spread for 90 day T–Bills to 90 day commercial paper was 448 basis points on October 13, 2008, compared to an average spread of 53 basis points between April 1, 1997 and December 31, 2009.

[10] *Technical Conference on Credit and Capital Issues Affecting the Electric Power Industry,* Docket No. AD09–2–000, held January 13, 2009.

[11] *Id.* at Tr. 100:22–101:13 (Mr. Philip Leiber, Chief Financial Officer and Treasurer, CAISO).

[12] *Id.* at Tr. 91:23–25 (Mr. Robert Ludlow, Vice President and Chief Financial Officer, ISO–NE); *see also Id.* at Tr. 126–162 (question and answer).

[13] *Credit Reforms in Organized Wholesale Electric Markets,* Notice of Proposed Rulemaking, 75 FR 4310 (Jan. 27, 2010), FERC Stats. & Regs. ¶ 32,651 (2010) (NOPR).

the ISO or RTO may invoke a "material adverse change" clause in requiring additional collateral; and (7) establishment of a standard grace period to "cure" collateral calls.

12. The Commission reasoned that the proposed reforms were necessary to address the lack of standardized credit practices and the potential for mutualized default risk.[14]

D. The Need for Credit Reform in the Organized Wholesale Electric Markets

13. Sound credit practices are necessary to prevent a disruption in the system, and it is not acceptable to wait until after a disruption to implement the necessary standards. The Commission acknowledges the short-term costs of compliance with the credit practices required in this Final Rule but finds that they are outweighed by the stability that those credit practices provide to the markets and their participants. Therefore, in compliance filings to be submitted providing tariff revisions to comply with the Final Rule, ISOs and RTOs should apply these standards to market participants.

14. The Commission has considered the comments submitted, as well as the practices of electricity markets outside the United States and in other commodity markets.[15] The Commission has used the experience of these markets in addition to its own review of the organized markets in issuing this Final Rule.

15. Comments were due on or before March 29, 2010.[16] Commission staff held a subsequent technical conference on May 11, 2010 on whether ISOs and RTOs should adopt tariff revisions to clarify their status as a party to each transaction so as to eliminate ambiguity regarding their ability to "set-off" market obligations. Additional comments on that subject were due on or before June 8, 2010.[17]

[14] *Id.* P 9.

[15] Committee of Chief Risk Officers (CCRO) submitted comments about the credit practices of electricity markets outside the United States, such as NordPool Clearing ASA (Scandinavian countries), Powernext (France), NEMMCO (Australia), SEMO (Ireland), Elexon (Britain), and EMC (Singapore). CCRO March 29, 2010 Comments at 4 and Attachment B at 25–26. *See* also, *e.g.,* Market Reform, "PJM Credit and Clearing Analysis Project Findings and Recommendations" (June 2008), for a review of other markets, at *http://www.pjm.com//media/committees-groups/committees/mc/20080626/20080626-item-03d-crmsc-market-reform-credit-recommendations.ashx;* and CME market requirements at *http://www.cmegroup.com/clearing/financial-and-collateral-management.*

[16] The commenters are listed in an appendix to this Final Rule.

[17] Notice Establishing Date for Comments, 75 FR 27552 (May 17, 2010).

III. Discussion

A. Shortening the Settlement Cycle

16. As noted above, in developing this Final Rule, the Commission has considered the practices of other commodity markets, as well as electricity markets around the world. While we note that many other commodity markets employ risk management practices that are useful in minimizing the risk of a socialized default among other participants in those markets, we are also mindful of the importance of the continued reliable delivery of electricity and that some market participants have "provider of last resort" obligations that require them to continue transacting in a market, even under challenging financial conditions.

17. The Commission and participants in the electric industry have recognized a correlation between a reduction in the "settlement cycle"[18] and a reduction in costs attributed to a default. As the Commission noted in its Policy Statement, "the size of credit risk exposure is, in large part, a function of the length of time between completion of various parts of electricity transactions, i.e., the provision of service, the billing for service, and the payment of service."[19]

18. Currently, each ISO and RTO has its own time period for billing and settlement. ISO–NE has weekly billing (soon to be twice-weekly), with payment due no later than the second business day after the invoice is issued.[20] Midwest ISO has weekly billing, with payment due seven days after the weekly invoice is issued.[21] PJM has weekly billing and settlement.[22] SPP has weekly billing, with payment due the Wednesday after the invoice is issued.[23] CAISO has semi-monthly billing, with five additional days for settlement.[24] NYISO has monthly billing, with payment due by the first banking day common to all parties after the 15th day of the month that the invoice is rendered by the ISO.[25]

[18] Some parties sought clarification of the Commission's definition of "settlement cycle" in the NOPR, recognizing that settlement encompasses both the billing period and the additional time for final payment of the billed amount. The Commission will therefore refer to each period separately as the "billing period" and the "settlement period."

[19] *Policy Statement,* 109 FERC ¶ 61,186, at P 21.

[20] *ISO New England, Inc. and New England Power Pool,* 132 FERC ¶ 61,046 (2010).

[21] Midwest ISO March 29, 2010 Comments at 4.

[22] PJM March 29, 2010 Comments at 21.

[23] SPP March 29, 2010 Comments at 3.

[24] CAISO March 29, 2010 Comments at 8.

[25] Northeast ISOs March 29, 2010 Comments at n.17; NYISO OATT at section 2.7.3.2.

19. To minimize the risk associated with the duration of the settlement period, the Commission proposed in the NOPR to require no more than seven days for each ISO/RTO market billing period plus no more than seven calendar days for settlement. The Commission cited a PJM study that found that movement from monthly to weekly billing would reduce credit risk exposure by $2.1 billion (68 percent), and that necessary financial security provided by members would be reduced by $700 million (73 percent).[26] Further, the Commission's earlier Policy Statement cited an ISO–NE report that its movement to a weekly billing period resulted in a 67 percent reduction in financial assurances that had to be produced by its market participants.[27] The Commission also sought comment on the practicality of moving organized wholesale electric markets to daily billing within one year of implementation of weekly billing.

20. The Commission recognized that net buyers in organized markets might incur cash management costs because they would be obligated to pay their debts on a seven-day basis, but receive cash from retail sales on a 30-day basis. In the NOPR, the Commission thus recognized that cash management facilities to facilitate more frequent payments might be necessary and sought comments on this particular issue.

21. The Commission also noted that ISOs and RTOs may need to make software changes to accommodate a shortened settlement cycle and encouraged ISOs and RTOs to use software that is already in use in markets that are currently operating on a seven-day settlement cycle.

1. Comments

22. Parties in favor of the proposal include a number of the ISOs and RTOs, as well as financial entities such as "Financial Marketers,"[28] Citigroup Energy (Citigroup), J.P. Morgan Ventures Energy Corporation (J.P. Morgan), and

[26] NOPR, FERC Stats. & Regs. ¶ 32,651 at P 14 & n.20 (citing PJM Credit & Clearing Analysis Project: Findings & Recommendations (June 2008) (found on Dec. 31, 2009 at: *http://www.pjm.com/~/media/committees-groups/committees/mc/20080626/20080626-item-03d-crmsc-market-reform-credit-recommendations.ashx*)).

[27] *See Policy Statement,* 109 FERC ¶ 61,186, at P 22 (citing Memorandum to NEPOOL Participants Committee re: Amendments to Billing Policy and Financial Assurance Policies to Implement Weekly Billing, Paul Belval and Scott Myers, NEPOOL Counsel, Feb. 21, 2004).

[28] SESCO Enterprises LLC, Jump Power LLC, Energy Endeavors LP, Big Bog Energy LP, Silverado Energy LP, Gotham Energy Marketing LP, Rockpile Energy LP, Coaltrain Energy LP, Longhorn Energy LP, and GRG Energy LLC.

Morgan Stanley Capital Group (Morgan Stanley). The staff of the Division of Clearing & Intermediary Oversight at the Commodity Futures Trading Commission (CFTC staff) also supports moving the billing cycle to, at most, seven days.[29]

23. Many industry participants who are normally "net sellers" of supply such as Constellation, NRG, Calpine, Dominion, Mirant, and Powerex also support the proposed shortened billing time-period.[30] CCRO supports a standard seven-day billing period as "consistent" with its review of best practices in the electric industry.[31] The New York Suppliers note that NYISO is the lone organized market in the nation with a monthly billing period.[32] The New York Suppliers contend that allowing NYISO—or CAISO which currently has a two-week billing cycle—to remain out of step with a weekly standard elsewhere increases the risks to participants in New York and California.[33] The Independent Power Producers of New York (IPPNY) comments that, since the beginning of weekly billing in ISO–NE, the number of market participants has increased in every sector and the total number of market participants increased by over 60 percent,[34] suggesting that not only was liquidity enhanced by shorter billing but the change did not pose a barrier to entry.

24. Powerex states that moving to a weekly standard for billing will lower the amount of financial security required which should address concerns of smaller or municipal market participants. Powerex also agrees with the Commission's suggestion that ISOs and RTOs should use existing software that can accommodate this billing cycle, in order to minimize any transition delays.[35]

25. CAISO, alone among the organized markets, doubts that moving to a weekly billing standard would result in significant benefits as it would reduce aggregated outstanding liabilities by only an additional 10 percent. CAISO expresses concern that weekly billing could significantly affect market participants given that it has already shortened the cycle from 90 days and that going further now might be disruptive. Nevertheless, CAISO also explains that its future plans are to move to weekly billing.[36]

26. Parties opposing the proposal include the City of New York, the New York State Public Service Commission (NYPSC) and "Six Cities."[37] Indeed, the City of New York and the NYPSC argue that the Commission should not impose a shorter settlement period just for the sake of uniformity and that the Commission should give deference to the policies adopted through ISO and RTO governance processes.[38] The NYPSC and the New York State Consumer Protection Board (NYSCPB) further contend that weekly billing could result in a wealth transfer from some market participants to others.[39]

27. Other parties oppose movement to weekly billing based on data concerns, including net sellers such as Midwest Transmission Dependent Utilities (Midwest TDU)[40] and Consolidated Edison Solutions.[41] This point was similar to the concerns of Bonneville Power Administration (BPA) who, while supportive of weekly billing, has concerns about the ability of CAISO to effectively manage the resulting increased demands. PG&E argues against reducing billing cycles in the organized wholesale market without a similar billing period in the bilateral market, because it would create an opportunity for sellers to operate with reduced need for working capital and shifts liquidity risk from sellers to buyers.[42]

28. Regarding the Commission's request for comment on the practicality of organized wholesale electric markets implementing daily settlement periods within one year of implementation of weekly settlement periods, there was very little commenter support for this proposal. Most of the support for this proposal came from financial entities. CFTC staff, J.P. Morgan and Morgan Stanley support this proposal.[43] CFTC staff argues that routine and frequent settlement imposes discipline on participants, in that it discourages participants from entering into new positions without first ensuring that they have adequate liquidity to support such positions. CFTC staff also states that the collection of payments from FTR market participants should happen promptly, within hours or overnight.[44]

29. Calpine also supports daily settlement. Calpine notes that this is achievable, as shown by ISO–NE in its plans to implement twice weekly billing.[45] Calpine also notes that some stakeholders oppose compression of the settlement cycle, arguing that operational issues and the quality of data available do not support daily settlements. Calpine states that these concerns may be true for the real time market (RTM), but they do not apply to the day-ahead market (DAM).[46] Calpine requests that the Commission consider moving towards daily billing by requiring ISOs/RTOs to split the DAM from other markets and settle the DAM daily.[47]

30. However, many stakeholder group members opposed daily settlement. CAISO, the IRC, Midwest ISO, and PJM do not support daily invoicing. CAISO, Midwest ISO and PJM all cite financial and logistical concerns as reasons to oppose daily billing. The IRC does not believe the Commission should mandate a move to daily settlement periods, but should allow ISOs/RTOs to work with stakeholders to research the proposal further to evaluate the daily costs and benefits. PJM states that stakeholder discussions should occur prior to determining whether such a change would be cost beneficial to the market participants in the PJM region. PJM also states that its current settlement system does not have the flexibility to issue daily invoices.[48]

31. APPA, NRECA, NYAPP, and New Jersey Public Power cite the cost of daily settlements as their reason not to support it.[49] Basin Electric believes daily settlements would be administratively burdensome.[50]

[29] Although the comments submitted by CFTC staff were focused on the FTR markets, they also recommend requiring each ISO or RTO to establish daily settlement as soon as practicable. CFTC staff March 29, 2010 Comments at 5.

[30] New York Suppliers March 29, 2010 Comments at 7; Calpine March 29, 2010 Comments at 1; Dominion March 29, 2010 Comments at 2; Mirant March 29, 2010 Comments at 3–4; Powerex March 29, 2010 Comments at 4–5.

[31] CCRO March 29, 2010 Comments at 3.

[32] New York Suppliers March 29, 2010 Comments at 9.

[33] *Id.* at 9–10.

[34] IPPNY March 29, 2010 Comments at 12–13.

[35] Powerex March 29, 2010 Comments at 6–7.

[36] CAISO March 29, 2010 Comments at 7–8.

[37] The "Six Cities" include the cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, all located in California.

[38] City of New York March 29, 2010 Comments at 6–7; NYPSC March 29, 2010 Comments at 3–4.

[39] NYPSC March 29, 2010 Comments at 7–8; NYSCPB March 29, 2010 Comments at 3.

[40] Indiana Municipal Power Agency, Madison Gas & Electric Company, Missouri River Energy Services, Southern Minnesota Municipal Power Agency and WPPI Energy.

[41] Midwest TDU March 29, 2010 Comments at 7–9; Consolidated Edison Solutions March 29, 2010 Comments at 3–4.

[42] PG&E March 29, 2010 Comments at 2.

[43] J.P. Morgan Comments at 6; MSCG Comments at 2–3.

[44] CFTC staff Comments on 5.

[45] Calpine Comments at 4 & n.8 (citing *ISO New England, Inc. and New England Power Pool* March 26, 2010 filing, Docket No. ER10–942–000).

[46] Calpine Comments at 4.

[47] *Id.* at 5.

[48] CAISO Comments at 9; IRC Comments at 4–5; MISO Comments at 5; PJM Comments at 21–23.

[49] APPA Comments at 17; NRECA Comments at 10; NYAPP Comments at 10; PPANJ Comments at 10–11.

[50] Basin Electric Comments at 3.

Midwest TDUs state that daily settlements are unworkable now and in the foreseeable future, and should be addressed by the individual ISOs/RTOs.[51] NRECA also points out that the movement to shortened settlement cycles would occur at the same time utilities implement "smart grid" applications and NRECA questions whether all metering and computer hardware and software systems can be done at the same time.[52] Western Area Power Administration (WAPA) believes daily settlements are impractical and it would not allow the opportunity to correct errors which could use up all available funds unnecessarily in a matter of a few days. WAPA is concerned about daily settlements and the timing of the CAISO invoices, which are issued at midnight, because it would unfairly shorten the daily settlement processing period to less than 24 hours.[53]

2. Commission Determination

32. In this Final Rule, the Commission adopts the NOPR proposal to direct each ISO and RTO to submit a compliance filing that includes tariff revisions to establish billing periods of no more than seven days and settlement periods of no more than seven days after issuance of bills. This compliance filing must be submitted by June 30, 2011, with the tariff revisions to take effect October 1, 2011. While the Commission has, in the past, not required shortened billing periods, in order to promote market liquidity,[54] we find it is a necessary component of a package of reforms designed to reduce default risk, the costs of which would be socialized across market participants and, in certain events, of market disruptions that could undermine overall market function. We find unpersuasive comments that shortened billing and settlement cycles will compromise the liquidity of the organized wholesale electric markets.

33. The basic premise for shorter billing periods is that the reduced amount of unpaid debt left outstanding reduces the size of any default and therefore reduces the likelihood of the default leading to a disruption in the market such as cascading defaults and dramatically reduced market liquidity. In addition, the reduction in outstanding obligation also decreases the amount of collateral that market participants must post, which mitigates the affect on market participants of reducing the amount of unsecured credit the ISOs and RTOs can extend. The Commission's decision is supported by the studies performed by ISO–NE and PJM.[55]

34. The Commission does not agree with the statement of the NYPSC or the City of New York that the movement to a weekly billing period will be a "wealth transfer" from buyers to sellers. The Commission is focused on the benefits of reduced risk afforded to all market participants by a minimum standard of weekly billing. While short-run working capital costs may be shifted, the result is that the overall cost of default will be lower for every market participant. Thus, all participants will benefit in this circumstance.

35. The Commission also disagrees that there may be problems verifying data. ISO–NE, SPP, and Midwest ISO have shown that they can administer weekly billing without significant incident. The experience of these markets suggests that data handling and verification should not pose insurmountable challenges. Regarding PG&E's discussion of reduction of billing time in the bilateral markets, the Commission believes that individual counterparties to bilateral contracts may negotiate their own billing terms.

36. As for parties that urged the Commission to not mandate a "one size fits all" approach in establishing minimum billing periods or that the Commission should defer to stakeholders in this matter, the Commission disagrees. Nothing in this record suggests that any of the organized wholesale electric markets is differently situated in a manner that warrants deviating from this minimum standard for billing periods.

37. Recognizing the benefits that will flow from requiring billing to be at least weekly, and balancing the incremental benefits and incremental burdens of daily billing, we will not require daily billing at this time. Instead we will require, as discussed above, weekly billing.

B. Use of Unsecured Credit

38. The use of unsecured credit varies among the organized markets. SPP currently limits extensions of unsecured credit to any single entity or affiliated group of entities to $25 million.[56] CAISO and PJM extend no more than $50 million per market participant.[57] Midwest ISO and ISO–NE allow up to $75 million per market participant,[58] and NYISO extends up to $150 million per market participant.[59]

39. In the NOPR, the Commission proposed to require each ISO and RTO to revise its tariff provisions to reduce the extension of unsecured credit to no more than $50 million per market participant. The Commission sought comment on whether there should be a further corporate cap to cover an entire corporate family. Consideration of an overall corporate family cap on the use of unsecured credit was based on experience in the RTO and ISO markets where many entities have multiple subsidiary companies operating in the same market. Since these entities often use the same balance sheet for credit purposes, limits on the entire corporate family would ensure that multiple, related market participants could not defeat the purpose of limiting unsecured credit. Finally, the Commission sought comment on whether it should eliminate the extension of unsecured credit in connection with adopting daily settlements.

1. Comments

a. Individual Market Participant Cap

40. Many commenters support the proposal to limit the extension of unsecured credit to no more than $50 million per participant, but make more nuanced comments in how the credit limit should be applied. CAISO, the Northeast ISOs,[60] and the ISO–RTO Council (IRC) favor a generic $50 million "cap" on the use of unsecured credit per participant, rather than a mandated limit of $50 million per participant, such that individual ISOs or RTOs may file with the Commission to establish lower limits on unsecured credit as appropriate.

41. The proposed limit on unsecured credit is supported by financial participants (Citigroup Energy Inc., Financial Marketers), some public power participants (Northern California Power Agency, Public Power Association of New Jersey and Madison, New Jersey (New Jersey Public Power), and Basin Electric), some retail providers (Direct Energy), and suppliers (the Electric Power Supply Association

[51] Midwest TDUs Comments at 11–12.

[52] NRECA Comments at 10.

[53] WAPA Comments at 5–6.

[54] *Policy Statement,* 109 FERC ¶ 61,186, at P 24.

[55] *See,* e.g., Market Reform, "PJM Credit and Clearing Analysis Project Findings and Recommendations" (June 2008) see *http://www.pjm.com/~/media/committees-groups/committees/mc/20080626/20080626-item-03d-crmsc-market-reform-credit-recommendations.ashx;* NEPOOL Participants Committee, Weekly Billing Presentation, (January 9, 2004).

[56] SPP March 29, 2010 Comments at 4.

[57] CAISO March 29, 2010 Comments at 10–11 and PJM Tariff at Sixth Revised Sheet No. 523G.

[58] Midwest ISO March 29, 2010 Comments at 6 and Exhibit IA (ISO New England Financial Assurance Policy) of ISO New England Inc. Transmission, Markets and Services Tariff.

[59] NYISO March 29, 2010 Comments at 10.

[60] The Northeast ISOs refer to joint comments filed by ISO–NE, PJM, and NYISO.

(EPSA)). While they support the proposed limit on unsecured credit, New Jersey Public Power state that there may come a time when a $50 million cap is not adequate and preventing full participation in PJM markets so the Commission should provide flexibility to allow municipal utility participation without such an unsecured credit cap.[61] One party, DC Energy, does not believe that the use of unsecured credit should be allowed in any market. Powerex suggests that, not only should the Commission adopt a $50 million limit on the use of unsecured credit, the Commission should attempt to determine if the amount could be further reduced as a consequence of a minimum standard on billing periods.[62] The National Rural Electric Cooperative Association (NRECA) specifically does not oppose the proposed limit on unsecured credit. Hess Corporation (Hess) states that the limit of unsecured credit should be no more than $50 million and should apply to all market participants.

42. The CPUC asserted that the Commission should not arbitrarily limit unsecured credit. To the extent the Commission decides to limit unsecured credit, CPUC suggests limiting unsecured credit to a level that corresponds to the settlement cycle.[63] When determining the amount of unsecured credit for a given entity, the CPUC recommends using a process which is based on a consistent, systematic, and non-discriminatory approach. The CPUC states that market participants with higher credit ratings should be allowed to have higher unsecured credit.[64]

43. A number of commenters support the continued use of unsecured credit, and state that the Commission should allow each ISO/RTO, through the stakeholder process, to determine a formula or method to limit the amount of unsecured credit.[65] EEI states that the Commission should require the ISO/RTO to justify the maximum amount of unsecured credit that the ISO/RTO permits to any participants using a formula. Morgan Stanley states that credit should be extended based upon an application of objective financial criteria to evaluate carrying capacity and default probabilities.[66] Consolidated Edison Solutions states that a national cap would not recognize the creditworthiness of financially strong companies and may set the level too low for regions with high energy costs.[67] APPA believes that each RTO should tailor their credit policies to take into account the respective financial strengths and business models of the various market participants.[68]

44. Similarly, Consumers Energy indicates that a uniform $50 million cap would be an illusory goal given the differing methods for analyzing credit in the ISOs/RTOs.

b. Aggregate Corporate Family Cap

45. Most parties also support an aggregate family cap but debate whether it should be mandated by the Commission or determined by each ISO/RTO through a stakeholder process. The Northeast ISOs argue that, due to regional variations, market operators should have flexibility in determining the appropriate level of any aggregate corporate cap.[69] Basin Electric agrees with this approach, but argues that the criteria should be consistently applied.[70]

46. NRECA indicates it does not oppose an aggregate cap on corporate families and suggests an unsecured credit limit of $100 million per corporate family.[71] Shell Energy, on the other hand, agrees with the proposal to have an aggregate corporate cap but suggests that it be the same as the $50 million cap suggested in the NOPR for an individual participant.[72]

47. Morgan Stanley opposes an aggregate cap and further urges the Commission to explicitly mandate that, in determining how much credit to extend to a market participant, the ISOs and RTOs consider the parent company guarantees of a market participant's market activity.[73] EPSA states that an aggregate cap does not make sense for a holding company that holds both regulated utility subsidiaries and unregulated market participants.[74] San Diego Gas & Electric (SDG&E) also opposes an aggregate cap, stating that it is both unnecessary in California and would frustrate the CPUC affiliate transaction rules, which "requires that a parent backing its affiliates be subject to a $50 million maximum unsecured credit limit." [75]

c. Different Cap for Markets of Different Size

48. In the NOPR, the Commission asked whether the caps on unsecured credit should differ as a result of differing market size. BP Energy specifically notes that the size of the market should make a difference in terms of the amount of unsecured credit allowed and that the Commission should not mandate a particular amount. MidAmerican agrees and states that any limit should be formulaic. Mirant favors avoiding a "one size fits all" approach to setting unsecured credit limits. PSEG suggests that the cap should be based upon the risk of each individual market participant and factors unique to each ISO/RTO. Consequently, PSEG argues, this issue is best left to each ISO/RTO and its stakeholders.

2. Commission Determination

49. The Commission adopts the NOPR proposal to require each ISO and RTO to revise its tariff provisions to reduce the extension of unsecured credit to no more than $50 million per market participant.

50. The Commission is concerned that RTOs and ISOs, even after analyzing the creditworthiness of market participants, have allowed large amounts of unsecured credit in their markets (during the financial crisis in fall 2008, ranging from 50 to 80 percent). The Commission recognizes that unsecured credit may provide increased liquidity in the organized wholesale electric markets and is only extended after the ISO/RTO has performed a credit analysis of the market participant receiving the unsecured credit. However, the Commission is concerned that the assumptions upon which any credit analysis is made can change rapidly. For instance, Lehman Brothers was rated as "investment grade" by all ratings agencies on Friday, September 12, 2008, only to file for bankruptcy on Monday, September 15, 2008.[76] The Commission considered several factors, as well as the comments, in establishing the $50 million cap on unsecured credit per market participant. We note that CAISO and PJM have adopted a $50

[61] New Jersey Public Power Comments at 10.

[62] Powerex March 29, 2010 Comments at 7–8.

[63] CPUC March 29, 2010 Comments at 3.

[64] *Id.* at 3–4.

[65] AMP, APPA, CES, EEI, MSCG, NIPSCO, SPP, Midwest TDUs, and Wisconsin parties.

[66] NSCG March 29, 2010 Comments at 4.

[67] Consolidated Edison Solutions March 29, 2010 Comments at 4.

[68] APPA March 29, 2010 Comments at 4.

[69] Northeast ISOs March 29, 2010 Comments at 6–7.

[70] Basin Electric March 29, 2010 Comments at 3.

[71] NRECA March 29, 2010 Comments at 11.

[72] Shell Energy March 29, 2010 Comments at 7.

[73] Morgan Stanley March 29, 2010 Comments at 4–5.

[74] EPSA March 29, 2010 Comments at 7.

[75] SDG&E March 29, 2010 Comments at 4.

[76] While Lehman Brothers was not itself a public utility, it was in many ways no different from other financial institutions that are or are affiliated with public utilities. In a June 17, 2009 email to market participants, PJM indicated that Lehman Brothers Commodity Services, Inc., defaulted on $18.1 million in obligations to PJM. *http://www.pjm.com//media/about-pjm/member-services/default-notification/lbcs-default-update.ashx.*

million cap on unsecured credit for a single market participant, indicating that this level has already been accepted and incorporated into the business practices of market participants throughout the country. Most importantly, based on experience with past defaults, we are persuaded that the organized wholesale electric markets could withstand a default of this magnitude by a single market participant.[77] The Commission further believes that this cap on unsecured credit per market participant balances the interests of market participants by not raising costs by an unreasonable amount while still protecting the markets and their participants from unacceptable disruption.

51. Moreover, as noted in the NOPR, as the timeframe of settlement shrinks, so does the amount of unsecured credit that a participant may need. This is because the number of outstanding transactions and the size of the amounts outstanding become smaller, thus minimizing the credit exposure to any market participant.[78] Reducing the amount of unsecured credit extended before there is a crisis, combined with a shortened settlement cycle, should reduce the risk of a mutualized default and any potential market disruption.

52. As discussed earlier, the Commission must balance the needs of market liquidity with overall risk. To achieve this balance, the Commission directs each ISO and RTO to submit a compliance filing that includes tariff revisions to establish a limit on unsecured credit of no more than $50 million per market participant. This compliance filing must be submitted by June 30, 2011, and the tariff revisions will take effect October 1, 2011. In response to commenters who argue that markets that are a different size should have different caps on unsecured credit, we note that the $50 million limit on unsecured credit is a ceiling, not a mandated amount. Any organized wholesale electric market may establish a lower limit, either for individual market participants or based on the market administrator's credit analysis of a particular market participant.

53. The Commission further establishes, for each organized wholesale electric market, a maximum level of $100 million of unsecured credit for all entities within a corporate family. This level would allow multiple market participants within one corporate family to each have access to a significant level of unsecured credit, up to $50 million in each organized wholesale electric market as indicated above, to conduct business. Adoption of an overall corporate family cap of $100 million of unsecured credit in each organized wholesale electric market reflects our experience in the RTO and ISO markets where many entities have multiple subsidiary companies operating in the same market. By implementing a cap on a corporate family, the Commission avoids a scenario in which multiple market participants within one corporate family have $50 million in unsecured credit per participant, and a bankruptcy of the entire corporate family results in a significant default in an organized wholesale electric market.[79] As indicated by Mr. Duane's testimony at the technical conference, a default of $100 million in an organized wholesale electric market would be significant, even in a market the size of PJM. Moreover, we believe that this level of unsecured credit strikes a balance by not raising costs for market participants by an unreasonable amount while still protecting the markets and their participants from unacceptable disruption.

54. The Commission thus directs each ISO and RTO to submit a compliance filing that includes tariff revisions to establish an aggregate cap on unsecured credit per corporate family of no more than $100 million. This compliance filing likewise must be submitted by June 30, 2011, and the tariff revisions will take effect October 1, 2011. Similar to the cap on individual market participants, each ISO or RTO may establish a lower level for the aggregate cap.

55. The Commission views the limits as an upper ceiling or limit which will allow for varied amounts below the $50 million and $100 million thresholds. The Commission agrees that limits below the Commission-prescribed levels can be set depending on relative market size, the price of energy, the number of megawatt hours, and the size and number of the members, for example.

56. The Commission also believes that the contention of Morgan Stanley, that ISOs and RTOs should explicitly consider parent guarantees in their evaluation of credit, is contrary to the point of this rulemaking. Parent guarantees are simply another form of unsecured credit that will not necessarily protect a market from default by market participants if the parent company experiences financial distress, and the Commission directs ISOs and RTOs to not take them into account in establishing the appropriate level of unsecured credit for a market participant or aggregate cap.

57. The Commission further disagrees that an aggregate cap is not needed in a corporate family structure that has both unregulated entities and regulated utilities. Regulated entities, even those with cost-of-service rates, do not necessarily have a revenue stream guaranteed to cover wholesale market costs, and thus should not be assumed to be without risk of default.

C. Elimination of Unsecured Credit for Financial Transmission Rights Markets

58. The proposal to eliminate the allocation of unsecured credit in FTR markets or their equivalent is based on the unique nature of FTRs.[80] The value of the FTR can vary widely over very short periods of time. Further, owing to the relationship to the physical state of the electric grid, the state of which is known to all market participants, there are few if any participants who would be willing to "step into" the shoes of a party that is nearing default as a FTR position deteriorates financially. FTR markets entail obligations that are normally active over a long period of time, often a year or more, and their potential change in value over this time frame is quite large.

59. The value of so-called "prevailing flow" FTRs[81] are generally predictable when there are no substantial changes in fuel prices or the physical state of the electric grid. However, outages on the transmission system and substantial changes in fuel prices can cause

[77] To date, the Power Edge LLC default of $51.7 million in PJM was the most significant in total value in an organized wholesale electric market. *PJM Interconnection, L.L.C.* v. *Accord Energy, LLC,* 127 FERC ¶ 61,007, Enforcement Staff Report at 1 n.5 (2009).

[78] NOPR, FERC Stats. & Regs. ¶ 32,651 at P 17 (*citing California Independent System Operator Corp.,* 129 FERC ¶ 61,142 at P 14 (2009) (adopting limit of $50 million of unsecured credit per market participant); *PJM Interconnection, L.L.C.,* 127 FERC ¶ 61,017 at P 5 (2009) (adopting limit of $50 million for a member company and $150 million for an affiliated group)).

[79] For instance, Lehman Brothers declared bankruptcy as a corporate family, disrupting the financial markets. *See* Report of Anton R. Valukas, Examiner, submitted in *In re Lehman Brothers Holdings Inc., et al.,* (Bankr. S.D.N.Y., Mar. 11, 2010), found at: *http://lehmanreport.jenner.com/VOLUME%201.pdf.* A similar default by a market participant could result in a significant disruption in an organized wholesale electric market.

[80] A firm transmission right or FTR is a "financial instrument[] used to hedge the risk of transmission congestion by entitling the holders of [this] instrument[] to compensation for transmission congestion charges." *PJM Interconnection, LLC,* 127 FERC ¶ 61,025, at P 2 (2009).

[81] A "prevailing flow" FTR is one in which the historic movement of power from a lower priced area to a higher priced area occurs under normal transmission system operation. This is normally defined over a period of years by the ISO/RTO and may reflect contractual obligations that predate ISO or RTO establishment.

unforeseen flow patterns and result in a rapid and dramatic drop in the value of an FTR position.[82] For example, a large transformer or major transmission line can fail, thus changing flows of electricity and causing increased congestion in other areas. This will happen nearly instantaneously and the effect on the flows of electricity will remain in effect for whatever period of time it takes to repair or replace the equipment. In some cases, this could be months or longer. Thus the use of unsecured credit in a market with risk that is difficult to quantify can lead to unforeseen and substantial costs in the event of a default.

60. In the NOPR, the Commission proposed to revise its regulations to require that each RTO and ISO include in the credit provisions of its tariff provisions that eliminate unsecured credit in financial transmission rights markets.

1. Comments

61. The response to the Commission's proposal to eliminate the use of unsecured credit in FTR markets is mixed. Parties that support the proposal include SPP, Basin Electric, the Organization of Midwest ISO States (OMS), Calpine, Citigroup, DC Energy, Dominion, Shell Energy, the Northeast ISOs, the New York Transmission Owners (NYTO), National Energy Marketers Association (NEMA), and J.P. Morgan.[83]

62. NYISO states general support for the elimination of unsecured credit for its TCC[84] market but argues that the Commission should clarify that those holding "fixed price" TCCs should be exempt.[85] Similarly, CAISO states that it supports the elimination of unsecured credit for FTRs, but asserts that a variety of specific practices would meet this requirement.[86] CAISO allows netting of collateral posted for their equivalent FTR market participation and the auction of these rights, which CAISO suggests eases capital burdens while mitigating risk. Additionally, CAISO does not distinguish between credit for their FTR equivalent market and all other markets. Consequently, collateral posted for all markets can effectively be used interchangeably.

63. The CPUC advises against elimination of unsecured credit in FTRs because load serving entities (LSE) use FTRs for hedging congestion risk on behalf of consumers, and elimination of unsecured credit in FTRs could result in higher costs passed on to ratepayers.[87]

64. Joint Commenters,[88] Wisconsin Public Service Corporation and Upper Peninsula Power Company (Wisconsin Parties), and the Edison Electric Institute (EEI) state that risks associated with FTRs are not addressed by simply requiring FTR market participants to be fully collateralized. The Joint Commenters suggest that the Commission should instead direct the ISOs and RTOs to work together to develop a set of "Best Practices" for valuing FTRs and, to the extent possible, standardize valuation methodologies across ISOs and RTOs.[89] Similarly, EEI states that the Commission should require ISOs and RTOs to reassess their methodology for valuing FTRs and report back to the Commission in one year.[90] The Wisconsin Parties do not take a position with regard to the issue but note that the real credit issue relates to calculating the FTRs' future value and the resulting future liability exposure.[91]

65. Similarly, MidAmerican and PSEG state that the NOPR proposal to eliminate unsecured credit in FTR markets is misguided because it does not address valuation of FTRs. MidAmerican states that, if the Commission is intent on eliminating unsecured credit for FTRs, it should require each ISO/RTO to allow a market participant to offer the ISO/RTO a security interest in receivables from non-FTR market activities as an acceptable form of collateral for FTR market activity.[92]

66. SDG&E also states that eliminating unsecured credit in the FTR market will require even LSEs to post collateral which increases costs. SDG&E argues in favor of allowing such entities to be exempt from the prohibition on unsecured credit in FTRs and adds that CAISO should provide for a transparent mechanism to calculate collateral for FTR positions on a daily or weekly basis.[93]

67. Midwest ISO states that the Commission should avoid applying the same approach to all market participants, regardless of their business model. APPA also opposes any standardized Commission action in this regard, arguing that elimination of unsecured credit for LSEs holding FTRs could deal a fatal blow to the ability of public power systems to secure long-term FTRs. However, APPA favors FTR collateral requirements for RTO market participants that are not participating in FTR markets to hedge congestion associated with physical transmission service taken to serve their loads, but instead are doing so for speculative reasons.[94]

68. First Energy, EMCOS, IMEA, Midwest TDUs, NRECA, NYAPP, NCPA, Western, CPUC, MSCG, MidAmerican, PSEG, and SCE oppose the Commission's proposal to eliminate unsecured credit in the FTR markets. First Energy Service Company (First Energy) argues that defaults that occurred in the PJM market in December 2007 were not due to the use of unsecured credit, but rather the abuse of FTR markets.[95] First Energy recommends that the Commission not eliminate unsecured credit, but instead use independent market monitors that are in place in each ISO/RTO, in addition to the enforcement capabilities granted to the Commission in the Energy Policy Act of 2005, to ensure that no market manipulation is taking place.[96] MidAmerican and the PSEG state that the Commission's proposal is misguided and should be abandoned because it fails to address the most important underlying issue with respect to FTRs, which is one of valuation.[97] In addition, Midwest TDUs, NRECA, NYAPP, and NCPA state that the elimination of unsecured credit for FTRs could create unnecessary collateral obligations on LSEs.[98]

69. Some parties such as Northern Indiana Public Service Company

[82] Division of Market Oversight, Federal Energy Regulatory Comm'n, 2009 State of the Markets Report at 20 (April 15, 2010), available at *http://www.ferc.gov/market-oversight/st-mkt-ovr/som-rpt-2009.pdf*.

[83] SPP March 29, 2010 Comments at 5–6; Basin Electric March 29, 2010 Comments at 4; OMS March 29, 2010 Comments at 3; Calpine March 29, 2010 Comments at 7; Citigroup March 29, 2010 Comments at 4; DC Energy March 29, 2010 Comments at 9; Dominion March 29, 2010 Comments at 7; Shell Energy March 29, 2010 Comments at 6; Northeast ISOs March 29, 2010 Comments at 7; NYTO March 29, 2010 Comments at 8; NEMA March 29, 2010 Comments at 6; and J.P. Morgan March 29, 2010 Comments at 10.

[84] A fixed-price TCC is a series of TCCs, each with a duration of one year, renewed annually for a period of at least five years at a fixed price that is obtained through the conversion of expired or expiring Existing Transmission Agreements. NYISO OATT, Section 1.6 Definitions—F. These are legacy obligations that predate the ISO.

[85] NYISO March 29, 2010 Comments at 12–13.

[86] CAISO March 29, 2010 Comments at 12–14.

[87] CPUC March 29, 2010 Comments at 4.

[88] Joint Commenters include Constellation Energy Commodities Group, Inc., Constellation NewEnergy, Inc., and Integrys Energy Services, Inc.

[89] Joint Commenters March 29, 2010 Comments at 12.

[90] EEI March 29, 2010 Comments at 11.

[91] Wisconsin Parties March 29, 2010 Comments at 6–7.

[92] MidAmerican March 29, 2010 Comments at 7.

[93] SDG&E March 29, 2010 Comments at 3–4.

[94] APPA March 29, 2010 Comments at 6.

[95] First Energy March 29, 2010 Comments at 3.

[96] *Id.* at 5.

[97] MidAmerican March 29, 2010 Comments at 6–7; PSEG March 29, 2010 Comments at 12.

[98] Midwest TDUs March 29, 2010 Comments at 13–14; NRECA March 29, 2010 Comments at 13; NYAPP March 29, 2010 Comments at 12; NCPA March 29, 2010 Comments at 6–7, 9.

(NIPSCO), and Xcel Energy Services (Xcel) did not oppose elimination of unsecured credit for FTR markets *per se.* NIPSCO and Xcel suggested that a stakeholder process develop an unsecured credit policy appropriate to each ISO/RTO.[99]

2. Commission Determination

70. The Commission adopts the NOPR proposal to eliminate unsecured credit for FTR positions. The Commission understands the value that FTR markets provide to market participants that need to hedge congestion risk. Nevertheless, the risk associated with the potentially rapidly changing value of FTRs warrants adoption of risk management measures, including the elimination of unsecured credit. Because financial transmission rights have a longer-dated obligation to perform which can run from a month to a year or more, they have unique risks that distinguish them from other wholesale electric markets, and the value of a financial transmission right depends on unforeseeable events, including unplanned outages and unanticipated weather conditions.[100] Moreover, financial transmission rights are relatively illiquid, adding to the inherent risk in their valuation.[101]

71. For example, PJM suffered a significant default in December 2007 in its FTR market[102] and moved to eliminate the use of unsecured credit in that market due to its risk.[103] That default illustrates the unique risk of FTRs. Given a change in market conditions, a set of FTR positions became highly unprofitable. Because FTR obligations cannot be terminated prior to the expiration of the contract, from one month to several years, losses can mount to the point that the FTR holder goes bankrupt.

72. It is difficult to quantify, and therefore limit, the risks inherent in FTR markets, as evidence by the substantial difference between FTR auction values and realized day ahead congestion value experienced over the past few years.[104] For instance, the outage of a transformer at a key node in a network system during a peak season can have enormous financial consequences. Such an outage may be prolonged because replacement parts are expensive and not standardized, and thus not likely to be readily available. Under such circumstances, FTRs that had been "prevailing flow" or "in the money" may suddenly be counter-flow during an entire peak season or longer with costs that continue to widen depending on usage, flows, temperature and other factors. Because FTR market participants are all aware of large transmission events affecting FTR values, an FTR that is suddenly "out of the money" will be difficult to sell or liquidate. Thus the owner can be stuck with a financial position that continues to be a burden and that could force a large default. While elimination of unsecured credit may not necessarily have prevented previous defaults, requiring collateral to support all FTR transactions, rather than continued reliance on unsecured credit, will reduce the risk, and resulting costs, of defaults that are mutualized across all market participants.

73. As for the assertion of the CPUC that the elimination of unsecured credit should be avoided as it will raise the costs of LSEs who use FTRs for hedging congestion risk, the Commission acknowledges this possibility. However, as discussed above, even LSEs using FTRs to hedge costs are not without risk. Further, just as there are costs associated with the reduction of unsecured credit in energy transactions, the overall savings to all parties can be significant. The Commission is persuaded that the benefits of the elimination of unsecured credit over the long term, through reducing risk and minimizing the effect of defaults that would be socialized among all market participants, will compensate all parties for the short-term costs of fully securing FTR transactions.[105]

74. As for those that argue against a uniform, nationwide prohibition on the use of unsecured credit in FTR markets, the Commission notes that there has been no evidence to suggest that the generation mix or transmission system of any particular ISO or RTO is inherently unique in its physical performance or equipment that would allow it to avoid the risks discussed above. In response to those that argue that the nature of the participants and their business model should exempt those participants from this aspect of the Final Rule, the Commission addresses this issue below.

75. Thus, the Commission directs each ISO and RTO to submit a compliance filing that includes tariff revisions to eliminate the use of unsecured credit in its FTR, or FTR-equivalent, markets. This compliance filing must be submitted by June 30, 2011, and the tariff revisions will take effect October 1, 2011.

76. The Commission acknowledges the parties that suggest that valuation of FTRs is important to protecting against the risk to participants associated with possible defaults. While the Commission agrees that ISOs and RTOs may face challenges in valuing FTRs, those comments are beyond the scope of this rulemaking proceeding.

77. The Commission disagrees with commenters that assert that LSEs using FTRs to hedge for congestion should be exempt from the prohibition on the use of unsecured credit in the FTR market. Even an LSE with generation backing the FTR may encounter changes in the system that outstrip (perhaps substantially outstrip) the hedge, as in the transmission outage example used above. Similarly, municipal utilities that hold an FTR position can find that their position is "out of the money" due to an unforeseen, but large, transmission outage. The Commission also notes that low risk activities may be subject to lower security and collateral requirements for FTR positions. Thus, if LSEs, municipal utilities and other entities are engaged in "low-risk" transactions in the FTR markets, then this lower risk will be reflected in the credit analysis done by the market administrator in setting security and collateral requirements for their transactions in the FTR market, in contrast to higher requirements that may be established for those engaged in high-risk speculative transactions.

78. The Commission also disagrees with the assertion of CAISO and Mid-American that "netting" of credit requirements between FTR and non-FTR activity should be allowed. Intermingling credit for these distinctly different markets would defeat the purpose of the Commission's attempt to reduce market-disrupting risk. Such a practice could lead to reduction in the daily market activity, for example, to engage in more speculative activity in

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[99] NIPSCO March 29, 2010 Comments at 6; Xcel March 29, 2010 Comments at 12.

[100] For a financial transmission right, an unexpected outage can cause unforeseen congestion or movement in flows and the resulting charges or credits can swing very substantially either way.

[101] *PJM Interconnection, L.L.C.,* 127 FERC ¶ 61,017 at P 36.

[102] *PJM Interconnection, L.L.C.,* 122 FERC ¶ 61,279 at P 26 n.10 (2008) (citing defaults by Excel and Power Edge in PJM's financial transmission rights market).

[103] *PJM Interconnection, L.L.C.,* 127 FERC ¶ 61,017 at P 8, 36.

[104] In 2008, dramatic changes in fuel prices at mid-year led to FTR values that differed dramatically from realized day-ahead congestion values. Division of Market Oversight, Federal Energy Regulatory Comm'n, 2008 State of the Markets Report at 18 (2009), *available at http://www.ferc.gov/market-oversight/st-mkt-ovr/2008-som-final.pdf.* In 2009, changes in demand similarly led to divergence of FTR values and day-ahead congestion values. Division of Market Oversight, Federal Energy Regulatory Comm'n, 2009 State of the Markets Report at 20 (April 15, 2010), *available at http://www.ferc.gov/market-oversight/st-mkt-ovr/som-rpt-2009.pdf.*

[105] *PJM Interconnection, L.L.C.,* 131 FERC ¶ 61,017 at P 31–34, *order on reh'g,* 132 FERC ¶ 61,180 (2010).

FTR markets. This would serve to have the effect of "loosening" credit in an area where the Commission desires to see less risk.

79. Additionally, the Final Rule does not provide exemptions for holders of "fixed price TCCs," or other products, from the prohibition on the use of unsecured credit in this market as they may vary in value despite being called "fixed price."

D. Ability To Offset Market Obligations

80. In order to help market participants manage their capital as efficiently as possible, market participants who are buying and selling energy and other products to and from the organized wholesale electric markets seek to net those transactions against each other for the purpose of determining the collateral requirement, thereby reducing the amount of collateral that a market participant must hold with the ISO/RTO. In this way, the ISO/RTO can administer the market, while imposing fewer demands on the limited capital of its participants.

81. However, if a market participant files for bankruptcy protection, it may assert that the ability of the ISO/RTO to offset accounts receivable against accounts payable is not valid and seek a claim to amounts owed to the market participant by the ISO/RTO. To ensure that ISOs/RTOs are not left owing the market participant without the ability to net amounts owed by the market participant, there must be an adequate legal basis to protect the ISOs/RTOs in the bankruptcy context.

82. This concern provided the basis for the Commission's proposal in the NOPR to clarify the ISO's/RTO's legal status to take title to transactions, thereby becoming the central counterparty for transactions in an effort to establish mutuality in the transactions as legal support for set-off in bankruptcy.

1. Comments

83. PJM supports the Commission's approach. Besides providing certainty, PJM argues that credit clearing solutions could provide attractive opportunities to RTO market participants to optimize the credit value of off-setting the positions that these companies hold in different market or trading environments, including across several RTOs.[106] In addition, PJM argues that the Commission's approach is not without precedent. In support, it notes that Elexon, the company that serves the balancing and settlement function in the United Kingdom, created a wholly-owned subsidiary to act as the counterparty to trading charge and reconciliation charge transactions to address the same type of mutuality concern. PJM also states that ISO–NE has effectively identified itself as counterparty to FTR transactions that are undertaken in its markets by defining itself as a forward contract merchant and/or swap participant within the meaning of the Bankruptcy Code.[107]

84. Similarly, CFTC staff believes that the proposal would materially reduce credit risk for ISOs and RTOs. CFTC staff also states that it is unusual to rely on credit arrangements that are not iron-clad and that the legal theory underlying Mirant's claims is well-known and easily available to any similarly-situated debtor in the future.[108]

85. J.P. Morgan supports the Commission's proposal because it will provide an ability to manage defaults, offset market obligations in instances of bankruptcy, and minimize the collateral requirements of market participants. J.P. Morgan agrees with the Commission that there is legitimate uncertainty as to whether the netting provisions will withstand a challenge in a bankruptcy proceeding because of the ambiguity related to the identity of the counterparty. In addition, J.P. Morgan notes that some ISOs and RTOs have tried to address the concern by requiring market participants to assign the ISO or RTO a perfected security interest in the receivables from the ISO or RTO.[109] J.P. Morgan is concerned that this approach is a substantial administrative burden that, if not executed flawlessly, might not fully protect against the bankruptcy of a market participant.

86. CCRO explains that it reviewed this issue through a designated subcommittee of member companies that conducted a comprehensive study on netting. It asserts that it is emerging "best practice" in intra-ISO netting for an ISO to create or designate a central counterparty entity through which market participants may execute transactions. CCRO encourages the Commission to formulate policy and regulations which enable cost-effective implementation of this best practice. In addition, it encourages the Commission to support innovations in netting consistent with emerging best practice.

87. Many commenters voice strong views in opposition to this proposal. CAISO and Midwest ISO note that the argument that transactions between a market participant and ISO/RTO are not mutual, and therefore cannot be set-off in bankruptcy, has only been raised once and that there may be reasons why the argument has not been raised again.[110] They encourage consideration of less burdensome alternatives.

88. Other commenters question whether, absent steps taken in this rulemaking, there will really be a problem in upholding netting in the bankruptcy context. For instance, Shell Energy urges the Commission to more clearly define the problem and that a speculative problem is not an adequate basis to change the fundamental nature and role of an RTO.[111] NRECA also asserts that the bankruptcy set-off risk to RTOs is largely hypothetical. MidAmerican Energy concurs with the joint comments of CAISO and Midwest ISO and asserts that the Mirant bankruptcy proceeding only marginally supports the proposition that an ISO or RTO may not be able to offset market participant obligations due to lack of mutuality.[112]

89. Dominion argues that the set-off risk has not yet been demonstrated and asserts that the proposal is unreasonable.[113] In addition, NYISO states that it has found no case law supporting the proposition that a creditor must be a central counter-party in a transaction to set-off payment obligations.[114] EPSA does not take a position on the proposal and instead asks the Commission to more clearly define the problem that it is trying to solve.

90. In contrast, NYISO argues that, because ISO and RTO tariffs specifically establish a contractual obligation of payment to the ISO or RTO, a bankruptcy court would likely allow an ISO or RTO to set-off the obligations of a market participant. Moreover, NYISO

[106] PJM March 29, 2010 Comments at 18–19.

[107] *Id.* at 10–11.

[108] CFTC March 29, 2010 Comments at 2 n.7.

[109] Midwest ISO has adopted an approach similar to this, discussed below.

[110] In the NOPR, the Commission cited the Mirant bankruptcy and resulting default in the CAISO market as support for its proposal that ISOs/RTOs clarify their ability to offset market obligations. NOPR, FERC Stats. & Regs. ¶ 32,651 at P 24 (2010). Mirant argued in bankruptcy that CAISO would not be able to show the mutuality required to establish a right of setoff under section 553 of the bankruptcy code. Memorandum by Wachtell, Lipton, Rosen & Katz to PJM regarding Setoffs and Credit Risk of PJM in Member Bankruptcies at 10–11 (Mar. 17, 2008) (found on Sept. 7, 2010 at *http://www.pjm.com/~/media/committees-groups/committees/crmsc/20080423/20080423-wachtell-netting-memo.ashx*). CAISO has since clarified that Mirant settled with CAISO, thus no court ever ruled on Mirant's arguments. Joint Comments of CAISO and Midwest ISO, March 15, 2010 Comments at 2–3.

[111] Shell Energy March 29, 2010 Comments at 8.

[112] MidAmerican Energy March 29, 2010 Comments at 7–8.

[113] Dominion March 29, 2010 Comments at 7–10.

[114] NYISO March 29, 2010 Comments at 15.

believes that a bankruptcy court may, for policy reasons, defer to the Commission-approved tariff provisions of the ISO or RTO, or uphold ISO or RTO netting under the doctrine of recoupment,[115] thereby circumventing a challenge for mutuality.[116]

91. Many commenters argue that it could increase costs, raise jurisdictional concerns, and create legal issues and tax implications. They recommend that the Commission consider alternative solutions, allowing ISOs and RTOs to work through their stakeholder processes, or requiring each ISO and RTO to report back to the Commission concerning their rights to net transactions and what rights they would assert in bankruptcy proceedings.

92. Six Cities urges the Commission to not adopt the proposal because it could increase the complexity of the settlement process and potentially create additional costly obligations and liabilities for market operators that market participants would have to pay. Six Cities believes that other mechanisms, such as net invoicing as utilized by CAISO, can be used to protect market participants.[117]

93. Citigroup agrees that netting, and set-off in bankruptcy, is an important tool for managing risk, but states that the proposal presents many complex issues related to netting, offsets, defaults and bankruptcy that will be different for each ISO and RTO. Citigroup states that each ISO and RTO has its own unique tariff terms and markets, thus implementation would have to be tailored to each market.[118] Therefore, Citigroup argues that each ISO and RTO should consider these issues through its stakeholder process. OMS is of two minds on this issue in that it supports the Commission's desire to clarify the legal foundation for the ISO/RTO to net, but believes that it is important that the proposal does not expose the ISOs and RTOs to unforeseen ramifications, such as increased liability or the incurrence of additional obligations.[119]

2. Technical Conference

94. The Commission held a technical conference to delve further into the issues raised by its proposal. The technical conference provided additional evidence on the ISOs and RTOs ability to net obligations and conduct setoff in the bankruptcy context. Mutuality was identified by several participants as important in allowing the ISOs and RTOs to perform this vital function, who asserted that mutuality was most easily achieved by the market administrator "taking title" or being the buyer to all sellers and seller to all buyers in all transactions in the market. Mr. Duane from PJM supported the Commission's proposal by stating: "* * * the obvious and direct way to establish mutuality is simply to be a contract party to the transactions that you're setting up." [120] Mr. Duane further stated: "I would regard the Commission's initiatives here as overdue" and "the proposal here would remove a real disability that is a cloud over the enforcement of a broad set of rights that the RTOs have in outside forums, particularly beyond this Commission." [121] According to Mr. Novikoff a "best practice" is "to create mutuality by using a central counterparty and have that counterparty deal with all of the participants." [122]

95. However, the Midwest ISO participant and the CAISO participant represented two different ways in which their organizations sought to deal with the issue, as opposed to the PJM proposal to change its tariff to allow an entity to explicitly take title and act as the central counterparty to achieve mutuality.

96. At the technical conference, Mr. Holstein of Midwest ISO discussed the "first short-pay, then uplift" system used by Midwest ISO, stating that it works well and is revenue neutral in all transactions. Mr. Holstein stated that, if a market participant doesn't pay a charge that it owes, which is the net charge of the invoice, Midwest ISO short-pays the other market participants who are net-owed funds in that billing cycle, thus remaining revenue neutral for that billing cycle. Midwest ISO later makes up the difference by "uplifting" the default to all market participants, that is, charging extra in the next billing cycle and redistributing the proceeds to those who were initially short-paid.[123] Further, any party in Midwest ISO who wishes to net their obligations across its various markets (e.g., real time, day ahead, reserves, etc.) must provide Midwest ISO a security interest in these transactions. By doing this, Midwest ISO asserts that it is able to safely set credit exposure to a net, rather than a gross, obligation. Midwest ISO stated that ten percent of its market participants grant Midwest ISO a security interest, but certain public power entities are not able to use that approach.[124] During the technical conference, participants noted the difficulties raised by using the security interest approach given that many lending agreements prohibit granting liens and some entities, such as municipalities, cannot engage in such practices.[125] For these reasons stakeholders in Midwest ISO decided against mandatory requirements of security interest and opted for voluntary use of security interest.

97. Mr. Daniel Shonkwiler of CAISO did not perceive a potential inability to offset market participants' claims and obligations as a risk, because CAISO's ordinary monthly settlements involve net invoices. Under CAISO's tariff, CAISO asserts that market participants only have the right to receive the net payment from CAISO for market sales, with no competing claims and obligations. CAISO indicates that a legal issue arises where a market participant fails to pay an invoice, but in a subsequent month, has a payment due back to it. In such a situation, CAISO states that its tariff allows it to recoup that later payment to pay the previous month's default. CAISO does not see a material risk because it does not assume a right to set-off when it is calculating the amount of financial security required. CAISO further states that its market is not at risk because it ensures that its market participants are adequately secured; many market participants are exclusively buyers or sellers, and thus netting their invoices would not reduce their exposure; litigating the issue would be so expensive as not to be worthwhile for a market participant in bankruptcy; and bankruptcy is rare in the CAISO

[115] "In bankruptcy, both recoupment and setoff are sometimes invoked as exceptions to the rule that all unsecured creditors of a bankrupt stand on equal footing for satisfaction. Recoupment or setoff sometimes allows particular creditors preference over others. Setoff is allowed in only very narrow circumstances in bankruptcy. But a creditor properly invoking the recoupment doctrine can receive preferred treatment even though setoff would not be permitted. A stated justification for this is that when the creditor's claim arises from the same transaction as the debtor's claim, it is essentially a defense to the debtor's claim against the creditor rather than a mutual obligation, and application of the limitations on setoff in bankruptcy would be inequitable." *Newbery Corp.* v. *Fireman's Fund Ins. Co.,* 95 F.3d 1392, 1400 (9th Cir. 1996) (quoting *In re B & L Oil Co.,* 782 F.2d 155, 157 (10th Cir. 1986)).

[116] NYISO March 29, 2010 Comments at 16–17.

[117] Six Cities March 29, 2010 Comments at 6.

[118] Citigroup March 29, 2010 Comments at 5.

[119] OMS March 16, 2010 Comments at 4–5.

[120] Testimony at Technical Conference on *Credit Reforms in Organized Wholesale Electric Markets,* Tr. 13:5–7 (May 11, 2010) (Mr. Vince Duane, General Counsel and Vice President, PJM).

[121] *Id.* at Tr. 15:25–16:1; 16:12–16 (Mr. Vince Duane, General Counsel and Vice President, PJM).

[122] *Id.* at Tr. 72:2–4; 72:15–16 (Mr. Harold S. Novikoff, Esquire, Wachtell, Lipton, Rosen & Katz).

[123] *Id.* at Tr. 18:1–20:2 (May 11, 2010) (Mr. Michael Holstein, Chief Financial Officer, Midwest ISO).

[124] *Id.* at Tr: 45:18–48:13.

[125] *Id.* at Tr: 87: 6–25 (Mr. Stephen J. Dutton; Barnes & Thornburg).

market.[126] CAISO's method of "net invoicing" characterizes a market participant's monthly bill as one transaction with multiple line items. One bankruptcy expert testified that such a "tariff" approach to the problem is weaker than the establishment of mutuality and even weaker than the use of "collateral" or security interest to allow netting, and that a hostile creditors committee would be unlikely to agree to claims made on the basis of a tariff, rather than established mutuality.[127]

98. The Commission also invited parties to submit further comment in response to the issues discussed in the technical conference.

3. Comments Submitted After the Technical Conference

99. Several commenters assert that it is unlikely that a bankruptcy court would refuse an ISO/RTO's netting a market participant's obligations and therefore the Commission's concern does not justify the Commission's central counterparty proposal.[128] Dominion states that CAISO has identified a number of practical reasons why the risk is minimal, such as that many market participants are unlikely to be in a position to use setoff because they are not both a buyer and seller in a given market. Dominion and SPP state that most market participants that want to continue to operate post-bankruptcy require transmission service and therefore will work with the ISO/RTO during bankruptcy proceedings. According to Midwest ISO, only an estimated 20 percent of its market participants are not dependent on transmission service, and thus do not net any transactions, and potentially would challenge the ISO's/RTO's ability to off-set. NYISO believes that its credit exposure is limited because most market participants in New York are not both buyers and sellers of energy in NYISO-administered markets.

100. CCRO acknowledges that a market participant going into bankruptcy and challenging the ISO's/RTO's ability to net transactions is a low probability event, but it argues that the Commission cannot ignore such potentially high risk events. However, CAISO believes that the Commission needs additional evidence regarding the scope of the risk. CAISO suggests that the Commission first determine the number of market participants that likely would challenge set-off and then gather historical data about the difference between their net position and gross credits. NYISO also questions the scope of the risk, and asserts that it would have sufficient collateral available to recover the market participant's payment obligations to the NYISO because it calculates distinct credit requirements for each of its markets without assuming that it will be able to net across markets in a bankruptcy proceeding. NYISO also asserts that its tariff allows it to draw from its pre-funded working capital fund to facilitate timely payment to market participants and maintain the liquidity of the NYISO-administered markets.

101. Many commenters argue that the central counterparty approach does not definitively eliminate the risk that a bankruptcy court would refuse an ISO/RTO's netting obligations between the ISO/RTO and the debtor market participant. For instance, Eastern Massachusetts, Dominion and NYISO believe that a bankruptcy court that is hostile to set-off would question whether the ISO/RTO is the central counterparty in form only and not substance. NYISO explains that taking title is just one factor that a bankruptcy court may consider in determining whether there is mutuality between the ISO/RTO and the market participant. NYISO points out that under PJM's proposal, PJM is only obligated to pay market sellers to the extent of its collections from market buyers. Thus, NYISO argues that PJM may not truly be taking on the debt obligation for market purchases, but rather be acting as an agent for many different buyers. Although NYISO acknowledges that this argument is unlikely to succeed, it demonstrates that the risk is not eliminated. In addition, Dominion points to Midwest ISO's argument that the central counterparty model does not defend against a challenge based on the absence of mutuality in netting across commodities and services. However, bankruptcy counsel noted that there would have to be a major change in case law for a challenge to an identified central counterparty to be successfully upheld regarding its ability to set-off in a bankruptcy.[129]

102. Numerous commenters oppose the central counterparty proposal because they believe that it will require the ISOs/RTOs to expend significant resources to implement it and may have negative consequences for the ISOs/RTOs and their market participants. According to Dominion, EPSA, Shell Energy, and SPP, the proposal is not a clarification in status, but instead is a radical departure from the current business model used for ISO/RTO transactions. Shell Energy believes that, as a result of the clarification, existing ISOs/RTOs will be administrators only and the new central counterparty will be a new public utility that should be treated similar to other public utilities. Thus, Shell Energy argues that implementing central counterparty status will require a radical restructuring of ISOs/RTOs.

103. As for potential consequences and impacts on the ISOs/RTOs, Constellation cites Midwest ISO's Chief Financial Officer's comment that if an ISO/RTO is the central counterparty to energy market transactions, then its revenue neutrality may be jeopardized and liquidity and insolvency risk is introduced to the market.[130] Similarly, EPSA states that Midwest ISO believes that it would be obligated to pay for defaults in the event other parties to the transaction could not pay, and that an event like this potentially could bankrupt the ISO/RTO. Eastern Massachusetts highlights CAISO's comments regarding the potential for increased cost of credit used to fund market operations.

104. CAISO also states that, by becoming a central counterparty to transactions within its market, it could become a "point of regulation" under greenhouse gas regulatory schemes. CAISO states that the Air Resources Board of California is regulating greenhouse gas emissions which extend to electricity produced and/or consumed within California. CAISO is concerned that if it is required to take title to the transactions, it will be subject to greenhouse gas regulations with no ability to procure alternative, non-carbon intensive fuels in the power pool. In fact, CAISO states that such a construct could provide an incentive for electricity exporters into California to dump the energy onto CAISO's system prior to entering California, so the exporters would not be subject to the greenhouse gas regulations. CAISO further states that national clearing could take place without ISOs and RTOs becoming the counterparty to transactions within their markets.[131]

105. Dominion, NYISO, Shell Energy and SPP argue that the central counterparty model potentially exposes ISOs/RTOs to new requirements, risks

[126] *Id.* at Tr: 21:22–26:14 (Mr. Daniel J. Shonkwiler, Senior Counsel, CAISO).

[127] *Id.* at Tr: 89: 1–25–90: 1–19 (Mr. Harold Novikoff, Wachtell, Lipton, Rosen & Katz).

[128] NYISO June 8, 2010 Comments at 11; CAISO June 8, 2010 Comments at 5; Dominion June 8, 2010 Comments at 8; Midwest ISO June 8, 2010 Comments at 3.

[129] *Id.* at Tr: 101:1–12 (Mr. Harold Novikoff, Wachtell, Lipton, Rosen & Katz).

[130] Constellation June 8, 2010 Comments at 4.

[131] CAISO July 23, 2010 Comments at 6.

and costs associated with complying with generally acceptable accounting principles requirements, loss of legal status, indemnification, and tax liability. They also believe that there may be unintended consequences that could cause significant harm, such as the imposition of state and local sales taxes on ISOs/RTOs, implications regarding the independence of an ISO/RTO, regulatory uncertainty resulting from potential multi-agency jurisdictional oversight of ISOs/RTOs, negative impacts on financing options, and increases in financing costs. In light of these uncertainties, Constellation argues that the Commission should develop a full record, particularly regarding the consequences for ISOs/RTOs.

106. PG&E also believes that CAISO already is considering and implementing numerous changes and improvements to its tariffs and markets and therefore does not have sufficient time to undertake additional effort.

107. Eastern Massachusetts argues that the central counterparty proposal could result in interference with the ability of eligible municipal market participants to continue existing tax exempt financing or to use such financing to expand productive assets. Although NEPOOL does not take a formal position in its comments, it also believes that the central counterparty proposal could have profound and unintended consequences on market participants. SPP is concerned that, if the ISOs/RTOs operate as clearinghouses, then market participants such as cooperatives or municipalities will be unable to meet credit requirements.

108. CCRO generally supports the Commission's proposal and believes that any approved procedure should be standardized across the ISOs/RTOs to the extent practical. CCRO also encourages the Commission to adopt rules that do not deter the development of innovations that can further limit credit exposure, such as the advent of netting of transactions across all the ISOs/RTOs and the over-the-counter markets.

109. Some commenters argue that there are less costly approaches that ISOs/RTOs can employ to address the Commission's concerns without adopting the central counterparty proposal.[132]

110. Eastern Massachusetts argues that other changes in credit policies proposed under the NOPR may reduce the magnitude of any potential exposure without any need to adopt a central counterparty provision. Dominion and Midwest ISO believe the risk has been significantly mitigated by other risk management tools that ISOs/RTOs already have implemented, including shorter settlement periods. Dominion urges the Commission to fine tune these tools before making any radical changes to the ISO/RTO structure. Along those lines, Shell Energy argues that the better solution is to rely on a combination of a cap on unsecured credit and a seven-day billing cycle.

111. Other comments identify different approaches to addressing the Commission's concerns. EPSA believes that, in addition to the central counterparty proposal, there are two other possible solutions, including creating a collateral arrangement that will reach the same economic result and rewriting tariffs so that they establish a net obligation, rather than a gross obligation. EPSA argues that the Commission either should conduct a more thorough exploration of these three options or allow each ISO/RTO to work with its stakeholders to create a regionally tailored solution.

112. CAISO, NYISO, and SPP also point to Midwest ISO's voluntary security interest approach as an alternative to the central counterparty approach. Although CAISO believes that Midwest ISO's approach is less costly and simpler to implement, it also believes it would require a long lead time to facilitate discussions between market participants and their lenders. SPP notes concerns with the security interest approach, because it may be difficult for most market participants to supply such a security interest due to existing financing arrangements and the burden of perfecting a security interest.

113. Dominion argues that it may not be necessary to amend ISO/RTO tariffs because there are existing defenses of netting under the current ISO/RTO structure that moot the need for the NOPR proposal. For instance, SPP notes that a bankruptcy court may be hesitant to set aside a Commission-approved tariff that requires payment netting or set-off. Dominion points to Midwest ISO's and NYISO's comments that the tariff, which market participants agree to be bound by, satisfies the mutuality of party requirement.

114. NYISO also argues that its existing tariff may provide sufficient protection in the event a market participant raises the mutuality argument. According to NYISO and SPP, the commercial relationship between ISOs/RTOs and their market participants is distinguishable from the typical scenarios in which parties have successfully challenged setoff rights in a bankruptcy proceeding. According to NYISO, the important distinction is that the net obligations are between NYISO and a specific debtor market participant directly and NYISO is acting in the same capacity on both sides of market transactions.

115. As an alternative to seeking setoff in bankruptcy, CAISO, NYISO and SPP believe that a bankruptcy court likely would allow it to net obligations under the equitable defense of recoupment. According to NYISO, a bankruptcy court would likely uphold the NYISO's right to recoupment within each market because it would be inequitable for a market participant to benefit from its participation in a single market without also having to meet its obligations related to its transactions in that market.

4. Commission Determination

116. Organized wholesale electric markets typically arrange for settlement and netting of transactions entered into between market participants and the market administrator, but do not take title to the underlying contract position of a participant at the time of settlement. The Commission is concerned that, if a market participant files for bankruptcy protection, it may argue against setting-off amounts owed against amounts to be paid to an ISO or RTO, which could lead to a larger default in the market that must be socialized among all other participants. The Commission supports netting, which allows ISOs and RTOs to collect less collateral from market participants,[133] but netting must be established in a way that helps ensure that market participants are protected from a substantial default should a participant file for bankruptcy protection.

117. While the Commission, in response to what it still considers to be a legitimate concern, originally proposed requiring ISOs and RTOs to establish themselves as the central counterparty to transactions with market participants, the Commission is open to considering other solutions to this concern. The Commission directs each ISO and RTO to submit a compliance filing that includes tariff revisions to include one of the following options:

- Establish a central counterparty as discussed above.
- Require market participants to provide a security interest in their transactions in order to establish collateral requirements based on net exposure.

[132] CAISO June 8, 2010 Comments at 6–7.

[133] *Policy Statement,* 109 FERC ¶ 61,186 at P 29.

• Propose another alternative, which provides the same degree of protection as the two above-mentioned methods.

• Choose none of the three above alternatives, and instead establish credit requirements for market participants based on their gross obligations.

118. This compliance filing must be submitted by June 30, 2011, with the tariff revisions to take effect October 1, 2011.

119. Evidence put before the Commission has demonstrated the need for establishing better protection against loss due to bankruptcy of a market participant. Allowing netting without adequate protection could pose a risk to the ISO and RTO markets and particularly their participants who would be assessed any shortfall. The ability for an ISO or RTO to net amounts owed to and owed by a market participant that has filed for bankruptcy protection is not clear. At the technical conference, Mr. Novikoff testified that "bankruptcy courts are quite hostile to setoff." [134] The Commission also notes that a recent court decision affirmed a bankruptcy court's finding that, "the mutuality required by Section 553, 'cannot be supplied by a multi-party agreement contemplating a triangular setoff.' " [135] Our effort to limit the amount of unsecured credit extended in ISO and RTO is less meaningful if an ISO or RTO establishes a collateral requirement based on net exposure that can not withstand a challenge in bankruptcy court. As to the view that there is a low probability that a market participant will file for bankruptcy and then challenge an ISO's/RTO's ability to net, the Commission agrees with CFTC staff and the CCRO that that this low probability is balanced by a high cost to market participants and the stability of the market if it does occur.

120. While we continue to believe that the NOPR proposal provides a sound approach to this issue, we are open to considering other solutions. Two alternatives to the central counterparty solution were presented; one proposed by the CAISO and one proposed by Midwest ISO, described in more detail in the comment section above. The Commission is convinced that Midwest ISO's approach, in which market participants grant a security interest in their transactions to Midwest ISO, provides a basis for the ISO or RTO to net market obligations. A security interest is a form of collateral which provides certain protection in the bankruptcy context, but it may be unworkable under some lender agreements.[136] The Commission notes that not all parties may be able to grant a security interest in their transactions, however, this method provides an alternative for ISOs and RTOs that wish to allow market participants to continue to net their transactions. However, the Commission is concerned that CAISO's method of "net invoicing," which treats all events on a market participant's monthly invoice as one transaction, may not be adequate in the context of a bankruptcy.[137] Because of the uncertainties about the viability of CAISO's theory under bankruptcy law, the Commission does not believe that market participants should be allowed to net their financial obligations based on CAISO's "net invoicing" solution.

121. Some participants have suggested that the Commission direct that all ISO/RTO tariffs have explicit language allowing these markets to perform netting and set-off to provide legal cover in bankruptcy. While RTOs and ISOs may propose such tariff language as an additional measure, the Commission believes that it is not sufficient protection to simply direct the ISOs and RTOs to include the ability to net in their tariff. Based on testimony cited above, the Commission is concerned that, if the issue were raised in bankruptcy court, the existence of a Commission-approved tariff, even with such language, may not persuade a bankruptcy court to allow the set-off of financial obligations between an ISO/RTO and a market participant who is in bankruptcy. For this reason, the Commission will require more than mere tariff language to ensure the right of an ISO/RTO to net in the bankruptcy context. In the absence of a central counterparty, security interest, or another method that provides the same degree of protection to support netting, the remaining solution is to establish credit requirements to gross market obligations rather than net obligations.

122. Many parties also state that the Commission should not pursue the counterparty model due to tax and administrative costs. Given that ISOs and RTOs already function in ways similar to a central counterparty, it is not clear how it will lead to increased administrative costs.[138] As to possible tax implications, no specific evidence has been presented showing that the central counterparty model will lead to increased tax obligations. However, we need not decide these points here, and RTOs and ISOs may consider these points in deciding how to comply with this Final Rule.

E. Minimum Criteria for Market Participation

123. The Commission has always been wary of unnecessary barriers to entry to market participants, with a goal of ensuring sufficient participation, adequate liquidity, and competitive results. However, this consideration must be balanced with protecting the market from risks posed by under-capitalized participants without adequate risk management procedures in place. Having minimum criteria in place can help minimize the dangers of mutualized defaults posed by inadequately prepared or under-capitalized participants.

124. Consequently, the Commission proposed that each ISO and RTO have tariff language to specify minimum participant criteria for all market participants. The Commission sought comment on the type of process used to arrive at the criteria and recommendations on what the criteria should be.

1. Comments

125. The proposal to require minimum participation criteria has widespread support. Parties such as Citigroup Energy, Dynegy, NEMA, NEPOOL, and PG&E favor the proposal. The OMS suggests requiring market participants in FTR markets to have a minimum net worth. CFTC staff suggests something similar; participants in FTR markets should have a minimum capitalization. CFTC staff also states that the Commission should establish a system to evaluate the risk management capabilities of each prospective participant at the time of admission and of each participant on a periodic basis after admission.

126. DC Energy suggests that the CFTC and Securities and Exchange Commission (SEC) requirements for participation in their markets could be a basis for determining minimum

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[134] Testimony at Technical Conference on *Credit Reforms in Organized Wholesale Electric Markets,* Tr: 65: 23–25 (May 11, 2010) (Mr. Harold Novikoff, Wachtell, Lipton, Rosen & Katz).

[135] *Chevron Products Co.* v. *SemCrude, L.P.,* 428 B.R. 590, at 594 (D. Del. 2010) (*quoting In re SemCrude, L.P.,* 399 B.R. 388, 397–398 (Bankr. D. Del. 2009)). The court goes on to note that a "contract exception" does not exist under section 553, 11 U.S.C. 553, which governs set-off under the bankruptcy code. *Id.*

[136] *Id.* at Tr. 84:5–25, 85:1–22 (Iskender H. Catto; Kirkland & Ellis on behalf of the Committee of Chief Risk Officers).

[137] *Id.* at Tr: 73:16–21 (May 11, 2010) (Mr. Harold Novikoff, Wachtell, Lipton, Rosen & Katz).

[138] As to the effect on costs of establishing a counterparty in each ISO or RTO, experience with PJM to date suggests costs will not increase. *See,* e,g., *PJM Interconnection, L.L.C.,* 132 FERC ¶ 61,207, at P 47 (2010) (noting that, in establishing PJM Settlement as a counterparty, PJM is not changing its administrative charges and "that the costs that PJM Settlement will incur are costs that PJM already incurs today.")

requirements. J.P. Morgan, likewise, recommended that every market participant in the ISO/RTO markets meet the requirements of an "Eligible Contract Participant" as defined in the Commodity Exchange Act.[139]

127. APPA supports development of ISO/RTO rules that limit the activities of "financial-only" market participants, including maximum position and credit limits for financial-only ISO/RTO market participants and suggests a follow-on NOPR dealing specifically with these issues. NRECA suggests that ISOs/RTOs should be encouraged to develop minimum participation criteria for cooperative utilities that would be different than investor-owned utilities.

128. Morgan Stanley agrees that certain risk management capabilities and minimum capital requirements be established but cautioned against making these criteria too onerous. Moreover, Morgan Stanley stated that criteria applied only to financial-only participants should be avoided. A similar argument was made by the Western Power Trading Forum (WPTF), which states that objective criteria should apply to all market participants. WPTF further states that, if the Commission seeks to "enhance certainty and stability in the markets," then it should require each ISO/RTO to apply their credit policies to all market participants.

129. Many parties, such as Detroit Edison, Direct Energy, PSEG and SCE, recommend that the stakeholder process should determine appropriate criteria in each ISO and RTO. On the other hand, Dominion asserts that the proper forum for establishing such criteria is the current rulemaking proceeding, and not the "popular vote" of market participants with competing interests in the stakeholder process.

130. Other parties did not agree on the need for minimum criteria.[140] Midwest TDUs suggest the Commission is not well positioned to design such criteria. The NYTOs argue the need for such criteria has not been established. Consumers Energy states that, as long as each RTO accurately determines creditworthiness, there is no need to further specify minimum criteria for participation. Financial Marketers argue that erecting barriers to market entry through the establishment of market participation criteria, such as minimum net worth or minimum size requirements, would be anticompetitive, unjust, and unreasonable.[141]

2. Commission Determination

131. The Commission is persuaded that each ISO and RTO should include in its tariff language to specify 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. This will help protect the markets from risks posed by under-capitalized participants or those who do not have adequate risk management procedures in place. Minimum criteria for market participation could include the capability to engage in risk management or hedging or to out-source this capability with periodic compliance verification, to make sure that each market participant has adequate risk management capabilities and adequate capital to engage in trading with minimal risk, and related costs, to the market as a whole.

132. However, the Commission will not specify criteria at this time, and instead directs that each ISO and RTO develop these criteria through their stakeholder processes. Consequently, the Commission directs each ISO and RTO to submit a compliance filing that includes tariff revisions to establish minimum criteria for market participation. Each ISO and RTO will need to consider the minimum criteria that are most applicable to its markets, this compliance filing must be submitted by June 30, 2011 and to take effect by October 1, 2011.

133. In taking this approach, the Commission is aware that stakeholder groups with competing interests may disagree on these criteria, and so the Commission will review proposed tariff language to ensure that it is just and reasonable and not unduly discriminatory. The Commission believes that such standards might address adequate capitalization, the ability to respond to ISO/RTO direction and expertise in risk management. The Commission directs that these criteria apply to all market participants rather than only certain participants.

134. The Commission does not agree with the argument that minimum criteria are not necessary if ISOs and RTOs apply vigorous standards in determining the creditworthiness of each market participant. While an analysis of creditworthiness may capture whether the market participant has adequate capital, it may not capture other risks, such as whether the market participant has adequate expertise to transact in an ISO/RTO market. Moreover, the ISOs' and RTOs' ability to accurately assess a market participant's creditworthiness is not infallible, and this additional safeguard should not be unduly burdensome compared to the need to protect the stability of the organized markets.

F. Use of "Material Adverse Change"

135. Events in credit markets can change the fortunes of a participant very quickly.[142] Consequently, risk management is not a static endeavor. Every market administrator needs to perform frequent risk analysis on its participants to ensure that existing collateral and creditworthiness standards are sufficient. Nevertheless, even with such scrutiny, events may transpire that require the market administrator to invoke a "material adverse change" clause to justify changing the risk assessment of a participant and requiring additional collateral.

136. The Commission is concerned that ambiguity as to when an ISO or RTO may invoke a "material adverse change" clause could itself have damaging effects on a market administrator's ability to manage risk on behalf of all the participants. If a market administrator is concerned about when it may invoke a "material adverse change" clause, it could delay requests for collateral or orders for the cessation of a participant's right to transact, which could further endanger the other participants and, in extreme cases, the market function itself.

137. In addition, material adverse change clauses need to be sufficiently forward-looking to allow market administrators to request additional collateral before a crisis starts. The Commission is concerned that any attempt to acquire additional collateral during or after a crisis has begun would either fail or destabilize the party asked to provide additional credit. Specifically, news that a market participant was unable to secure additional collateral could negatively affect the perception of the market participant's viability and potentially undermine confidence in an organized market's viability.

138. The Commission therefore proposed in the NOPR to require ISOs

[139] J.P. Morgan Comments at 14 (referring to the Commodity Exchange Act definition of Eligible Contract Participant. 7 U.S.C. 1a(12)). Examples of criteria-determined Eligible Contract Participants include financial institutions, insurance companies, mutual funds, and corporations with assets in excess of $10 million.

[140] Midwest TDUs, NYTOs, Consumers Energy, Wisconsin Parties and Financial Marketers.

[141] Financial Marketers March 29, 2010 Comments at 2–3.

[142] As noted above, Lehman Brothers was rated as "investment grade" by all ratings agencies on Friday, September 12, 2008, only to file for bankruptcy on Monday, September 15, 2008.

and RTOs to include in their tariffs language to more clearly specify circumstances when the market administrator may invoke a "material adverse change" clause.

1. Comments

139. CAISO, Midwest ISO, NYISO, SPP, California Department of Water Resources State Water Project (SWP), Midwest TDUs, NRECA, Detroit Edison, EPSA, Mirant, NIPSCO, Powerex, Xcel, and IRC state that the Commission should preserve the authority for each ISO/RTO to maintain flexibility as to when to request a collateral call for unforeseen events. IRC presents an example of language of such a material adverse change provision:

A "Material Change" in financial status may include, but is not limited to, the following:

(i) A downgrade from any rating by any rating agency;

(ii) Being placed on credit watch with negative implication by any rating agency;

(iii) A bankruptcy filing or other insolvency;

(iv) A report of a significant quarterly loss or decline of earnings;

(v) The resignation of key officer(s); or

(vi) The filing of a material lawsuit that could materially adversely impact current of future financial results.[143]

140. Hess states that the material adverse change clauses in the ISO/RTO tariffs must include non-exclusive illustrative lists of potential material change events, and require ISO/RTO credit officers to exercise caution prior to invoking the "material adverse change" clause.

141. CFTC staff notes that it is critical for a market administrator to have the ability to call for additional collateral in unusual or unforeseen circumstances. Therefore, CFTC staff recommends either: (1) Removing any requirement for a market administrator to wait until a participant experiences a "material adverse change" in credit status before calling for additional collateral to support FTR positions; or (2) permit a market administrator to define "material adverse change" in a manner that would allow a market administrator to have broad discretion in calling for additional collateral to support FTR positions.

142. CPUC, Dynegy, and SCE state that they support clear guidelines on the definition of "material adverse change." CPUC and SCE argue that CAISO's current tariff provision specifying under what circumstances a market administrator may invoke a "material adverse change" clause to require additional collateral is adequate.[144] Therefore, CPUC requests that the Commission adopt guidelines that would allow the CAISO to maintain the status quo. Shell Energy also states that the Commission should propose a generic material adverse change provision, then allow the ISOs and RTOs to work with stakeholders to produce an illustrative list of instances where material adverse change provisions would or should be triggered and to file that language with the Commission. However, even then, the tariff language should still allow a market administrator to act in the event that special circumstances arise.

143. EEI states that the ISO/RTO should be able to explain its procedures and provide the types of circumstances under which it would invoke the "material adverse change" clause that requires a market participant to post collateral within two days. EEI also states that the procedures that the ISO/RTO employs should, at a minimum, provide written notice of the reasons for its action within thirty days and an opportunity to appeal to the Chief Executive Officer of the ISO/RTO. Additionally, EEI states that the Commission should require the ISOs/RTOs to incorporate in their tariffs examples of the conditions under which they will invoke a "material adverse change" clause with the explicit requirement that the ISO/RTO put the rationale for its determination in writing and allow the market participant an opportunity for an appeal.

144. MidAmerican states that it is not practical nor prudent to require a comprehensive and all-inclusive list of circumstances in which an ISO/RTO may invoke a material adverse change, but the required justification provided by an ISO/RTO for invoking a material adverse change provision should include reasonable, objective evidence of the occurrence of an identifiable event or condition with respect to the affected market participant. MidAmerican also states that the Commission should require each ISO/RTO to specify a reasonable process for resolving any disagreement between the ISO/RTO and market participants with respect to the impact of any identified event or condition on the ability of the market participant to continue as a going concern or otherwise honor its obligations to the ISO/RTO.

145. APPA proposes a committee on "material adverse changes," that is, a balanced advisory group of RTO employees dealing with credit issues and their counterparts from representatives of various types of RTO market participants. This group would be responsible for developing "model" protocols, to be the subject of a subsequent NOPR, which would guide an RTO in invoking the material adverse change provisions of the credit provisions of its tariff and business practices.[145]

146. Because "material adverse change" is ambiguous and could be inconsistently and inappropriately applied, PG&E recommends that it not be incorporated into ISO/RTO tariff language. However, if the Commission does incorporate such language, PG&E recommends an initiative to develop clearer definitions. In addition, PG&E states that invocation of a "material adverse change" clause should be selective and limited to only adverse conditions due to a participant's financial strength or ability to meet its contractual obligations, but not the requirements of the customers and/or the regulators.

2. Commission Determination

147. We adopt the NOPR proposal to require ISOs and RTOs to specify in their tariffs the conditions under which they will request additional collateral due to a material adverse change. However, we are persuaded by commenters that this list should not be exhaustive and the tariff provisions should allow the ISOs and RTOs to use their discretion to request additional collateral in response to unusual or unforeseen circumstances. We are also persuaded that a market participant should receive a written explanation explaining the invocation of the material adverse change clause.

148. While market participants are generally familiar with "material adverse change" clauses, a market administrator's right to invoke such a

[143] IRC March 29, 2010 Comments at 9.

[144] CAISO's current "material adverse change" clause is as follows:

CAISO may review the Unsecured Credit Limit for any Market Participant whenever the CAISO becomes aware of information that could indicate a Material Change in Financial Condition. In the event the CAISO determines that the Unsecured Credit Limit of a Market Participant must be reduced as a result of a subsequent review, the CAISO shall notify the Market Participant of the reduction, and shall, upon request, also provide the Market Participant with a written explanation of why the reduction was made.

Material negative information in these areas may result in a reduction of up to one hundred percent (100%) in the Unsecured Credit Limit that would otherwise be granted based on the six-step process described in Section 12.1.1.1 of the ISO Tariff. A Market Participant, upon request, will be provided a written analysis as to how the provisions in Section 12.1.1.1 and this section were applied in setting its Unsecured Credit Limit.

"Material Change in Financial Condition," CAISO Tariff Appendix A at Original Sheet No. 894.

[145] APPA March 29, 2010 Comments at 35.

clause must be clarified in order to avoid any confusion, particularly during times of market duress, as to when such a clause may be invoked. Specifically, the Commission is concerned that a market participant in financial straits could exploit ambiguity as to when a market administrator may invoke a "material adverse change," or a market administrator may be uncertain as to when it may invoke a "material adverse change," and so delay, or even prevent entirely, actions that would insulate the market from unnecessary damage.

149. The Commission therefore directs each ISO and RTO to submit a compliance filing that includes tariff revisions to establish and clarify when a market administrator may invoke a "material adverse change" 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 tariff revisions should state examples of which circumstances entitle a market administrator to invoke a "material adverse change" clause, but this list should be illustrative, rather than exhaustive. The tools used to determine "material adverse change" should be sufficiently forward looking to allow the market administrator to take action prior to any adverse effect on the market, but provide the market participants with notice as to what events could trigger a collateral call or a change in activity in the market. We believe that the language proposed by the IRC is a good start, but note that it generally includes items that potentially lag the events that constitute a material adverse change. For instance, credit ratings tend to change slowly. As discussed above, the several ISOs have noted that they were concerned about large, destabilizing defaults from investment-grade companies. Other criteria, like large changes in the price for a collateralized debt security, are potentially more forward looking and would allow the ISO or RTO to request collateral before a market participant is in financial distress.

150. The Commission agrees with those parties that suggest that it would be short-sighted to limit the discretion of the market administrator to only those specified instances when it could invoke a "material adverse change" clause to compel certain actions. Experience has demonstrated that unforeseen circumstances can arise, which will require action to protect the markets from ongoing disruption. We are not adopting a *pro forma* list ourselves, but allowing the ISOs and RTOs to develop their own "material adverse change" clauses. Nevertheless the compliance filing related to this directive must be submitted by June 30, 2011 to take effect no later that October 1, 2011.

151. The Commission is also sensitive to the need for a record of the market administrator's actions when exercising this discretion. Therefore, the Commission directs the ISOs and RTOs to provide reasonable advance notice [146] to a market participant, when feasible, when the ISOs and RTOs are compelled to invoke a "material adverse change" clause. The notification should be in writing, contain the reasoning behind invocation of the "material adverse change" clause, and be signed by a person with authority to represent the ISO/RTO in such actions. This will allow for a timely remedy for continued market participation, but also provide for a possible dispute to be resolved after the fact.

G. Grace Period to "Cure" Collateral Posting

152. Under certain circumstances, a market administrator may require the market participant to post additional collateral in order to continue to transact. Currently the organized wholesale electric markets vary as to the amount of time they allow a market participant to post additional collateral to "cure" its position. NYISO and PJM allow two days to provide additional collateral.[147] Midwest ISO allows two to three days (the market participant gets an additional business day if notice of invocation of the material adverse change clause occurs after noon Eastern Daylight Time).[148] CAISO and SPP allow three days.[149] In general, ISO–NE requires almost immediate remedy from market participants who exceed all of the credit tests. By 10 a.m. the next morning, all typical market functions of the market participant are suspended (some functions are lost immediately). In the event that this credit test failure was caused by the market participant or a guarantor dropping a single rating grade or from a bank issuing a letter of credit being downgraded, however, it may have five to ten days to "cure" this situation.[150]

153. Establishing a brief but standard time period to "cure" a collateral posting will bring certainty to the market which can stabilize the market and its prices, while controlling the risk and costs of a default. However, the Commission is aware of the importance of the continued reliable delivery of electricity and that some market participants have "provider of last resort" obligations. Consequently, the Commission attempted to strike a balance that allows an entity who is required to post additional collateral a reasonable chance to find a provider of capital—a bank or similar creditworthy institution—to assist in maintaining that participant's activity, while at the same time not posing a risk to the market. The Commission therefore proposed in the NOPR a two-day time limit for entities to post additional collateral and sought comment on the appropriate time limit.

1. Comments

154. The IRC agrees that establishing an outer limit on the amount of time granted for the posting of additional collateral will promote confidence in the ISO/RTO markets by limiting default exposure and by shortening collateral posting periods.[151] The Joint Commenters, EEI, PSEG, and Wisconsin Parties support standardization across the ISOs/RTOs, while NRECA, NIPSCO, and SCE support allowing the ISOs/RTOs and their stakeholders discretion to decide whether to revise their tariffs' time periods for curing collateral calls. NIPSCO claims that the Commission and ISOs/RTOs should be mindful that shortening the time a market participant has to react to margin calls could result in a higher rate of defaults.[152] APPA believes the time period to cure collateral calls should be referred to the working group APPA recommends for Material Adverse Changes.[153] NEPOOL argues that the ISO–NE Financial Assurance Policy [154] currently provides a suitable level of protection and urges that the Commission not issue any final

[146] We will leave to the discretion of the individual ISOs and RTOs how much notice may be reasonable in particular circumstances.

[147] NYISO Tariff, Attachment K (June 30, 2010) Section 26.8.3 for wholesale transmission service charges (virtual transactions and demand side resources offering ancillary services policies differ and may be result in shorter required response times); PJM Interconnection Tariff (6th Revised Version), Seventh Revised Sheet No. 523K.

[148] Midwest ISO Tariff (4th Revision), Sheet No. 2481.

[149] California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff, Section 12.4; Southwest Power Pool, Fifth Revised Electric Tariff, Original Sheet No. 717.

[150] ISO New England Inc. Transmission, Markets and Services Tariff at 106–09 (Aug. 30, 2010).

[151] IRC March 29, 2010 Comments at 9.

[152] NIPSCO March 29, 2010 Comments at 9.

[153] APPA March 29, 2010 Comments at 33–35.

[154] The ISO–NE Financial Assurance Policy includes credit review procedures to assess the ability of an applicant or of a market participant to pay for service transactions under the Tariff, identifies alternative forms of security deemed acceptable to the ISO, and provides the conditions under which the ISO will conduct business in a non-discriminatory way so as to avoid the possibility of failure of payment and to deal with market participants who are delinquent. ISO–NE Tariff, Section I, Exhibit IA.

rule that would require changes to that policy.[155]

155. Certain parties believe there should be different time periods for certain market participants. For example, while SWP supports a standardized time period across ISOs/RTOs, it believes the time period should also recognize the differences in market participants. SWP states that entities that participate in markets on a purely financial basis should post additional collateral within two days, but entities with an obligation to serve should have a minimum of three days.[156] Basin Electric believes the length of the cure period should be related to the severity of the material adverse change giving rise to the need to cure.[157] New Jersey Public Power suggests that a longer, sixty-day period is more appropriate for municipal utilities.[158]

156. Regarding the appropriate time period to post additional collateral, several parties from California [159] support keeping the current CAISO rule of a three-day cure period. These parties express concerns about the burdens of a shorter time period. For example, Six Cities argue that the internal review and authorization processes applicable to collateral commitments for Six Cities would make it difficult to post additional collateral within two business days, so the current three-day period should remain in effect, at least for governmental entities.[160]

157. Other parties, however, believe a two-day period to post additional collateral is more appropriate. Calpine requests that the Commission require ISOs and RTOs to adopt a standardized two-day cure period.[161] DC Energy, Direct Energy, Dominion, and Dynegy all support a standardized two-day cure period across all ISOs/RTOs. Midwest ISO and NRECA support a two-day cure period. Midwest ISO states that it views this proposal as generally being a standard practice in wholesale electric markets.[162] NRECA acknowledges that the standard financial industry practice allows two business days to post additional collateral after receipt of the demand, but the ISO/RTO stakeholder process is the best vehicle for addressing this on a regional basis.[163] Morgan Stanley and the NYTOs find that the current two-day period is sufficient in PJM and NYISO, respectively.[164] OMS, Consumers Energy, EPSA, FirstEnergy, Shell Energy, and CEI and MidAmerican state that two days is a reasonable amount of time to post additional collateral.

158. Additional parties have various opinions on the appropriate time period to post additional collateral. While SPP currently requires market participants to post additional security within three days, it states a two-day period strikes a reasonable balance between the need to reduce identified risk and the challenges a demand for collateral might place on a market participant. Midwest TDUs state that the Commission should not adopt a limit to the time period for collateral calls, but if it does, three business days would be appropriate and two days is the minimum.[165] J.P. Morgan supports a cure period of one or two business days, recognizing that market participants have the ability to post cash immediately and then subsequently replace such cash deposits with permitted financial instruments of their choosing (e.g., letters of credit).[166]

159. Finally, CFTC staff believes that a two-day cure period may be too long for collateral calls.[167] CFTC staff states that a cure period of more than one day is inconsistent with the purpose of such a call, since the risk exposure of the ISO/RTO is diminished by the posting of additional collateral.[168]

2. Commission Determination

160. The Commission adopts the NOPR proposal to require each ISO and RTO to include in the credit provisions of its tariff language to limit the time period allowed to post additional collateral. In addition, we require each ISO and RTO to allow no more than two days to "cure" a collateral call. The Commission directs each ISO and RTO to submit a compliance filing that includes tariff revisions to 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. This compliance filing must be submitted by June 30, 2011, and the tariff revisions will take effect October 1, 2011.

161. The Commission recognizes the difficult position parties can find themselves in when additional collateral is required on short notice. Nevertheless, the time allowed for a "cure" needs to be short to minimize uncertainty as to a participant's ability to participate in the market, and to minimize the risk and costs of a default by a participant (which, as noted elsewhere, affects other participants). The Commission also understands the rationale presented by CFTC staff when they suggest that any period longer than a day can be hazardous to the market. We thus seek to strike a balance: to minimize the potential for market disruptions and the risk and costs of a default, while allowing participants sufficient time to obtain additional capital so that they can continue to participate in the market. The Commission is persuaded that a limit of no more than two days to cure a collateral call achieves the desired balance.

162. Two days should be sufficient for a market participant which is called upon to "cure" to arrange reasonable capital requirements. In reaching this determination, we note that some of the ISO/RTO markets already have a two-day cure period, so it should not prove overly burdensome to mandate this standard for all markets.[169] Additionally, commenters point out that a two-day limit is a standard financial industry practice.[170]

163. We disagree with the argument that the Commission should not apply the same limit to all the ISO/RTO markets. We see no distinction between the ISO/RTO markets that warrant differentiation.

H. General Applicability

164. When the Commission issued the NOPR, we requested comment "on whether the credit practices discussed below should be applied in the same way to all market participants or whether they should be applied differently to certain market participants depending on their characteristics." [171] The Commission received substantial comment on this question both for uniform applicability of credit practices and against uniform application but received little in the way of verifiable evidence to support either contention. The Commission has also reviewed historic and recent developments in debt markets which tend to reflect risk of default—a central element of this

[155] NEPOOL March 29, 2010 Comments at 20.

[156] SWP March 29, 2010 Comments at 8.

[157] Basin Electric March 29, 2010 Comments at 6.

[158] New Jersey Public Power March 29, 2010 Comments at 15.

[159] CAISO, NCPA, CPUC, the Six Cities, and PG&E.

[160] Six Cities March 29, 2010 Comments at 6–7.

[161] Calpine March 29, 2010 Comments at 11–12.

[162] Midwest ISO March 29, 2010 Comments at 21.

[163] NRECA March 29, 2010 Comments at 19.

[164] Morgan Stanley March 29, 2010 Comments at 10; NYTO March 29, 2010 Comments at 10.

[165] Midwest TDUs March 29, 2010 Comments at 20–21.

[166] J.P. Morgan March 26, 2010 Comments at 13.

[167] CFTC staff notes its comments are focused on FTRs even though they may be applicable to other markets as well. CFTC staff March 29, 2010 Comments at 2.

[168] *Id.* at 10.

[169] *See* Midwest ISO March 29, 2010 Comments at 21.

[170] NRECA March 29, 2010 Comments at 19.

[171] NOPR, FERC Stats. & Regs. ¶ 32,651 at P 8.

rulemaking process—in order to obtain additional information to consider the question asked in the NOPR.

165. Based on, among other things, a review of comments, Commission experience, and our review of the historic and recent developments in the debt markets, the Commission determines that the credit practices in this Final Rule will apply to all market participants. In making this determination, the Commission is aware that ISOs and RTOs may, through their stakeholder processes, ask for specific exemptions based on their experience and appropriate supporting evidence, particularly for individual entities whose participation is such that a default would not risk significant market disruptions. The Commission, however, will not, at this time in this generic rulemaking, adopt any exemptions.

IV. Information Collection Statement

166. The Office of Management and Budget's (OMB) regulations require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

167. This Final Rule amends the Commission's regulations pursuant to section 206 of the Federal Power Act, to reform credit practices of organized wholesale electric markets to limit potential future market disruptions. To accomplish this, the Commission requires RTOs and ISOs to adopt tariff revisions reflecting these credit reforms. Such filings would be made under Part 35 of the Commission's regulations. The information provided for under Part 35 is identified as FERC–516.

168. Under section 3507(d) of the Paperwork Reduction Act of 1995,[172] the reporting requirements in this rulemaking will be submitted to OMB for review. In their notice of March 18, 2010, OMB took no action on the NOPR, instead deferring their approval until review of the Final Rule.

169. The Commission solicited comments on the need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. The Commission did not receive any specific comments regarding its burden estimates. The Public Reporting burden for the requirements contained in the Final Rule is as follows:

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
FERC–516:				
Transmission Organizations with Organized Electricity Markets	6	1	100	600

Information Collection Costs: The Commission has projected the average annualized cost of all respondents to be the following:

600 hours @ $300 per hour = $180,000 for respondents. No capital costs are estimated to be incurred by respondents.

Title: FERC–516, Electric Rate Schedule Tariff Filings.

Action: Information Collection.

OMB Control No: 1902–0096.

Respondents: Businesses or other for profit and/or not-for-profit institutions.

Necessity of the Information: The information from FERC–516 enables the Commission to exercise its wholesale electric power and transmission oversight responsibilities in accordance with the Federal Power Act. The Commission needs sufficient detail to make an informed and reasonable decision concerning the appropriate level of rates, and the appropriateness of non-rate terms and conditions, and to aid customers and other parties who may wish to challenge the rates, terms, and conditions proposed by the utility.

170. This Final Rule amends the Commission's regulations to ensure that credit practices currently in place in organized wholesale electric markets reasonably protect consumers against the adverse effects of default. To promote confidence in the markets, the Commission believes it is appropriate to adopt specific requirements regarding credit practices for organized wholesale electric markets. These requirements include shortening of billing and settlement periods and reducing the amount of unsecured credit. The Commission believes these actions will enhance certainty and stability in the markets, and in turn, ensure that costs associated with market participant defaults do not result in unjust or unreasonable rates.

171. *Internal Review:* The Commission has reviewed the requirements pertaining to organized wholesale electric markets and determined the proposed requirements are necessary to its responsibilities under section 206 of the Federal Power Act.

172. These requirements conform to the Commission's plan for efficient information collection, communication and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

173. Interested persons may obtain information on this information collection by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, Attention: Ellen Brown, Office of the Executive Director, phone: (202) 502–8663, fax: (202) 273–0873, e-mail: *DataClearance@ferc.gov*.

174. Comments concerning this information collection can be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–4650, fax: (202) 395–7285].

V. Environmental Analysis

175. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[173] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is

[172] 44 U.S.C. 3507(d).

[173] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

required for this Final Rule under Section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to rates and charges and terms and conditions for transmission or sales subject to the Commission's jurisdiction.[174]

VI. Regulatory Flexibility Act Certification

176. The Regulatory Flexibility Act of 1980 (RFA)[175] requires a description and analysis of rules that will have a significant economic impact on a substantial number of small entities.[176] The Commission is not required to make such analyses if a rule would not have such an effect.

177. The RTOs and ISOs regulated by the Commission do not fall within the RFA's definition of small entity. In addition, the vast majority of market participants in RTOs and ISOs are, either alone or as part of larger corporate families, not small entities. And the protections proposed here will protect all market participants, including small market participants, by reducing risk by reducing the likelihood of defaults and minimizing the impact of any defaults.

178. California Independent Service Operator Corp. is a nonprofit organization comprised of more than 90 electric transmission companies and generators operating in its markets and serving more than 30 million customers.

179. New York Independent System Operator, Inc. is a nonprofit organization that oversees wholesale electricity markets serving 19.2 million customers. NYISO manages a 10,775-mile network of high-voltage lines.

180. PJM Interconnection, L.L.C. is comprised of more than 450 members including power generators, transmission owners, electricity distributors, power marketers and large industrial customers and serving 13 states and the District of Columbia.

181. Southwest Power Pool, Inc. is comprised of 50 members serving 4.5 million customers in eight states and has 52,301 miles of transmission lines.

182. Midwest Independent Transmission System Operator, Inc. (Midwest ISO) is a non-profit organization with over 131,000 megawatts of installed generation. Midwest ISO has 93,600 miles of transmission lines and serves 15 states and one Canadian province.

183. ISO New England Inc. is a regional transmission organization serving six states in New England. The system is comprised of more than 8,000 miles of high voltage transmission lines and several hundred generating facilities of which more than 350 are under ISO–NE's direct control.

184. Therefore, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities. As a result, no regulatory flexibility analysis is required. As discussed in Order No. 2000,[177] in making this determination, the Commission is required to examine only the direct compliance costs that a rulemaking imposes upon small businesses. It is not required to consider indirect economic consequences, nor is it required to consider costs that an entity incurs voluntarily. This rulemaking does not impose significant compliance costs upon small entities; the RTOs and ISOs directly affected—in that they have to adopt new or revised tariff language—are not small entities. Further, as to entities indirectly affected, *i.e.,* market participants, most of them are not small entities. And, in any event, as to all market participants large and small, as we explained in Order No. 2000, *supra,* they have a choice of whether to join an RTO and whether to be a market participant or not. Moreover, the Commission believes that, to the extent that the credit reforms required by this Final Rule indirectly may impose potentially higher costs on some entities in the short-term, these reforms will also protect the markets and their participants from unacceptable disruptions and resulting costly defaults.[178] Thus, this rulemaking will not have a significant economic impact upon any small entities.

VII. Document Availability

185. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

186. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type "RM10–13" in the docket number field.

187. User assistance is available for eLibrary and the Commission's Web site during normal business hours. For assistance, please contact FERC Online Support at 1–866–208–3676 (toll free) or 202–502–6652 (e-mail at *FERCOnlineSupport@FERC.gov*), or the Public Reference Room at 202–502–8371, TTY 202–502–8659 (e-mail at *public.referenceroom@ferc.gov*).

VIII. Effective Date and Congressional Notification

188. This Final Rule will take effect November 26, 2010. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a major rule within the meaning of section 251 of the Small Business Regulatory Enforcement Fairness Act of 1996.[179] The Commission will submit this Final Rule to both Houses of Congress and the General Accountability Office.[180]

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

[174] 18 CFR 380.4(a)(15).

[175] 5 U.S.C. 601–12.

[176] The RFA definition of "small entity" refers to the definition provided in the Small Business Act, which defines a "small business concern" as a business that is independently owned and operated and that is not dominant in its field of operation. 5 U.S.C. 601(3) (citing Section 3 of the Small Business Act, 15 U.S.C. 632). The Small Business Size Standards component of the North American Industry Classification System defines a small electric utility as one that, including its affiliates, is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and whose total electric output for the preceding fiscal years did not exceed 4 million MWh. 13 CFR 121.201.

[177] *See Regional Transmission Organizations,* Order No. 2000, 65 FR 809 (January 6, 2000), FERC Stats. & Regs., Regulations Preambles July 1996–December 2000 ¶ 31,089, at 31,237 & n.754 (1999), *order on reh'g,* Order No. 2000–A, 65 FR 12,088 (March 8, 2000), FERC Stats. & Regs., Regulations Preambles July 1996–December 2000 ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish, County Washington v. FERC, 272 F.3d 607, 348 U.S. App. D.C. 205 (D.C. Cir. 2001)* (*citing Mid-Tex Elec. Coop. v. FERC, 773 F.2d 327* (D.C. Cir. 1985) (Commission need only consider small entities "that would be directly regulated"); *Colorado State Banking Bd.* v. *RTC,* 926 F.2d 931 (10th Cir. 1991) (Regulatory Flexibility Act not implicated where regulation simply added an option for affected entities and did not impose any costs)).

[178] The credit practices required by this Final Rule are akin to insurance against a disruption in the market that could lead to a major default and result in costs being socialized among all market participants. The Commission believes that the benefit of avoiding major market disruptions outweighs the cost of such insurance.

[179] *See* 5 U.S.C. 804(2).

[180] *See* 5 U.S.C. 801(a)(1)(A).

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

■ In consideration of the foregoing, the Commission amends part 35, Subchapter B, Chapter I, Title 18, *Code of Federal Regulations,* as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

■ 1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. Subpart J is added to read as follows:

Subpart J—Credit Practices In Organized Wholesale Electric Markets

Sec.

§ 35.45 Applicability.

This subpart establishes credit practices for organized wholesale electric markets for the purpose of minimizing risk to market participants.

§ 35.46 Definitions.

As used in this subpart:

(a) *Market Participant* means an entity that qualifies as a Market Participant under § 35.34.

(b) *Organized Wholesale Electric Market* includes an independent system operator and a regional transmission organization.

(c) *Regional Transmission Organization* means an entity that qualifies as a Regional Transmission Organization under 18 CFR 35.34.

(d) *Independent System Operator* means an entity operating a transmission system and found by the Commission to be an Independent System Operator.

§ 35.47 Tariff provisions regarding credit practices in organized wholesale electric markets.

Each organized wholesale electric market must have tariff provisions that:

(a) Limit the amount of unsecured credit extended by an organized wholesale electric market to no more than:

(1) $50 million for each market participant; and

(2) $100 million for all entities within a corporate family.

(b) Adopt a billing period of no more than seven days and allow a settlement period of no more than seven days.

(c) Eliminate unsecured credit in financial transmission rights markets and equivalent markets.

(d) Establish a single counterparty to all market participant transactions, or require each market participant in an organized wholesale electric market to grant a security interest to the organized wholesale electric market in the receivables of its transactions, or provide another method of supporting netting that provides a similar level of protection to the market and is approved by the Commission. In the alternative, the organized wholesale electric market shall not net market participants' transactions and must establish credit based on market participants' gross obligations.

(e) Limit to no more than two days the time period provided to post additional collateral when additional collateral is requested by the organized wholesale electric market.

(f) Require minimum participation criteria for market participants to be eligible to participate in the organized wholesale electric market.

(g) Provide a list of examples of circumstances when a market administrator may invoke a "material adverse change" as a justification for requiring additional collateral; this list does not limit a market administrator's right to invoke such a clause in other circumstances.

Note: The following Appendix will not be published in the Code of Federal Regulations.

APPENDIX LIST OF INTERVENORS AND COMMENTERS

Commenters

Acronym	Name
AMP	American Municipal Power.
APPA	American Public Power Association.
Basin Electric	Basin Electric Power Cooperative.
BP Energy	BP Energy Company.
BPA	Bonneville Power Administration.
CAISO	California Independent System Operator Corporation.
Calpine	Calpine Corporation.
CCRO	Committee of Chief Risk Officers.
CFTC staff	Commodity Futures Trading Commission.
Citigroup	Citigroup Energy Inc.
City of New York	City of New York.
Constellation/NRG	Constellation Companies and NRG Companies.
CPUC	California Public Utility Commission.
DC Energy	DC Energy, LLC.
Detroit Edison	Detroit Edison Company.
Direct Energy	Direct Energy Services, LLC.
DMEC	Delaware Municipal Electric Corporation, Inc.
Dominion	Dominion Resources Services Inc.
Duke	Duke Energy Corporation.
Dynegy	Dynegy Power Marketing, Inc.
East Texas Electric Cooperatives	East Texas Electric Cooperatives.
EEI	Edison Electric Institute.
EMCOS	Eastern Massachusetts Consumer-Owned Systems, including Braintree Electric Light Department, Concord Municipal Light Plant, Hingham Municipal Lighting Plant, Reading Municipal Light Department, Taunton Municipal Lighting Plan, Wellesley Municipal Light Plant.
EPSA	Electric Power Supply Association.
Financial Marketers	Jump Power, LLC; Energy Endeavors LP; Big Bog Energy, LP; Silverado Energy LP; Gotham Energy Marketing LP; Rockpile Energy LP; Coaltrain Energy LP; Longhorn Energy LP; MET MA, LLC; Solios Power, LLC; and JPTC, LLC.

APPENDIX LIST OF INTERVENORS AND COMMENTERS—Continued

Commenters	
Acronym	Name
First Energy	First Energy Service Company, including American Transmission Systems, Inc., The Cleveland Electric Illuminating Company, Jersey Central Power & Light Company, Pennsylvania Power Company, The Toledo Edison Company, and FirstEnergy Solutions Corp.
Hess	Hess Corporation.
IMEA	Illinois Municipal Electric Agency.
IPPNY	Independent Power Producers of New York.
IRC	ISO/RTO Council.
ISO–NE	ISO New England Inc.
J.P. Morgan	J.P. Morgan Ventures Energy Corporation.
Joint Commenters	Constellation Energy Commodities Group, Inc., Constellation NewEnergy, Inc., and Integrys Energy Services, Inc.
MidAmerican	MidAmerican Energy Holdings Company.
Midwest ISO	Midwest Independent Transmission Operator, Inc.
Midwest TDUs	Indiana Municipal Power Agency, Madison Gas & Electric Company, Missouri River Energy Services, Southern Minnesota Municipal Power Agency, and WPPI Energy.
Mirant	Mirant Corporation.
Morgan Stanley	Morgan Stanley Capital Group Inc.
NEMA	National Energy Marketers Association.
NEPOOL	New England Power Pool Participants Committee.
New Jersey Public Power	Public Power Association of New Jersey and Madison, New Jersey.
New York Consumers	Multiple Intervenors, including more than 50 large industrial, commercial, and institutional end-use energy consumers located in New York.
New York Suppliers	Small Customer Marketer Coalition (The Constellation Companies, The CENG Companies, and The NRG Companies).
NIPSCO	Northern Indiana Public Service Company.
Northeast ISOs	ISO–NE, NYISO, and PJM Joint Comments.
Northern California Power Agency	Northern California Power Agency.
NRECA	National Rural Electric Cooperative Association.
NYISO	New York Independent System Operator, Inc.
NYPSC	New York Public Service Commission.
NYSCB	New York State Consumer Protection Board.
NYTOs	New York Transmission Owners, including Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., Long Island Power Authority, New York Power Authority, New York State Electric & Gas Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.
OMS	Organization of Midwest ISO States.
PG&E	Pacific Gas & Electric Company.
PJM	PJM Interconnection, L.L.C.
Powerex	Powerex.
PSEG	Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.
SCE	Southern California Edison Company.
SDG&E	San Diego Gas & Electric Company.
Shell Energy	Shell Energy.
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
SPP	Southwest Power Pool, Inc.
SWP	California Department of Water Resources State Water Project.
WAPA	Western Area Power Administration.
Wisconsin parties	Wisconsin Public Service Commission and Upper Peninsula Power Company.
WPTF	Western Power Trading Forum.
Xcel	Xcel Energy Services.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 40

[Docket No. RM09–15–000; Order No. 740]

Version One Regional Reliability Standard for Resource and Demand Balancing

Issued October 21, 2010.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: Under section 215 of the Federal Power Act, the Commission hereby remands a revised regional Reliability Standard developed by the Western Electricity Coordinating Council and approved by the North American Electric Reliability Corporation, which the Commission has certified as the Electric Reliability Organization responsible for developing and enforcing mandatory Reliability Standards. The revised regional Reliability Standard, designated by WECC as BAL–002–WECC–1, would set revised Contingency Reserve requirements meant to maintain scheduled frequency and avoid loss of firm load following transmission or generation contingencies.

DATES: *Effective Date:* This rule will become effective November 26, 2010.

FOR FURTHER INFORMATION CONTACT:

Nick Henery (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8636.

Scott Sells (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6664.

A. Cory Lankford (Legal Information), Office of General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6711.

SUPPLEMENTARY INFORMATION:

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Before Commissioners: Jon Wellinghoff, Chairman; Marc Spitzer, Philip D. Moeller, John R. Norris, and Cheryl A. LaFleur

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission hereby remands a revised regional Reliability Standard developed by the Western Electricity Coordinating Council (WECC) and approved by the North American Electric Reliability Corporation (NERC), which the Commission has certified as the Electric Reliability Organization (ERO) responsible for developing and enforcing mandatory Reliability Standards.[2] The revised regional Reliability Standard, designated by WECC as BAL–002–WECC–1,[3] is meant to ensure that adequate resources are available at all times to maintain scheduled frequency, and avoid loss of firm load following transmission or generation contingencies. As discussed below, the Commission finds that the proposed regional Reliability Standard does not meet the statutory criteria for approval that it be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4]

2. The Commission remands the proposed regional Reliability Standard based on concerns that WECC has not provided adequate technical support to demonstrate that the requirements of the proposed regional Reliability Standard are sufficient to ensure the reliable operation of the Bulk-Power System within WECC. Specifically, WECC's data indicates that extending the reserve restoration period from 60 to 90 minutes presents an unreasonable risk that a second major contingency could occur before reserves are restored after an initial contingency. Without further technical justification demonstrating that this less stringent requirement will adequately support reliability in the Western Interconnection, the Commission is unable to determine that the proposed regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Accordingly, we remand WECC regional Reliability Standard BAL–002–WECC–1 to the ERO so that the Regional Entity may develop further modifications consistent with this final rule.[5]

[1] 16 U.S.C. 824o (2006).

[2] *North American Electric Reliability Corp.,* 116 FERC ¶ 61,062, order on reh'g & compliance, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa, Inc.* v. *FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

[3] NERC designates the version number of a Reliability Standard as the last digit of the Reliability Standard number. Therefore, original Reliability Standards end with "-0" and modified version one Reliability Standards end with "-1."

[4] 16 U.S.C. 824o(d)(2).

[5] In Order No. 672, the Commission found that it should order only the ERO to modify a Reliability Standard because the ERO is the only entity that may directly submit a proposed Reliability Standard to the Commission for approval. *Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204, at P 423, *order on reh'g,* Order No. 672–A, 71 FR 19814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006).