cause the rudder pedal mechanism to detach from the brake cylinder. We are issuing this proposed AD to detect and correct discrepancies of the brake master cylinder pivot pin, which could lead to detachment of the rudder pedal mechanism from the brake master cylinder with consequent loss of control.

(f) Actions and Compliance

Unless already done, do the following actions in paragraphs (f)(1) through (3) of this AD:

(1) Within 300 hours time-in-service (TIS) after the effective date of this AD or within 300 hours TIS after the last inspection required by AD 2015–11–01, whichever occurs first, and repetitively thereafter at intervals not to exceed 300 hours TIS or 12 months, whichever occurs first, inspect the brake master cylinder pivot pins part number (P/N) T67M–45–539 installed on rudder pedal assemblies number 1 and number 4. Do this action following paragraph C. INSPECTION of the Accomplishment Instructions in Marshall Aerospace and Defense Group Service Bulletin SBM 200, Revision 2, dated December 2015 (SBM 200, Revision 2).

(2) If any cracking or distortion of the brake master cylinder pivot pins is found or the pivot pin fails the dimensional check during any of the inspections required in paragraph (f)(1) of this AD, before further flight, replace the affected pivot pin with a serviceable part following paragraph C. INSPECTION of the Accomplishment Instructions in SBM 200, Revision 2.

(3) Replacement of the brake master cylinder pivot pins as required by paragraph (f)(2) of this AD does not terminate the repetitive inspections required by paragraph (f)(1) of this AD. If both brake master cylinder pivot pins are replaced at the same time, the first repetitive inspection after replacement of the pivot pins can be deferred until 1,000 hours TIS after replacement of the pivot pins.

(g) Credit for Actions Accomplished in Accordance With Previous Service Information

This AD provides credit for any inspections required in paragraph (f)(1) of this AD if completed before the effective date of this AD following the Accomplishment Instructions of Marshall Aerospace and Defense Group Service Bulletin SBM 200, Revision 1, dated April 2015.

(h) Other FAA AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, Standards Office, FAA, has the authority to approve AMOCs for this AD, if requested using the procedures found in 14 CFR 39.19. Send information to ATTN: Jim Rutherford, Aerospace Engineer, FAA, Small Airplane Directorate, 901 Locust, Room 301, Kansas City, Missouri 64106; telephone: (816) 329–4165; fax: (816) 329–4090; email:. Before using any approved AMOC on any airplane to which the AMOC applies, notify your appropriate principal inspector (PI) in the FAA Flight Standards District Office (FSDO), or lacking a PI, your local FSDO.

(2) *Airworthy Product:* For any requirement in this AD to obtain corrective actions from a manufacturer or other source, use these actions if they are FAA-approved. Corrective actions are considered FAA-approved if they are approved by the State of Design Authority (or their delegated agent). You are required to assure the product is airworthy before it is returned to service.

(i) Related Information

Refer to MCAI EASA AD 2016–0214, dated October 27, 2016, for related information. You may examine the MCAI on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2017–0048. For service information related to this AD, contact Marshall Aerospace and Defence Group, The Airport, Newmarket Road, Cambridge, CB5 8RX, UK; telephone: +44 (0) 1223 399856; fax: +44 (0) 7825365617; email: *mark.bright@marshalladg.com;* Internet: *www.marshalladg.com.* You may review copies of the referenced service information at the FAA, Small Airplane Directorate, 901 Locust, Kansas City, Missouri 64106. For information on the availability of this material at the FAA, call (816) 329–4148.

Issued in Kansas City, Missouri, on January 18, 2017.

Melvin Johnson,

Acting Manager, Small Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2017–01768 Filed 2–6–17; 8:45 am]

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM17–2–000]

Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to revise its regulations to require that each regional transmission organization (RTO) and independent system operator (ISO) that currently allocates the costs of real-time uplift due to deviations should allocate such real-time uplift costs only to those market participants whose transactions are reasonably expected to have caused the real-time uplift costs. The Commission also proposes to revise its regulations to enhance transparency by requiring that each RTO/ISO post uplift costs paid (dollars) and operator-initiated commitments (megawatts) on its Web site; and define in its tariff its transmission constraint penalty factors, as well as the circumstances under which those penalty factors can set locational marginal prices, and any procedure for changing those factors.

DATES: Comments are due April 10, 2017.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- *Electronic Filing through http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

Stanley Wolf (Technical Information), Office of Energy Policy and Innovation, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–6841, *Stanley.Wolf@ferc.gov*

Keatley Adams (Technical Information), Office of Energy Market Regulation, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8678, *Keatley.Adams@ferc.gov*

Colin Beckman (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8049, *Colin.Beckman@ferc.gov*

SUPPLEMENTARY INFORMATION:

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1. In this Notice of Proposed Rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) proposes to revise its regulations to address potentially unjust and unreasonable approaches to real-time uplift cost allocation and transparency practices by regional transmission organizations (RTOs) and independent system operators (ISOs).

2. While the Commission and RTOs/ISOs have taken steps to reduce the amount of uplift in the energy and ancillary services markets, the complexity inherent in the electric system and limitations in the tools available to maintain reliable operations can lead to system operators taking out-of-market actions to manage reliability. When they do so, energy and ancillary service prices may not reflect the marginal cost of production and some resources may therefore need make-whole payments to ensure recovery of operating costs. Since the limitations in representing the complexity of the electric system in market models are unlikely to ever be fully resolved, uplift costs are also unlikely to be completely eliminated. As a result, RTOs/ISOs need to have a method for allocating these costs to market participants. At the highest level, the allocation of uplift costs should, to the extent possible, encourage behavior that will reduce the need for uplift-creating actions and avoid discouraging market participant behavior that lowers total production costs (*i.e.,* enhances efficiency). The reforms proposed in this NOPR are designed to achieve these objectives.

3. Given that RTOs/ISOs are likely going to need to take some out-of-market actions, there is a need to provide transparency regarding those actions and the associated uplift costs. The lack of transparency regarding uplift and operator-initiated commitments,[1] which can cause uplift, hinders a market participant's ability to plan and efficiently respond to system needs. Market participants may lack the information necessary to evaluate the need for and value of additional investment, such as transmission upgrades or new generation. Also, without sufficient transparency, market participants may not be able to assess each RTO's/ISO's operator-initiated commitment practices and raise any issues of concern through the stakeholder process. The transparency reforms proposed in this NOPR are designed to allow market participants to understand the actions RTOs/ISOs are taking and respond accordingly.

4. First, we preliminarily find that certain practices of allocating the cost of real-time uplift[2] to market participants who deviate from day-ahead market schedules (deviations) are inconsistent with cost causation, which may distort market outcomes, potentially resulting in unjust and unreasonable rates.

[1] An operator-initiated commitment is a commitment that is not associated with a resource clearing the day-ahead or real-time market on the basis of economics and that is not self-scheduled. *See* FERC, *Operator Initiated Commitments in RTO and ISO Markets,* Docket No. AD14–14–000 at 8–20 (Dec. 2014), *http://www.ferc.gov/legal/staff-reports/2014/AD14-14-operator-actions.pdf.*

[2] Real-time uplift refers to uplift payments to resources committed after the close of the day-ahead market, including any uplift associated with reliability commitments, whether or not the RTO/ISO considers such commitments outside of the day-ahead market, *e.g.,* the Reliability Unit Commitment or RUC process. As such, uplift payments to resources committed in a reliability unit commitment process would be considered real-time uplift for the purposes of this NOPR).

Specifically, some RTO/ISO practices of allocating real-time uplift costs to deviations that could not reasonably be expected to have caused those uplift costs can distort market outcomes by inappropriately penalizing behavior that can improve price formation. Therefore, we propose to require that, if an RTO/ISO allocates real-time uplift costs to deviations, it must do so based on cost causation, as further discussed below. For the purposes of allocating uplift costs to deviations, we propose that deviations are megawatt hour differences between a market participant's scheduled deliveries or receipts at particular points—as determined by the day-ahead market clearing process—and those amounts actually delivered or received in real-time that are not related to real-time economic or reliability-related operator dispatch instructions. This proposal would apply only to real-time uplift cost allocation to deviations. This NOPR does not apply to other methods used by RTOs/ISOs to allocate uplift costs. If an RTO/ISO does not currently allocate real-time uplift costs to deviations, this NOPR does not impose a requirement on those RTOs/ISOs to allocate real-time uplift costs to deviations.

5. Second, we preliminarily find that current practices with respect to reporting uplift payments, operator-initiated commitments, and transmission constraint penalty factors [3] are unjust and unreasonable. The lack of transparency into the costs allocated to market participants, and into the causes of such costs, hinders the ability of market participants to assess the effectiveness of current operational practices or to evaluate the need for additional investment, such as transmission upgrades or new generation. Similarly, the lack of transparency with respect to transmission constraint penalty factors may hinder a market participant's ability to effectively understand how an RTO's/ISO's actions affect energy prices and thus, hinder its ability to hedge energy market transactions. As discussed further below, for these reasons we preliminarily find that these practices may result in rates that are unjust and unreasonable. We therefore propose to require that each RTO/ISO: (1) Report total uplift payments for each transmission zone, broken out by day and uplift category; (2) report total uplift payments for each resource on a monthly basis; (3) report megawatts (MW) of operator-initiated commitments in or near real-time and after the close of the day-ahead market, broken out by transmission zone and commitment reason; and (4) define in its tariff the transmission constraint penalty factors, as well as the circumstances under which those factors can set locational marginal prices (LMPs), and the process by which they can be changed.

6. The goals of the price formation proceeding are to: (1) Maximize market surplus for consumers and suppliers; (2) provide correct incentives for market participants to follow commitment and dispatch instructions, make efficient investments in facilities and equipment, and maintain reliability; (3) provide transparency so that market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system; and (4) ensure that all suppliers have an opportunity to recover their costs.[4]

7. The reforms proposed in this NOPR address two of the Commission's price formation goals. First, the proposed reforms to uplift costs allocated to deviations should improve market participants' incentives to perform in real-time consistent with operator instructions and bid into the day-ahead market and submit day-ahead schedules consistent with expected real-time system conditions. Second, the proposed transparency reforms will help market participants understand how prices reflect the actual marginal cost of serving load and the operational constraints of reliably operating the system.

8. We seek comment on these proposed reforms 60 days after publication of this NOPR in the **Federal Register**.

I. Background

9. In June 2014, the Commission initiated a proceeding, in Docket No. AD14–14–000, Price Formation in Energy and Ancillary Services Markets in Regional Transmission Organizations and Independent System Operators, to evaluate issues regarding price formation in the energy and ancillary services markets operated by RTOs/ISOs (Price Formation Proceeding). The notice initiating that proceeding stated that there may be opportunities for the RTOs/ISOs to improve the price formation process in the energy and ancillary services markets. As set forth in the notice, prices used in energy and ancillary services markets ideally "would reflect the true marginal cost of production, taking into account all physical system constraints, and these prices would fully compensate all resources for the variable cost of providing service." [5] Pursuant to the notice, staff conducted outreach and convened technical workshops on the following four general issues: (1) Use of uplift payments; (2) offer price mitigation and offer price caps; (3) scarcity and shortage pricing; and (4) operator actions that affect prices.[6]

10. In January 2015, the Commission requested comments on questions that arose from the price formation technical workshops.[7] As a result of these comments, the Commission identified, among other things, five topics with potential for reform to improve price formation, but for which further information was needed.

11. In November 2015, the Commission issued an order that directed each RTO/ISO to report on these five price formation topics: Fast-start pricing; managing multiple contingencies; look-ahead modeling; uplift allocation; and transparency.[8] Specifically, the order directed each RTO/ISO to file a report providing an update on its current practices in the five topic areas, outlining the status of its efforts (if any) to address issues in each of the five topic areas, and responding to specific questions contained in the order. In the reports filed and the subsequent comments, RTOs/ISOs and other commenters addressed the issues of uplift cost allocation and transparency,[9] which are the subject of this NOPR.

II. Discussion

A. Uplift Cost Allocation

12. In this section, we first provide a brief background on uplift payments and deviations between day-ahead and real-time schedules as a way to determine uplift cost allocation. We

[3] Transmission constraint penalty factors are the values at which an RTO's/ISO's market software will relax the limit on a transmission constraint rather than continue to re-dispatch resources to relieve congestion associated with that constraint.

[4] *See Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice Inviting Post-Technical Workshop Comments, Docket No. AD14–14–000, at 1 (Jan. 16, 2015) (Notice Inviting Comments); *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators,* Notice, Docket No. AD14–14–000 (June 19, 2014) (Price Formation Notice).

[5] Price Formation Notice, Docket No. AD14–14–000, at 2 (June 19, 2014).

[6] *Id.* at 1, 3–4.

[7] Notice Inviting Comments, Docket No. AD14–14–000 (Jan. 16, 2015).

[8] *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators,* 153 FERC ¶ 61,221 (2015) (Order Directing Reports).

[9] A list of commenters and the abbreviated names used in this NOPR appears in the Appendix.

then review current RTO/ISO practices and comments regarding these practices submitted prior to and after the issuance of the Order Directing Reports. Finally, we explain the need for reform and set forth the proposal in detail.

1. Uplift Cost Allocation Background

13. Uplift generally refers to payments that RTOs/ISOs make to a resource whose commitment and dispatch result in a shortfall between the costs in a resource's offer and the revenue earned through market clearing prices.[10] For example, if a resource is committed and is not able to fully recover its costs from the energy and ancillary services markets, it would receive an uplift payment. As noted in the Staff Analysis of Uplift, modeling, software, and certain other limitations are inherent in the complexity of the electric system and the tools available to maintain reliable operations. As a result, system operators may have to take out-of-market actions to manage reliability, with resulting energy and ancillary service prices not reflecting the marginal cost of production. Uplift, or make-whole, payments may therefore be needed to ensure that resources committed and dispatched out-of-market are able to recover their operating costs. These modeling, software, and other limitations will likely persist, making uplift an inherent element of centralized wholesale energy and ancillary services markets that may not be completely eliminated. Therefore, RTOs/ISOs must have a method to allocate these costs to market participants. Generally, RTOs/ISOs allocate uplift costs either directly to market participants who caused the uplift or to load. Allocation of uplift costs to load is motivated by several considerations. Load can be viewed as the ultimate beneficiary of the actions the system operator takes to maintain reliability. Further, one principle of cost allocation is to allocate costs in a way that is least likely to distort market participant behavior. In electricity markets, load is the class of market participants that is currently the least sensitive to price and for whom an allocation of uplift costs is arguably least likely to distort behavior. For shorthand, allocating uplift costs to load is referred to as ''beneficiary pays.'' In practice, RTOs/ISOs often use a combination of the two approaches, with load receiving all of the uplift costs that are not allocated through cost-causation methods, such as a deviations-based approach.

14. In its Order Directing Reports, the Commission asked the RTOs/ISOs to explain whether and how the RTO/ISO allocates real-time energy and ancillary services market uplift costs based on deviations from market participants' day-ahead schedules, and whether deviations that increase the need for actions that cause real-time uplift payments (harming deviations) are netted against deviations that reduce the need for actions that cause real-time uplift payments (helping deviations).[11]

15. In response, most RTOs/ISOs state that they classify certain schedule differences between the day-ahead and real-time markets as deviations and allocate at least some portion of real-time uplift costs to those deviations. Allocation of real-time uplift costs to deviations is the focus of this NOPR because deviations may increase the need for operator actions that cause real-time uplift, such as additional unit commitments in real-time to replace a shortfall in generation or an increase in load compared to the day-ahead market solution. This NOPR does not address other methods of uplift cost allocation, such as allocation to load obligations, and does not propose to require RTOs/ISOs to allocate real-time uplift costs to deviations.

2. Current RTO/ISO Practices

16. All of the RTOs/ISOs state that they use some form of beneficiary pays or cost-causation principles to allocate uplift costs.[12] However, the current uplift cost allocation methods of the RTOs/ISOs vary significantly, both in terms of granularity and the exemption of certain types of transactions. The definition of what precisely constitutes a deviation also varies across RTOs/ISOs.

17. NYISO generally allocates uplift costs based on the beneficiary pays principle.[13] NYISO allocates uplift costs associated with state-wide reliability to all loads in the New York Control Area, and allocates uplift costs associated with local reliability to load within the transmission district where the reliability actions were taken. NYISO allocates real-time uplift costs on a beneficiary pays basis to load obligations, using real-time metered load during the hours in which uplift costs were incurred.[14] NYISO also explains that it eliminated all uplift costs associated with Coordinated Transaction Scheduling (CTS)[15] in a reciprocal fashion with ISO–NE, and that it supports the elimination of all uplift cost allocation and fees on exports because these fees reduce trade between regions and adversely impact total production costs.[16]

18. CAISO explains that it has many categories of uplift, and that it allocates uplift costs to transmission owners (who pass uplift costs to transmission customers), loads, and exports, depending on whether the system operator made the dispatch decision to address transmission constraints, energy imbalance, real-time congestion, or bid cost recovery.[17] CAISO asserts that any allocation based on deviations should consider the wide variability in scheduling and metering granularity for different resources and that there might be implementation challenges in a more granular cost allocation.[18]

19. ISO–NE states that roughly half of its uplift costs are allocated to deviations, which include generator deviations, load deviations, increment (virtual) deviations, and import deviations.[19] ISO–NE calculates each market participant's deviations hourly, netting virtual demand bids and deviations from day-ahead load across all locations.[20] However, hourly generator and virtual supply deviations are not subject to netting in ISO–NE.[21] ISO–NE does not allocate uplift costs to CTS transactions.[22]

20. PJM allocates uplift costs incurred for reasons other than reliability to deviations, including cleared virtual bids, transaction deviations, and load deviations.[23] PJM states that it assesses deviations daily by netting deviations separately within three different categories (demand, supply, and generation) at a single transmission zone, hub, or interface.[24] PJM explains that its current netting rule allows a supply or demand deviation from a virtual transaction in the day-ahead energy market to be netted against

[10] FERC, *Staff Analysis of Uplift in RTO and ISO Markets,* Docket No. AD14–14–000, at 1–2 (Aug. 2014), *https://www.ferc.gov/legal/staff-reports/2014/08-13-14-uplift.pdf.*

[11] Order Directing Reports, 153 FERC ¶ 61,221 at P 64, question 3.b.

[12] NYISO Report at 45; PJM Report at 28; SPP Report at 19; MISO Report at 42; ISO–NE Report at 43; CAISO Report at 35.

[13] NYISO Report at 46.

[14] *Id.* at 40.

[15] CTS is a set of real-time market rules that allow imports and exports to be scheduled based on a bidder's willingness to purchase energy sourced from one RTO/ISO and sell the energy at a sink in another, adjacent RTO/ISO, if the difference between the forecasted prices at the sink and source is greater than or equal to the dollar value specified in the CTS Interface Bid (spread bid).

[16] NYISO Report at 45–46.

[17] CAISO Report at 40–45.

[18] *Id.* at 37.

[19] ISO–NE Report at 54–55.

[20] *Id.* at 50.

[21] *Id.*

[22] ISO–NE Report at 53.

[23] PJM Report at 30–31.

[24] *Id.* at 31.

internal bilateral transactions [25] occurring at the same location.[26] PJM does not consider up-to-congestion transactions [27] to be deviations and does not allocate uplift to them.[28] PJM considers CTS transactions (and other imports and exports) to be deviations, and allocates uplift to them.

21. SPP states that it allocates uplift costs based on causation when the cause is identifiable and the cost of doing so does not outweigh the benefit.[29] For example, real-time uplift costs are allocated to deviations from day-ahead schedules and SPP dispatch instructions.[30] SPP states that virtual transactions are considered deviations, but virtual supply offers are netted against a countervailing deviation between day-ahead and real-time schedules (*i.e.,* a load or export decrease, or import increase, relative to its day-ahead schedule) at the same settlement location.[31]

22. MISO has a granular approach to allocating uplift costs that it states is based on determining cost-causation where possible. MISO has several categories of uplift, but, for example, MISO's Revenue Sufficiency Guarantee uplift category has six different methodologies for distributing costs based on the reason a resource was committed.[32] MISO also allocates uplift costs according to a set of defined categories based on what MISO determines to be the cause of the uplift. Uplift costs resulting from real-time capacity commitments are largely allocated to deviations, including physical supply and demand deviations, virtual transactions, and import and export physical schedules.[33] A portion of uplift resulting from transmission constraint relief is assigned to the deviations that caused the congestion.[34] MISO has also noted that it will not allocate uplift costs to CTS between itself and PJM, which is expected to be implemented in the spring of 2017.[35]

3. Comments

a. Practices for Allocating Uplift Costs to Deviations

23. Some commenters criticize the practice of allocating uplift costs to real-time deviations from day-ahead schedules. For example, Appian Way asserts that deviations-based approaches to uplift cost allocation create market inefficiencies in the form of unnecessary and inappropriate barriers to market participants accessing the spot market, and also shift the cost responsibility for uplift from load to other market participants.[36]

24. Others, however, support allocating uplift costs to deviations from day-ahead schedules, but argue that such deviations should be netted based on whether they contribute to or alleviate the condition causing uplift.[37] Some commenters contend, for example, that netting such deviations is consistent with cost causation principles because it ensures that only market participants deviating from their day-ahead schedules in a manner that increases uplift payments will incur those costs.[38]

25. Multiple commenters also recommend the creation of more specific uplift cost allocation categories that are better aligned with cost causation. To this end, some commenters suggest creating a congestion management category that would distinguish uplift incurred for congestion management from uplift incurred for capacity needs or voltage and local reliability and allocate uplift costs accordingly.[39]

26. MISO Market Monitor asserts that uplift costs should be minimized to the extent possible by incorporating reliability requirements into market-based products, but any remaining uplift costs should then be allocated based on cost causation. MISO Market Monitor believes that allocating uplift costs to those that cause it or benefit from it gives market participants an incentive to act to minimize it. MISO Market Monitor also asserts that MISO's uplift cost allocation approach is the best practice in the industry because it determines why the uplift was incurred and allocates the costs accordingly.[40] MISO Market Monitor also argues that for both capacity-related and congestion-related uplift, cost allocations should be based on deviations from the market participants' day-ahead schedules.[41]

b. Virtual Transactions and Uplift

27. Allocation of uplift costs to virtual transactions is a contentious issue, and commenters hold disparate opinions. Some commenters argue that virtual transactions contribute to price convergence between the day-ahead and real-time markets, thus reducing, rather than increasing, uplift. They also argue that virtual transactions are easily forced out of the market by added fees, such as uplift. These commenters support either reducing or eliminating the allocation of uplift costs to virtual transactions.[42] For example, XO Energy argues that it is unjust and unreasonable to allocate energy deviation-related uplift costs to virtual transactions as XO Energy asserts these transactions do not impact unit commitment because the energy impacts ''net out'' and do not affect the system's power balance.[43]

28. Other commenters disagree, arguing that virtual transactions should be allocated uplift costs because they affect day-ahead commitment and dispatch, and thus can impact uplift.[44] For example, PJM states that allocating uplift costs to virtual transactions is consistent with cost causation, and that up-to-congestion transactions should be allocated uplift costs similar to other virtual transactions, although they are not currently allocated such costs.[45] Several commenters also contend that cost allocation rules for virtual transactions may need to be revised.[46] For example, EEI notes that in PJM, virtual transactions, including increment offers and decrement bids, are allocated uplift costs, while up-to-congestion transactions are not. EEI asserts that up-to-congestion transactions should not be given preferential treatment and should instead be allocated a share of uplift costs.[47]

[25] Internal bilateral transactions are a type of bilateral transaction used to purchase or sell one or more electricity market product(s) within a region. In all of the RTOs/ISOs, internal bilateral transactions are financial agreements that the two parties report to the RTO/ISO to streamline accounting and settlement. None of the RTOs/ISOs model internal bilateral transactions in the real-time or day-ahead market, and internal bilateral transactions do not affect market dispatch or power flows.

[26] PJM Report at 33.

[27] An up-to-congestion transaction is a form of virtual transaction that combines an offer to sell energy at a source, with a bid to buy the same MW quantity of energy at a sink where such transaction specifies the maximum difference between the LMP at the source and sink.

[28] PJM Report at 33.

[29] SPP Report at 20.

[30] *Id.* at 22.

[31] *Id.* at 38.

[32] MISO Report at 42–43.

[33] *Id.* at 44.

[34] *Id.*

[35] *Midcontinent Indep. Sys. Operator, Inc.,* 155 FERC ¶ 61,038, at P 3 (2016).

[36] Appian Way Comments at 1, 7.

[37] Financial Marketers Coalition Comments at 31.

[38] *Id.* at 14, 31.

[39] *Id.* at 14; XO Energy Comments at 24.

[40] MISO Market Monitor Feb. 24, 2015 Comments at 16–17.

[41] *Id.* at 17.

[42] Appian Way Comments at 10; Financial Marketers Coalition Comments at 14–15; XO Energy Comments at 21.

[43] XO Energy Comments at 19–21.

[44] PSEG Companies Comments at 10; EEI Comments at 4.

[45] PJM Report at 33.

[46] EPSA/P3 Comments at 12; DC Energy, Inertia Power, and Vitol Comments at 4–5.

[47] EEI Comments at 4.

c. Coordinated Transaction Scheduling

29. CTS transactions are scheduled in real-time by the participating RTO/ISOs[48] based on forecasted prices. CTS is not used in all RTO/ISO markets and the allocation of uplift costs to CTS varies by market, as described herein. Some RTOs/ISOs, such as MISO, view CTS transactions as economically dispatched, similar to the economic dispatch of a generator, and therefore do not consider them to be deviations for the purpose of allocating uplift costs. NYISO and ISO–NE do not allocate uplift costs to CTS transactions between their markets. PJM, however, views CTS transactions as deviations, indistinguishable in effect from other deviations that cause uplift.

d. Additional Comments

30. Commenters also provide feedback on several other market design mechanisms related to uplift. For example, several commenters discuss the netting of internal bilateral transactions against other deviations when allocating uplift costs in PJM. While some advocate eliminating this market rule,[49] others support it, contending that internal bilateral transactions are valuable hedging tools which allow market participants to counteract a deviation from a virtual transaction in the day-ahead market and promote convergence between day-ahead and real-time prices.[50]

4. Need for Reform

31. We preliminarily find that some existing RTO/ISO practices of real-time uplift cost allocation to deviations may be unjust and unreasonable. Specifically, these real-time uplift cost allocation practices may result in unjust and unreasonable rates by allocating costs to deviations that could not reasonably be expected to have caused those costs. Allocating costs to deviations that did not cause these costs can inappropriately penalize certain types of transactions that may be beneficial to price formation. We note that the Commission is not proposing to require RTOs/ISOs to allocate any amount of uplift costs to deviations, rather we are simply proposing reforms to uplift cost allocation to deviations to the extent an RTO/ISO chooses to allocate some uplift costs to deviations.

32. While there are several approaches to allocating uplift costs, most RTOs/ISOs allocate at least a portion of real-time uplift costs to market participants that deviate from their day-ahead market schedules. When market participants deviate from their day-ahead schedule, RTOs/ISOs may have to take actions in real-time to address differences between the day-ahead market solution and real-time system conditions. These actions, such as committing additional resources, can result in real-time uplift costs.

33. However, RTOs/ISOs do not always consider whether a deviation likely contributed to increasing or decreasing real-time uplift costs when allocating real-time uplift costs. Deviations from day-ahead market schedules that create the need for additional resource commitments in real-time tend to increase real-time uplift costs. On the other hand, deviations can also contribute to the convergence of the day-ahead and real-time markets by helping to ensure that the day-ahead market solution and the attendant day-ahead schedule reduces the need for system operator actions in real-time. If real-time uplift costs are assigned improperly, such costs may impact market behavior in a manner that limits otherwise beneficial transactions, which in turn may distort prices and market outcomes. This distortion can lead to increased real-time uplift payments, higher overall costs to consumers, and potentially unjust and unreasonable rates.[51]

34. Therefore, we preliminarily find unjust and unreasonable real-time uplift cost allocation rules that fail to distinguish between deviations that help converge day-ahead and real-time markets[52] and those that harm efforts to address system needs. Such rules fail to appropriately assign real-time uplift costs to market participants that are likely to cause such costs and inappropriately deter transactions that are likely to minimize these costs.

5. Proposal

35. To remedy the potentially unjust and unreasonable rates resulting from allocating real-time uplift costs to deviations in a manner inconsistent with cost causation, we propose that, pursuant to section 206 of the Federal Power Act,[53] each RTO/ISO that currently allocates real-item uplift costs to deviations must follow the practices described below when allocating such costs. Specifically, the following practices ensure that if an RTO/ISO chooses to allocate real-time uplift costs to deviations, it must do so consistent with cost causation. Accordingly, we first propose that RTOs/ISOs categorize real-time uplift costs allocated to deviations into at least two categories based on the reason uplift costs were incurred, a system-wide capacity category and a congestion management category as discussed in more detail below. Second, we propose to require each RTO/ISO to distinguish between deviations that are ''helping'' to address system needs and those that are ''harming'' efforts to address system needs. Further, within each uplift category, uplift costs must be allocated to a market participant's net ''harming'' deviations, *i.e.,* relevant ''harming'' deviations net of relevant ''helping'' deviations. Third, we propose to clarify that a resource responding to an RTO/ISO-initiated real-time dispatch instruction should not be allocated deviations-related real-time uplift costs. Finally, we propose that real-time uplift costs allocated to deviations must be settled using hourly uplift rate calculations. Each proposed practice is described in detail below.

36. This proposal would apply only to real-time uplift costs allocated to deviations. The NOPR does not propose to require that RTOs/ISOs allocate uplift costs to deviations, and we recognize that there are other methods for allocating uplift costs that are not based on deviations, such as allocations based on load obligation. Further, we recognize that there are many causes of uplift and this NOPR does not propose to address the allocation of all uplift costs. Rather, to improve upon existing RTO/ISO cost allocation practices, this NOPR addresses the allocation of uplift costs caused by market participants that deviate from their day-ahead market schedules.

37. Most RTOs/ISOs allocate some real-time uplift costs to deviations, although their methods for doing so vary. We set forth here a definition of deviations to delineate what type of real-time uplift cost allocation is the subject of this NOPR. We propose that deviations are megawatt hour differences between a market participant's scheduled deliveries or receipts at particular points cleared in the day-ahead market and those amounts actually delivered or received at those points in real-time that are not related to real-time economic or reliability-related operator dispatch instructions. We propose that, to the

[48] Currently, CTS is effective between NYISO and ISO–NE and NYISO and PJM. MISO and PJM expect to implement CTS in 2017.

[49] PJM Market Monitor Comments at 13; PJM Report at 33; Appian Way Comments at 8.

[50] EPSA/P3 Comments at 12–13.

[51] FERC, *Staff Analysis of Uplift in RTO and ISO Markets,* Docket No. AD14–14–000, at 5–7 (Aug. 2014), *https://www.ferc.gov/legal/staff-reports/2014/08-13-14-uplift.pdf.*

[52] Deviations that help converge day-ahead and real-time markets are deviations that bring day-ahead and real-time prices, commitments, and dispatch closer together.

[53] 16 U.S.C. 824e.

extent an RTO/ISO allocates real-time uplift costs to deviations, it must do so consistent with this proposed definition. We seek comment on the proposed definition of deviations.

38. We propose that if an RTO/ISO allocates real-time uplift costs to deviations, it must allocate such costs only to deviations that can reasonably be expected to have caused those costs. Real-time uplift costs are most likely to be incurred when, for various reasons, the day-ahead market clearing process does not schedule sufficient resources to satisfy the system's real-time needs, and instead, RTOs/ISOs must procure additional resources after the day-ahead market has cleared. Market participants that deviate from their day-ahead schedules will either more closely align the day-ahead market solution with actual real-time system needs or contribute to a divergence from the day-ahead solution. Scheduling practices that contribute to these divergences may require operator actions, such as operator-initiated commitments, in real-time.

39. RTO/ISO day-ahead and real-time price signals provide economic incentives to respond to system needs. Allocating real-time uplift costs to deviations consistent with cost causation would help ensure that real-time uplift cost allocation does not discourage or deter behavior that may converge day-ahead and real-time market solutions. By eliminating the allocation of real-time uplift costs to transactions that are beneficial to meeting system needs, this proposal strengthens the economic incentives for market participants to respond to system needs. Further, allocating real-time uplift costs consistent with cost causation rewards the ability to perform in real-time consistent with operator instructions and disciplines forward scheduling practices by encouraging market participants to bid into the day-ahead market and submit day-ahead schedules consistent with expected real-time system conditions.

a. Real-Time Uplift Categories

40. We propose to require each RTO/ISO to categorize real-time uplift costs allocated to deviations into at least two categories based on the reason the uplift cost was incurred: (1) A system-wide capacity category and (2) a congestion management category. The system-wide capacity category would include real-time uplift related to resource commitments made to ensure sufficient system-wide online capacity to meet energy and operating reserve requirements. The congestion management category would include real-time uplift related to resource commitments to manage transmission congestion on specific constraints. Under this proposal, we require that an RTO/ISO establish at least these two categories for real-time uplift cost allocation to deviations, but propose to provide flexibility to an RTO/ISO to establish additional categories.

41. We propose distinguishing the two categories, system-wide capacity and congestion management. The distinction ensures real-time uplift costs are allocated more specifically to the market participant that caused the uplift. Two examples illustrate how delineating these two categories is consistent with cost causation.

42. As a first example, consider a market participant that owns a generator that in real-time produces less than the output set forth in its day-ahead schedule when it did not receive dispatch instructions to do so. That generator's deviation impacted the RTO's/ISO's ability to maintain real-time energy and operating reserve requirements and required a new commitment to make up for the generator's deviation. However, absent impacting the power flows on a system constraint, the generator did not contribute to congestion on any constraint. Such a generator should be allocated real-time uplift costs for capacity but not congestion management. The generator caused a need for more capacity to come online, but did not cause a need to relieve congestion on a constraint.

43. As a second example, suppose that the same generator is owned by a market participant that also serves real-time load. If the market participant reduces its real-time load in an amount that equals the generator's deviation (*i.e.,* its reduced supply), the market participant's behavior on net did not impact the RTO's/ISO's ability to maintain real-time energy and operating reserve requirements. However, if this behavior—on net—impacts congestion on the system, the market participant should be allocated real-time uplift costs related to congestion management.

44. We request comments on whether the proposed reforms should recognize the need for regional flexibility with regard to the uplift categories. We also request comment on whether other categories should be required.

b. Netting

45. In allocating uplift costs to deviations, we propose to require each RTO/ISO to distinguish between deviations that are ''helping'' efforts to address system needs and those that are ''harming'' efforts to address system needs. The particular system need of relevance will depend on the category of uplift costs at issue, as discussed further below. Within each uplift category, uplift costs must be allocated to a market participant's net ''harming'' deviations, *i.e.,* relevant ''harming'' deviations net of relevant ''helping'' deviations. Such allocation should be commensurate with a market participant's share of total net ''harming'' deviations.

46. Under the proposed system-wide capacity category, a market participant would be allocated a portion of the total real-time uplift costs incurred to maintain energy and operating reserve requirements in the real-time market based on the net contributions of its deviations to those costs. This method would require an RTO/ISO to determine if each market participant's deviations are, on net, ''helping'', by converging the day-ahead scheduled unit commitment and dispatch to the unit commitment and dispatch needed to meet real-time energy and operating reserve requirements, or if they are ''harming'', by exacerbating the difference between the day-ahead scheduled unit commitment and dispatch and the unit commitment and dispatch needed to meet real-time energy and operating reserve requirements. For example, if the system operator committed an additional resource to maintain energy and operating reserve requirements in the real-time market, a market participant with net deviations that increased demand (or decreased supply) would be allocated a portion of real-time uplift costs in the system-wide category, while a market participant with net deviations that increased supply (or decreased demand) would not.

47. Under the proposed congestion management category, a market participant would be allocated real-time uplift costs if its net deviations contributed to a difference between the congestion on a specific constraint in the day-ahead market and the real-time congestion on that constraint. This method would require an RTO/ISO to determine if each market participant's deviations are, on net, ''helping'', by converging day-ahead and real-time congestion patterns, or if they are ''harming'', by exacerbating the difference between day-ahead and real-time congestion on a constraint. Market participants would be allocated real-time uplift costs in this category only if their net deviations are harming by contributing to differences between day-ahead and real-time congestion on a constraint.

48. For netting within this congestion management category, we propose to require each RTO/ISO to determine real-time uplift cost allocation based on the net impact of a market participant's deviations on a constraint. To make this determination, an RTO/ISO should net the deviations that relieve real-time congestion on the constraint with those that contribute to it.

49. Deviations caused by non-market transactions (such as internal bilateral transactions) would not be netted in either the proposed system-wide capacity category or the proposed congestion management category because they take place outside of the day-ahead and real-time markets. Transactions that take place outside of the markets do not affect real-time scheduling or dispatch and therefore should not offset transactions that do affect real-time scheduling or dispatch.

50. We seek comment on whether there should be advanced notification requirements in determining helpful deviations. That is, is there a period of time prior to the operating hour at which a deviation should no longer be considered helpful because notification of the deviation was provided to the RTO/ISO too close to the operating hour? If so, we seek comment on what the advanced notification requirement should be.[54] Under the proposed definition of deviations, transactions related to real-time economic or reliability-related operator dispatch instructions would not be used in determining a market participant's net deviations for both the system-wide capacity and congestion management categories. We also request comment on whether and how such transactions should be used to determine a market participant's net deviations.

c. Deviations That Result From Following Dispatch

51. Based on the discussion above and consistent with the proposed definition of deviations, we clarify that if the RTO/ISO instructs a resource to deviate from its day-ahead schedule, be that a market-based or out-of-market instruction, that resource would not be regarded as deviating for purposes of this NOPR, and should not be allocated real-time deviation-related uplift costs, because it is helping to address differences between the day-ahead market solution and real-time system needs.

52. Consistent with this clarification, first, we propose that an RTO/ISO may not allocate deviation-related real-time uplift costs to a transaction that is economically evaluated by the RTO/ISO in the real-time market. Such transactions include real-time energy transactions and CTS transactions. Such real-time transactions are responding to real-time market price signals and are not deviations for the purposes of this NOPR. These transactions are helping to address real-time system needs and allocating real-time deviation-related uplift costs to such transactions could distort incentives to respond to these signals. Conversely, transactions that are not economically evaluated in the real-time market and do not have day-ahead schedules, such as self-scheduled real-time transactions, should be treated as deviations for the purposes of allocating real-time deviation-related uplift costs.

53. Second, consistent with this clarification, we further propose that instructed deviations (those initiated by the RTO/ISO) are not deviations for the purposes of allocating real-time uplift costs, and therefore, an RTO/ISO may not allocate real-time uplift costs based on deviations that result from a market participant following a reliability-related dispatch instruction. Following such a dispatch instruction, by definition, helps the system. Allocating real-time uplift costs to market participants who follow dispatch instructions unfairly penalizes market participants that are responding to system needs in real-time. Further, assessing real-time uplift costs to such deviations could discourage a market participant from following dispatch instructions. At times of system stress, it is essential that resources follow dispatch instructions. For instance, an RTO/ISO may issue out-of-market dispatch instructions or deploy reserves to address immediate reliability issues. A resource that responds to such an RTO/ISO instruction performs an essential reliability function and should not be allocated real-time deviation-related uplift costs for following the dispatch instruction.

54. By excluding instructed deviations from the definition of a deviation, the Commission is also proposing that instructed deviations would not be used in any 'helping' and 'harming' netting process. We seek comment on whether instructed deviations should be included in any netting calculations.

d. Settlement

55. Regarding settlement of uplift costs, under both the system-wide capacity category and the congestion management category, we propose to require RTOs/ISOs to allocate and net real-time uplift costs on an hourly basis. RTOs/ISOs typically allocate uplift costs either hourly or daily. Hourly allocation would most closely align the imposition of costs with the incentives to behave efficiently in the market, since the costs of real-time uplift and the actions that cause that real-time uplift can and usually do change from hour to hour. Under hourly cost allocation, the costs for real-time uplift during a particular hour are allocated only to those market participants that contribute to the need for that uplift in that hour.

e. Other Comments Sought

56. We recognize that considering real-time uplift cost allocation to deviations for system-wide capacity and congestion management separately may require a method for dividing costs between the two categories for circumstances in which real-time uplift is incurred for the benefit of both categories (*e.g.,* committing a unit to relieve transmission congestion will also impact system-wide capacity requirements). We seek comment on the best methods to quantify this impact and to perform the appropriate cost allocation. We also seek comment on the process for netting of transactions and deviations set forth in the proposal for each category. Finally, we seek comment on the clarifications provided herein regarding those transactions that should not be considered deviations for the purpose of real-time uplift cost allocation and whether there are additional transactions that should be included in this category.

B. Transparency

57. In this section, we first provide a brief background on the benefits of transparency in the wholesale electric power markets operated by RTOs/ISOs with respect to reporting uplift, operator-initiated commitments, and transmission constraint penalty factors. We then review current RTO/ISO practices with regard to reporting uplift and operator-initiated commitments, and summarize comments on transparency requirements, frequency of reporting, type of uplift information to be reported, inclusion of reasons for uplift or operator-initiated commitments, granularity with respect to location, and the inclusion of transmission constraint penalty factors in RTO/ISO tariffs. Then, we explain the

[54] For example, MISO determines whether a deviation is helpful based on whether it occurred before or after a notification deadline which is four hours prior to the operating hour. *See generally* MISO, FERC Electric Tariff, Definitions, ''Notification Deadline'', 1.N & Real-Time Energy and Operating Reserve Market Settlement Cal, 40.3.3.

need for the reform regarding reporting of uplift, operator-initiated commitments, and transmission constraint penalty factors. Finally, we request comment on two additional topics: Reporting of transmission outages and availability of network models.

1. Background

58. Visibility into the process by which prices are developed in energy and ancillary services markets supports the functioning of efficient markets by enhancing predictability, identifying system needs, and facilitating investment decisions. Moreover, understanding how RTOs/ISOs calculate prices and how events impact those prices is critical to hedging, investment, and resource entry and exit decisions. While all RTOs/ISOs release some information, either through periodic reports or making data available on their Web sites, as discussed below, there is significant variation in the timing, granularity, and types of data released.

2. Current RTO/ISO Practices

a. Reporting Uplift

59. All RTOs/ISOs report information about uplift payments. However, the extent of the information reported varies widely. For example, ISO–NE and NYISO provide monthly reports of uplift that generally provide information that is aggregated across zones and over the month.[55] NYISO also makes aggregated uplift costs (in dollars) available to stakeholders on a daily basis through its daily reconciliation reports.[56] MISO provides a number of monthly reports to market participants on categories of uplift costs; the reports aggregate the uplift data by category by month and provide historical monthly data for comparison.[57] CAISO aggregates uplift data to its 10 existing local capacity requirement areas and reports daily total uplift costs for each month by the market in which the uplift is incurred (*e.g.,* day-ahead or real-time), and by the type of costs incurred, *i.e.,* start-up costs, minimum load costs or energy bid costs.[58] PJM has recently adopted new rules to allow the reporting of daily uplift information by transmission zone, with certain exceptions for confidentiality reasons.[59] SPP provides uplift information in a report that divides uplift costs into seven categories.[60]

60. RTO/ISO reporting practices are driven, in part, by the time needed to complete the settlement process. Some settlement periods last three to five business days and CAISO provides uplift cost information based on its 12-business day recalculation statement, although the settlement period is shorter.[61] Because of this lag, RTOs/ISOs typically report uplift on a monthly basis, with the information aggregated to a zonal or settlement area level.

61. Most RTOs/ISOs cite confidentiality issues as an additional reason for their current reporting practices, particularly in regions with few market participants.[62] Uplift information is typically aggregated to avoid publishing information for individual resources. All RTOs/ISOs assert that they are prohibited from publicly revealing resource-specific data, as specified in their confidentiality rules.[63] Some RTOs/ISOs note that they cannot provide information on a more granular basis without changes to their confidentiality rules or information policies.[64]

62. It is worth noting that market participants with market-based and traditional cost of service rate authority are required to report uplift payments in the Electric Quarterly Report (EQR). Pursuant to EQR reporting requirements, uplift payments are required to be reported at a granular level. Those reporting requirements require market participants to report when the uplift payment changes. Because many resources are commercially organized as stand-alone limited liability corporations, many individual resources report uplift payments to EQR within 30 days following the end of a quarter. While EQR provides a significant amount of information, it does not provide detailed information regarding uplift. For example, EQR contains only a single ''uplift'' category which does not differentiate between different types of uplift (*e.g.,* day-ahead, voltage and local reliability).

b. Reporting Operator-Initiated Commitments

63. RTOs/ISOs also vary in the amount, granularity, and timing of information that is reported on operator-initiated commitments. For example, CAISO, MISO, and NYISO provide information regarding operator-initiated commitments either shortly after the operating day or in near real-time. CAISO and MISO both report total operator-initiated commitments aggregated across the RTO/ISO, including the reasons for the commitments.[65] MISO provides its reports in near real-time, while CAISO releases its report several days after the operating day. Throughout the operating day, NYISO posts operational announcements providing information about individual operator-initiated commitments, including the units involved, level of unit commitment, and the reason for the commitment, with a reference to the relevant reliability rule, if applicable.[66]

64. In addition, all RTOs/ISOs provide summary reports of operator-initiated commitments over longer time periods. CAISO's monthly performance report provides metrics on exceptional dispatch [67] and operator-initiated commitments organized by market (*i.e.,* day-ahead or real-time), trade date, reason, or local area.[68] CAISO also files a monthly report on the frequency and volume of exceptional dispatch, pursuant to directives in previous Commission orders.[69] ISO–NE publishes weekly, monthly, and quarterly reports that describe notable operational events, but it does not provide any information regarding the location or capacity of committed units.[70] ISO–NE also reports the number of units committed after the close of the day-ahead market (but not including real-time commitments) each day.[71] SPP reports monthly the MW of operator-initiated commitments.[72]

65. PJM states that, although its confidentiality provisions prevent it from reporting individual operator-initiated commitments in real-time, it

[55] ISO–NE Report at 60; NYISO Report at 56–57.

[56] NYISO Report at 59.

[57] MISO Report at 60.

[58] CAISO Report at 56.

[59] PJM, Business Practice Manual 33: Administrative Services for the PJM Interconnection Operating Agreement at 23–24.

[60] SPP Report at 40.

[61] ISO–NE Report at 64–65; PJM Report at 51; CAISO Report at 58.

[62] PJM Report at 48, 54–55; SPP Report at 41, 44; ISO–NE Report at 61, 67; NYISO Report at 60.

[63] CAISO Report at 59; NYISO Report at 58; PJM Report at 50–51; SPP Report at 42; ISO–NE Report at 63–64; MISO Report at 58–59.

[64] PJM Report at 48; ISO–NE Report at 61.

[65] MISO Report at 60; CAISO, Daily Exceptional Dispatch Report, *http://www.caiso.com/market/Pages/DailyExceptionalDispatch/Default.aspx.*

[66] NYISO Report at 56–57 and n.32.

[67] CAISO states that its system operator issues exceptional dispatches to resources to address system issues that cannot be addressed by the constraints modeled within the market. CAISO Report at 41.

[68] *Id.* at 56.

[69] *Id. See also Cal. Indep. Sys. Operator Corp.,* 131 FERC ¶ 61,100 (2010) (clarifying the reporting timeline for reporting exceptional dispatches).

[70] ISO–NE Report at 60.

[71] *Id.* at 61–62.

[72] SPP Report at 40.

does provide regionally aggregated information on uneconomic commitments in the day-ahead market at the end of the business day. In addition, PJM posts total capacity committed during the Reliability Assessment and Commitment period to meet forecasted load and reserves, as well as resources committed for transmission constraints, voltage/reactive constraints, or conservative operations.[73] ISO–NE also states its confidentiality provisions prohibit reporting of operator-initiated commitments in real-time, while CAISO states providing information about exceptional dispatches more frequently than monthly would require significant changes to its systems.[74] SPP states it is technically feasible to report commitments resulting from operator actions in real-time, but notes such reporting could disclose sensitive reliability information.[75]

c. Transmission Constraint Penalty Factors

66. Transmission constraint penalty factors are the values at which an RTO's/ISO's market software will relax the flow-based limit on a transmission element to relieve a constraint caused by that limit rather than re-dispatch resources to relieve the constraint. The cost of re-dispatching resources can be regarded as the re-dispatch price. Transmission constraint penalty factors represent the maximum re-dispatch price that the system will pay before allowing flows to exceed a given transmission element's limit.[76] The penalty factors should be set at levels that are high enough to avoid relaxing constraints too frequently, but low enough to avoid extremely expensive re-dispatch solutions that are more expensive than the expected cost of exceeding a given transmission element's limit. While these penalty factors can have significant impacts on prices, changes are not always made public nor do all RTOs/ISOs file them with the Commission. Specifically, PJM and ISO–NE do not include transmission constraint penalty factors in their respective tariffs.[77] Further, MISO is the only RTO/ISO that details in its tariff how transmission constraint penalty factors are temporarily changed.[78]

3. Comments

a. General Comments

67. Various commenters recommend reporting of uplift and operator-initiated commitments that is more regular, more geographically granular, more specific about the size of the action (in MW), and/or more informative of the reason for uplift or operator action. Numerous commenters argue that such reporting about uplift and operator-initiated commitments should be mandatory.[79] Exelon urges the Commission to require RTOs/ISOs to identify out-of-market actions and the resulting uplift in regular reports.[80] Several commenters propose that RTOs/ISOs be required to post information in a way that is uniform, consistent, and comparable across RTOs/ISOs.[81]

b. Comments on Uplift Reporting

68. In terms of frequency, some commenters recommend monthly reporting of uplift to improve transparency.[82] Energy Storage Association requests that RTOs/ISOs provide daily summary data on uplift credits. Energy Storage Association asserts that such information should, at a minimum, be at a zonal level and should be made available by all RTOs/ISOs several days after the operating day.[83]

Several commenters request more granular locational information regarding uplift.[84] These commenters argue that it is difficult to reduce or eliminate uplift when market participants do not know where it originates. To address this request, many commenters, including CAISO, ISO–NE, and PJM, support reporting uplift on a zonal basis.[85] CAISO, ISO–NE, and PJM state that zonal reporting strikes a balance between granularity and confidentiality.[86] In contrast, SPP and MISO caution that reporting uplift on a zonal basis could reveal sensitive market participant information.[87]

69. Commenters have differing views on what uplift information should be reported. PSEG Companies argue that uplift can be effectively reported on a dollar basis.[88] Energy Storage Association states that RTOs/ISOs should share daily summary data on uplift in dollars, including the reasons for the uplift and the location (at a minimum at a zonal level) of the resources that receive it.[89] The PJM Market Monitor recommends reporting uplift charges by resource as well as detailed reasons for incurring uplift.[90] EPSA and EPSA/NEPGA recommend reporting the settled uplift dollar impact on a MW basis, as well as the reasons for out-of-market commitments every month.[91] EPSA asserts that reporting additional information on the drivers of uplift and out-of-market dispatch can be made public without compromising sensitive information, because NYISO currently does so in monthly reports.[92]

70. EPSA/IPPNY warns that reporting uplift more frequently than daily could potentially reveal confidential information.[93] Energy Storage Association suggests that, given confidentiality concerns, the Commission could allow an RTO/ISO to request an exemption from reporting zonal or locational information in certain situations where there are few participants in a zone or location.[94] ISO–NE and MISO suggest that the level of aggregation be adjusted to ensure that confidentiality is maintained.[95]

c. Comments on Reporting Operator-Initiated Commitments

71. Several commenters recommend monthly reporting of operator-initiated actions, including the reasons for out-of-market actions, to improve

[73] PJM Report at 49–50.

[74] ISO–NE Report at 65; CAISO Report at 58, 62.

[75] SPP Report at 41.

[76] Transmission constraint penalty factors create a cap on the shadow price of a transmission constraint. *See* MISO Market Monitor Comments, Docket No. AD14–14–000, at 20–21 (Feb. 24, 2015).

[77] CAISO, MRTU Tariff 27.4.3.1–27.4.3.3; SPP, OATT, Sixth Revised Volume No. 1, Attachment AE, 8.3.2, Addendum 1; NYISO Tariffs, NYISO Markets and Services Tariff 1.20; MISO, FERC Electric Tariff, Schedule 28A.

[78] MISO, FERC Electric Tariff, Schedule 28A.

[79] DC Energy, Inertia Power, and Vitol Comments at 18; EPSA Comments (on MISO Report) at 22; EPSA/NEPGA Comments at 14; Energy Storage Association Comments at 2–3; Exelon Comments at 17–18; PSEG Companies Comments at 16.

[80] Exelon Comments at 17–18.

[81] DC Energy, Inertia Power, and Vitol Comments at 18; EPSA Comments (on price formation) at 22; EPSA Comments (on MISO Report) at 22; EPSA/IPPNY Comments at 13; EPSA Comments (on SPP Report) at 10; EPSA/NEPGA Comments at 14–15; EPSA/P3 Comments at 15; EPSA/WPTF Comments at 10.

[82] EPSA Comments (on MISO Report) at 21–22; EPSA/NEPGA Comments at 13.

[83] Energy Storage Association Comments at 2–3.

[84] Financial Marketers Coalition Comments at 45; Energy Storage Association Comments at 6; Golden Spread Comments at 8–9.

[85] Financial Marketers Coalition Comments at 45; Energy Storage Association Comments at 6; PJM Market Monitor Comments at 20; CAISO Report at 61; PJM Report at 52; ISO–NE Report at 64, 66.

[86] PJM Report at 53; ISO–NE Report at 66; CAISO Report at 61.

[87] MISO Report at 60–61; SPP Report at 43.

[88] PSEG Companies Comments at 12, 15–16.

[89] Energy Storage Association Comments at 2.

[90] PJM Market Monitor Comments at 20–21.

[91] EPSA and its joint commenters support several variations of ''reporting actual settled uplift dollar impacts, on a Megawatt (MW) basis.'' It is unclear whether this is referring to reporting uplift dollars divided by the total capacity of resources that receive uplift payments, or reporting the total capacity of committed resources in lieu of identifying specific units. EPSA Comments (on price formation) at 23; EPSA Comments (on MISO Report) at 21–22; EPSA/NEPGA Comments at 13.

[92] EPSA Comments (on price formation) at 23.

[93] EPSA/IPPNY Comments at 12–13.

[94] Energy Storage Association Comments at 3.

[95] ISO–NE Report at 66; MISO Report at 61.

transparency.[96] Commenters argue that understanding the reasons for out-of-market commitments will help market participants discern what types of investments are needed to meet system needs.[97] Moreover, the Financial Marketers Coalition states that, when out-of-market commitments are identified by location and explained, financial participants will refrain from bidding because they know that prices will not converge and uplift is likely.[98]

72. Some commenters also suggest that RTOs/ISOs report operator-initiated commitments closer to real-time. In particular, PSEG Companies suggest that NYISO's approach to disclosing out-of-market commitment and dispatch decisions should be considered a best practice.[99]

74. Several commenters request more granular locational information regarding out-of-market operator actions.[100] PSEG Companies note that when RTOs/ISOs provide only aggregated data, it is not possible to discern whether the RTO/ISO needed those units or how many MW were actually required.[101]

d. Comments on Transmission Constraint Penalty Factors

75. The MISO Market Monitor asserts that transmission constraint penalty factors substantially affect market outcomes but are not filed with or approved by the Commission for some RTOs/ISOs. MISO Market Monitor adds that increasing transmission constraint penalty factors during real-time operations to relieve constraints may indicate that constraints were undervalued previously, and lowering transmission constraint penalty factors during real-time operations may indicate that the RTO/ISO is attempting to manually reduce congestion costs. MISO Market Monitor contends that these concerns can be addressed by: (1) Establishing parameters that reflect the reliability value of managing the constraints, which likely varies by constraint; (2) filing these values in the RTO's/ISO's tariffs so they are known and approved by the Commission; and (3) filing tariff provisions that specify the procedures and authority for RTOs/ISOs to modify transmission constraint penalty factors.[102]

76. XO Energy states that transmission constraint penalty factors can have a significant impact on prices; however, there is not necessarily clear insight as to how transmission constraint penalty factors are determined or calculated in the pricing and dispatch algorithms.[103] XO Energy contends that, in some cases, the default transmission constraint penalty factors can be arbitrarily assigned and modified on a case-by-case basis.[104]

4. Need for Reform

77. We preliminarily find that some existing RTO/ISO practices of reporting uplift, operator-initiated commitments, and transmission constraint penalty factors may result in unjust and unreasonable rates. The lack of transparency regarding uplift and operator-initiated commitments, which can cause uplift, hinders market participants' ability to plan and efficiently respond to system needs. Market participants may lack the information necessary to evaluate the need for and value of additional investment, such as transmission upgrades or new generation. Also, without sufficient transparency, market participants may not be able to assess each RTO's/ISO's operator-initiated commitment practices and raise any issues of concern through the stakeholder process.

78. Reporting that specifies the location and causes of uplift and operator-initiated commitments will help incent appropriate market responses to system needs. For example, if resources are routinely committed out-of-market to resolve a local voltage issue and require uplift payments as a result, it may be beneficial to release information on the uplift associated with using such resources to alert market participants about the problem. Providing more detailed information about the uplift incurred to address a local reliability issue could potentially incent market participants to advocate for changes to the RTO/ISO's operational procedures or to undertake investments that could resolve the local reliability issue more efficiently (*e.g.,* install additional capacitors).

79. While all RTOs/ISOs provide some information regarding the locations and causes of uplift and operator-initiated commitments, the information is often highly aggregated or lacks detail, limiting its usefulness. Information about the location and causes of uplift and operator-initiated commitments that is overly aggregated or lacks detail hinders the ability of a market participation to evaluate RTO/ISO operating practices and potentially respond to system needs by undertaking new investments. For example, reports that aggregate uplift payments over the month may not provide sufficient information, since monthly reports can obscure daily trends, which may be more relevant to those evaluating operating practices or potential investments. Therefore, increasing transparency with respect to the location and cause of uplift can provide market participants additional information to evaluate the effectiveness of current operating practices. Without sufficient information to evaluate existing operating practices or the need for additional investment, market efficiency may be reduced, resulting in unjust and unreasonable rates. Allowing market participants to better evaluate the need for changes in operating practices or additional investment could ultimately reduce the level of uplift, thereby resulting in rates that are just and reasonable.

80. Similarly, the lack of transparency with respect to transmission constraint penalty factors may hinder the ability of market participants to undertake efficient transactions. For example, if market participants are unaware of what transmission constraint penalty factors are used and whether they will be used to set LMPs, market participants may not be able to adequately understand how an RTO's/ISO's actions affect clearing prices and thus may not be able to hedge transactions appropriately or effectively assess the RTO's/ISO's actions and raise concerns through the stakeholder process. Without the ability to appropriately hedge transactions, market participants may either over-hedge or under-hedge their positions, reducing market efficiency. Also, if market participants are not able to raise concerns about changes in transmission constraint penalty factors, RTOs/ISOs may alter transmission constraint penalty factors more often than necessary, which impacts market clearing prices. Therefore, the resulting rates may be unjust and unreasonable.

81. Some RTOs/ISOs report that there are a variety of stakeholder initiatives and discussions underway to improve transparency,[105] while others do not

[96] EPSA Comments (on MISO Report) at 21–22; EPSA/NEPGA Comments at 13; Exelon Comments at 18; EPSA Comments (on price formation) at 23 EPSA/IPPNY Comments at 13; EPSA/P3 Comments at 15–16.

[97] EPSA Comments (on price formation) at 23; EPSA/P3 Comments at 15–16.

[98] Financial Marketers Coalition Comments at 42.

[99] PSEG Companies Comments at 11.

[100] Financial Marketers Coalition Comments at 45 (referring to SPP); Energy Storage Association Comments at 6 (referring to MISO and SPP); Golden Spread Comments at 8–9.

[101] PSEG Companies Comment at 14.

[102] Comments of MISO Market Monitor, Docket No. AD14–14–000, at 20–21 (Feb. 24, 2015).

[103] XO Energy Comments at 67–68.

[104] *Id.* at 68.

[105] CAISO Report at 55; MISO Report at 56; NYISO Report at 55; PJM Report at 47.

mention any specific plans.[106] Despite these efforts, it is not clear that the transparency concerns discussed in this NOPR will be addressed through existing stakeholder initiatives. Accordingly, we preliminarily find that some existing RTO/ISO practices with respect to reporting uplift, operator-initiated commitments, and transmission constraint penalty factors may be unjust and unreasonable.

5. Proposal

82. To remedy these potentially unjust and unreasonable reporting practices, we propose, pursuant to section 206 of the Federal Power Act, to require that each RTO/ISO: (1) Report total uplift payments for each transmission zone on a monthly basis, broken out by day and uplift category; (2) report total uplift payments for each resource on a monthly basis; (3) report the MW of operator-initiated commitments in or near real-time and after the close of the day-ahead market, broken out by zone and commitment reason; and (4) list in its tariff the transmission constraint penalty factors, the circumstances under which they can set LMPs, and the procedure by which they can be temporarily changed.

a. Uplift Reporting

83. We propose to require that, within 20 days of the end of each month, each RTO/ISO post on its Web site two reports, at minimum, regarding uplift payments. First, the RTO/ISO should report the total uplift payments in dollars paid daily to the resources in each transmission zone, subject to certain exceptions described below. Each RTO/ISO must post the total amount of uplift in dollars in each category (*e.g.,* day-ahead, real-time, voltage and local reliability) paid to resources in each transmission zone for each day within the calendar month. We propose to require that each RTO/ISO post uplift payment amounts based on its specific uplift categories to allow market participants to distinguish between different types of uplift. Second, each RTO/ISO must post the resource name and the total amount of uplift paid in dollars aggregated across the month to each resource that received uplift payments within the calendar month. We seek comment on whether these resource-specific reports should also be broken out by uplift category, be reported using a different time duration, or contain other additional details.

84. Information on uplift payments should be posted in a machine readable format on a publicly accessible portion of the RTO's/ISO's Web site. With this information, market participants may be able to evaluate possible solutions to reduce the incurrence of uplift. For example, with more granular information on the location, amounts, and types of uplift, market participants can better evaluate the benefits of additional transmission upgrades that could reduce the need for unit commitments.

85. We also propose to define ''transmission zone'' as a geographic area that is used for the local allocation of charges. For example, this could include a load zone that is used to settle charges for energy. We request comments on this proposed definition of transmission zone, including the appropriate level of geographic granularity.

86. Regarding the timeliness of posting this information, we recognize that each RTO/ISO has a different settlement window and uplift is finalized during the settlement process. As such, it is not possible for an RTO/ISO to release information immediately at the end of the month. In order to account for differences in settlement periods and the time necessary to prepare the uplift data for publication, we propose to require that both reports described above be released no later than 20 calendar days following the end of the month. While we believe this is a reasonable timeframe for release, we seek comment on the timeframe for releasing the information after the end of each month. In addition, we seek comment on the proposed requirement for a daily breakdown of uplift categories by charge code, including any obstacles or difficulties related to such reporting and whether different categorizations would be more useful.

87. Many commenters express concern that greater transparency in uplift reporting could unintentionally disclose a resource's uplift payments or energy offers, which some characterize as confidential or commercially-sensitive information. Commenters' core concerns appear to relate to two issues: first, that disclosing a resource's uplift payments will allow other market participants to calculate energy offers and may result in collusion between market participants.[107] Second, commenters appear to be concerned that revealing uplift payments may put a resource at a competitive disadvantage by disclosing commercially sensitive information like fuel procurement strategies.

88. While we understand the need to protect certain types of information, we are not persuaded that revealing a resource's daily uplift payments or energy offer, after some minimal time lag, would result in any significant harm to competition or individual market participants. First, many individual resources already publicly report their uplift payments pursuant to Electric Quarterly Reporting requirements (with a 90-day lag). Second, RTO/ISO energy markets are mitigated, so concerns about the potential for collusion can be addressed through must offer requirements and market power mitigation rules. Third, after the 20-day lag for reporting following the end of the month, fuel costs and other conditions have often changed, diminishing the potential usefulness of any resource offer information. These three factors limit the potential for anti-competitive behavior and any harm to market participants.

89. Nevertheless, to address commenters' concerns, we seek to balance the benefits of greater transparency with the desire to preserve a reasonable level of confidentiality. Specifically, for the reporting requirements aggregated by transmission zone, we propose that transmission zones with fewer than four resources need not be reported individually; rather, transmission zones with fewer than four resources may be aggregated with a neighboring transmission zone and reported collectively. If only one transmission zone exists and it has fewer than four resources or, if when combined with a neighboring transmission zone the combined transmission zone still has fewer than four resources, then these transmission zones would be exempted from reporting the uplift information described above. Similarly, for the resource-specific reporting requirements proposed above, we will require that uplift payment data for each resource be aggregated across the month, rather than reporting daily uplift payments to each resource. We expect that this temporal aggregation should mask daily behavior that some commenters have expressed concerns over revealing.

b. Reporting Operator-Initiated Commitments

90. We also propose to require that each RTO/ISO post all operator-initiated commitments on its Web site. For the purposes of this NOPR, we propose to define operator-initiated commitments as a commitment that is not associated

[106] ISO–NE Report at 59; SPP Report at 39.

[107] In conjunction with other information, uplift payments could potentially be used to determine a resource's energy offers. For example, if a market participant knew a resource's output, LMP, and uplift payments, it could potentially calculate the resource's energy offer because the uplift would make the resource whole up to its offer costs.

with a resource clearing the day-ahead or real-time market on the basis of economics and that is not self-scheduled.[108] This definition would include any commitment, whether manual or automated, made after the execution of the day-ahead market that is made outside of the real-time market. Such commitments include commitments made through a residual unit commitment processes after the execution of the day-ahead market, commitments made through look-ahead commitment processes, and manual commitments made in real-time. We acknowledge that this definition of operator-initiated actions could result in reporting most commitments that occur after the day-ahead market. Moreover, we understand that whether a commitment cleared the market on the basis of economics could be a point of confusion, particularly with respect to look-ahead commitment processes. Therefore, we request comment on this aspect of the definition of operator-initiated actions.

91. The report posted on each RTO's/ISO's Web site would include the following: (1) The upper economic operating limit of the committed resource in MW (*i.e.,* its economic maximum); (2) the transmission zone in which the resource is located; and (3) the reason for commitment.[109] We propose that each RTO/ISO post this information on a publicly accessible portion of its Web site in machine-readable format as soon as practicable after the resource has been committed (*i.e.,* directed to start up by the RTO/ISO). As above, we propose to define ''transmission zone'' as a geographic area that is used for the local allocation of charges. We request comments on this proposed definition, including the appropriate level of geographic granularity. Also, as discussed further below, we propose that real-time commitments be posted as soon as practicable after they occur, but no later than four hours after the commitment.

92. Many commenters express concern about the lack of transparency surrounding operator-initiated commitments and request that the Commission require RTOs/ISOs to provide more information.[110] We agree that current RTO/ISO practices may not provide sufficient transparency regarding operator-initiated commitments and that a minimum level of transparency is necessary as operator-initiated commitments can affect rates. In particular, operator-initiated commitments can affect energy and ancillary service prices and can result in uplift. In addition, greater transparency will allow stakeholders to better assess the RTO's/ISO's operator-initiated commitment practices and raise any issues of concern through the stakeholder process.

93. While most commenters focus on reporting of manual operator-initiated commitments (*i.e.* not through automated software),[111] operator-initiated commitments made through automated processes like look-ahead commitment can also have a significant impact on uplift. In addition, as noted by several RTOs/ISOs, manual operator-initiated commitments are generally infrequent. Because posting all operator-initiated commitments, whether manual or automated, would help market participants to better understand the drivers behind the incurrence of uplift in each zone and the impact of such commitments on rates, we propose that all operator-initiated commitments be posted, whether manual or automated. We also seek comment on the types of unit commitments that should be reported as operator-initiated commitments.

94. In addition, we propose that real-time commitments be posted as soon as practicable after they occur, but no later than four hours after the commitment. We understand that this type of reporting could require significant changes to current RTO/ISO systems and processes. Accordingly, we seek comment on the proposed reporting timeframe, including the potential software upgrades necessary to facilitate reporting in near real-time and other potential implementation challenges. We also seek comment on whether a different reporting timeframe (*e.g.,* reporting once daily or monthly) would provide sufficient transparency.

95. We also understand that reporting the reason for an operator-initiated commitment may require the development of new internal processes. In particular, we understand that the reasons for operator-initiated commitments can vary based on the particular situation. Therefore, our proposal would only require RTOs/ISOs to report the commitment reason within broad categories (*e.g.,* voltage support, capacity-related). We seek comment on whether the Commission should define a common set of categories for use across all RTOs/ISOs and, if so, what categories should be included, or whether it is more appropriate to allow each RTO/ISO to establish a set of appropriate operator-initiated commitment reasons on compliance. In addition, we note that some RTOs/ISOs currently provide more granular or detailed information about the reason for operator-initiated commitments.[112] Therefore, we seek comment on whether the proposal provides sufficient transparency, or if more information is needed (*e.g.,* specific constraint name), as well as any potential concerns with requiring additional information (*e.g.,* required software upgrades or impact on operational processes).

c. Transmission Constraint Penalty Factors

96. We propose to require that all RTOs/ISOs include certain provisions related to transmission constraint penalty factors in their tariffs because transmission constraint penalty factors can significantly impact market clearing prices.

97. First, we propose to require that all RTOs/ISOs include their transmission constraint penalty factor values in their tariffs. This requirement would only apply to penalty factors used for transmission constraints and would not include other penalty factors used in commitment and dispatch algorithms. If the RTO/ISO uses different transmission constraint penalty factors for different processes, we propose to require that all sets of transmission constraint penalty factors be included in the tariff. For example, if an RTO/ISO uses different transmission constraint penalty factors in its security constrained unit commitment and its security constrained economic dispatch, it should include both sets of transmission constraint penalty factors in its tariff.

98. Second, we propose to require that RTOs/ISOs include in their tariffs an explanation as to if and when transmission constraint penalty factors may be used to set LMPs. If the RTO/ISO has different processes for allowing transmission constraint penalty factors to set LMPs in different circumstances, this should be explained in the tariff. As part of its explanation, the RTO/ISO should also make clear whether there are any specific restrictions or

[108] *See supra* text accompanying note 1.

[109] For example, if a resource with two combustion turbines with a capacity of 50 MW each was committed to manage congestion on a transmission facility, the RTO/ISO would be required to report the committed capacity (100 MW) and the reason (*e.g.,* constraint management).

[110] *E.g.,* EPSA Comments at 22–23; Exelon Comments at 17–18; Financial Marketers Coalition Comments at 42; PSEG Comments at 12.

[111] CAISO Report at 60; ISO–NE Report at 65; SPP Report at 42; PSEG Companies Comments at 12, 14–16, 21.

[112] For example, for real-time commitments made to manage congestion, MISO identifies the specific constraint that prompted the commitment. MISO Report at 60.

conditions under which transmission constraint penalty factors are allowed to set LMPs, such as a minimum duration for transmission constraint violations.

99. Finally, if RTOs/ISOs wish to have the flexibility to temporarily change transmission constraint penalty factors to account for changes in system conditions, they must include the procedures for doing so in their tariffs. We also propose to require these procedures to include a requirement that notice of the temporary change be provided to market participants. For example, an RTO/ISO could notify market participants of the temporary change by posting on its Web site.

d. Comment Sought on Transmission Outages

100. We seek comment on whether additional reporting of transmission outages should be required. Transmission outages can affect RTO/ISO commitment and dispatch decisions and resulting market clearing prices, and thus are an important facet of price formation. Though the current record on this issue is limited, we seek comment as to whether additional transparency in this regard would be beneficial to stakeholders and if RTOs/ISOs have any limitations in providing more detailed data in this regard, including any appropriate time lag for reporting.

e. Comment Sought on Availability of Market Models

101. Some commenters indicate that distribution of the network model may be limited to certain market participants.[113] For the purposes of this NOPR we define network model as the RTO's/ISO's model used in its energy management system for the real-time operation of the transmission system (*e.g.,* state-estimation, contingency analysis). We seek comment on whether certain classes of market participants are prohibited from obtaining the network model in certain RTOs/ISOs. Moreover, if there are limitations to which market participants are able to obtain the model, we seek comment on the justification for any such limitations.

III. Compliance

102. We propose to require that each RTO/ISO submit a compliance filing within 90 days of the effective date of any eventual Final Rule in this proceeding to demonstrate that it meets the proposed requirements set forth in the Final Rule. We note that this compliance deadline is for RTOs/ISOs to submit proposed tariff changes or otherwise demonstrate compliance with the Final Rule. We understand that implementing the reforms required by any Final Rule in this proceeding may be a complex endeavor. However, we preliminarily find that implementation of these reforms is important to ensure rates are just and reasonable. Therefore, we propose that tariff changes filed in response to a Final Rule in this proceeding must become effective no more than six months after compliance filings are due.

103. We seek comment on whether 90 days is sufficient time for RTOs/ISOs to develop new tariff language in response to the Final Rule.

104. To the extent that any RTO/ISO believes that it already complies with the reforms proposed in this NOPR, the RTO/ISO would be required to demonstrate how it complies in the compliance filing required 90 days after the effective date of any Final Rule in this proceeding. To the extent that any RTO/ISO believes that its existing market rules are consistent with or superior to the reforms adopted in any Final Rule, the Commission will entertain those at that time.[114]

IV. Information Collection Statement

105. The Paperwork Reduction Act (PRA)[115] requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons or contained in a rule of general applicability. OMB's regulations[116] require approval of certain information collection requirements imposed by agency rules. Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of an agency rule will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

106. The reforms proposed in this NOPR would amend the Commission's regulations to improve the operation of organized wholesale electric power markets operated by RTOs/ISOs. The Commission proposes to require each RTO/ISO that allocates the costs of real-time uplift due to deviations should allocate such real-time uplift costs to only those market participants whose transactions are reasonably expected to have caused the real-time uplift. The Commission also proposes to revise its regulations to enhance transparency by requiring that each RTO/ISO post uplift costs paid (dollars) and operator-initiated commitments (megawatts) on its Web site; and define in its tariff its transmission constraint penalty factors, as well as the circumstances in which the penalty factors can set locational marginal prices, and any procedure for changing the penalty factors. The reforms proposed in this NOPR would require one-time filings of tariffs with the Commission and potential software upgrades to implement the reforms proposed in this NOPR. The Commission anticipates the reforms proposed in this NOPR, once implemented, would not significantly change currently existing burdens on an ongoing basis. The Commission will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[117]

107. While the Commission expects the adoption of the reforms proposed in this NOPR to provide significant benefits, the Commission understands implementation can be a complex endeavor. The Commission solicits public comments on its need for this information, whether the information will have practical utility, the accuracy of burden and cost estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

108. Public Reporting Burden Estimate and Information Collection Costs: The Commission believes that the burden estimates that follow are representative of the average burden on respondents, including necessary communications with stakeholders.

[113] DC Energy, Inertia Power, and Vitol Comments at 21, 26; Financial Marketers Coalition Comments at 43.

[114] *See, e.g., Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Order No. 825, FERC Stats. & Regs. ¶ 31,384, at P 72 (2016); *Demand Response Compensation in Organized Wholesale Energy Markets,* Order No. 745, FERC Stats. & Regs. ¶ 31,322, at P 4 & n.7, *order on reh'g and clarification,* Order No. 745–A, 137 FERC ¶ 61,215 (2011), *reh'g denied,* Order No. 745–B, 138 FERC ¶ 61,148 (2012), *vacated sub nom. Elec. Power Supply Ass'n* v. *FERC,* 753 F.3d 216 (D.C. Cir. 2014), *rev'd & remanded sub nom. FERC* v. *Elec. Power Supply Ass'n,* 136 S. Ct. 760 (2016).

[115] 44 U.S.C. 3507 (2012).

[116] 5 CFR 1320 (2016).

[117] 44 U.S.C. 3507(d).

FERC–516G, AS MODIFIED BY THE NOPR IN DOCKET RM17–2–000

	Number of respond- ents [118]	Annual number of responses per respondent	Total number of responses	Average burden (hours) & cost per response [119]	Total annual burden hours & total annual cost	Cost per respondent ($)
	(1)	(2)	(1) × (2) = (3)	(4)	(3) × (4) = (5)	(5) ÷ (1)
Uplift Allocation	6	1	6	500; $36,500	3,000; $219,000	$36,500
Transparency	6	1	6	500; $36,500	3,000; $219,000	36,500

Cost to Comply: The Commission has projected the total cost of compliance, within Year 1 to be $438,000. After Year 1, the reforms proposed in this NOPR, once implemented, would not significantly change existing burdens on an ongoing basis.

Title: FERC–516G, Electric Rate Schedules and Tariff Filings in Docket RM17–2–000.

Action: Proposed revisions to an existing information collection.

OMB Control No.: TBD.

Respondents for this Rulemaking: RTOs/ISOs.

Frequency of Information: One-time.

Necessity of Information: The Federal Energy Regulatory Commission implements this rule to improve competitive wholesale electric markets in the RTO/ISO regions.

Internal Review: The Commission has reviewed the changes and has determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has specific, objective support for the burden estimates associated with the information collection requirements.

109. *Interested persons may obtain information on the reporting requirements by contacting the following:* Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], email: *DataClearance@ferc.gov,* Phone: (202) 502–8663, fax: (202) 273–0873. Comments concerning the collection of information and the associated burden estimate(s) may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. Due to security concerns, comments should be sent electronically to the following email address: *oira_submission@omb.eop.gov.* Comments submitted to OMB should refer to FERC–516G and OMB Control No TBD.

V. Environmental Analysis

110. 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.[120] We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this NOPR 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 the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[121]

VI. Regulatory Flexibility Act

111. The Regulatory Flexibility Act of 1980 (RFA)[122] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

112. This rule would apply to six RTOs/ISOs (all of which are transmission organizations). The average estimated annual cost to each of the RTOs/ISOs is $73,000. The RTOs/ISOs are not small entities, as defined by the RFA.[123] This is because the relevant threshold between small and large entities is 500 employees and the Commission understands that each RTO/ISO has more than 500 employees. Furthermore, because of their pivotal roles in wholesale electric power markets in their regions, none of the RTOs/ISOs meet the last criterion of the two-part RFA definition of a small entity: ''not dominant in its field of operation.'' As a result, the Commission certifies that the reforms proposed in this NOPR would not have a significant economic impact on a substantial number of small entities.

VII. Comment Procedures

113. The Commission invites interested persons to submit comments on the matters and issues proposed in this document to be adopted, including any related matters or alternative proposals that commenters may wish to

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[118] Respondent entities are either RTOs or ISOs.

[119] The estimated hourly cost (salary plus benefits) provided in this section are based on the salary figures for May 2015 posted by the Bureau of Labor Statistics for the Utilities sector (*available at http://www.bls.gov/oes/current/naics2_22.htm#00-0000*) and scaled to reflect benefits using the relative importance of employer costs in employee compensation from December 2015 (*available at http://www.bls.gov/news.release/ecec.nr0.htm*). The hourly estimates for salary plus benefits are:

Legal (code 23–0000), $129.12

Computer and Mathematical (code 15–0000), $60.63

Information Security Analyst (code 15–1122), $58.08

Accountant and Auditor (code 13–2011), $53.86

Information and Record Clerk (code 43–4199), $37.75

Electrical Engineer (code 17–2071), $64.29

Economist (code 19–3011), $74.53

Computer and Information Systems Manager (code 11–3021), $91.76

Management (code 11–0000), $89.07

The average hourly cost (salary plus benefits), weighting all of these skill sets evenly, is $73.23. For the calculations here, the Commission rounds it to $73 per hour.

[120] *Regulations Implementing the National Environmental Policy Act of 1969,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987).

[121] 18 CFR 380.4(a)(15) (2016).

[122] 5 U.S.C. 601–12 (2012).

[123] 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. The Small Business Administrations' regulations at 13 CFR 121.201 define the threshold for a small Electric Bulk Power Transmission and Control entity (NAICS code 221121) to be 500 employees. See 5 U.S.C. 601(3), citing to Section 3 of the Small Business Act, 15 U.S.C. 632.

discuss. Comments are due April 10, 2017. Comments must refer to Docket No. RM17–2–000, and must include the commenter's name, the organization they represent, if applicable, and their address.

114. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov.* The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

115. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

116. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VIII. Document Availability

117. 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 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

118. From the Commission's Home Page on the Internet, this information is available on 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 the docket number excluding the last three digits of this document in the docket number field.

119. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

List of Subjects in 18 CFR Part 35

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

By direction of the Commission.

Issued: January 19, 2017.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Regulatory Text

In consideration of the foregoing, the Commission proposes to amend Part 35, Chapter 1, 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. Amend § 35.28, by adding new paragraph (g)(11) to read as follows:

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(g) * * *

(11) *Uplift allocation and transparency*—(i) *Uplift allocation.* Each Commission-approved independent system operator or regional transmission organization that allocates the costs of real-time uplift to deviations must allocate such costs only to those market participants whose transactions are reasonably expected to cause the uplift costs. For purposes of this allocation, deviations are megawatt hour differences between a market participant's scheduled deliveries or receipts at particular points cleared in the day-ahead market and those amounts actually delivered or received in real-time that are not related to real-time economic or reliability-related operator dispatch instructions. Costs of uplift payments must be allocated to at least two distinct categories: System-wide capacity and congestion management. For purposes of this allocation, each Commission-approved independent system operator or regional transmission organization must distinguish between deviations that help efforts to address system needs and those that harm efforts to address system needs. A market participant's net harmful deviations are its harmful deviations less its helpful deviations. Within each uplift category, uplift costs must be allocated to a market participant's net harmful deviations commensurate with the extent to which those deviations harm efforts to address system needs. Within the system-wide capacity category, a market participant shall be allocated a portion of the total real-time uplift costs incurred to maintain energy and operating reserve requirements in the real-time market based on the net contributions of its deviations to those costs. Within the congestion management category, costs shall be allocated based on whether a market participant's deviations on net contributed to the real-time congestion at a given constraint. For the purposes of real-time uplift allocated to deviations, a market participant's deviations must be netted hourly. Real-time uplift allocated to deviations must be settled on an hourly basis.

(ii) *Transparency*—(A) *Uplift reporting.* Each Commission-approved independent system operator or regional transmission organization must post two reports, at minimum, regarding uplift on a publicly accessible portion of its Web site. Such postings shall be made within 20 calendar days of the end of each month. First, each Commission-approved independent system operator or regional transmission organization must post uplift, paid in dollars, and categorized by transmission zone, day, and uplift category. Transmission zone shall be defined as the geographic area that is used for the local allocation of charges. Transmission zones with fewer than four resources may be aggregated with a neighboring transmission zone and reported collectively. If, for any given monthly report, only one transmission zone exists and it has fewer than four resources or, if when combined with a neighboring transmission zone, the combined transmission zones still have fewer than four resources, these transmission zones may be omitted from the reporting requirements described in this section. Second, each Commission-approved independent system operator or regional transmission organization must post the resource name and the total amount of uplift paid in dollars aggregated across the month to each resource that received uplift payments within the calendar month.

(B) *Reporting operator-initiated commitments.* Each Commission-approved independent system operator or regional transmission organization must post operator-initiated commitments in megawatts, categorized by transmission zone and commitment reason, on a publicly accessible portion of its Web site as soon as practicable after the resource has been committed, but no later than four hours after the commitment. Transmission zone shall be defined as a geographic area that is used for the local allocation of charges.

(C) *Transmission constraint penalty factors.* Each Commission-approved independent system operator or regional transmission organization must include, in its tariff, its transmission constraint penalty factor values; the circumstances, if any, under which the transmission constraint penalty factors can set locational marginal prices; and the procedure, if any, for temporarily changing the transmission constraint penalty factor values. Any procedure for temporarily changing transmission constraint penalty factor values must provide for notice of the change to market participants.

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

Appendix: List of Short Names/ Acronyms of Commenters

Short name/acronym	Commenter
Appian Way	Appian Way Energy Partners, LLC.
CAISO	California Independent System Operator Corporation.
DC Energy, Inertia Power, and Vitol	DC Energy, LLC, Inertia Power, LP, and Vitol Inc.
EEI	Edison Electric Institute.
EPSA	Electric Power Supply Association.
EPSA/IPPNY	Electric Power Supply Association and Independent Power Producers of New York.
EPSA/NEPGA	Electric Power Supply Association and New England Power Generators Association, Inc.
EPSA/P3	Electric Power Supply Association and PJM Power Providers.
EPSA/Western Power Trading Forum	Electric Power Supply Association and Western Power Trading Forum.
Energy Storage Association	Energy Storage Association.
Entergy	Entergy Services, Inc. commented on behalf of the Entergy Operating Companies (Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy New Orleans, Inc.; and Entergy Texas, Inc.).
Exelon	Exelon Corporation.
Financial Marketers Coalition	Financial Marketers Coalition.
Golden Spread Electric	Golden Spread Electric Cooperative, Inc.
ISO–NE	ISO New England Inc.
MISO	Midcontinent Independent System Operator, Inc.
MISO Market Monitor	Potomac Economics, LLC.
PJM Market Monitor	Monitoring Analytics, LLC.
NYISO	New York Independent System Operator, Inc.
PJM	PJM Interconnection, L.L.C.
PSEG Companies	PSEG Companies (Public Service Electric and Gas Company, PSEG Power LLC and PSEG Energy Resources & Trade LLC).
Public Interest Organizations	Public Interest Organizations.
SPP	Southwest Power Pool, Inc.
XO Energy	XO Energy, LLC.

[FR Doc. 2017–02332 Filed 2–6–17; 8:45 am]

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DEPARTMENT OF DEFENSE

Department of the Army, U.S. Army Corps of Engineers

33 CFR Part 209

[COE–2016–0016]

RIN 0710–AA72

Use of U.S. Army Corps of Engineers Reservoir Projects for Domestic, Municipal & Industrial Water Supply

AGENCY: Army Corps of Engineers, DoD.

ACTION: Notice of proposed rulemaking; correction and extension of time for public comments.

SUMMARY: The U.S. Army Corps of Engineers (USACE) is correcting a notice of proposed rulemaking that appeared in the **Federal Register** of December 16, 2016 and extending the comment period on this rulemaking.

DATES: The comment period for the proposed rule published December 16, 2016 at 81 FR 91556 is extended until May 15, 2017.

ADDRESSES: You may submit comments, identified by docket number and/or Regulatory Information Number (RIN) and title, by any of the following methods:

Federal eRulemaking Portal: http://www.regulations.gov. Follow the instructions for submitting comments.

Email: WSRULE2016@usace.army.mil. Include the docket number, COE–2016–0016, in the subject line of the message.

Mail: U.S. Army Corps of Engineers, ATTN: CECC–L, U.S. Army Corps of Engineers, 441 G St. NW., Washington, DC 20314.

Hand Delivery/Courier: Due to security requirements, we cannot receive comments by hand delivery or courier.

FOR FURTHER INFORMATION CONTACT: *Technical information:* Jim Fredericks, 503–808–3856. *Legal information:* Daniel Inkelas, 202–761–0345.

SUPPLEMENTARY INFORMATION: In response to requests from multiple parties, USACE is extending the time for public comments by 90 days. The date listed in the **DATES** section by which comments must be received is changed from February 14, 2017 to May 15, 2017. Additionally, the document contained an incorrect docket number in the **ADDRESSES** section. The second docket number referenced in that section, for submission of public comments, is corrected as: COE–2016–0016.

Dated: January 31, 2017.

Theodore A. Brown,

Chief, Policy and Planning Division, Directorate of Civil Works, U.S. Army Corps of Engineers.

[FR Doc. 2017–02415 Filed 2–6–17; 8:45 am]

BILLING CODE 3720–58–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2015–0032; FRL–9956–86]

Receipt of Several Pesticide Petitions Filed for Residues of Pesticide Chemicals in or on Various Commodities

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of filing of petitions and request for comment.

SUMMARY: This document announces EPA's receipt of several initial filings of