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18 CFR Part 35

Electricity Market Transparency Provisions of Section 220 of the Federal Power Act; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–12–000; Order No. 768]

Electricity Market Transparency Provisions of Section 220 of the Federal Power Act

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Commission is revising its regulations pursuant to section 220 of the Federal Power Act (FPA), as enacted by section 1281 of the Energy Policy Act of 2005 (EPAct 2005), to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce. In doing so, the Commission revises its regulations to require market participants that are excluded from the Commission's jurisdiction under FPA section 205 and have more than a *de minimis* market presence to file Electric Quarterly Reports (EQR) with the Commission.

In addition, the Commission revises the existing EQR filing requirements applicable to market participants in the interstate wholesale electric markets by adding new fields for: reporting the trade date and the type of rate; identifying the exchange used for a sales transaction, if applicable; reporting whether a broker was used to consummate a transaction; reporting electronic tag (e-Tag) ID data; and reporting standardized prices and quantities for energy, capacity and booked out power transactions. The Commission also requires EQR filers to indicate in the existing ID data section whether they report their sales transactions to an index publisher and, if so, to which index publisher(s), and, if applicable, identify which types of transactions are reported. The Commission also eliminates the time zone from the contract section and the Data Universal Numbering System (DUNS) data requirement. These refinements to the existing EQR filing requirements reflect the evolving nature of interstate wholesale electric markets, will increase market transparency for the Commission and the public, and will allow market participants to file the information in the most efficient manner possible.

DATES: *Effective Date:* This rule will become effective December 10, 2012.

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SUPPLEMENTARY INFORMATION:

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Before Commissioners: Jon Wellinghoff, Chairman; Philip D. Moeller, John R. Norris, Cheryl A. LaFleur, and Tony T. Clark.

Final Rule

Issued September 21, 2012.

1. To facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce, the Federal Energy Regulatory Commission (Commission) pursuant to section 220 of the Federal Power Act (FPA) [1] revises its regulations to require market participants that are excluded from the Commission's jurisdiction under section 205 of the FPA [2] and have more than a *de minimis* market presence to file Electric Quarterly Reports (EQR) with the Commission.[3] After consideration of the comments filed in response to the Notice of Proposed Rulemaking (NOPR),[4] the Commission concludes that the requirements in this Final Rule will allow the Commission and the public to gain a more complete picture of interstate wholesale electric power and transmission markets by providing additional information concerning price formation and market concentration in these electric markets. Public access to additional sales and transmission-related information in the EQR improves market participants' ability to assess supply and demand fundamentals and to price interstate wholesale electric market transactions. It also strengthens the Commission's ability to identify potential exercises of market power or manipulation and to

[1] EPAct 2005, Public Law 109–58, 119 Stat. 594 (2005).

[2] 16 U.S.C. 824d.

[3] This Final Rule refers to market participants that are not public utilities under section 201(f) of the FPA as ''non-public utilities.'' FPA section 201(f) provides: No provision in this Part shall apply to, or be deemed to include, the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 *et seq.*) or that sells less than 4,000,000 megawatt hours of electricity per year, or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, employee of any of the foregoing acting as such in the course of his official duty, unless such provision makes specific reference thereto. 16 U.S.C. 824(f). In the NOPR, the Commission proposed to amend Part 35 to add a definition of ''non-public utility,'' and incorrectly referenced 16 U.S.C. 824f. In this Final Rule, we have corrected the reference, which now refers to 16 U.S.C. 824(f).

[4] *Electricity Market Transparency Provisions of Section 220 of the Federal Power Act,* Notice of Proposed Rule Making, FERC Stats. & Regs. ¶ 32,676 (2011) (NOPR).

better evaluate the competitiveness of interstate wholesale electric markets.

2. In adopting the requirements in this Final Rule, the Commission has balanced the need to increase transparency with the burden on non-public utilities associated with filing the EQR by revising some of the proposals in the NOPR. As explained below, the Commission uniformly adopts a 4,000,000 MWh *de minimis* threshold for all non-public utilities, including for non-public utilities that are Balancing Authorities. The Commission also will not require non-public utilities to report the following types of wholesale sales: (1) Sales by a non-public utility, such as a cooperative or joint action agency, to its members; and (2) sales by a non-public utility under a long-term, cost-based agreement required to be made to certain customers under a Federal or state statute.

3. In addition, the Commission revises the existing EQR filing requirements applicable to market participants in the interstate wholesale electric markets. The Commission revises the EQRs currently filed by public utilities under FPA section 205(c) and that will be filed by non-public utility filers under FPA section 220. These revisions include the addition of new fields for: (1) Reporting the trade date and the type of rate; (2) identifying the exchange used for a sales transaction, if applicable; (3) reporting whether a broker was used to consummate a transaction; (4) reporting electronic tag (e-Tag) ID data; and (5) reporting standardized prices and quantities for energy, capacity, and booked out power transactions. The Commission also requires EQR filers to indicate in the existing ID data section whether they report their sales transactions to an index publisher and, if so, to which index publisher(s) and, if applicable, which types of transactions are reported. The Commission also eliminates the time zone from the contract section and the Data Universal Numbering System (DUNS) data requirement. These refinements to the existing EQR filing requirements reflect the evolving nature of interstate wholesale electric markets, will increase market transparency for the Commission and the public, and will allow market participants to file the information in the most efficient manner possible.[5]

4. The requirement for certain non-public utilities to file EQRs will be implemented at the same time as the requirement for all EQR filers (both public utilities and non-public utilities) to report the data fields discussed in this rule, *i.e.,* beginning the third quarter of 2013.

I. Introduction

A. Order No. 2001

5. The Commission set forth the EQR filing requirements in Order No. 2001.[6] Order No. 2001 requires public utilities to electronically file EQRs summarizing transaction information for short-term and long-term cost-based sales and market-based rate sales and the contractual terms and conditions in their agreements for all jurisdictional services.[7] The Commission established the EQR reporting requirements to help ensure the collection of information needed to perform its regulatory functions over transmission and sales of electric energy,[8] while making data more useful to the public and allowing public utilities to better fulfill their responsibility under FPA section 205(c)[9] to have rates on file in a convenient form and place.[10] As noted in Order No. 2001, the EQR data is designed to ''provide greater price transparency, promote competition, enhance confidence in the fairness of the markets, and provide a better means to detect and discourage discriminatory practices.''[11]

6. Since issuing Order No. 2001, the Commission has provided guidance and refined the reporting requirements, as necessary, to simplify the filing requirements and to reflect changes in the Commission's rules and regulations.[12] For instance, in 2007 the Commission adopted an Electric Quarterly Report Data Dictionary, which provides in one document the definitions of certain terms and values used in filing EQR data.[13] Moreover, in 2007, the Commission required transmission capacity reassignments to be reported in the EQR.[14] The refinements to the existing EQR requirements that we are adopting in this Final Rule build upon the Commission's prior improvements to the reporting requirements and further enhance the goals of providing greater price transparency, promoting competition, instilling confidence in the fairness of the markets, and providing a better means to detect and discourage anti-competitive, discriminatory, and manipulative practices.

B. EPAct 2005

7. In EPAct 2005, Congress added section 220 to the FPA,[15] directing the Commission to ''facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce'' with ''due regard for the public interest, the integrity of those markets, fair competition, and the protection of consumers.''[16] FPA section 220 grants the Commission authority to obtain and disseminate ''information about the availability and prices of wholesale electric energy and transmission service to the Commission, State commissions, buyers and sellers of wholesale electric energy, users of transmission services, and the public.''[17] The statute specifies that the Commission may obtain this information from ''any market participant,''[18] except for entities with a *de minimis* market presence.[19] EPAct

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[5] The Commission has proposed to change the process for filing EQRs. Specifically, the Commission has proposed to replace the Visual FoxPro-based EQR software with two new filing options. *See Revisions to Electric Quarterly Report Filing Process,* 139 FERC ¶ 61,234 (2012).

[6] *Revised Public Utility Filing Requirements,* Order No. 2001, 67 FR 31043 (May 8, 2002), FERC Stats. & Regs. ¶ 31,127, *reh'g denied,* Order No. 2001–A, 100 FERC ¶ 61,074, *reh'g denied,* Order No. 2001–B, 100 FERC ¶ 61,342, *order directing filing,* Order No. 2001–C, 101 FERC ¶ 61,314 (2002), *order directing filing,* Order No. 2001–D, 102 FERC ¶ 61,334, *order refining filing requirements,* Order No. 2001–E, 105 FERC ¶ 61,352 (2003), *order on clarification,* Order No. 2001–F, 106 FERC ¶ 61,060 (2004), *order revising filing requirements,* Order No. 2001–G, 72 FR 56735 (Oct. 4, 2007), 120 FERC ¶ 61,270, *order on reh'g and clarification,* Order No. 2001–H, 73 FR 1876 (Jan. 10, 2008), 121 FERC ¶ 61,289 (2007), *order revising filing requirements,* Order No. 2001–I, 73 FR 65526 (Nov. 4, 2008), 125 FERC ¶ 61,103 (2008).

[7] Order No. 2001, FERC Stats. & Regs. ¶ 31,127.

[8] *Id.* PP 13–14.

[9] 16 U.S.C. 824d(c).

[10] Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 31.

[11] *Id.*

[12] *See, e.g., Revised Public Utility Filing Requirements for Electric Quarterly Reports,* 124 FERC ¶ 61,244 (2008) (providing guidance on the filing of information on transmission capacity reassignments in EQRs); *Notice of Electric Quarterly Reports Technical Conference,* 73 FR 2477 (Jan. 15, 2008) (announcing a technical conference to discuss changes associated with the EQR Data Dictionary).

[13] Order No. 2001–G, 120 FERC ¶ 61,270.

[14] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, 72 FR 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, at P 817, *order on reh'g,* Order No. 890–A, 73 FR 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g and clarification,* Order No. 890–B, 73 FR 39092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 74 FR 12540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890–D, 74 FR 61511 (Nov. 25, 2009), 129 FERC ¶ 61,126.

[15] 16 U.S.C. 824t.

[16] In addition, FPA section 220(b)(1–2) directs the Commission to exempt from disclosure information that is ''detrimental to the operation of an effective market or [that would] jeopardize system security,'' and ''to ensure that consumers and competitive markets are protected from the adverse effects of potential collusion or other anticompetitive behaviors that can be facilitated by untimely public disclosure of proprietary trading information.'' 16 U.S.C. 824t(b)(1–2).

[17] *Id.* 824t(a)(2).

[18] *Id.* 824t(a)(3)(A).

[19] *Id.* 824t(d).

2005 added a similar transparency provision in the Natural Gas Act,[20] which led to additional filing and posting requirements for the sale or transportation of physical natural gas in interstate commerce in Order Nos. 704 and 720.[21]

8. The Commission did not previously extend transparency requirements under FPA section 220 to wholesale electricity markets because the Commission was considering other reforms to its regulation of electricity markets.[22] In particular, the Commission was undertaking open access transmission service reforms and the more general review of competition in wholesale electricity markets.[23] As a result of these efforts, the Commission issued two final rules. In Order No. 890, the Commission exercised its remedial authority ''to limit further opportunities for undue discrimination, by minimizing areas of discretion, addressing ambiguities and clarifying various aspects of the *pro forma* [Open Access Transmission Tariff].'' [24] Moreover, in Order No. 719, the Commission made reforms ''to improve the operation [and competitiveness] of organized wholesale electric power markets'' in connection with ''fulfilling its statutory mandate to ensure supplies of electric energy at just, reasonable and not unduly discriminatory or preferential rates.'' [25] Although these final rules improved transparency in wholesale markets in a number of ways, the Commission believes the revisions required in this Final Rule are necessary to facilitate price transparency in wholesale electricity markets.

C. Procedural History

9. On January 21, 2010, the Commission issued a Notice of Inquiry [26] seeking comments on whether the Commission should apply the EQR filing requirements to non-public utilities and whether the Commission should consider other refinements to the existing EQR filing requirements. Based on comments received in response to the Transparency NOI, the Commission drafted the proposals in the NOPR. The Commission issued the NOPR in this proceeding on April 21, 2011. In response, the Commission received 28 comments.[27]

II. Discussion

A. Extending the EQR Filing Requirements to Non-Public Utilities

1. Need for Information From Non-Public Utilities and Commission's Legal Authority

a. Value of Information From Non-Public Utilities

i. NOPR

10. In the NOPR, the Commission stated that the market transparency provisions in section 220 of the FPA authorize the Commission to ''prescribe such rules as the Commission determines necessary and appropriate'' for the dissemination of ''information about the availability and prices of wholesale electric energy and transmission service.'' [28] The Commission explained that the transparency provisions expand the Commission's authority to collect such information not only from jurisdictional utilities, but also ''from any market participant'' [29] with more than a *de minimis* market presence.[30] The Commission also stated that the phrase ''any market participant'' is not defined in section 220 and is not limited to public utilities subject to the Commission's jurisdiction under section 205 of the FPA. The Commission interpreted ''any market participant'' to include non-public utilities that fall under FPA section 201(f).[31] The Commission stated that such an interpretation of ''any market participant'' is consistent with the broad mandate in section 220 to ''facilitate price transparency in the markets for the sale and transmission of electric energy in interstate commerce, having due regard for the public interest, the integrity of those markets, fair competition, and the protection of consumers.'' Furthermore, the Commission stated that, in EPAct 2005, Congress amended section 201(b)(2) of the FPA to provide that, ''[n]otwithstanding section 201(f),'' the entities described in section 201(f) shall be subject to the Commission's jurisdiction for purposes of carrying out certain provisions, including FPA section 220. Thus, the Commission concluded that reading FPA section 201(b)(2) in conjunction with section 220, EPAct 2005 granted the Commission authority to collect information concerning the availability and prices of wholesale electric energy and transmission service from entities that are not public utilities. Accordingly, the Commission proposed to fulfill its responsibility under section 220 of the FPA by requiring non-public utilities with more than a *de minimis* market presence in wholesale markets to comply with the EQR filing requirements.

11. As part of its justification for its proposals in the NOPR, the Commission explained that applying the EQR filing requirements to non-public utilities that fall above the *de minimis* threshold will increase price transparency to the public and the Commission and aid the Commission in its oversight of wholesale power and transmission markets. The Commission stated that non-public utilities have a significant presence in national and regional wholesale electricity markets [32] so that obtaining information about their sales transactions is important to unmasking

[20] 15 U.S.C. 717t–2.

[21] *See Transparency Provisions of Section 23 of the Natural Gas Act,* Order No. 704, 73 FR 1014 (Jan. 4, 2008), FERC Stats. & Regs. ¶ 31,260 (2007), *order on reh'g,* Order No. 704–A, 73 FR 55726 (Sept. 26, 2008), FERC Stats. & Regs. ¶ 31,275, *order dismissing reh'g and clarification,* Order No. 704–B, 125 FERC ¶ 61,302 (2008), *order granting clarification,* Order No. 704–C, 75 FR 35632 (June 23, 2010), 131 FERC ¶ 61,246 (2010); *see also, Pipeline Posting Requirements under Section 23 of the Natural Gas Act,* Order No. 720, 73 FR 73494 (Dec. 2, 2008), FERC Stats. & Regs. ¶ 31,283 (2008), *order on reh'g,* Order No. 720–A,75 FR 5178 (Jan. 21, 2010), FERC Stats. & Regs. ¶ 31,302, *order on reh'g and clarification,* Order No. 720–B, 75 FR 44893 (July 30, 2010), FERC Stats. & Regs. ¶ 31,314 (2010), *vacated, Texas Pipeline Ass'n v. FERC,* 661 F.3d 258 (2011).

[22] *See Transparency Provisions of Section 23 of the Natural Gas Act; Transparency Provisions of the Energy Policy Act,* Notice of Proposed Rulemaking, 72 FR 20791 (April 26, 2007), FERC Stats. & Regs. ¶ 32,614, at PP 9–11 (2007) (Natural Gas Transparency NOPR) (''The Commission does not propose action with respect to electric markets at this time. The Commission has recently addressed and is currently addressing electric market transparency in other proceedings.'').

[23] *Id.*

[24] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 40.

[25] *Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, 73 FR 64100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g,* Order No. 719–A, 74 FR 37776 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292, *order on reh'g and clarification,* Order No. 719–B, 129 FERC ¶ 61,252 (2009).

[26] *Electricity Market Transparency Provisions of Section 220 of the Federal Power Act,* Notice of Inquiry, 75 FR 4805 (Jan. 29, 2010), FERC Stats. & Regs. ¶ 35,565 (2010) (Transparency NOI).

[27] *See* Attachment B for a list of commenters and their abbreviated names as used here.

[28] 16 U.S.C. 824t(a)(2).

[29] *Id.* 824t(a)(3). This section states, in relevant part, that ''[t]he Commission may obtain the information described in paragraph (2) from *any market participant.'' Id.* (emphasis added).

[30] *Id.* 824t(d).

[31] *See id.* at 824t(a)(3)(A).

[32] In the NOPR, the Commission stated that, based on the most recent data available in the 2009 U.S. Energy Information Administration's (EIA's) Form 861, non-public utilities account for significant volumes of the 3.2 billion MWh of total annual wholesale electricity sales made within the 48 contiguous states (excluding ERCOT). The Commission noted that about 29 percent of those wholesale sales were made by non-public utilities, with non-public utilities accounting for 60 and 70 percent of wholesale sales within the Western Electric Coordinating Council (WECC) and SERC Reliability Corporation (SERC) regions, respectively, and about 80 percent of all wholesale sales that occur within the Florida Reliability Coordinating Council (FRCC). *See* NOPR, FERC Stats. & Regs. ¶ 32,676 at P 23.

how prices are formed in electricity markets. The lack of information from non-public utilities results in an incomplete picture of these markets, and hampers the ability of the public and the Commission to detect and address the potential exercise of market power and manipulation.

ii. Comments

12. Several commenters argue that extending the EQR filing requirements to non-public utilities will not increase transparency in wholesale electric markets regulated by the Commission.[33] NYMPA/MEUA argue that, contrary to the Commission's contention in the NOPR, reporting information about the limited wholesale sales made by municipal utilities will add little to the Commission's oversight of the markets it regulates.[34] Southwestern Power Administration states that it makes cost-based sales pursuant to statute; therefore, its sales play no role in price formation in wholesale markets and do not materially affect wholesale prices or rates paid to jurisdictional entities.[35] NRECA states that the majority of wholesale sales by non-public utilities are sales to their members pursuant to long-term bilateral contracts, which do not take place within wholesale electricity markets and have no impact on wholesale market prices. APPA, Public Systems, and TAPS argue that requiring Regional Transmission Operators (RTOs) and Independent System Operators (ISO) to make bid information publicly available with a shorter time lag is the most effective way to improve market transparency and oversight of RTO and ISO markets.[36]

13. APPA, supported by NRECA, asserts that the Commission's estimate of sales by non-public utilities overstates the percentage of sales made by non-public utilities.[37] For instance, APPA argues that not all wholesale sales are reported in EIA Form 861, and that wholesale power sales in Alaska, Hawaii, and ERCOT cannot be excluded from the percentage of nationwide wholesale sales made by non-public utilities because EIA data are not reported in sufficient detail to accurately determine which sales should be excluded.[38] In particular, APPA states that its analysis of EIA data indicates that non-public utilities accounted for only 19.4 percent of wholesale sales in the United States in 2009 rather than 29 percent, as stated in the NOPR. In addition, APPA argues that the NOPR's estimates of non-public utility wholesale sales by region, i.e., 80 percent in FRCC, 70 percent in SERC, and 60 percent in WECC, are overstated because EIA reports a power marketer's sales as being from a single region even though it may make sales in several regions. APPA also argues that the EQR data supports its contention that the Commission overstated in the NOPR the percentage of wholesale sales attributable to non-public utilities.[39]

14. NRECA also argues that the NOPR overestimated the number of wholesale sales made by non-public utilities in regional markets because the EIA data used to calculate those numbers do not distinguish between non-public utility sales made to members and non-members and appear to omit certain large power marketers as they do not report sales by NERC Reliability Region.[40] In particular, NRECA states that the percentage of non-public utility wholesale sales in FRCC was less than 80 percent of all wholesale sales in FRCC, with only two non-public utilities in FRCC selling above 4,000,000 MWh of wholesale energy in 2009, primarily to their own members. NRECA contends that the Commission made a similar mistake in its analyses of non-public utility sales in the Western Electricity Coordinating Council.[41]

15. Other commenters, such as EEI and Joint Market Monitors, not only argue that the Commission has the authority to require non-public utilities to submit EQRs, but also that this information will increase transparency. Moreover, Joint Market Monitors argue that the Commission's jurisdiction over market manipulation constitutes a standalone basis for requiring all market participants to file EQRs. Joint Market Monitors state that the Commission's market-based rate program is based on a theory of regulation through competition, which relies on a lack of market power or adequate mitigation to ensure just and reasonable pricing.[42]

16. Moreover, certain commenters agree with the Commission that information from non-public utilities will increase transparency in interstate wholesale electric power and transmission markets.[43] Joint Market Monitors assert that the jurisdictional status of a market participant has no bearing on the impact of its participation and conduct on electricity markets. Furthermore, Joint Market Monitors agree that the Commission must have an understanding of what transpires in a market as a whole to fully understand any particular part of it. Given that all market participants participate in price formation, Joint Market Monitors argue that all market participants should be required to provide data adequate to ensure that the Commission is able to fulfill its basic regulatory duties.[44]

17. Pennsylvania Commission states that cooperatives and municipalities play a significant role in serving Pennsylvania residents; thus, expanding EQR requirements to include them will strengthen the Commission's ability to monitor wholesale markets and Pennsylvania Commission's ability to monitor its retail markets for anti-competitive and manipulative behavior.[45]

18. EEI states that public utilities would benefit from access to EQR information from non-public utilities in undertaking analyses used for market-based rate applications.[46] In contrast, LPPC asserts that information regarding long-term agreements would not assist the Commission in conducting a delivered price test (DPT) for market-based rate authorizations and mergers. LPPC asserts that the delivered price test measures concentration in short-term markets and focuses on the ability

[33] *See, e.g.,* California DWR at 1–2; NRECA at 4; NYMPA/MEUA at 3; Southwestern Power Administration at 3.

[34] NYMPA/MEUA at 3.

[35] Southwestern Power Administration at 3.

[36] APPA at 4; Public Systems at 2; TAPS at 17–20.

[37] APPA at 9–10; NRECA at 8.

[38] APPA at 8–9.

[39] *Id.* at 10. For example, APPA states that Morgan Stanley Capital Group's 2009 wholesale sales reported on EIA Form 861 are assigned to the ReliabilityFirst Corporation (RFC) region of North American Electric Reliability Corporation (NERC), but that the company's fourth quarter 2009 EQR shows that not all of those sales were in the RFC region. Morgan Stanley reported energy sales and bookouts of 27.5 million MWhs in WECC and 5.1 million MWhs in SERC. APPA concludes that for that quarter, ''Morgan Stanley sold more in the WECC region than any public power utility or cooperative sold in WECC for all of 2009, but the Morgan Stanley sales were not part of FERC's analysis of the WECC region.'' APPA makes a similar observation regarding sales by Constellation Energy Commodities Group for fourth quarter 2009 and notes that Calpine Energy Services and Dynegy Power Marketing both report large amounts of wholesale sales on the 2009 EIA Form 861, but leave the NERC region blank. EQRs for the fourth quarter show that Calpine sold 22.2 million MWhs in WECC, 3.1 million MWhs in SERC, and 136,000 MWhs in FRCC; Dynegy sold 1.1 million MWhs in WECC. APPA claims that regional calculations based on EIA Form 861 data would not include those sales in the appropriate regions, thus overstating the percentage of non-public utilities' sales in those regions.

[40] NRECA at 7–8.

[41] *Id.*

[42] Joint Market Monitors at 3.

[43] *See, e.g.,* DC Energy at 3; EEI at 3–6; Joint Market Monitors at 3; NYMPA/MEUA at 3; Pacific Northwest IOUs at 2; Pennsylvania Commission at 6; Powerex at 4; Ronald Rattey at 10; Shell Energy at 2.

[44] Joint Market Monitors at 3–4.

[45] Pennsylvania Commission at 7.

[46] EEI at 3–4.

of suppliers to deliver energy to relevant markets as measured by their short-term variable costs. LPPC therefore contends that disclosure of the prices reflected in long-term wholesale contracts between non-public utilities would do nothing to improve the accuracy of determining either short-term destination market prices or the short-term variable costs of potential suppliers.[47]

iii. Commission Determination

19. We conclude that FPA section 201(b)(2), read in conjunction with section 220, grants the Commission authority to collect information about the availability and prices of wholesale electric energy and transmission service from non-public utilities notwithstanding section 201(f) .[48] We further conclude, for the reasons discussed in the NOPR and based on our review of the record, that it is appropriate to adopt the NOPR proposal to extend EQR filing requirements to non-public utilities above the *de minimis* threshold under FPA section 220 with the following modifications. In the NOPR, the Commission proposed to require non-public utilities above the *de minimis* threshold to report all of their wholesale sales in the EQR to increase price transparency to the public and the Commission. The Commission modifies its NOPR proposal by excluding the following types of wholesale sales from the EQR reporting requirement for non-public utilities above the *de minimis* threshold: (1) Sales by a non-public utility, such as a cooperative or joint action agency, to its members; and (2) sales by a non-public utility under a long-term, cost-based agreement required to be made to certain customers under a Federal or state statute.

20. The NOPR explained that transactions made by both public utility and non-public utility market participants provide critical pricing information that market participants can use to make better-informed decisions about, among other things, sales, purchases, and infrastructure investments. Moreover, access to reliable data reduces differences in available information among various market participants, results in greater market confidence, lowers transaction costs, and ultimately supports competitive markets, which helps lower electricity costs for consumers.

21. The NOPR also pointed out that non-public utilities have a significant presence in national and regional wholesale electric markets so that obtaining information about their sales transactions is important to unmasking how prices are formed in electric markets. Therefore, the lack of information from non-public utilities results in an incomplete picture of these markets, and hampers the ability of the public and the Commission to detect and address the potential exercise of market power and manipulation.[49]

22. In addition, as stated in the NOPR, obtaining EQR information from non-public utilities would strengthen the Commission's oversight of its market-based rate program under FPA section 205 and provide a better basis for considering whether to approve merger and acquisition proposals under FPA section 203.[50] The Commission's market-based rate program is grounded in an *ex ante* analysis of whether to grant a seller market-based rate authority and an *ex post* analysis of whether a seller with market-based rate authority has obtained the ability to exercise market power since it was granted authorization to transact at market-based rates or since its last updated market power analysis.[51] As stated in the NOPR, one tool used to conduct an *ex ante* analysis is the DPT, which is used if a seller fails one of the indicative screens of market power. The NOPR stated that obtaining more complete price and volume information for sales of electricity by non-public utilities would more accurately reflect market prices, improve the quality of the DPT results and assist the Commission in identifying whether sellers can exercise market power.[52] After consideration of various comments and careful balancing of the need to facilitate price transparency against the burden on non-public utilities associated with filing the EQR, the Commission modifies its NOPR proposal, as discussed above, by excluding certain non-public utility wholesale sales from the EQR reporting requirement. In particular, the Commission modifies its NOPR proposal by excluding the following types of wholesale sales from the EQR reporting requirement for non-public utilities above the *de minimis* threshold: (1) Sales by a non-public utility, such as a cooperative or joint action agency, to its members; and (2) sales by a non-public utility under a long-term, cost-based agreement required to be made to certain customers under a Federal or state statute. For purposes of this rulemaking, the Commission refers to non-public utility wholesale sales not subject to either of these two exclusions as ''surplus'' market sales. The Commission finds that information about a non-public utility's sales to its members, or by a non-public utility under a long-term, cost-based agreement required to be made to certain customers under statute, will not materially contribute to additional price transparency. These types of sales do not significantly impact wholesale price formation in electric markets because these sales generally take place between a non-public utility and a pre-determined customer without arm's-length negotiations. In addition, the benefit of obtaining information about such sales by non-public utilities may not outweigh the burden imposed on the non-public utilities that would need to report such sales in the EQR.

23. The Commission adopts the NOPR proposal to exempt utilities located entirely in Alaska and Hawaii from the EQR filing requirements because they are electrically isolated from the contiguous United States. In addition, this Final Rule does not apply to a transaction for the purchase or sale of wholesale electric energy or transmission services within ERCOT as it is described in section 212(k)(2)(A) of the FPA.[53]

24. APPA and NRECA argue that the NOPR overestimated the amount of nationwide wholesale sales made by non-public utilities. APPA contends that its calculations indicate that non-public utilities account for 19.4 percent of nationwide wholesale sales rather than 29 percent, as stated in the NOPR. APPA also points out that its calculation of non-public utility sales does not exclude certain sales in Alaska, Hawaii

[47] LPPC at 9–10.

[48] FPA section 201(b)(2) explicitly applies certain FPA provisions, including the transparency provision under FPA section 220, to entities covered by FPA section 201(f). This contrasts with the Natural Gas Act (NGA), which does not contain a similar provision setting forth the applicability of the transparency provision under NGA section 23 to natural gas pipelines that are exempted from the Commission's NGA jurisdiction under NGA section 1(b). On appeal of Order Nos. 720 and 720–A, whereby the Commission required major intrastate natural gas pipelines to post certain information under NGA section 23, the Fifth Circuit Court of Appeals concluded that the Commission's authority under NGA section 23 does not extend to intrastate pipelines because they are exempted from the Commission's NGA jurisdiction by NGA section 1(b). *See Texas Pipeline Ass'n* v. *FERC,* 661 F.3d at 262.

[49] NOPR, FERC Stats. & Regs. ¶ 32,676 at P 11.

[50] *Id.* P 27.

[51] The Ninth Circuit Court of Appeals has upheld the Commission's market-based rate program because it relies on a ''system [that] consists of a finding that the applicant lacks market power (or has taken sufficient steps to mitigate market power), coupled with strict reporting requirements to ensure that the rate is 'just and reasonable' and that markets are not subject to manipulation.'' *State of California, ex rel. Bill Lockyer* v. *FERC,* 383 F.3d 1006, 1013 (9th Cir. 2004), *cert. denied* (S. Ct. Nos. 06–888 and 06–1100, June 18, 2007)).

[52] NOPR, FERC Stats. & Regs. ¶ 32,676 at P 27.

[53] 16 U.S.C. 824t(f).

and ERCOT due to the lack of sufficient detail in EIA data.[54] Even if non-public utilities account for approximately 19.4 percent of nationwide wholesale sales, as APPA contends, the Commission finds this percentage of sales in the nationwide wholesale electricity market to be significant. APPA and NRECA also argue that the Commission's analysis using EIA Form 861 data overstated the number of non-public utility wholesale sales in regional markets. Although EIA data is not sufficiently detailed to provide a complete and precise estimate of wholesale sales made by non-public utilities, the Commission's market analysis using EIA data nevertheless indicates that non-public utilities account for a significant portion of sales in certain regional markets. The lack of publicly available data regarding non-public utility sales challenges the ability of the public and the Commission to rely on existing information sources to form an accurate picture of wholesale electricity markets and does not provide the level of price transparency that this Final Rule seeks to achieve.

25. As noted in the NOPR, the Commission believes its effort to increase transparency broadly across all wholesale markets subject to the Commission's jurisdiction by requiring additional information in the EQR is just as important as efforts the Commission has taken to improve transparency in RTO and ISO markets.[55] Obtaining information about sales in markets outside of RTO and ISO regions will enable the Commission and the public to better understand non-public utilities' effect on market dynamics. For example, in the Pacific Northwest, the supply of power from non-public utilities ebbs and flows with the water levels powering hydroelectric facilities. During times of high flows, power prices may fall and public utilities' fossil fuel and wind-fired generation can become less competitive. During times of drought or dry seasons, power prices may rise.

26. With respect to the suggestion by certain commenters that the Commission should require shorter time lags for RTO and ISO postings of bid and offer data, we note that the Commission has previously addressed the time lag for such data and we will not address that issue again here. Specifically, in Order No. 719, the Commission shortened the release period for bid and offer data and provided RTOs and ISOs with the flexibility to propose a different lag period.[56] Furthermore, the EQR provides a level of transparency that RTO or ISO postings of bid and offer data do not, because it informs the public which market participants are involved across markets and at what level.

27. We disagree with LPPC's statements that information about long-term agreements between non-public utilities would not assist the Commission in conducting a DPT analysis for market-based rate authorizations and mergers. The DPT measures market concentration by identifying the sellers that could compete to sell electricity in a relevant market. In defining the relevant market, the DPT identifies potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier's economic capacity and available economic capacity for each season/load condition.[57] A supplier's economic capacity measures the amount of generating capacity owned or controlled by a potential supplier with variable costs low enough that energy from such capacity could be economically delivered to the destination market.[58] To determine the total supply in the relevant market, the DPT adds the total amount of economic or available economic capacity located in the relevant market (including capacity owned by the seller and competing suppliers) with that of economic or available economic capacity that can be imported into the relevant market.[59] Economic capacity is based on total nameplate or seasonal capacity of generation owned or controlled through contract and firm purchases, reduced by operating reserves, and long-term firm sales. Available economic capacity is calculated by deducting long-term obligations including native load obligations from the economic capacity value. Therefore, information about long-term sales agreements between non-public utilities can be used to help determine the total supply in the relevant market. In addition, information about sales made by non-public utilities, including under long-term agreements, can assist the Commission in performing *ex post* analyses to determine whether a seller with market-based rate authority has obtained the ability to exercise market power since the original authorization to transact at market-based rates or since its last updated market power analysis.

b. Existing Sources of Information

i. NOPR

28. In the NOPR, the Commission concluded that existing sources of information regarding non-public utility wholesale electricity market transactions did not provide sufficient price transparency. The Commission considered the information made publicly available by the Energy Information Administration (EIA) Form 861, Rural Utilities Service (RUS) Form 12, RTO or ISO postings related to wholesale market prices and market participant bid/offer data, daily index publications, organized exchanges, commercial data providers, and through the Open Access Same-Time Information System (OASIS). Thus, the Commission proposed to expand EQR filing requirements to non-public utilities to provide price transparency that is not available through these existing sources of information.

ii. Comments

29. Certain commenters agree with the Commission that information available from existing price publishers and trade processing services is incomplete and, thus, inadequate.[60] However, other commenters argue that the Commission's NOPR is overly broad and proposes to collect duplicative information.[61] They further argue that the Commission must tailor its request to collect information that it currently lacks. California DWR asserts that the Paperwork Reduction Act requires the Commission to certify that a new reporting requirement such as this one is not unnecessarily duplicative of information otherwise reasonably accessible to the Commission. In addition, California DWR asserts that FPA section 220(a)(4) similarly requires that, before additional reporting to ensure price transparency in electric markets may be ordered, the Commission must make a determination

[54] APPA at 8–9.

[55] *See* NOPR, FERC Stats. & Regs. ¶ 32,676 at P 25.

[56] Order No. 719, FERC Stats. & Regs. ¶ 31,281 at P 421, *order on reh'g,* Order No. 719–A, FERC Stats. & Regs. ¶ 31,292 at P 156.

[57] *See Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, FERC Stats. & Regs. ¶ 31,252, at P 106, *clarified,* 121 FERC ¶ 61,260 (2007), *order on reh'g,* Order No. 697–A, 73 FR 25832 (May 7, 2008), FERC Stats. & Regs. ¶ 31,268, *order on reh'g,* Order No. 697–B, 73 FR 79610 (Dec. 30, 2008), FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g,* Order No. 697–C, 74 FR 30924 (June 29, 2009), FERC Stats. & Regs. ¶ 31,291 (2009), *aff'd sub nom. Montana Consumer Counsel* v. *FERC,* No. 08–71827, 2011 U.S. App. LEXIS 20724 (9th Cir. Oct. 13, 2011).

[58] *See id.* P 96.

[59] *See id.* P 37.

[60] *See, e.g.,* DC Energy at 3; EEI at 3–6; Joint Market Monitors at 3; NYMPA/MEUA at 3; Pacific Northwest IOUs at 2; Pennsylvania Commission at 6; Powerex at 4; Ronald Rattey at 10; Shell Energy at 2.

[61] California DWR at 3–5; NRECA at 4–5; Public Systems at 13–16.

that existing data sources are insufficient. California DWR states that in this respect, the NOPR disregards redundant requirements, and requires governmental entities to reformat and re-report already existing data.[62]

30. Numerous commenters argue that sufficient information is already publicly available to meet the objectives of FPA section 220 to ''ensure that consumers and competitive markets are protected from the adverse effects of potential collusion or other anticompetitive behaviors'' without requiring non-public utilities to file EQRs.[63] NRECA argues that the additional information that would be available in the EQR does not justify the increased burden on non-public utilities.[64] For instance, NRECA states that, as recognized in the NOPR, non-public utilities annually file Form EIA–861 ''Annual Electric Power Industry Report'' and that cooperatives receiving RUS financing also are required to file RUS Form 12.[65] California DWR adds that the NOPR concedes that data is available from EIA as well as from RTOs and ISOs.[66]

31. NRECA states that a substantial amount of information is available from these sources and others. For example, it asserts that EIA provides access to the daily volumes, high and low prices, and weighted average prices from hubs around the country and that Energy Management Institute provides results of a daily survey of wholesale transactions that it conducts in all the major trading regions of the country. NRECA further submits that forward market prices are available through the New York Mercantile Exchange and the Intercontinental Exchange (ICE). NRECA argues that it is inappropriate to increase reporting burdens on consumer-owned entities merely to avoid some effort on the part of the government to collect this information from various sources. NRECA concludes that the increased burden on non-public utilities that would be imposed by the EQR filing requirement is not justified by the information that would be obtained.[67]

32. California DWR, Public Systems, and TAPS also note that significant amounts of data also are available from RTOs and ISOs.[68] California DWR states that most of the desired information may be obtained from existing sources such as RTOs, ISOs or Commission-jurisdictional counterparties of governmental entities.[69] EEI and Public Systems argue that the Commission should collect EQR information directly from RTOs and ISOs because, as the Commission recognized in the NOPR, RTOs, and ISOs already make information publicly available.[70] Public Systems state that ISO–NE., the Commission, and others publish reams of data that facilitate price transparency in the New England markets. They note that ISO–NE's ''Markets'' page provides links to numerous data compilations and descriptions, including a real-time ''LMP Price Ticker'' and a link to its real-time ''LMP Map.''[71] Public Systems further state that the NOPR would require non-public utilities to repackage the voluminous market-settlement data that they receive from the RTO and to file that data in EQRs.

33. Public Systems state that the NOPR does not rely on data that RTOs already publish ''to the maximum extent possible'' under FPA section 220. Rather, argues Public Systems, the NOPR identifies certain information gaps in existing sources, such as information about bilateral transactions in the RTO market or sales outside of the RTO markets, and then uses those gaps to justify requiring non-public utilities to file EQRs covering *all* of their wholesale transactions, including those settled in the RTO markets. Public Systems state that, as a result, the NOPR would require a non-public utility with more than a *de minimis* presence in organized markets to file data about bilateral transactions and sales outside the RTO markets in its EQR along with voluminous market-settlement data that they receive from the RTO.[72]

34. California DWR states its wholesale transactions already are captured in EIA reports and California ISO postings, with the exception of non-California ISO bilateral transactions that California DWR may engage in. Thus, argues California DWR, the NOPR would require extensive duplication through a full EQR filing to collect a relatively small amount of data. California DWR states that in this respect, the NOPR disregards redundant requirements, and requires governmental entities to reformat and re-report already existing data.[73] Similarly, EEI also encourages the Commission to ensure that the EQR only requires reporting of information that is truly necessary, though it states that it agrees with the Commission that available information from existing price publishers and trade processing services is incomplete and thus inadequate.[74]

iii. Commission Determination

35. The Commission finds that the degree of price transparency provided by existing sources of information about wholesale markets is insufficient for the Commission to fulfill Congress' directive in FPA section 220 to facilitate price transparency in interstate markets for the sale and transmission of electric energy. As discussed in the NOPR,[75] the Commission has considered the degree of price transparency provided by a number of sources of publicly available information, including EIA Form 861 and RUS Form 12,[76] RTO and ISO postings, index publications, organized exchanges, commercial data providers, and through OASIS, and concludes that the degree of price transparency provided by these existing information sources is not sufficient to help ensure an adequate level of transparency in jurisdictional markets.

36. In general, the Commission and the public need a more compete picture of markets across the country, including smaller markets, even if a significant part of those markets is served by non-public utilities. Market dynamics, including markets dominated by non-public utilities, can change throughout the year through a host of factors including weather conditions, outages, and contract expirations.

37. Annual data collections from two of the most significant publicly available forms that capture information about non-public utility power sales, the EIA Form 861 and the RUS Form 12, do not provide sufficiently detailed or

[62] California DWR at 3, 5–6.

[63] *See, e.g.* California DWR at 4–5; NRECA at 2, 5; Transmission Dependent Utility Systems at 3.

[64] NRECA at 5–6. Allegheny, Associated Electric Cooperative, and South Mississippi Electric each support NRECA's comments.

[65] NRECA at 4–6 (''This form [EIA–861] includes information regarding peak load, generation, electric purchases, sales, revenues, customer counts and demand-side management programs, green pricing and net metering programs, and distributed generation capacity.'' RUS Form 12 ''includes information regarding electric purchases, sales and revenues.'').

[66] California DWR at 3.

[67] NRECA at 5.

[68] California DWR at 3; Public Systems at 14; TAPS at 18.

[69] California DWR at 2–3.

[70] EEI at 21; Public Systems at 13.

[71] Public Systems at 14–15. Public Systems explains that the ''LMP Map'' shows: (1) Day-ahead market locational marginal prices (LMP) for the current hour, by load zone, along with the relevant binding constraints; (2) corresponding LMPs and constraints for the real-time energy market; and (3) real-time reserve-market clearing prices and regulation prices.

[72] *Id.* at 15.

[73] California DWR at 4–5.

[74] EEI at 6.

[75] NOPR, FERC Stats. & Regs. ¶ 32,676 at PP 34–39.

[76] RUS Form 12 was recently renamed the RUS Financial and Operating Report Electric Power Supply.

timely information to assess those market dynamics. As stated in the NOPR, EIA Form 861 does not detail individual wholesale transactions, including the counterparty, location, price, and delivery timeframe as well as other transaction details combined in the EQR.[77] Instead, EIA Form 861 filers report their aggregated annual volume of sales for resale and corresponding revenues. In addition, cooperatives that fall under 7 U.S.C. 901 provide accounting details, including the energy purchaser and other contract details for individual energy sales in RUS Form 12. However, as stated in the NOPR, RUS Form 12 provides only limited price transparency because the form does not contain information on delivery location and timing, which are critical elements for gaining insight into price formation.[78]

38. As recognized by certain commenters, and in the NOPR,[79] RTOs, and ISOs make available a significant amount of information about the availability and prices for wholesale sales and transmission service within these markets. However, as stated in the NOPR, the Commission believes that it is equally important to increase transparency broadly across all markets subject to the Commission's jurisdiction by requiring market participants, including non-public utilities with more than a *de minimis* presence in those markets, to provide information through EQRs.[80] The Commission finds that this information should include not only non-public utilities' bilateral transactions in an RTO or ISO market or sales outside of the RTO or ISO markets, but also sales made by non-public utilities to the RTO or ISO markets. The EQR provides a level of transparency that RTO or ISO postings do not because it informs the public which market participants were involved across markets and at what level. Obtaining information about such sales will improve transparency by providing the public and the Commission with the ability to view a broader universe of non-public utility sales. Specifically, the EQR provides a greater level of transparency by providing information in one place about a filer's wholesale transactions, including the counterparty, delivery location, price, and delivery timeframe as well as other transaction details. Furthermore, in response to Public Systems' concern that non-public utilities would be required to repackage voluminous market-settlement data that they receive from the RTO and to file that data in EQRs, we note that Order No. 2001 permitted RTOs and ISOs to file power sales transaction information on behalf of members or market participants as an agent, if authorized to do so by the member or market participant.[81] The Commission has also encouraged efforts that allow market participants to request EQR-ready settlement reports from RTOs and ISOs and will continue to do so.[82]

39. Moreover, the Commission finds that the information collected through the EQR filing requirements in this Final Rule will not result in unnecessary duplication of information accessible to the Commission and the public. Market transparency is not served if market participants are required to piece together various sources with disparate, inconsistent, or potentially incomplete data. The EQR will facilitate price transparency by providing a uniform electronic information system with filers timely reporting data under a consistent set of rules for a specific period of time.

c. De Minimis Threshold

i. NOPR

40. In the NOPR, the Commission proposed that a non-public utility would be exempt under the *de minimis* market presence threshold from filing EQRs if it makes 4,000,000 MWh or less of annual wholesale sales (based on an average of the wholesale sales it made in the preceding three years), unless the non-public utility is a Balancing Authority that makes 1,000,000 MWh or more of annual wholesale sales (based on an average of wholesale sales it made in the preceding three years). Furthermore, the Commission concluded that FPA section 220 focuses on the availability and prices of ''wholesale electric energy and transmission service,'' and therefore proposed to use only the wholesale electricity sales made by non-public utilities for purposes of calculating the *de minimis* market presence threshold. The Commission proposed that a non-public utility use the annual wholesale sales volume it currently reports to EIA as ''Sales for Resale'' to calculate whether it meets the *de minimis* threshold.

ii. Comments

(a) Setting the Threshold

41. Many commenters support the Commission's proposal in the NOPR to set a *de minimis* threshold of 4,000,000 MWh of annual wholesale sales for non-public utilities.[83] LPPC asserts that EQR information from non-public utilities with relatively small roles in the marketplace would be of minimal value to the Commission and the public, and contribute little to transparency goals.[84]

42. However, other commenters suggest lowering the *de minimis* threshold to 1,000,000 MWh for all non-public utilities.[85] EEI and Pacific Northwest IOUs state that this would more accurately and fairly honor the statutory exception for *de minimis* participants, and would provide a clearer picture of transactions occurring in the nation's electricity markets and the operation of those markets.[86] DC Energy states that the threshold should be lowered to 1,000,000 MWh to ensure that all entities that may have an impact on wholesale market prices are required to submit EQR data and to provide for complete price transparency across the wholesale electricity markets.[87]

43. EEI submits that setting the threshold at 4,000,000 MWh would still leave a significant portion of the market unreported. EEI states that by setting the threshold at 1,000,000 MWh, the Commission would gain substantial additional information while inconveniencing a modest number of non-public utilities. EEI explains that, according to the EIA, of the 3,265 entities (including both public and non-public utilities) that filed the Form EIA–861 in 2009, 138 had sales over 4,000,000 MWh representing 91.8 percent of total U.S. wholesale sales, whereas 254 had sales over 1,000,000 MWh representing 98.7 percent of total U.S. wholesale sales. Of the 116 entities with sales between 1,000,000 and 4,000,000 MWh, EEI asserts that 67 were public power agencies and cooperatives representing approximately 3.9 percent of total U.S. wholesale sales, and the remaining 49 were investor-owned utilities and private power marketers representing 3.0 percent of such sales.[88] EEI further states that according to the

[77] *See* NOPR, FERC Stats. & Regs. ¶ 32,676 at P 35.

[78] *Id.*

[79] *Id.* P 25.

[80] *Id.*

[81] Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 336.

[82] Order No. 2001–E, 105 FERC ¶ 61,352 at P 12.

[83] *See, e.g.,* Allegheny at 4; APPA at 4; Cities/M–S–R at 8–9; LPPC at 3; NRECA at 2; NYMPA/MEUSA at 1; Pennsylvania Commission at 8; Powerex at 3; Public Systems at 7; TAPS at 4.

[84] LPPC at 1.

[85] *See, e.g.,* DC Energy at 5; EEI at 7; Pacific Northwest IOUs at 2.

[86] EEI at 7; Pacific Northwest IOUs at 2.

[87] DC Energy at 5.

[88] EEI at 8 (citing NOPR, FERC Stats. & Regs. ¶ 32,676 at P 125).

NOPR's burden statement, only five non-public utility Balancing Authorities are picked up if the threshold for Balancing Authorities is reduced from 4,000,000 to 1,000,000 MWh.[89]

44. Conversely, other commenters suggest that the Commission should increase the 1,000,000 MWh annual wholesale sale threshold for Balancing Authorities to 4,000,000 MWh or less.[90] NRECA suggests that a threshold of at least 4,000,000 MWh annual wholesale sales, akin to that used for non-Balancing Authorities, would still capture sales by non-public utility Balancing Authorities with a significant market presence without exposing small Balancing Authorities to a reporting requirement that would place a significant burden on them with no corresponding benefit to the Commission or to the market. NRECA states that the proposed 1,000,000 MWh threshold reflects an approximately 114 MW baseload energy sale, which is too small to have more than a *de minimis* impact on any market. Therefore, NRECA asserts that the requirement places the burden of filing EQRs on Balancing Authorities that do not have more than a *de minimis* market presence.[91]

45. Similarly, TAPS requests that the Commission apply the 4,000,000 MWh wholesale sales *de minimis* threshold uniformly, regardless of whether the non-public utility is a Balancing Authority. TAPS asserts that applying a lower *de minimis* threshold to non-public utilities that are Balancing Authorities is insufficiently explained, unduly discriminatory, and inconsistent with the statute. TAPS argues that the Commission's authority to require reporting by non-public utilities turns on whether the non-public utility at issue has a *de minimis* market presence. TAPS states that being a Balancing Authority does not magnify the market impact of a non-public utility's sales. TAPS states that nothing in the NOPR justifies a finding that a Balancing Authority that sells 1,000,000 MWh at wholesale annually has more than a *de minimis* market presence, and that there is nothing about being a Balancing Authority that should lead to such a conclusion.[92]

46. Finally, Shell Energy supports adopting a *de minimis* level below which specific transactions would not be required to be reported in the EQRs. Shell Energy states that a minimum threshold for reporting by all EQR filers could be either a volume cut-off or a capacity cut-off, and that a reasonable threshold would be transactions below 10 MWh or under $1,000. Alternatively, Shell Energy asserts that the Commission should exclude from EQR reporting any transactions that are under 10 MWh or $1000 and are undertaken simply for balancing energy with an RTO or ISO. Shell Energy explains that it is involved in large numbers of such balancing transactions, each of a very small volume and the reporting of such transactions is onerous while not providing very helpful information to the Commission.[93]

(b) *Applying the Threshold*

47. Several commenters suggest that the Commission should exclude intra-familial sales by non-public utilities for purposes of the annual sales threshold.[94] NRECA notes that FPA section 220(d) provides that, ''[t]he Commission shall not require entities who have a *de minimis* market presence to comply with the reporting requirement of this section.''[95] Allegheny, NRECA, and Public Systems state that intra-familial sales transactions do not result in any ''market presence'' because they take place entirely outside of the markets.[96] NRECA argues, as such, intra-familial sales are outside the scope of transactions in section 220 of the FPA.[97]

48. According to NRECA, member cooperatives enter into long-term, cost-based, pass-through power contracts. NRECA states that the prices and volumes of such power sales are not influenced by market prices, and have no influence on market prices because they are established without regard to wholesale markets.[98] Allegheny submits that such sales are essentially the distribution cooperative members supplying themselves. Allegheny further states that these G&T cooperative sales are not market sales and do not affect the general marketplace for electricity because: (1) The sales are available only to the member-owners; (2) the member-owners are required to purchase the amounts covered by the contract and therefore they cannot purchase these amounts in the market; and (3) the G&T cooperatives cannot elect to sell these resources to third parties instead of to their members. Therefore, Allegheny asserts that such sales should be excluded from the 4,000,000 MWh threshold.[99]

49. Allegheny, NRECA, Public Systems, and Transmission Dependent Utility Systems submit that intra-familial transactions by non-public utilities are functionally equivalent to the operation of vertically-integrated public utilities.[100] NRECA states that it would be unjust and unreasonable for the Commission to require non-public utilities to include intra-familial transactions in calculating the 4,000,000 MWh sales threshold and in reporting data in EQRs when it does not require investor-owned utilities to report transfers between their bulk power and distribution functions, because those contracts do not have any relationship to markets for the wholesale sale of power.[101]

50. NRECA further alleges that the Commission's justification for including intra-familial transactions in calculating the 4,000,000 MWh threshold is not valid; the inclusion of such transactions in EQRs will not assist the Commission or the public in understanding RTO or ISO market price formation because these transactions do not impact the market price.[102] Transmission Dependent Utility Systems suggest that the Commission should restrict any EQR filing obligations imposed on G&T cooperatives that are non-public utilities to wholesale sales to parties other than their distribution cooperative members where those wholesale sales to third parties equal or exceed the 4,000,000 MWh threshold.[103]

51. TAPS suggests that if the Commission adopts a final rule providing that G&T cooperatives' cost-based sales to their members do not count toward determining where the cooperative has more than a *de minimis* wholesale market presence, comparability requires that joint action agency sales to members be treated in the same fashion.[104] Associated Electric Cooperative and NRECA comment that if the Commission does not exclude intra-familial transactions, it should at least not require both tiers of G&T cooperatives in a three-tier system to

[89] *Id.*

[90] *See, e.g.,* NRECA at 16; TAPS at 6.

[91] NRECA at 16–17.

[92] TAPS at 6.

[93] Shell at 12.

[94] *See, e.g.,* Allegheny at 4; Associated Electric Cooperative at 3; NRECA at 10; Public Systems at 2; Transmission Dependent Utility Systems at 3.

[95] NRECA at 12.

[96] Additionally, TAPS states that the fact that joint action agencies and G&T cooperatives cost-based inter-familial sales are not market sales justify excluding those transactions. TAPS at 10.

[97] NRECA at 12.

[98] *Id.* at 10–11.

[99] Allegheny at 4–5.

[100] NRECA at 11–12; Allegheny at 5; Transmission Dependent Utility Systems at 5; Public Systems at 11.

[101] NRECA at 11–12.

[102] *Id.* at 12.

[103] Transmission Dependent Utility Systems at 8.

[104] TAPS at 10.

report their sales on their EQRs, because this would result in double reporting.[105]

52. Cities/M–S–R state that the proposal that EIA data should be used by the joint action agency to determine whether it meets the *de minimis* threshold for filing EQRs is reasonable and should be included in the final rule. However, Cities/M–S–R request that sales by joint action agencies to the joint action agencies' members should be excluded from reporting because the EIA data currently posted from 2009 do not appear to include in the ''Sales for Resale'' figure the sales from joint action agencies to their members. Accordingly, Cities/M–S–R state that it is not clear how the Commission plans to compile data regarding sales by joint action agencies to their own members. If the Commission does not exclude transactions between joint action agencies and their members, then Cities/M–S–R request that the Commission clarify how joint action agencies should determine their volume of sales for purposes of determining whether or not they exceed the threshold.[106]

53. Southwestern Power Administration states that the Commission's proposal of a *de minimis* threshold with no procedure for waiver is unreasonable for entities largely reliant upon recent weather patterns to determine sales volumes. Southwestern Power Administration explains that its annual sales from Corps Hydropower facilities are dependent upon annual inflows, which vary greatly from year-to-year. Establishing a threshold based on a one- to three-year timeframe may require utilities such as Southwestern Power Administration, which are dependent upon inflow in order to make sales, subject to the filing requirements simply because of a period of above average rainfall and may not truly reflect the utility's presence in the region.[107]

iii. Commission Determination

54. The Commission will uniformly adopt a 4,000,000 MWh *de minimis* threshold for all non-public utilities, including for non-public utilities that are Balancing Authorities. Specifically, the Commission will exempt under the *de minimis* market presence threshold non-public utilities that make 4,000,000 MWh or less of annual wholesale sales (based on an average of the wholesale sales it made in the preceding three years). To ensure the uniform application of the *de minimis* threshold, the Commission will not adopt the NOPR proposal to require a non-public utility that is a Balancing Authority making 1,000,000 MWh or more of annual wholesale sales to file EQRs. Instead, the Commission will apply the 4,000,000 MWh threshold to these non-public utility Balancing Authorities. As set forth in the NOPR, the Commission will use wholesale sales, as reported in EIA Form 861, ''Sales for Resale,'' to calculate the *de minimis* market presence threshold.

55. In response to commenters that suggest a 1,000,000 MWh *de minimis* threshold, we note that the 4,000,000 MWh threshold adopted by this Final Rule will significantly increase transparency, particularly in certain markets with large non-public utility concentrations. In requiring non-public utilities to report EQR information, we must balance transparency benefits associated with the data collection with any burdens it may create. EEI comments that EIA Form 861 data indicates that setting the threshold at 1,000,000 MWh instead of 4,000,000 MWh would capture sales from an additional 67 public power agencies and cooperatives representing approximately 3.9 percent of the nation's wholesale sales. However, the Commission finds that the value of collecting information from non-public utilities making between 1,000,000 and 4,000,000 MWh of annual wholesale sales does not outweigh the burden that would be imposed on these small non-public utilities. This determination is consistent with the definition of a small utility under the Regulatory Flexibility Act[108] and Small Business Act.[109] The Small Business Administration's implementing regulations at 13 CFR 121.201 define a utility as small ''if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.'' This 4,000,000 MWh threshold is also consistent with the threshold used in FPA section 201(f) to exclude certain electric cooperatives from the Commission's jurisdiction.[110] Therefore, the Commission will not lower the *de minimis* threshold to 1,000,000 MWh of annual wholesale sales for non-public utilities, as suggested by certain commenters.

56. We will not adopt Shell Energy's suggestion to establish a *de minimis* reporting threshold for EQR filers based on their transactional volumes or capacity or exclude from reporting certain transactions undertaken for balancing energy with an RTO or ISO. As set forth in Order No. 2001, public utilities are required to file information in the EQR to comply with the requirement under FPA section 205(c) to show all rates, terms, and conditions of jurisdictional services.[111] The Commission has granted waiver of the EQR filing requirements for certain small public utility entities based on a number of factors.[112] Based on the statutory requirement for all public utility rates, terms and conditions to be on file with the Commission and the ability for small public utility entities to apply for waiver from the EQR filing requirement, the Commission concludes it is not necessary to establish a minimum reporting threshold based on the volume or nature of transactions undertaken by public utilities. The Commission also finds that this Final Rule appropriately sets the *de minimis* threshold for non-public utility filers based on their annual wholesale sales rather than on the volume or nature of their transactions.

57. Consistent with the NOPR proposal, the Commission finds it appropriate to use the total annual wholesale sales volumes reported as ''Sales for Resale'' in EIA Form 861 for purposes of calculating the *de minimis* threshold.[113] Basing the threshold calculation on the total annual wholesale sales figure already reported by non-public utilities in EIA Form 861 will avoid the need for them to make a separate calculation of annual wholesale sales for EQR purposes and ensure a consistent method for calculating the threshold. Therefore, in response to Cities/M–S–R's request for clarification of how joint action agencies should determine whether they exceed the *de minimis* threshold, we clarify that they should use the wholesale sales volumes reported as their ''Sales for Resale'' figure in EIA Form 861. However, as

[105] NRECA at 17; Associated Electric Cooperative at 3–4.

[106] Cities/M–S–R at 10–11.

[107] Southwestern Power Administration at 4–5.

[108] *See* 5 U.S.C. 601.

[109] *See* 15 U.S.C. 632.

[110] FPA section 201(f) provides, in relevant part: ''[n]o provision in this subchapter shall apply to, or be deemed to include * * * an electric cooperative that receives financing under the Rural Electrification Act of 1936 (7 U.S.C. 901 *et seq.*) or that sells less than 4,000,000 megawatt hours of electricity per year.'' 16 U.S.C. 824(f).

[111] Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at PP 11, 44.

[112] *See Bridger Valley Elect. Assoc., Inc.*, 101 FERC ¶ 61,146 (2002).

[113] EIA Form 861 instructions for Line 12, define ''Sales for Resale'' as the amount of electricity sold for resale purposes, including ''sales for resale to power marketers (reported separately in previous years), full and partial requirements customers, firm power customers and nonfirm customers.'' *See* EIA, Annual Electric Power Industry Report Instructions, *available at http://www.eia.gov/survey/form/eia_861/instructions.pdf.*

explained below, the Commission will not require non-public utilities to report sales made to members, or intra-familial sales, in the EQR.[114] In light of the determination to exclude from the EQR reporting requirement sales by cooperatives or joint action agencies to their members, we will not address comments concerning how to report such member sales.

58. In response to Southwestern Power Administration's comments that its annual sales vary greatly from year-to-year due to rainfall rates, the Commission finds that using a three-year average of total wholesale sales to calculate an entity's filing status helps moderate possible fluctuations in an entity's filing status. Moreover, information capturing fluctuations in wholesale sales can provide valuable details on the competitiveness of electricity markets.[115]

2. Filing Requirements for Non-Public Utilities

a. Scope of EQR Filing Requirements for Non-Public Utilities

i. NOPR

59. The Commission proposed to require a non-public utility with more than a *de minimis* market presence to report the same contractual and transactional information about its wholesale sales and transmission service, including cost-based and market-based sales, transmission service, and transmission capacity reassignments, that public utilities currently report. The Commission also proposed to include sales made by G&T cooperatives, joint action agencies, state agencies, and power or water districts to their own members. The Commission proposed to exclude, however, certain fields that it concluded may not be applicable to filings made by non-public utilities. As an example, the Commission noted that non-public utilities may not possess an appropriate FERC Tariff Reference to include in contract data Field Number 19 (FERC Tariff Reference) and transaction data Field Number 50 (FERC Tariff Reference) and would mark ''Not Required'' or ''n/r'' in these fields.

ii. Comments

60. EEI agrees that the Commission should require all parties to file the same basic EQR information. However, EEI also encourages the Commission to ensure that the EQR only requires reporting of information that is necessary and useful for the Commission to collect and that market participants can provide in the normal course of business.[116]

61. Several commenters argue that the Commission should not require entities such as joint action agencies, state agencies, power districts, and G&T cooperatives to report sales made to their own member utilities or long-term distribution customers under long-term agreements.[117] TAPS asserts that requiring joint action agencies and G&T cooperatives to report their cost-based sales to members is contrary to FPA section 220 because it imposes reporting requirements that do not advance the section's objective of enhancing market transparency. TAPS contends that reporting such sales would provide no information regarding the rates, terms or conditions under which a joint action agency would be willing to sell power to a non-member, nor would it provide information about the alternative rates, terms, and conditions under which the members could obtain power from other sources.[118]

62. APPA similarly argues that such sales play no role in price formation. According to APPA, sales by a joint action agency to its members are cost-based sales under long-term contracts that do not reflect current commercial conditions or market supply and demand.[119] Cities/M–S–R state that such sales typically reflect only the cost of production of the energy and the repayment of bond financing and are not arm's-length transactions that reflect market conditions; thus, such transactions should not be reported.[120]

63. While Public Systems agree that such sales are technically wholesale sales, they argue that such sales are not market sales and therefore do not reflect the rates, terms, or conditions on which a joint action agency would be able or willing to sell energy at wholesale to any other entities.[121] Transmission Dependent Utility Systems state that distribution cooperatives form G&T cooperatives to obtain cost efficiencies and that they enter into long-term contracts with their members to serve as security to finance generation and transmission facilities. Transmission Dependent Utility Systems argue that even though sales by a G&T cooperative to its members are wholesale sales, these sales are not the type of arm's-length sales between two wholesale market participants that determine market prices. Instead, Transmission Dependent Utility Systems argue that the initial purchase of power by the G&T cooperative is the significant transaction. According to Transmission Dependent Utility Systems, such sales are already reported in the EQR by the selling market participant. Thus, Transmission Dependent Utility Systems argue that there is no additional price information to be gleaned from the flow-through of purchased power from a G&T cooperative to its distribution member cooperative.[122]

64. A number of commenters argue that joint action agencies and G&T cooperatives are analogous to vertically-integrated utilities.[123] APPA states that joint action agencies are virtually vertically integrated with their member distribution systems, and argues that if they were literally vertically integrated, then there would be no wholesale sale to report. APPA argues that the same is true of sales by state agencies and power districts to neighboring distribution utilities through full requirement or other types of firm, long-term contracts.[124] TAPS argues that transactions involving G&T cooperatives and joint action agencies are wholesale sales in name only, and arise only because the individual members were too small to conduct such activities on their own and had to create a distinct legal entity to perform them on a joint basis.[125] Public Systems also assert that joint action agencies and G&T cooperatives use contracts to accomplish what vertically-integrated utilities accomplish through their corporate structure and thus sales to their members should not be considered wholesale sales.[126]

65. Public Systems and TAPS argue that requiring joint action agencies and G&T cooperatives to report sales to their members is unduly discriminatory because the Commission does not require other non-market transactions that affect the amount of demand served through the market.[127] For instance, TAPS states that the Commission does not require a load-serving entity to report when it engages in demand response, installs energy efficiency

[114] We note that while the threshold calculation is based on total wholesale sales, entities may not have to report all of their wholesale sales. For additional discussion, see *supra* § II.A.1.a. and *infra* § II.A.2.a.

[115] *See* discussion at *supra* P 18.

[116] EEI at 6–7.

[117] *See, e.g.,* APPA at 4; Cities/M–S–R at 9; Public Systems at 9; TAPS at 11.

[118] TAPS at 11.

[119] APPA at 4–5.

[120] Cities/M–S–R at 10.

[121] Public Systems at 9.

[122] Transmission Dependent Utility Systems at 5–6.

[123] *See, e.g.,* APPA at 5; Public Systems at 12; TAPS at 9.

[124] APPA at 5.

[125] TAPS at 9.

[126] Public Systems at 10.

[127] Public Systems at 12; TAPS at 12.

measures, or relies on its own generation to serve its load even though such activities reduce the load-serving entity's need for market purchases.[128]

66. TAPS also argues that it may be difficult to fit joint action agency sales to members into the categories the Commission has developed to describe other types of transactions. TAPS contends that this is evidence that such sales are not market transactions and cannot be compared to them meaningfully.[129]

67. Transmission Dependent Utility Systems argue that there is no potential in the transaction between the G&T cooperative and its member for exploitation of the kind that the FPA is intended to prevent. In support, Transmission Dependent Utility Systems state that the Commission has recognized in a number of orders that affiliate abuse is not a concern for cooperatives owned by other cooperatives.[130] APPA also cites to a Commission order that reasoned that ''sales of power by G&T cooperatives to their member G&T cooperatives or their member distribution cooperatives do not constitute marketing functions under the Standards of Conduct.''[131] Thus, APPA contends that there is no need for a joint action agency to report sales to members in its EQR.

68. Cities/M–S–R disagree with the Commission's assertion that if a joint action agency, state agency, or power or water district did not supply its members then its members would have to purchase supply from other sources in the market. Instead, Cities/M–S–R assert that without the joint action agency, a member would likely develop its own resource.[132]

69. TAPS asserts that if a member makes a sale of excess power into the market, then it would be required to report that sale in the EQR, assuming that the selling member had more than a *de minimis* market presence. Thus, TAPS argues that a potential resale at wholesale of power supplied by a joint action agency or G&T cooperative to its members does not justify requiring joint action agencies and G&T cooperatives to report sales to their members.[133]

70. If the Commission does not exclude a G&T cooperative's sales to its members from reporting requirements, then NRECA argues that the Commission should not require cooperatives with multiple tiers of G&T cooperatives to report their sales. For example, NRECA states that Basin Electric Power Cooperative, a G&T cooperative, sells electric power and energy at wholesale to its 'Class A' members, which are also G&T cooperatives. NRECA further states that the Class A members, acting as middlemen, then sell power and energy at wholesale to their distribution cooperative members at essentially the same price as they paid. Given that the price is essentially identical, NRECA argues that the Commission should not require both tiers of these G&T cooperatives to report; otherwise it will lead to double counting.[134]

71. APPA states that a more reasonable alternative would be for the Commission to require state agencies and power districts to report such transactions in their EQRs only to the extent that the applicable firm, long-term contract expires in less than three years.[135] Similarly, LPPC encourages the Commission to exempt from reporting agreements of longer than three years between non-public utilities.[136] In support, LPPC states that much of the power sold pursuant to these long-term arrangements is not available to private entities purchasing power in Commission-jurisdictional markets due to Internal Revenue Service Code restrictions. According to LPPC, these restrictions generally prohibit non-public utilities from selling more than a minimal amount of electricity to private entities; power sold in excess of this limit jeopardizes the nonpublic utility's tax-exempt financing.[137]

72. In contrast, EEI asserts that non-public utilities should report transaction and contract information on sales between non-jurisdictional entities as well as between non-jurisdictional and jurisdictional entities to provide a more complete picture of energy markets.[138]

iii. Commission Determination

73. The Commission adopts the NOPR proposal to require non-public utilities to report the same information about wholesale sales, transmission service, and transmission capacity reassignments that are currently reported by public utilities, with modifications. Expanding the same EQR data elements to non-public utilities will help ensure comparability and consistency with filings by public utilities, which will make it easier for the public and the Commission to use the information. In addition, requiring the same sales and transmission-related information from non-public utilities will allow the Commission to better evaluate the performance of wholesale markets as a whole and make it easier to determine whether jurisdictional prices are just and reasonable.[139]

74. Many commenters argue that the Commission should not require non-public utilities to report wholesale sales made to their own members or made under long-term, cost-based agreements. As mentioned above, the Commission will modify its NOPR proposal to exclude the following types of wholesale sales from the EQR reporting requirement for non-public utilities above the *de minimis* threshold: (1) sales by a non-public utility, such as a cooperative or joint action agency, to its members; and (2) sales by a non-public utility under a long-term, cost-based agreement required to be made to certain customers under Federal or state statute.[140] To the extent wholesale sales made by a non-public utility do not meet either of these criteria, the non-public utility must report those sales in the EQR.

75. The Commission recognizes that certain data fields in the EQR may not be applicable to filings made by non-public utilities. As stated in the NOPR, non-public utilities may not possess a FERC Tariff Reference (Field Numbers 19 and 50) for certain wholesale contracts and transactions. In cases where a FERC Tariff Reference is not applicable, the Commission will require that a filer mark ''NPU,'' (to indicate ''Non-Public Utility'') in those fields. If a non-public utility has a previously filed reciprocity open access transmission tariff (OATT), it should refer to that reciprocity OATT in Field Number 19 under FERC Tariff Reference. In addition, non-public utilities should mark ''NPU'' with respect to the ''cost-based'' or ''market-based'' options available under ''Product Type Information'' captured in Field Number 30, because these options are defined based on types of Commission-approved tariffs. If transmission capacity is reassigned

[128] TAPS at 12.

[129] *Id.* 14.

[130] Transmission Dependent Utility Systems at 7–8 (citing *Desert Generation & Transmission, Inc.,* 115 FERC ¶ 61,306, at P 14 (2006)).

[131] APPA at 5–6 (citing *Standards of Conduct for Transmission Providers,* Order No. 717, FERC Stats. & Regs. ¶ 31,280 (2008), *order on reh'g and clarification,* Order No. 717–A, FERC Stats. & Regs. ¶ 31,297 (2009), *order on reh'g and clarification,* Order No. 717–B, 129 FERC ¶ 61,123, *order on reh'g and clarification,* Order No. 717–C, 131 FERC ¶ 61,045, at P 21 (2010)).

[132] Cities/M–S–R at 9–10.

[133] TAPS at 13.

[134] NRECA at 17–18.

[135] APPA at 7, n.11.

[136] LPPC at 4.

[137] *Id.* at 6.

[138] EEI at 6.

[139] See NOPR, FERC Stats. & Regs. ¶ 32,676 at P 45.

[140] *See* discussion at *supra* § II.A.1.a.

under a non-public utility's reciprocity OATT, the non-public utility should follow the existing conventions for transmission providers reporting transmission capacity reassignments in the EQR.

b. Burden

i. NOPR

76. In the NOPR, the Commission recognized that extending the EQR filing requirements to non-public utility market participants will impose a new burden on those market participants. The Commission agreed that it would make every effort to provide guidance and technical assistance prior to implementation of the EQR filing requirements for non-public utilities.

ii. Comments

77. Some commenters question whether the Commission has adequately considered the burden imposed on non-public utilities. For example, Southwestern Power Administration asserts that section 220 of the FPA provides the Commission with limited authority to seek information from certain non-public utilities and requires the Commission to weigh the value of the information against the regulatory burden it would impose on those entities. Southwestern Power Administration argues that requiring it to report information about its sales will serve no useful purpose that would justify the burden of reporting this information and that the Commission has not shown otherwise.[141]

78. California DWR argues that the NOPR fails to comply with Federal statutes that require the Commission to carefully consider the costs and benefits of imposing burdens on governmental entities. For instance, California DWR states that the Paperwork Reduction Act requires agencies to certify that a new reporting requirement is not unnecessarily duplicative and that the Unfunded Mandates Reform Act of 1995 requires agencies to prepare a written statement of intergovernmental mandates that describe the analyses and consultations on the unfunded mandate.[142] California DWR also states that Executive Order 12866 requires agencies to propose or adopt regulations after it determines that the benefits of the intended regulation justify the costs and that the Regulatory Right to Know Act requires agencies to conduct cost-benefit analysis of their regulatory initiatives and report their findings to the Office of Management and Budget.[143]

79. Southwestern Power Administration states that it does not have the staffing needed to track and report EQR data, and that hiring additional staff to comply would pose increased costs with no commensurate benefit to its customers or incremental improvement to market transparency.[144] California DWR argues that the NOPR as written would give non-public utilities an incentive to self-supply to avoid wholesale power sales in order to reduce reporting burdens, which appears contrary to business requirements.[145]

80. If the Commission requires non-public utilities to submit EQRs, then NRECA argues that the Commission could reduce the burden on non-public utilities by simplifying the filing requirements as it relates to billing adjustments. NRECA states that it is common practice for a cooperative to bill its members under long-term contracts on the basis of budgets and that these charges are later trued-up to reflect the actual costs associated with the sale. NRECA states that EQR regulations require entities to file either revised EQRs or new transactions with the class name ''Billing Adjustments'' to report changes in billing data after the initial EQR filing deadlines. NRECA asserts that it would be very burdensome for cooperatives that use budget-based billing to submit revised EQRs or Billing Adjustments to reflect true-ups to actual costs. Thus, NRECA argues that the Commission should simplify the filing requirements for cooperatives that use budget-based billing by specifying that true-ups associated with budget-based billing do not trigger the requirement to submit revised EQRs or Billing Adjustments.[146]

81. LPPC encourages the Commission to provide sufficient lead time to enable non-public utilities to comply, and suggests a period of six months from the date of the final rule. LPPC also requests that the Commission have staff assist in training programs that will facilitate compliance.[147]

iii. Commission Determination

82. The Commission has carefully weighed, in developing this Final Rule, the burden associated with an entity filing the EQR against the benefits associated with greater transparency in the nation's wholesale electric markets. The Commission concludes that the burden of reporting information in the EQR is outweighed by the benefits of greater transparency provided by the EQR.

83. The burden of preparing an EQR filing varies, depending on the complexity of a company's transactions. If a company has a few long-term contracts of limited complexity, its EQR filing is simple: an unchanging description of its contracts from quarter to quarter with monthly or quarterly reports of the transactions under that contract. As the company's sales activities become more complex, with more frequent adjustments to price and a greater variety of counterparties and sales locations, its technological capabilities for tracking its transactions tend to become more sophisticated. As a result, complex, detailed EQRs tend to be associated with companies more capable of generating such a filing. Filers whose participation in the electric wholesale markets occurs under long-term, cost-based contracts with a limited number of counterparties will expend relatively little effort in complying with the EQR filing requirement. In addition, we believe that excluding from the reporting requirement sales by non-public utilities under long-term, cost-based agreements required to be made to certain customers under Federal or state statute will help lessen the burden on non-public utilities. Therefore, we believe that non-public utilities would not be encouraged to self-supply to avoid the reporting requirements, as suggested by California DWR.

84. In response to NRECA's concern about the difficulty for non-public utility cooperatives that use budget-based billing to submit revised EQRs or billing adjustments to reflect true-ups or actual costs, the Commission will not require true-ups by non-public utility cooperatives with budget-based billing in the EQR. The Commission's policy regarding refilings or billing adjustments stems from the statutory requirement under FPA section 205(c) to have a public utility's rates on file. Specifically, in recognition of the fact that public utilities may not have complete, final data for the full quarter by EQR filing deadlines, the Commission requires that any additions or changes to an EQR filing must be made by the end of the following quarter, when the filer is expected to file the best available new data.[148] Filers are

[141] Southwestern Power Administration at 2–3.

[142] California DWR at 6–7 (citing Paperwork Reduction Act, 44 U.S.C. 3506(c)(3) (2006); Unfunded Mandates Reform Act of 1995, 2 U.S.C. 1531, *et seq.* (2006)).

[143] *Id.* at 5–6 (citing Executive Order 12866, 58 FR 51735 (Oct. 4, 1993); Regulatory Right to Know Act, 31 U.S.C. 1105 (2006)).

[144] Southwestern Power Administration at 4.

[145] California DWR at 7.

[146] NRECA at 18–19.

[147] LPPC at 10.

[148] Order No. 2001–E, 105 FERC ¶ 61,352 at PP 9–10. According to the EQR Data Dictionary, a

Continued

required to file material changes, either as a full refiling or as a transaction with the class name ''Billing Adjustment.'' [149] It is worth emphasizing that refiling EQRs, with a billing adjustment to reflect the receipt of new information, is only necessary if the filer considers the change to previous EQR totals to be material.[150] The Commission has found that this policy balances the need for timely, accurate EQR data, while reducing the burden on filing entities by identifying price changes on a transaction-by-transaction basis due to some after-the-fact billing transaction long after the EQR was due.[151] In the case of budget-based billing, non-public utility cooperatives are not covered by FPA section 205 and the true-up process will likely have little effect on the market dynamics the Commission is trying to capture with this Final Rule. For these reasons, the Commission will exclude true-ups by non-public utility cooperatives associated with budget-based billing from the EQR's refiling or billing adjustment policy.

85. We agree with LPPC that the Commission should provide sufficient lead time to enable non-public utilities to comply. Over the past ten years, the Commission has been proactive in its outreach on many aspects of the EQR; in issuing this Final Rule, the Commission acknowledges that new filers will need the opportunity to learn about the filing. Accordingly, non-public utility filers are required to file EQRs beginning with the third quarter (Q3) of 2013, covering the period July through September 2013. The Commission directs staff to assist filers with compliance. For example, the Commission intends to convene a staff-led technical conference, to be announced at a future date, to assist non-public utilities in collecting and filing EQR data.

B. Refinements to the Existing EQR Requirements

1. General Refinements

a. Trade Date & Time and Type of Rate

i. NOPR

86. In the NOPR, the Commission proposed to require any market participant that is required to file an EQR to report in the EQR the date on which parties to a reported transaction agreed upon a price (trade date) and the type of rate by which the price was set. The Commission stated in the NOPR that the term ''trade date'' means ''the date upon which the parties agree upon the price of a transaction.'' The Commission also proposed four types of rates: ''fixed,'' ''formula,'' ''index,'' and ''RTO/ISO price.'' A fixed rate would be defined as a fixed charge per unit of consumption. A formula rate would be defined as a calculation of a rate based upon a formula that does not contain an index component. An index rate would be defined as a calculation of a rate based upon an index or a formula that contains an index component. An ''RTO/ISO price'' would be defined as a rate that is based on an RTO/ISO published price or formula that contains an RTO/ISO price component. The Commission also proposed to require market participants to report the time of trade, defined as ''the time upon which the parties agree upon the price of a transaction.''

ii. Comments

87. DC Energy, Joint Market Monitors, and Pennsylvania Commission support the Commission's proposal to require the trade date and time and type of rate in EQR.[152] However, as discussed further below, many commenters are opposed to parts of the proposal.

(a) Trade Date

88. With respect to the proposed requirement to report the trade date, Powerex states it should not be onerous to report such data because market participants likely already track it.[153] However, some commenters question the need for trade data and note some difficulty in ascertaining the appropriate date to report. EEI questions the need for trade date information, arguing that contracts negotiated to cover specific transactions will include trade-specific details so that transactions can be distinguished based on the associated contract information in the EQR. In addition, EEI suggests that, if the Commission requires reporting of trade dates, it should clarify that the trade date is the effective date of the legally binding agreement between parties with respect to the transaction. In this vein, EEI contends that the ''official'' trade date agreed to by market participants for each transaction and documented in trade capture systems and related transaction documentation is the appropriate date to use. EEI states that its members and other market participants document the ''official'' date in their trade capture systems and related transaction documentation. EEI also recommends that the requirement for trade date apply only to transactions entered into after the Commission adopts a final rule.[154]

89. EPSA asks the Commission to clarify whether RTO or ISO sales are included in the date/time reporting requirement as these transactions do not meet the Commission's proposed definition of agreement of the parties upon a price because RTO or ISO mitigation schemes may alter awarded prices, which are not known to the market participant and are not received until after the flow data. EPSA notes that in its NOI comments it expressed concern that the date parties agree to a price is not synonymous with the transaction date. EPSA adds that there are several elements apart from price, including volume, point of delivery, nature of firmness, credit terms, duration, enabling agreement status, upon which the parties must reach agreement before they execute that trade. EPSA states that ''[i]f the final rule makes time and date determinations based on the setting of price there will be a need to clearly explain how that is done for the many scenarios in the power business; only with this additional explanation can complying entities ensure that EQR data is not only transparent but useful.''[155] Entergy questions the usefulness of the trade date and notes examples of situations where the price in effect when the transaction was entered would not be the rate when the transaction began.[156] Entergy adds that, for hourly market sales, a trade date would be difficult to determine because it may be subject to review and agreement at a later date.[157]

(1) Commission Determination

90. The Commission adopts, with modification, the NOPR proposal to require reporting of the trade date in the EQR. The NOPR proposed to define the trade date as the date on which parties

Billing Adjustment (BA) designates an incremental material change to one or more transactions due to a change in settlement results. BA may be used in a refiling after the next quarter's filing is due to reflect the receipt of new information. It may not be used to correct an inaccurate filing. *See* Order No. 2001–G, 120 FERC ¶ 61,270 at P 33.

[149] Order No. 2001–E, 105 FERC ¶ 61,352 at PP 9–10.

[150] Order No. 2001–G, 120 FERC ¶ 61,270 at PP 33–34.

[151] *Id.*

[152] *See, e.g.,* DC Energy at 4–5; Joint Market Monitors at 4–5; and Pennsylvania Commission at 4.

[153] Powerex at 14.

[154] EEI at 12–13.

[155] EPSA at 7.

[156] Entergy at 2 (''while a rate may be arranged at the outset, changes in tariff rates and other circumstances may affect the rate between the time the transaction was made and the date the transaction flows'').

[157] *Id.* at 2–3. Entergy provides the example of a price for an hourly market sale being agreed upon during the day ahead or on an hourly basis, but the final prices being subject to review and agreement at a later date. *Id.* at 3.

to a reported transaction agreed upon a price. We will clarify this definition of trade date, as suggested by EEI, to state that it is ''the date upon which the parties made the legally binding agreement on the price of the transaction.''

91. As stated in the NOPR, the trade date for transactions currently is not provided or collected publicly.[158] The trade date is essential to assessing the significance of prices in relation to market conditions in effect at that time. The EQR only collects the start and end date of physical transactions as well as other data details for contracts. In current EQR filings, trades entered into months before the transaction start and end dates are indistinguishable from trades entered into minutes before the transaction occurs, making it difficult to determine whether pricing is appropriate given market conditions. In addition, many of the prices reported in the EQR result from confirmation made under master agreements and the prices are not set in the contracts themselves, so the Commission is not able to determine from EQR data when the price was set. The Commission concludes that requiring market participants to report the date on which parties to a reported transaction agreed upon a price (trade date) is necessary to improve market transparency. The trade date should be reported in the EQR transaction section accompanied by each specific sales transaction.

92. We further clarify that, in cases where pricing detail is provided in the contract description, the Contract Execution Date should be considered the trade date. Where applicable, this clarification will virtually eliminate any additional burden associated with this field by allowing the filer to complete the trade date field for each transaction by using a date (Contract Execution Date in the contracts section) already provided in the filing. It also will obviate the need to identify whether this requirement applies to transactions with trade dates before the initial filing that includes this field. It is unlikely that a transaction will occur during or after the first filing under these new rules that both became legally binding before the effective date of this Final Rule and does not have an appropriate Contract Execution Date already reported.

93. In response to EPSA, we clarify that RTO and ISO transactions do, in fact, reflect an agreement of the parties upon a price. Parties are legally bound by the terms of the relevant RTO or ISO tariff and sellers agree to sell a product at the price at which their offer is awarded. Although the price may be altered after it is awarded due to the application of mitigation or other RTO or ISO market rules, we clarify that the trade date should reflect the price at the time of the initial award. RTOs and ISOs operate a number of different markets where similar products are offered. For example, energy can be offered day-ahead or real-time. Capacity is offered monthly, annually and several years in advance. In each of these cases, the addition of a trade date will help the Commission and the public gain a better understanding of the market environment in which a given transaction was consummated.

94. In response to Entergy's concern about hourly transactions being changed at a later date, we clarify that filers are expected to identify the price associated with the transaction as it was agreed to. If there is some disagreement or uncertainty between the parties regarding the terms of the transaction on the ''trade date,'' the Commission has promulgated a refiling policy to allow the selling party to correct those terms when the disagreement is settled or the uncertainty is eliminated. Correcting the reporting, however, does not change the fact that the reported transaction occurred because the parties to the transaction had agreed to something on a given date. That date would not change even if the parties' understanding of what they agreed to evolves.

95. In addition, in response to EEI's suggestion that the Commission should hold a technical conference to discuss the requirement for trade date data, the Commission notes that it intends to convene a staff-led technical conference following issuance of this Final Rule, to be announced at a future date, to discuss the additional fields required under this Final Rule, including the field for trade date.

(b) Time of Trade

96. Several commenters indicate concerns about the NOPR's proposal to require market participants to report the time of trade. Some commenters contend that the time of trade, defined in the NOPR as the time upon which parties agree upon the price of a transaction, can be difficult to identify definitively.[159] Certain commenters argue that the time parties agree on price may not be the time the trade occurred or was finalized.[160] For example, EDF Trading states that parties may agree to the price or pricing mechanism hours or even days before they come to an agreement regarding other material terms of the transaction, meaning that the time upon which parties agree upon the price of a transaction frequently will not correspond to the time at which parties execute or confirm that transaction.[161]

97. Several commenters also state that the actual price of a transaction may be subject to revision even after parties have reached agreement on the price.[162] For example, Westar asserts that if a market participant is party to a liquidated damages contract and the transaction is curtailed, the party will not know the price of the contract until weeks after the power is delivered.[163] Entergy states that rates for future transactions may be affected by changes in tariff rates and other circumstances between the time when the transaction was made and the date the transaction flows. Further, Entergy states that some hourly market sales may have final prices that are subject to review and agreement at a later date.[164] Finally, EPSA states that the Commission needs to clarify whether RTO or ISO sales are included in the date/time reporting requirement as these transactions do not meet the Commission's proposed definition of agreement of the parties upon a price.[165]

98. Some commenters also indicate that existing trade capture systems are not set up to capture the time of trade.[166] For example, Powerex states that the time of trade is not currently recorded and significant work would be required to record time of trade, which would need to account for trades made verbally.[167] EDF Trading states that under its existing systems and procedures, a trader gathers information regarding each transaction as he or she completes it, but does not enter the details of each transaction until later in the day when the trader has completed most trading activities. EDF Trading states that its electronic system creates a time stamp as soon as a trader enters a transaction and this system generates information reported in EDF Trading's EQRs. EDF Trading asserts that, if the

[158] NOPR, FERC Stats. & Regs. ¶ 32,676 at P 91.

[159] *See, e.g.,* EDF Trading at 7; EEI at 10–11; Entergy at 2–3; EPSA at 6–7; Pacific Northwest IOUs at 2; Westar at 2.

[160] *See, e.g.,* EDF Trading at 7; EEI at 10–11; Entergy at 2–3; EPSA at 7.

[161] EDF Trading at 7.

[162] *See, e.g.,* Entergy at 2–3; EPSA at 6–7; Westar at 3.

[163] Westar at 3.

[164] Entergy at 2–3.

[165] EPSA at 6 (''ISO/RTO mitigation schemes sometimes alter awarded prices, which are unknown to the market participant and are not received until substantially after the flow date.'').

[166] *See, e.g.,* EDF Trading at 7–8; EEI at 9; Entergy at 1–2; EPSA at 5; Financial Institutions Energy Group at 7; Pacific Northwest IOUs at 2; Powerex at 14; Shell Energy at 8; Westar at 3.

[167] Powerex at 14.

Commission requires market participants to report time of trade information, traders will be forced to interrupt their trading activities to enter each trade into the system electronically as soon as parties agree on pricing. According to EDF Trading, such a requirement would eliminate flexibility, reduce trading opportunities, potentially increase the bid/ask spreads, and impose additional time burden on traders during the trading day, the time of day when the markets are at their most active.[168] Similarly, EPSA states that a new requirement to log times will inhibit desk personnel and frustrate liquid markets.[169]

99. Financial Institutions Energy Group states that time of trade data may be prone to inaccuracies, noting that errors may arise from such factors as clocks that run slow or fast, clocks that are not synched, traders forgetting to look at the time or write it down, time zone confusions, and illegible handwriting. Financial Institutions Energy Group adds that the time on a time-stamped trade confirmation from a third party entity, such as a broker, cannot be independently verified.[170]

100. EEI and Powerex urge the Commission not to apply the proposal to report time of trade to existing transactions. Powerex states that it has some transactions that will continue to be reported to the Commission for years to come and it is not sure how to identify the time of trade for these long-term transactions.[171] Likewise, EEI suggests that the requirement should only apply prospectively for transactions entered into after the Commission adopts the final rule in this proceeding.[172]

101. EEI also suggests that the Commission hold a technical conference to: (1) Explore the need for time of trade or trade date data; (2) gain a better understanding of impacts on EQR filers and affected systems; and (3) ensure that any such reporting requirement is carefully tailored to maximize benefits while minimizing the burden on reporting entities.[173]

(1) Commission Determination

102. The Commission will not require the time of trade, as proposed in the NOPR. As noted in many comments, it may be difficult to specify definitively the time at which parties agreed upon the price of a transaction and the actual price of the transaction may be revised after parties have agreed on the price. In addition, certain commenters expressed concern that existing trade capture systems are not set up to capture the time of trade and such a requirement may impose additional time burden on market participants. In light of these comments, the Commission has determined not to require reporting of the time of trade.

(c) Type of Rate

103. EEI questions the need for information regarding the type of rate for each transaction and contends that the specific nature of the rate involved in a transaction can already easily be determined using the Contract Service Agreement ID information provided in the EQR contract data. In addition, EEI argues that the burden of providing rate type information separately will outweigh its value and asserts that rate type information may be difficult to specify, will be of little use, could be misleading, and will cause errors.[174] EEI states that, if the Commission requires rate type information, the Commission should allow substantial flexibility, recognizing the wide variety of rates currently in use.[175]

104. Finally, EEI asks for clarification as to what type of rate would apply to the following examples: (1) A formula rate with a gas or fuel index (or any other index that is not an energy or capacity index); (2) a rate used for an exchange agreement where one party pays an additional charge in addition to supplying return energy; (3) a rate structure that goes up (and/or down) a stated amount each year; and (4) a formula that is tied to an RTO price, i.e., the greater of the RTO price or the contract price.[176]

(1) Commission Determination

105. The Commission adopts the NOPR proposal to require the type of rate by which the price was set for each transaction to be reported in EQR, with slight modifications to the terms used to describe the types of rates. Specifically, the names proposed in the NOPR, ''fixed price,'' ''formula,'' ''index,'' and ''RTO/ISO price'' will be changed to ''fixed,'' ''formula,'' ''electric index,'' and ''RTO/ISO,'' as discussed below. For many of the same reasons discussed above in relation to trade date, the Commission disagrees with EEI's assertion that the information provided in the EQR contract data is sufficient for the Commission to discern which transactions belong to which of the following four types of rates proposed: ''fixed,'' ''formula,'' ''electric index,'' and ''RTO/ISO.'' The contract section of the EQR is incomplete in terms of identifying the manner in which the rate on a given transaction is calculated. Further, where a rate is detailed, the rate descriptions are entered as free-form text providing no opportunity to compare across similar transactions. For the many transactions without detailed rate descriptions, on the other hand, rate type will provide critical information not contained in the current filings.

106. Obtaining information about the type of rate associated with each transaction is critical to understanding the role of transactions within the market. Like the trade date, rate type will allow interested parties to better understand the market context of a given transaction. For instance, was the price a fixed number that both parties agreed on or an indexed number that was determined by the market? This distinction is particularly important in identifying potential market manipulation where fixed price transactions may be used to affect larger, index-priced positions. For these reasons, the Commission will require types of rates to be reported in a separate field in the EQR. The type of rate should accompany each specific sales transaction and be reported in the EQR transaction section.

107. EEI's comment that specifying the type of rate may be difficult for certain transactions is noted. To provide clarification, the following description will be referenced in the EQR Data Dictionary and one of the names of one of the rate type options will be changed. If the price is the result of an RTO/ISO market and the sale is made to the RTO/ISO, its rate type is ''RTO/ISO.'' If no variables are used to determine the rate, it should be marked as ''fixed.'' This would include transactions where the specific price is stated or a specific price with a predetermined escalator is provided (e.g., $35.00/MWh, increasing by 2 percent each year). Under a transaction classified with the rate type ''fixed,'' both parties would know on the trade date the exact price of the product(s) in that transaction.

108. If the transaction uses an electric-based index in any way, either as a base price or as a means to determine a basis, it should be identified as an ''electric index.'' This represents a clarification from the NOPR which included the

168 EDF Trading at 7–8.

169 EPSA at 5.

170 Financial Institutions Energy Group at 8.

171 Powerex at 14.

172 EEI at 13.

173 *Id.* at 14.

174 In particular, EEI notes that reporting rate type will require EQR filers to determine: whether a formula rate with a gas or fuel index (or any other index that is not an energy or capacity price index) is an ''index'' or ''formula'' rate; what rate type to use for an exchange agreement; and what to report if a trade is a combination of types. *Id.* at 15.

175 *Id.* at 14–15.

176 *Id.* at 15.

broader rate type ''index.'' If the price in the transaction is otherwise determined by a formula, including a formula that uses indices that do not describe specific electric prices, such as a cost of living index or coal or natural gas prices, it should be designated as rate type ''formula.'' In summary, the Commission will adopt this field with the following limited list of rates that are appropriate for this field: ''fixed,'' ''formula,'' ''electric index'', and ''RTO/ISO.''

b. Resale of Financial Transmission Rights in Secondary Markets

i. NOPR

109. In the NOPR, the Commission declined to require entities to report information about financial transmission rights in the EQR.

ii. Comments

110. The NOPR proposal not to collect information in EQRs about resales of financial transmission rights was supported by all who commented on the matter. EEI states that collecting this information would not significantly improve price transparency.[177] Financial Institutions Energy Group states that the burden imposed by adding a new reporting requirement for FTR trades in secondary markets would not be justified by the minimal value of the data.[178]

iii. Commission Determination

111. As indicated in the NOPR, requiring financial transmission rights data to be reported by market participants in the EQR, in addition to the information already provided by RTOs and ISOs, would not significantly improve price transparency in these markets. Although little information is available on secondary sales of financial transmission rights, there is also little evidence of an active secondary market. For these reasons, the Commission will not require reporting of secondary sales of FTRs at this time, but will continue to monitor market developments if in the future such a requirement becomes necessary.

c. Standardizing the Unit for Reporting Energy and Capacity Transactions

i. NOPR

112. In the NOPR, the Commission proposed to include a new field in the EQR transaction section to standardize the units for reporting energy and capacity within the EQR. Specifically, the Commission proposed to require a market participant to report energy transactions as $/MWh and capacity transactions as $/MW-month.

ii. Comments

113. Financial Institutions Energy Group and Joint Market Monitors support the NOPR proposal to use standardized units of $/MWh and $/MW-month for reporting energy and capacity transactions, respectively.[179] Joint Market Monitors state that standardization will avoid the considerable time and resources spent by analysts to ensure than the units conform before conducting any meaningful analysis.[180] Joint Market Monitors also state that, in some cases, the proposed standardization is needed so that the data reported can actually be utilized. Pennsylvania Commission supports the proposal to standardize units insofar as having common units for reporting energy and capacity will simplify data interpretation.[181]

114. Several commenters recommend revisions or clarifications to the NOPR proposal to standardize units. EEI agrees that common units for reporting energy and capacity transactions would simplify interpretation of the data, but requests clarification that such conversion consist only of KWh to MWh and KW to MW (i.e., filers can still report transactions in MW-Month, MW-Day, KVA, MVAR, etc.). EEI also states that some entities report capacity in KVAR and other units that do not easily convert to MW and certain rates, such as backup rates, may not fit well with standard units. As such, EEI suggests that the Commission also allow reporting in alternative units while encouraging EQR filers to use standard units if logical and feasible. In addition, EEI notes that the Commission will likely have to increase the number of digits in the ''Rate'' field to accommodate reporting in MWh.[182]

115. Entergy asserts that it currently reports transactions in accordance with the units used in the underlying contracts; thus many of the transactions it reports would require translation to match the proposed standardization. Entergy suggests that the Commission consider modifying the EQR software to include an automatic conversion formula to reduce errors and inconsistencies that would result from each reporting entity developing its own conversions.[183]

iii. Commission Determination

116. The Commission generally adopts the NOPR proposal to standardize the units for reporting energy and capacity sales within the EQR transaction section. In the NOPR, the Commission proposed to add a new field to capture a common unit for reporting energy and capacity transactions. However, instead of adding only one field, the Commission will include two new fields to the EQR transaction section and will require filers to standardize the units for reporting both prices and quantities for energy, capacity, and booked out power transactions within the EQR. Accordingly, filers must specify the quantity for energy in MWh and the price for energy in $/MWh. Filers must specify the quantity for capacity as MW-month and the price for capacity in $/MW-month. For booked out power transactions, filers must use the same quantity and price conventions associated with energy or capacity, as appropriate.

117. Standardized units will provide greater transparency and facilitate the Commission's and public's ability to analyze EQR data. Specifically, with price and quantity expressed consistently across all filings, EQR filers and users will benefit from the increased ease of comparing data for analysis and quality control. The Commission notes that, in 2011, energy sales were reported in the EQR approximately 1 percent of the time in units other than $/MWh and that capacity sales were reported in the EQR 86 percent of the time in units other than $/MW-month. In the case of energy transactions, these statistics refute Entergy's assertion that many of the transactions reported in the EQR would require translation. In response to EEI's comment, we recognize that some entities currently do not report in units that can be easily converted to $/MWh for energy and $/MW-month for capacity, however, we note that such conversions are even more difficult, if not impossible, for entities not actually involved in the transaction, including the Commission and the public. The Commission will ensure the appropriate number of digits in the EQR software to accommodate the conversion.

118. The Commission rejects Entergy's suggestion that having the EQR software do the data conversion would eliminate some of the potential

177 EEI at 8.

178 Financial Institutions Energy Group at 4.

179 Financial Institutions Energy Group at 3–4; Joint Market Monitors at 5–6.

180 Joint Market Monitors at 5–6. (stating that ''a substantial portion of bilateral capacity sales in the California ISO's markets have been reported without any indication of the amount of capacity (MW) covered by the sale,'' rendering such data ''useless'').

181 Pennsylvania Commission at 5.

182 EEI at 16.

183 Entergy at 3.

errors that might arise in having filers convert their own data from the units specified in the underlying contracts. There are many simple conversions that the EQR software could make. However, in certain instances, there may be insufficient information for the EQR software to accurately perform conversions. For example, capacity transactions are commonly reported in a ''flat rate'' price with a quantity of ''one.'' Transactions reported in this manner do not provide sufficient information regarding the price of a transaction and do not allow for conversion to a standardized unit. Adding new fields that display standardized prices and quantities will address these issues.

d. Omitting the Time Zone From the Contract Section of the EQR

i. NOPR

119. The Commission proposed to eliminate the Contract Time Zone (Field Number 45) from the EQR.

ii. Comments

120. The NOPR proposal to eliminate time zone information in the contracts section was supported by those that commented on the matter.[184] EEI states that time zone information is unnecessary and that eliminating it will reduce burden on filers.[185]

iii. Commission Determination

121. The Commission agrees with commenters supporting the elimination of the Contract Time Zone (i.e., currently Field Number 45) from existing EQR requirements. We find that this information is unnecessary and its elimination will reduce filers' burden. The Commission will, however, continue to require EQR filers to report the time zone where the transaction took place in the transaction section (i.e., new Field Number 56).

2. Additional EQR Enhancements

a. Identify Transactions Reported to Index Publishers

i. NOPR

122. The Commission proposed to require all market participants that are required to file an EQR to report in the transaction section of the EQR the particular electric or natural gas index price publisher to which they have reported their sales transactions, if applicable. The Commission also proposed to eliminate the requirement, under 18 CFR 35.41(c), that a market-based rate seller notify the Commission whether it is reporting transactions to an electricity or natural gas index publisher.

ii. Comments

123. DC Energy, Joint Market Monitors, and Pennsylvania Commission support the Commission's proposal to require all EQR filers to report in the transaction section of the EQR the index price publisher(s) to which they have reported their sales transactions.[186] Joint Market Monitors state that information about reporting to an index publisher will assist transparency in pricing.[187] Pennsylvania Commission states that such information is critical to better enable the Commission to understand how index prices are established and how market forces affect index prices.[188]

124. Other commenters assert that, if adopted, the proposal to identify every transaction reported to index publishers would result in a manual, burdensome process.[189] For example, EEI states that not all trades are reported to index publishers and that information on whether a trade is reported is not usually captured on a trade-by-trade basis in company trade capture systems. As such, EEI states that this proposal would require significant changes to business processes and systems as well as create a disincentive for companies to report transactions to index publishers.[190] EPSA states that the NOPR does not clearly state whether companies would report the names of publishers to whom they report generally or if they have to identify a publisher's name for every transaction that has been reported. EPSA argues that reporting the index publisher name for every transaction would be a difficult and expensive manual process.[191]

125. Financial Institutions Energy Group suggests that the Commission clarify that reporting entities have no responsibility for how brokers or trading facilities may use their data. Specifically, Financial Institutions Energy Group contends that if a broker elects to publish a daily index using information from trades it completed on behalf of its customers, reporting entities cannot be responsible for disclosing such use in any reporting notice or for trying to discern which of their trades were or were not included in the index.[192]

126. Certain commenters recommend alternatives to the Commission's proposal. EEI suggests an alternative proposal that would require an EQR filer to identify, in a general statement, the index publishers to which the filer provides transactional information and the types of transactions reported. Shell Energy similarly suggests that, instead of requiring sellers to identify the index developer to which a transaction was reported, the Commission could require that EQR filers reporting to index publishers make their reporting criteria available to the Commission.[193] Financial Energy Institutions Group also urges the Commission to retain the practice of requiring sellers to alert the Commission on their reporting status at a more generalized level, and, if needed, require additional detail in a reporting status statement. In addition, Financial Institutions Energy Group proposes that the Commission could embed these status reports in the EQR, somewhat like it has in FERC Form 552 for natural gas trades.[194]

iii. Commission Determination

127. The Commission will adopt the proposal in the NOPR to require all filers to report in the EQR the index price publisher to which they have reported their sales transactions, if applicable, with modifications. In light of comments by EPSA, EEI, Financial Institutions Energy Group and Shell Energy, expressing concern that identifying each applicable transaction in the transaction section would result in a manual and burdensome process, the Commission will allow index publisher information to be reported more generally, in the ID data section of the EQR, instead of on a transactional basis. Specifically, EQR filers should report in the ID data section of the EQR whether their transactions are reported to an index publisher, and if so, which index publisher(s). In addition, if EQR filers report specific types of transactions to index price publisher(s), they should specify the type(s) of transactions that they report.

128. For the reasons stated in the NOPR, the Commission believes that requiring filers to identify the index price publishers in the EQR to which they report their wholesale sale transactions would provide the Commission, market participants, and the public with greater transparency

[184] *See, e.g.,* EEI at 8–9; Financial Institutions Energy Group at 4.

[185] EEI at 8–9.

[186] *See, e.g.,* DC Energy at 4–5; Joint Market Monitors at 4–5; Pennsylvania Commission at 5.

[187] Joint Market Monitors at 5.

[188] Pennsylvania Commission at 5.

[189] *See, e.g.,* EEI at 16–17; EPSA at 8–9; Financial Institutions Energy Group at 10; Shell Energy at 8–10.

[190] EEI at 16–17.

[191] EPSA at 8–9.

[192] Financial Institutions Energy Group at 10.

[193] Shell Energy at 10.

[194] Financial Institutions Energy Group at 9.

into the market forces affecting those index prices and the level of companies' sales used to calculate the index prices.[195] In addition to market participants' significant use of index prices in contracting for sales in the physical electricity market, the use of index prices has expanded to forming settlement prices for financial products.[196] Given that physical spot markets are used to settle financial swaps, there is an incentive to manipulate the physical markets to benefit larger financial positions.[197] We find that greater transparency will further our understanding of how index prices are formed, thereby enhancing public confidence in their accuracy and reliability, improving the Commission's ability to monitor price formation in wholesale markets and potential exercises of market power and manipulation, and helping to ensure robust indices.[198]

129. Moreover, obtaining information from market participants, not only jurisdictional power sellers with market-based rate authorization from the Commission, about the sales reported to specific index publishers will strengthen the Commission's and public's ability to determine whether these index prices reflect market forces and provide market participants with greater confidence in the accuracy of index prices.[199] Therefore, we will require each EQR filer to report in the ID Data section the particular index publisher to which they report transactions, if applicable, and specify the types of transactions reported to the index publisher(s), if applicable. To the extent an EQR filer identifies only the name of an index publisher(s) in the ID data section of the EQR, the Commission expects the index publisher(s) reported in the EQR to reflect the entity or entities to which the market participant is reporting all of its trades.

130. To eliminate redundancy between the EQR filings and the notification required under 18 CFR 35.41(c) from market-based rate sellers,[200] we will amend that provision to no longer require notifications from these sellers to the Commission stating whether they are reporting transactions to electricity or natural gas index publishers, or updates of such notifications. The Commission has attached a list of index price publishers in Appendix G that filers can choose from in a restricted data field. We acknowledge that the index price publisher list may change from time to time. Therefore, consistent with notification of changes to the list of entries for other restricted fields in the EQR, Commission staff will email all EQR filers any future changes to the list of entries contained in the index publisher fields and post these changes on the EQR page of the Commission's Web site.[201] In addition, to assist the Commission in keeping the list of index publishers current, we expect filers to notify Commission staff by emailing *eqr@ferc.gov* if they begin reporting to an index publisher that is not listed in the EQR.

131. Since the requirement to identify index publishers is intended to reveal transactions that affect other index-based market instruments (e.g., transactions that settle using a published index price), the Commission will clarify, as requested by Financial Institutions Energy Group, that it will not apply to broker-published indices that are provided to the broker's clients. Finally, we clarify at Financial Institutions Energy Group's request, that the Commission is not requiring EQR filers to track, and report on, how brokers or trading facilities are using data from their transactions. However, we will require EQR filers to report which transactions were consummated using an exchange or broker service, as discussed below.[202]

b. Identify the Exchange/Broker Used to Consummate a Transaction

i. NOPR

132. The Commission proposed to require market participants to report in the EQR whether a market participant used an exchange or a brokerage service to consummate a transaction.

ii. Comments

133. DC Energy, Joint Market Monitors, and Pennsylvania Commission support the Commission's proposal to require all EQR filers to report information regarding whether exchanges or brokers were used to consummate a transaction.[203] In particular, Joint Market Monitors state that information about the involvement of brokers will assist in understanding the complicated relationship between Commission-jurisdictional markets and closely-related financial markets.[204] As with the proposal above to obtain information about index publishers, Pennsylvania Commission states that information about brokers and exchanges is critical to better enable the Commission to understand how index prices are established and how market forces affect index prices.[205]

134. EEI and EPSA state that broker and exchange information is not currently collected by most trade capture systems, so modification of the systems in order to meet the proposed requirement would add a significant burden.[206] However, Financial Institutions Energy Group states that its members generally capture broker and trading platform information for each trade in their trade capture systems.[207]

135. Several commenters assert that publicly reporting the name of the broker[208] or exchange[209] used to conduct a transaction may raise confidentiality concerns. EEI, EPSA and Financial Institutions Energy Group state that, depending on contractual terms, market participants may not have the ability to publicly disclose the name of a broker that was used or which transactions used a broker.[210] EEI states that revealing a broker's identity could lead to unwelcome solicitations by other brokers seeking new business.[211] To address confidentiality concerns, EEI and Financial Institutions Energy Group suggest that the Commission allow market participants to file their EQRs with a request for confidential treatment

[195] *See* NOPR, FERC Stats. & Regs. ¶ 32,676 at P 111.

[196] *Id.* P 112.

[197] For example, a market participant with fixed price financial-swap contracts could manipulate the physical index price by transacting power at a loss for transactions that contribute to the index. The market participant could profit from such activity because any loss from selling power that contributes to the index price could be more than offset by financial-swap gains resulting from moving the index price. *See id.*

[198] *See id.*

[199] *Id.* P 113.

[200] Section 35.41(c) of the Commission's regulations, 18 CFR 35.41(c), requires market-based rate power sellers to submit a notification to the Commission if they report transactions to electric or natural gas price index publishers. Section 35.41(c) of the Commission's regulations, 18 CFR 35.41(c), requires market-based rate power sellers to submit a notification to the Commission if they report transactions to electric or natural gas price index publishers. *See Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations,* 105 FERC ¶ 61,218, at PP 116–119 (2003).

[201] *See* Order No. 2001–G, 120 FERC ¶ 61,270 at P 5 (*citing Revised Public Utility Filing Requirements,* 106 FERC ¶ 61,281 (2004)).

[202] *See* discussion *infra* at § II.B.2.b.

[203] *See, e.g.,* DC Energy at 4–5; North American Market Monitors at 4–5; Pennsylvania Commission at 5.

[204] North American Market Monitors at 5.

[205] Pennsylvania Commission at 5.

[206] EEI at 17; EPSA at 10.

[207] Financial Institutions Energy Group at 11.

[208] *See, e.g.,* EEI at 17; EPSA at 9–10; Financial Institutions Energy Group at 11.

[209] Financial Institutions Energy Group at 11.

[210] EPSA at 9; Financial Institutions Energy Group at 11.

[211] EEI at 17–18.

when needed to avoid breaching confidentiality obligations.[212]

136. Finally, several commenters suggest clarifications to the Commission's proposal. EEI suggests that if the Commission does decide to collect information on broker and exchange use in the EQR, having a standardized list of codes for the exchange and brokers would help simplify reporting and analysis.[213] EPSA states that the Commission should clarify what specifically constitutes ''use.'' [214] Financial Institutions Energy Group notes that it assumes the NOPR's reference to ''exchanges'' refers to trading platforms like ICE.[215]

iii. Commission Determination

137. The Commission adopts, with modification, the NOPR proposal to require EQR filers to report whether an exchange or broker was used to consummate a transaction. As stated in the NOPR, exchanges and brokers routinely publish index prices composed of wholesale sale transactions that were consummated on their exchange or through their brokerage services.[216] Indices published by exchanges and brokers are used by market participants in contracting for sales in the physical electricity market and as a settlement price associated with financial products. By adding transparency as to how these indices are created, the Commission and the public will be able to better understand how these indices arrive at their published prices, thereby increasing public confidence in the indices, improving the Commission's ability to monitor price formation in wholesale markets and potential exercises of market power and manipulation, and helping to ensure robust indices.

138. For purposes of this rulemaking, we clarify that the term ''use'' of an exchange or broker encompasses instances where the exchange's or broker's services were used to consummate or effectuate a transaction. The term ''use'' does not cover instances where an index developed by an exchange or broker is used to identify or set the price for a transaction. We also clarify that ''exchanges'' refer to trading platforms like ICE or NYMEX. In addition, the Commission will provide a standardized list of codes for exchanges for EQR filers to use, as suggested by EEI. This list is included in Appendix H of the EQR Data Dictionary.

139. Certain commenters argue that publicly reporting the name of the broker or exchange may raise confidentiality concerns and suggest that the Commission allow requests for confidential treatment when market participants file EQRs. The transparency provisions of FPA section 220 require the Commission to balance the need to disseminate information to the public with concerns about confidentiality. The Commission must comply with Congress' directive that the rules to facilitate price transparency ''provide for the dissemination, on a timely basis, of information about the availability and prices of wholesale electric energy and transmission service to the Commission, State commissions, buyers and sellers of wholesale electric energy, users of transmission services, and the public.'' [217] However, the Commission must also ''seek to ensure that consumers and competitive markets are protected from the adverse effects of potential collusion or other anticompetitive behaviors that can be facilitated by untimely public disclosure of transaction-specific information.'' [218] Requiring filers to identify whether an exchange or broker was used to consummate a transaction provides for public dissemination of data that facilitates price transparency. We determine that the 30-day time delay after each calendar quarter in filing EQRs should prevent collusion or other anticompetitive behaviors that can result from untimely public disclosure of transaction-specific information. This finding is consistent with the Commission's determination in Order No. 2001 that the 30-day time delay in the filing of transaction-specific information in the EQR ''will greatly reduce the usefulness of the data as a tool for collusion.'' [219] Therefore, we find that the Commission has appropriately balanced the need for transparency with confidentiality concerns and, thus, we will not allow market participants to request confidential treatment for their EQR filings.

140. Given the use of exchanges in contracting for sales of electricity in physical markets and as a settlement price associated with financial products, we will require EQR filers to identify in the EQR the exchange used to consummate a transaction on a transactional basis. However, because broker-produced indices appear to be used less prevalently at this time by market participants and in light of commenter concerns that revealing the identity of a broker may encourage unwanted solicitation by brokers, the Commission will not require the names of the brokers to be disclosed. Instead, if a broker is utilized to consummate a transaction, the term ''BROKER'' shall be selected from the Commission-provided list in Appendix H of the EQR Data Dictionary.

141. Although EEI and EPSA indicate that broker and exchange information is not currently collected by most trade capture systems, we note that Financial Institutions Energy Group comments that its members generally collect this information. We expect that, on balance, the benefit of transparent pricing should outweigh the burden associated with developing automated systems to capture this data.

142. We acknowledge that the list of exchanges may change from time to time. Therefore, consistent with the notification of changes to the list of entries for other restricted fields in the EQR, Commission staff will email all EQR filers any future changes to the list of entries to the exchange fields and post these changes on the EQR page of the Commission's Web site.[220] In addition, to assist the Commission in keeping the list of exchanges current, we expect filers to notify Commission staff by emailing *eqr@ferc.gov* if they begin reporting to an exchange that is not listed in the EQR.

c. Collection of e-Tag ID Data

i. NOPR

143. The Commission proposed to require market participants to submit e-Tag IDs for each transaction reported in the EQR in the event an e-Tag is used to schedule the transaction.

ii. Comments

144. DC Energy, Joint Market Monitors, and Pennsylvania Commission support the Commission's proposal to require EQR filers to submit e-Tag IDs for each transaction reported in the EQR if an e-Tag is used to schedule the transaction.[221] However, as

[212] EEI at 17–18; Financial Institutions Energy Group at 11.

[213] EEI at 8.

[214] EPSA further states that in the NOPR, ''use'' of a broker could be construed as specifically using a broker's index to set the price of a transaction. Conversely, entities can also use a broker, EPSA states, without necessarily basing the price of the transaction on a broker index. EPSA at 10–11.

[215] Financial Institutions Energy Group at n.28.

[216] NOPR, FERC Stats. & Regs. ¶ 32,676 at P 114.

[217] 16 U.S.C. 824t(a)(2).

[218] *Id.* 824t(b)(2).

[219] Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at PP 17, 122; *see also* Order No. 2001–A, 100 FERC ¶ 61,074 at PP 19–21.

[220] *See* Order No. 2001–G, 120 FERC ¶ 61,270 at P 5 (citing *Revised Public Utility Filing Requirements,* 106 FERC ¶ 61,281 (2004)).

[221] *See, e.g.,* DC Energy at 4–5; Joint Market Monitors at 4–5; Pennsylvania Commission at 5.

detailed below, some other commenters oppose the proposal.

(a) Burdens

145. Some commenters oppose the proposal based on anticipated burdens associated with inclusion of e-Tag IDs in the EQR.[222] EDF Trading anticipates that this new requirement could add as much as eight hours of additional work each day, or a full-time equivalent employee, and would require additional technology investments.[223] EPSA states that the proposal would require significant, if not exorbitant, system modifications; their members have reported that, at a minimum, two or more full-time employees may need to be hired to properly compile e-Tag data.[224] Financial Institutions Energy Group notes that e-Tag IDs are not included in their trade capture systems; therefore, matching e-Tag IDs and individual transactions would raise significant information technology, manual intervention and reconciliation concerns. Financial Institutions Energy Group's members conservatively estimate that complying with the NOPR proposals, with e-Tags accounting for the greatest expenditures, would cost between $55,000 and $400,000 per company to implement and between $2,500 and $10,000 per company each quarter.[225] Commenters also state that one utility has estimated that the proposed e-Tag ID data could require that company to hire two to three or more new full-time personnel to extract, review, and report the data, ultimately, at ratepayer expense.[226] Joint Commenters and LPPC also note that they are unaware of any available off-the-shelf software that could perform this function and that contracting with a software developer would likely be a multi-million dollar proposition.[227]

(b) Implementation Issues

146. Some commenters assert that e-Tag IDs would not be easy to match with individual transactions.[228] EDF Trading argues that e-Tags do not reflect transactions; they reflect the culmination of transactions.[229] Westar states that there can be multiple e-Tags for any given trade and, if the Commission imposes this requirement, what is now a single line of data in the EQR will become multiple lines of data, substantially increasing the volume and burden of the reporting requirement for market participants. Similarly, Financial Institutions Energy Group states that transactions and schedules may not always align because a particular trade may be associated with more multiple e-Tags.[230]

147. Powerex contends that compliance with the EQR proposal with respect to e-Tags would constitute a dramatic change in industry practice for many market participants because each trade would be required to be represented with one e-Tag. Powerex adds that such a major change would have significant consequences, including a dramatic reduction in market efficiency.[231]

148. TAPS states that joint action agencies' and G&T cooperatives' use of network transmission service or secondary network transmission service to deliver resources to dispersed network loads may produce confusing results when filed with an e-Tag ID in EQR. For instance, TAPS asserts that if a joint action agency's resource is supplying multiple members' loads located in a different Balancing Authority, one e-Tag may be used to transfer power between Balancing Authority Areas and would not identify the particular loads being served or the quantities of power being served to those loads.[232]

149. Some commenters state that the Commission's proposal to require EQR filers to submit e-Tag IDs in the EQR would result in an incomplete picture because not all transactions are scheduled using e-Tags.[233] TAPS states that the resulting reporting of e-Tag ID information for only a subset of sales will cause confusion rather than enhance transparency. According to TAPS, the absence of e-Tag data for transactions within a Balancing Authority Area severely limits the utility of requiring and reporting of e-Tag data for interchange transactions.[234]

150. Some commenters mentioned that e-Tag and transaction information is captured by different systems and by separate personnel, complicating compliance with the Commission's proposal.[235] For example, Financial Institutions Energy Group states that the functions of scheduling and trading are performed at different times and by different personnel, so that the path used to schedule and tag a specific flow does not always indicate what may have motivated the trader to execute the trade.[236]

151. Joint Commenters and LPPC are concerned that the burdens of reporting e-Tag IDs will outweigh the value of such information. They note that power sales contracts typically specify a point of delivery, which already is reported in the EQR. Further, they state that most power sales contracts do not specify source or sink information (thus, such information is not typically collected in trade capture systems) because that information is not needed for market participants to negotiate a transaction and agree on its terms.[237]

152. Some commenters also mentioned that certain parties may not be privy to e-Tag data.[238] As EDF Trading states, a market participant in the middle of the path would report the transaction on its EQR, but may not have recorded the e-Tag information and, as such, would not be able to report it. Also, EDF Trading states, if a counterparty is inadvertently omitted from a multiple party transaction e-Tag, the market participant may be unable to view the e-Tag.[239] EPSA similarly states that in many cases, the seller does not have direct access to e-Tag data because the seller is not involved in scheduling.[240]

153. EPSA also states that e-Tag data may be commercially sensitive. Specifically, EPSA contends that if e-Tag information is made public it would allow a competitor to trace the supply sources used for specific customers and use that information to lure the customer away from the supplier. EPSA also argues that e-Tag data typically includes multiple counterparties and, as such, e-Tag data is not only commercially sensitive but most contracts do not allow the release of data regarding counterparties.[241]

[222] *See, e.g.,* EDF Trading at 6; EPSA at 17; Entergy at 3; Financial Institutions Energy Group at 16; Joint Commenters at 4; LPPC at 12–13; Pacific Northwest IOUs at 2–3; Shell Energy at 5.

[223] EDF Trading at 6.

[224] EPSA at 17.

[225] Financial Institutions Energy Group at 16.

[226] EPSA at 17; Joint Commenters at 4; LPPC at 12–13.

[227] Joint Commenters at 4; LPPC at 13.

[228] *See, e.g.,* EDF Trading at 3–4; EPSA at 16; Financial Institutions Energy Group at 12; Joint Commenters at 3–5; LPPC at 12–13; Pacific Northwest IOUs at 2; Powerex at 5–10; Shell Energy at 6–7; TAPS at 16–17; Ronald Rattey at 11–13; Westar at 4–5.

[229] EDF Trading at 3.

[230] Westar at 4.

[231] Powerex at 10.

[232] TAPS at 16–17.

[233] *See, e.g.,* EDF Trading at 3; Entergy at 3–4; Financial Institutions Energy Group at 13 (''e-Tags are not created for movements within Balancing Authorities, but rather for movements between them.''); LPPC at 12; NRECA at 19; TAPS at 15–17.

[234] TAPS at 15–16.

[235] *See, e.g.,* Entergy at 3; EPSA at 14–15; Financial Institutions Energy Group at 12–14; Joint Commenters at 5; LPPC at 14; Ronald Rattey at 11–13; Shell Energy at 5.

[236] Financial Institutions Energy Group at 12.

[237] Joint Commenters at 3; LPPC at 11–12.

[238] *See, e.g.,* EDF Trading at 3–5; EPSA at 13–14; Westar at 5.

[239] EDF Trading at 5.

[240] EPSA at 13.

[241] *Id.* at 17.

154. Several commenters propose modifications to or clarifications of the NOPR proposal. Shell Energy suggests that, if the Commission ultimately decides to adopt the proposal to include e-Tag IDs in the EQR, it should limit this requirement to real-time transactions. According to Shell Energy, excluding long-term transactions for which numerous e-Tag IDs could be generated without a substantive difference in the transaction itself would reduce the reporting burden.[242] MISO seeks clarification from the Commission that the requirement to provide e-Tag data as part of the EQR is in fact limited to market participants and is inapplicable to RTOs and ISOs.[243] MISO comments that a potential inaccuracy in reporting e-Tag data could arise if it is required to report this information. Although MISO provides its market participants with transaction files containing the net position of import and export schedules at a given node, MISO states that a market participant may have several import and export schedules at a given node with each schedule having its own e-Tag, which is reported as only one net transaction in the EQR file. Therefore, according to MISO, if it were required to provide e-Tag IDs as required transaction data, MISO would report each schedule as a separate transaction in the EQR file, rather than a net position, thereby overstating the market participant's net position.

155. Finally, Shell Energy states that the proposal to include e-Tag ID data in the EQR is unnecessary because the Commission is proposing to receive that data from the North American Electric Reliability Corporation (NERC) in the rulemaking proceeding in Docket No. RM11–12–000.[244]

iii. Commission Determination

156. As stated in the NOPR, e-Tags are used to schedule physical interchange transactions and contain information about where the power is sourced and delivered; the responsible parties in the receipt, delivery and movement of the power; the timing; and the volumes and specified details regarding which transmission paths are used.[245] The e-Tag ID is a subset of information associated with a full e-Tag that consists of four components: (1) Source Balancing Authority Entity Code;[246] (2) Purchasing-Selling Entity Code;[247] (3) e-Tag Code or Unique Transaction Identifier;[248] and (4) Sink Balancing Authority Entity Code.[249] The Commission will adopt its NOPR proposal to require EQR filers to submit e-Tag IDs for each transaction reported in the EQR if an e-Tag was used to schedule the transaction. Filers should report in the EQR the e-Tag ID matched up to the Transaction Unique Identifier, Field No. 50 along with the start and end dates for the tags, as noted in Attachment A, EQR Data Dictionary.

157. The Commission is cognizant of an increased burden associated with a requirement to match transactions with associated e-Tag IDs in the EQR. We find that, on balance, this burden is justified given the importance of this information for facilitating price transparency in jurisdictional markets. Requiring e-Tags as part of the EQR will allow the Commission to fill a significant gap in the existing EQR information by enabling the identification of linked transactions and the source location of wholesale sales transactions. Using the current EQR information, it is difficult to identify linked re-sales or chains of transactions between filers. By identifying separate transactions that share e-Tag IDs and delivery timeframes, the Commission and the public will be able to better understand the links and chains between transactions.[250] Therefore, accessing e-Tag IDs through the EQR will facilitate price transparency by enabling all market participants and the Commission to "follow" transactions across markets.

158. Furthermore, the mark-ups observed for linked transactions are a valuable indicator of competitiveness in the wholesale market. Specifically, one would expect the arbitrage value to be closely associated with the cost to secure transmission between the linked transaction delivery points. Persistent price differences that are not consistent with transmission costs could indicate an opportunity for market participants to participate economically in that market or it could indicate a market inefficiency that needs to be addressed. Without knowing where power is being generated, it is difficult to determine whether an interchange transaction is the result of competitively arbitraging price separations between markets or anti-competitive or manipulative behavior.

159. In addition, since there is currently no way to connect wholesale sales in the bilateral markets to their source generation through public data or data available to the Commission, it is difficult to identify the economic value of transmission usage, particularly outside of RTO and ISO markets. For example, when transmission is curtailed, there is no way for the Commission or the public to understand the economic impact of curtailment to the customer. Production cost studies estimate the effect of transmission curtailments through an idealized representation of economic dispatch, which is not reflective of the actual value of the curtailed transactions. Knowledge of the actual market value of transmission service between two regions would reveal more precisely the true value of increasing transmission capacity. This increased market transparency would both signal the need for new transmission investment and aid regional transmission planning. For example, revealing differences in relative value would help stakeholders prioritize the selection of competing transmission projects within regional planning debates. Having the tools to reveal the actual market value of transmission service also could be used by stakeholders to justify, and the Commission to evaluate, transmission cost allocation proposals. Where the difference in wholesale energy prices at source and sink exceeds the cost of delivery through transmission service, net economic gains can be directly tied to the availability and use of transmission deliveries.

160. Requiring e-Tag IDs could further aid in the identification of loop flows (unscheduled flows). To the extent that energy is delivered using complex contract paths, one would expect some degree of unscheduled flows. However, Balancing Authorities typically only have access to e-Tags that source, sink or wheel through their Balancing Authority Areas. As such, a Balancing

[242] Shell Energy at 7.

[243] MISO at 4.

[244] Shell Energy at 6 (citing *Availability of E-Tag Information to Commission Staff,* Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,675 (2011) (E-Tag Availability Rulemaking)).

[245] NOPR, FERC Stats. & Regs. ¶ 32,676 at P 115.

[246] The Source Balancing Authority is the Balancing Authority in which the generation is located.

[247] The Purchasing-Selling Entity is the entity creating and submitting the e-Tag request to the authority service, which authorizes implementation of interchange schedules between balancing authority areas. The Purchasing-Selling Entity also is the entity that purchases or sells, and takes title to, energy, capacity, and interconnected operation services.

[248] The e-Tag Code is a unique seven-character transaction identifier for each bilateral energy transaction scheduled on the transmission network. It is assigned by the e-Tag system when transmission service to accommodate the transaction is reserved.

[249] The Sink Balancing Authority is the Balancing Authority in which load is located.

[250] For example, the Commission and the public would be able to identify that an energy trade from Company A to Company B and an energy trade reported by Company B to Company C are, in fact, a re-sale of power from Company A to Company C because both sales would reflect the same e-Tag ID.

Authority may not see unscheduled flows through their Balancing Authority Area from interchange schedules that do not source, sink or wheel through their Balancing Authority Area (and thus are invisible to them). Requiring e-Tag IDs in the EQR would allow entities to identify interchange schedules that are affecting their system. Balancing Authorities and others could then use EQR data after the fact to help identify if some of these schedules corresponded to instances of unscheduled flows through their Balancing Authority Area. This knowledge could help them address instances of unscheduled flows in the future and allow staff to evaluate more fully the merits of related proposals.

161. Given the range of productive uses for this information, the Commission concludes that requiring EQR filers to submit e-Tag IDs in the EQR is necessary and appropriate for the dissemination of information about the availability and prices of wholesale electric energy and transmission service.[251] The Commission acknowledges commenters' concerns that requiring EQR filers to submit e-Tag IDs in the EQR could result in an incomplete picture for a particular transaction because not all transactions are scheduled using e-Tags. However, it does not follow that the Commission should not require the submission of e-Tag IDs for those transactions that are scheduled using e-Tags. Moreover, the Commission finds that the absence of an e-Tag ID itself provides valuable information to the Commission and the public regarding the nature of the transaction. For instance, e-Tags are not generally used for energy schedules that are contained within one Balancing Authority Area. If a transaction is not scheduled using e-Tags, the filer would leave those fields blank. The EQR currently has several fields that may be left blank because they do not apply. If the e-Tag ID fields are left blank, then we would assume that they there is no e-Tag associated with the sale to report.

162. In response to concerns about the difficulty of aligning e-Tag IDs to a particular transaction given the one-line per transaction format in the current EQR database, the Commission is making technical changes to the existing EQR database to accommodate the relationships between a transaction(s) and associated e-Tag ID(s). The Commission recognizes that there may not be a one-to-one relationship between a transaction reported in the EQR and the e-Tag ID(s) associated with that particular transaction. Therefore, the Commission will design, as seen in Attachment A, a separate EQR database table to accommodate the possibility of a one-to-many, many-to-one, or many-to-many relationship between a transaction(s) and associated e-Tag ID(s). The Commission will incorporate these technical changes to the EQR database before this requirement is implemented. In addition, the Commission may provide guidance on how to match e-Tag IDs to specific transactions in the EQR, to the extent filers seek such guidance.

163. Regarding Shell Energy's request for clarification that long-term transactions should be excluded from an e-Tag ID requirement, we find that requiring e-Tag IDs for only short-term transactions would not achieve the Commission's transparency goals in this proceeding. Specifically, long-term contracts commonly do not include source location details. Instead, the transaction source location may be determined every day based on economics and operating conditions of the system. Accordingly, we find that including e-Tag ID details for all applicable transactions, regardless of duration, would benefit the Commission and other users of the EQR. In response to MISO, we clarify that the requirement to provide e-Tag IDs associated with transactions is imposed on market participants rather than RTOs and ISOs. However, as noted in Order No. 2001, RTOs and ISOs may file power sales transaction information on behalf of their members or market participants as an agent, if authorized to do so by the member or market participant.[252] MISO expresses concern about compiling reports for market participants with transactions and associated e-Tag IDs because market participants may have several import and export schedules at a given node, with each schedule having its own associated e-Tag ID, being reported as only one net import/export transaction in the EQR. As discussed above, the Commission will make design changes to the existing EQR database structure that can accommodate multiple schedules with multiple associated e-Tag IDs. We believe this will enable MISO to continue to compile reports for market participants with multiple transactions and associated e-Tag IDs, if requested by market participants to do so.

164. Certain commenters state that they may not be privy to e-Tag data, they may be omitted from a multiple party transaction if they are in the middle of the path, or they may be sellers that did not schedule a transactions and thus lack access to the e-Tag. We note that the NAESB Electronic Tagging Functional Specifications,[253] governing the implementation of the e-Tag process, specify that the e-Tag must contain the entities along the path associated with the tracking of title and responsibility. In particular, Section 2.6.1.1 (Submitting a New e-Tag Request) of the Functional Specifications provides that the ''e-Tag Author must write a complete representation of the transaction as defined in NERC/NAESB Standards and supported in Section 6, Data Model Overview.'' Section 6.1.2.2 (Title Transfers) of the Functional Specifications specifies that the market segments of an e-Tag ''represent those portions of the path that are associated with the tracking of title and responsibility.'' Therefore, the Commission expects that market participants would be able to access e-Tags associated with their transactions even if the market participant is in the middle of the path or does not necessarily schedule a transaction.

165. Contrary to EPSA's comments, we do not find that the e-Tag IDs required to be reported under this Final Rule contain confidential information. As described above, the e-Tag ID information required to be provided under this Final Rule is only a subset of the information contained in a complete e-Tag. In particular, e-Tag IDs capture the following information: The source Balancing Authority in which generation is located; a unique transaction identifier assigned by the e-Tag system when transmission service to accommodate the transaction is reserved; and the sink Balancing Authority in which load is located. By revealing the Balancing Authority from where the power originated, the e-Tag ID is not revealing information about specific supply sources or generators, as suggested by EPSA. Furthermore, we note that the e-Tag ID information required to be filed under this Final Rule identifies only one party, i.e., the author of the tag, or Purchasing-Selling Entity. The e-Tag ID does not, as suggested by EPSA, reveal multiple

[251] 16 U.S.C. 824t(a)(2).

[252] Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 336.

[253] E-Tags are implemented through the requirements set forth in the *NAESB Electronic Tagging Functional Specifications,* Version 1.8.1 (Oct. 27, 2009). The NAESB Wholesale Electric Quadrant (WEQ) Business Practice Requirement 004–2 states that the ''primary method of submitting the Request for Interchange (RFI) to the Interchange Authority shall be an e-Tag using protocols in compliance with the Electronic Tagging Functional Specification, Version 1.8.'' *See NAESB Wholesale Electric Quadrant (WEQ) Business Practice Standards* (Version 002.1), published March 11, 2009.

counterparties. For these reasons, the Commission believes that the information contained in e-Tag IDs is not confidential.

166. Shell Energy asserts that requiring e-Tag IDs under this Final Rule is unnecessary because the Commission proposes to receive e-Tag information in the E-Tag Availability Rulemaking. However, there are key differences between the requirement under this Final Rule for EQR filers to provide e-Tag ID information and the proposal for Commission staff to obtain complete e-Tags in the E-Tag Availability Rulemaking. Under this Final Rule, EQR filers must match up a specific transaction with a particular e-Tag ID, if applicable. By matching up the e-Tag ID with specific pricing information captured by the EQR, market participants would be able to identify the source location of a transaction because one component of the e-Tag ID is the source Balancing Authority where the power originated. EQRs currently capture only the delivery location of transactions. By revealing the source and sink locations of transactions, the EQR will allow the Commission and the public to see the path that the transaction took. This knowledge of the transaction path will help improve the ability of market participants and the Commission to determine the actual market value of transmission service and to identify scheduled paths that appear inconsistent with physical flows.

167. In contrast to this Final Rule's requirement for filers to provide e-Tag IDs in the EQR, the Commission proposes in the E-Tag Availability Rulemaking to obtain market participants' complete e-Tags. A complete e-Tag contains not only e-Tag IDs, but also information about transmission reservations, firmness, and transmission curtailments. The complete e-Tags would be made available to Commission staff, not the public, because they may contain commercially sensitive information.

d. Eliminating the DUNS Number Requirement

i. NOPR

168. The Commission proposed to eliminate the DUNS number requirement from EQR filings.

ii. Comments

169. Some commenters support the Commission's proposal to eliminate DUNS identification from the EQR.[254] EEI strongly supports the Commission's proposal to eliminate DUNS numbers from EQR because DUNS numbers have not proven to be a unique method to identify market participants.[255] Financial Institutions Energy Group states that its members have expended tremendous resources trying to determine the correct DUNS numbers to use. Financial Institutions Energy Group also suggests that future attempts to rely on counterparty identifiers should not be pursued unless the Commission is certain that only one such identifier will apply to each entity and that such an identifier is readily available to any entity with an EQR reporting obligation.[256]

170. Certain commenters suggest that the Commission replace DUNS with another system that allows for the unique identification of companies. DC Energy states that without either a DUNS number or some other mandatory uniform unique identifier, inconsistent reporting of company names in EQR would make it difficult to cross-reference across separate filers and/or periods.[257] Entergy proposes to report the name of the entity exactly as it appears on the reported contract in both the contract and transaction reports.[258] Joint Market Monitors consider it very important that the EQR permit ready and exact identification of the transacting parties and propose that filing parties report the precise legal name under which the participant is organized.[259]

iii. Commission Determination

171. The Commission adopts the NOPR's proposal to eliminate the DUNS requirement. The Commission required DUNS numbers in an effort to help ensure more precise identification of sellers and counterparties. However, DUNS numbers have proven to be an imprecise identification system, as entities may have multiple DUNS numbers, only one DUNS number, or no DUNS number at all. The Commission has considered various alternatives to the use of DUNS numbers, but finds none of the suggested approaches would provide a viable replacement. Accordingly, the Commission will continue to rely on the insertion of customer company names in the free-form fields, Field Numbers 16 and 48. In this regard, however, the Commission finds reasonable Entergy's suggestion to require reporting of the name of the entity exactly as it appears on the reported contract,[260] in both the contract and transaction sections. Therefore, we will revise the EQR Data Dictionary to reflect this change, as reflected in Attachment A. The Commission will also consider the possibility of requiring other types of unique identifiers in future and recognizes that there is, for example, an effort currently led by the International Standards Organization to promote standard legal entity identifiers.

e. Other Issues

i. Comments

172. Ronald Rattey states that the data the Commission proposes to obtain in this proceeding and the E-Tag Availability Rulemaking, are unlikely to give Commission staff the capability to prevent, monitor or stop abuses. According to Ronald Rattey, the major flaws in EQR reporting requirements are that the data is three or more months old before the Commission collects it and the EQR does not require purchase transactions to be reported.[261] Ronald Rattey suggests that the Commission should attempt to establish links between EQR, transmission contracts and reservations, and e-Tag scheduling data.[262] In addition, he recommends that the Commission access and use real-time generation and transmission supply and demand data.[263] Ronald Rattey also states that the Commission should access and analyze bid and offer data in RTOs and ISOs and develop the expertise to monitor financial markets.[264]

ii. Commission Determination

173. As discussed above, the Commission believes the information to be provided in this proceeding will improve the transparency of wholesale power and transmission markets in interstate commerce and strengthen the Commission's ability to identify potential exercises of market power or manipulation. This information, along with the e-Tag information proposed to be provided through the rulemaking proceeding on E-Tag Availability Rulemaking, and other resources and information, will also help the Commission staff to identify and address potential exercises of market power or manipulation.

[254] *See, e.g.,* EEI; Entergy; Financial Institutions Energy Group; North American Market Monitors; Powerex; Shell Energy.

[255] EEI at 9.

[256] Financial Institutions Energy Group at 4–5.

[257] DC Energy at 6.

[258] Entergy at 4.

[259] Joint Market Monitors at 5.

[260] The reported contract would exclude multi-lateral master agreements, such as the WSPP Agreement, consistent with the Commission's determination in Order No. 2001–G, 120 FERC ¶ 61,270 at P 14.

[261] Ronald Rattey at 3–7.

[262] *Id.* at 13.

[263] *Id.* at 16–17.

[264] *Id.* at 17.

174. The Commission disagrees that EQR data is flawed because there is a reporting lag. In Order No. 2001, the Commission determined that the lag of 30 to 120 days in reporting EQR data appropriately balances the Commission's and public's need for data transparency while preventing possible harm to competitors and misuse of the data.[265] The Commission continues to find that the existing reporting timelines are appropriate. Moreover, we find that the 30 to 120 day lag in EQR data helps to protect consumers and competitive markets from the adverse effects of potential collusion or other anti-competitive behaviors that can be facilitated by untimely public disclosure of transaction-specific information, consistent with FPA section 220(b)(2).

175. In addition, the Commission will not require the reporting of purchase transactions in the EQR. The Commission established the EQR in Order No. 2001 using its authority under FPA section 205(c) to require public utility sellers to file information showing their rates, terms and conditions of service. The Commission is extending EQR reporting requirements to non-public utilities above the *de minimis* threshold as part of this rulemaking, pursuant to its authority under FPA section 220, to require information that will facilitate price transparency in jurisdictional markets for the sale and transmission of electricity. Requiring purchase transactions to be reported in the EQR would go beyond the scope of this proceeding. Finally, the Commission notes that it already accesses and uses information about financial markets for energy to investigate possible manipulation of physical energy markets.

III. Information Collection Statement

A. Comments

176. Certain commenters argue that the NOPR's burden estimates are too low.[266] EEI contends that the estimates dismiss the burden on filers who are required to file every quarter even if they have no transactions to report. EEI also states that the estimates lump together filers within a corporate family even though each company that must file an EQR bears its own burden and different staff is often involved in filing information on behalf of each company. EEI further notes that, if any of the proposed additions to data are adopted, companies will have to undertake software re-programming and staff training, which would involve significant costs that do not appear reflected in the burden estimates. According to EEI, one company has estimated that computer programming changes alone will cost nearly 900 hours of staff time and more than $66,000 to design, develop and test necessary software. EEI states that another company has estimated the cost of changes to its software to be between $200,000 and $500,000, depending on the nature of the application changes and time frame for implementing them.

177. Financial Institutions Energy Group asserts that the Commission should take into account the true technological costs and challenges associated with coming into and maintaining compliance with the proposed reporting requirements. Financial Institutions Energy Group states that the NOPR significantly underestimates the changes that reporting entities would need to make to their information technology systems and procedures to comply with certain aspects of the proposed rules. Financial Institutions Energy Group states that its members conservatively estimate their own implementation costs to run between $55,000 to $400,000 per company, with e-Tags accounting for the greatest expenditures. In addition, Financial Institutions Energy Group estimates that the ongoing costs would range from $2,500 to $10,000 per company for each quarterly report. With respect to the time involved in implementing the proposed changes for current filers, Financial Institutions Energy Group states its members estimate their own implementation timelines range from 190 to 1350 man hours per company and an ongoing 48 hours per company for each quarterly report.

B. Commission Determination

178. In response to EEI, we note that most of the revisions to the EQR required by this Final Rule are transaction-related. The revisions that are not transaction-related, including the elimination of the DUNS number requirement and requirement to report the time zone for contracts, will reduce the burden of filing an EQR. Although the Commission is allowing a seller to indicate information related to index publishers in the ID Data section, companies without transactions would have no transactions to report and would simply enter ''no.'' Because contracts tend to remain consistent from quarter to quarter, the EQR allows filers to copy this information forward from one filing to the next. The EQR software will provide the capability to do this without copying forward the deleted fields in the contracts section (customer DUNS number and time zone), thereby minimizing additional burden.

179. In developing the burden estimates, the Commission took into account the fact that filers within a corporate family should be able to benefit from cost-sharing efficiencies (such as sharing staff and EQR filing software) unavailable to independent filers. For purposes of calculating the number of respondents, we are counting each individual respondent, even though many companies submit a single filing for a number of subsidiary entities or submit several filings through a single Agent. As a rudimentary example, there are 31 filings from companies with names that begin with ''FPL Energy,'' 23 with ''NRG,'' 19 with ''PPL,'' 16 with ''Calpine,'' 14 with ''GenOn,'' 13 with ''Covanta,'' 11 with ''Dynegy,'' and 11 with ''Georgia-Pacific'' and each identify the same person ''as the Agent, usually the person who prepares the filing.''[267] The Commission recognizes that not all corporate families take advantage of possible efficiencies through using common personnel to file the EQR, but it would appear that certain efficiencies are possible and should be accounted for in estimating the reporting burden.

180. In response to comments that the Commission did not account for the information technology changes required to implement these new requirements, Commission staff has increased the estimate of the additional one-time implementation burden to be 400 hours for each non-public utility, 240 hours for each current filer with transactions, and 1 hour for each current filer with no transactions. Commission staff has estimated the additional recurring burden for each quarterly filing to be 19 hours for each non-public utility, 16 hours for each current filer with transactions, and no change for current filers with no transactions. The Commission's estimates of the additional average reporting burden and cost[268] due to the Final Rule in Docket RM10–12–000 follow.

[265] *See* Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at PP 17, 122, *order on reh'g,* Order No. 2001–A, 100 FERC ¶ 61,074 at PP 19–21.

[266] *See, e.g.,* EDF Trading; EEI; Financial Institutions Energy Group.

[267] EQR Data Dictionary. Company Data.

[268] The burden and cost estimates provided are in addition to the estimates for the current EQR reporting requirements for current filers.

In the pending EQR Refresh rule in Docket No. RM12–3–000, for current EQR filers and current filing requirements, the staff estimates the average burden per respondent per quarterly filing to be: 32 hours for Companies within non-California RTO, and large companies within the California RTO; 80 hours for medium/small Companies within the California RTO; 3 hours for Companies not within

Continued

FERC–920, in the Final Rule in Docket RM10–12–000	Number of respondents	Number of responses per respondent per year	Estimated additional implementing (one-time) burden per respondent		Estimated additional recurring burden per respondent per response		Estimated additional average annual burden per respondent (implementation averaged over years 1–3)	
			Burden hours	Cost ($)	Burden hours	Cost ($)	Burden hours	Cost ($)
Current Public Utility Filers								
Companies within non-California RTO, and large cos. within Cal. RTO	405	4	240.00	17,214.00	16.00	829.28	144.00	9,055.12
Medium/small companies within Cal. RTO	20	4	240.00	17,214.00	16.00	829.28	144.00	9,055.12
Companies not within RTO	663	4	240.00	17,214.00	16.00	829.28	144.00	9,055.12
Companies with no transactions	695	4	1.00	71.73	0.00	0.00	0.33	23.91
New Non-Public Utility Filers								
Non-Public Utility, with >4 million MWH wholesale sales per yr	53	4	400.00	28,690.00	19.00	984.77	209.33	13,502.41

181. When averaging the one-time implementation burden and cost over Years 1–3, the total additional annual burden and cost for all filers (due to the Final Rule in RM10–12) are 167,998.33 burden hours and $10,584,214.76.

182. The Commission recognizes that there will be an initial implementation burden for the new non-public utility filers, and an initial implementation burden related to the new data for existing filers. To help with this implementation, the Commission intends to convene a staff-led technical conference, to be announced at a future date, to assist non-public utilities in collecting and filing EQR data. In addition, non-public utility filers are required to file EQRs beginning with the third quarter (Q3) of 2013, covering the period July through September 2013. Current filers also are required to file EQRs consistent with this Final Rule beginning with Q3 of 2013.

183. The Commission directs staff to assist filers with compliance. The technical conference and staff assistance should minimize the implementation burden.

Information Collection Costs: The estimates of the additional one-time implementation cost and recurring cost are provided in the previous table. The Commission staff has estimated the implementation cost using the following professionals, hourly costs, and the estimated percent of implementation time: [269]

- Legal staff (at $250/hour), 10 percent of the implementation time
- Senior accountant (at $51.38/hr.), financial analyst (at $68.12/hr.), and/or support staff (at $35.99/hr.), averaged at $51.83/hr., 10 percent of the implementation time, and 100 percent of the recurring burden
- Information technology analyst (at $57.24/hour), 60 percent of the implementation time
- Support staff (at $35.99/hr), 20 percent of the implementation time.

Title: FERC–920, Electric Quarterly Report (EQR) [OMB No.: 1902–0255] [270] *Action:* Proposed new EQR filers and additional reporting requirements for all filers.

Respondents: Electric utilities

Frequency of Responses: Initial implementation and quarterly filings (beginning Q3 of 2013).

Need for Information: The Commission is revising the EQR to facilitate price transparency in markets for the sale and transmission of electric energy in interstate commerce. The Commission is requiring market participants that are excluded from the Commission's jurisdiction under FPA section 205 and have more than a *de minimis* market presence to file EQRs with the Commission. In addition, the Commission is making revisions to the existing filing requirements to reflect the evolving nature of interstate wholesale electric markets, to increase market transparency for the Commission and the public, and to allow market participants to file the information in the most efficient manner possible.

Internal Review: The Commission has reviewed the proposed changes and has determined that the 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 assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

184. Interested persons may obtain information on the reporting requirements by contacting: 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 on the requirements of this rule may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk

an RTO; and 0.083 hours [5 minutes] for Companies with no transactions. Comments on the estimates for current burden and cost should be submitted in Docket No. RM12–3–000.

[269] Hourly average wage is an average and was calculated using Bureau of Labor Statistics (BLS), Occupational Employment Statistics data for May 2011 (for NAICS 221100—Electric Power Generation, Transmission and Distribution, at *http://bls.gov/oes/current/naics4_221100.htm#00–0000*) for the senior accountant, financial analyst, information technology analyst, and support staff. The average hourly figure for legal staff is a composite from BLS and other resources, taking into account the hourly cost for both in-house and contractor organizations.

[270] The Commission is establishing the FERC–920 (OMB Control No. 1902–0255) for the EQR reporting requirements and separating the EQR reporting requirements from the remaining reporting requirements under FERC–516 (OMB Control No. 1902–0096). Upon approval by OMB of the FERC–920, FERC plans to remove the EQR and corresponding burden hours for the recurring filings under the current EQR system from the FERC–516.

Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by email to OMB at *oira_submission@omb.eop.gov.* Please reference OMB Control No. 1902–0255, FERC–920, and Docket No. RM10–12 in your submission.

IV. Environmental Analysis

185. 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.[271] The actions taken here fall within categorical exclusions in the Commission's regulations for information gathering, analysis, and dissemination.[272] Therefore, an environmental assessment is unnecessary and has not been prepared in this rulemaking.

V. Regulatory Flexibility Act

186. The RFA [273] generally requires a description and analysis of final rules that will have significant economic impact on a substantial number of small entities. The RFA mandates consideration of regulatory alternatives that accomplish the stated objectives of a proposed rule and that minimize any significant economic impact on a substantial number of small entities. The SBA's Office of Size Standards develops the numerical definition of a small business.[274] The SBA has established a size standard for electric utilities, stating that a firm is small if, including its affiliates, it is primarily engaged in the transmission, generation and/or distribution of electric energy for sale and its total electric output for the preceding twelve months did not exceed 4,000,000 MWh.[275]

187. As discussed in Order No. 2000,[276] in making this determination, the Commission is required to examine only the direct compliance costs that a rulemaking imposes upon small businesses. It is not required to consider indirect economic consequences, nor is it required to consider costs that an entity incurs voluntarily.

188. For non-public utilities, the Commission will exempt under the *de minimis* market presence threshold non-public utilities that make 4,000,000 MWh or less of annual wholesale sales (based on an average of the wholesale sales it made in the preceding three years). This *de minimis* threshold will exclude small non-public utilities. Therefore, this Final Rule will not have a significant economic impact on any small non-public utility.

189. This Final Rule also adopts revisions to the existing EQR filing requirements, and thus will affect current EQR filers. Based on analysis of the EQR filings made in the four quarters of 2011, there are 1,783 entities that currently file an EQR, but given clearly identifiable affiliate relationships, that number is reduced to 1,215 entities. Of those, 97 reported more than 4,000,000 million MWh of wholesale sales in the EQR. Of the remaining 1,118 entities that reported less than 4,000,000 MWh of wholesales sales in the EQR, 641 filed transactions in the EQR. The rest that would be subject to this Final Rule, 477 entities, did not file transactions in any quarter of 2011; we conclude that this Final Rule will minimally affect them.

190. As for the remaining 641 entities, we note that there are two types of companies among those currently filing EQRs that merit additional consideration. First, there are investor-owned utilities that make both wholesale and retail sales. The SBA's definition of a small utility is based on a utility's total electric output for the preceding twelve months, which includes a utility's retail sales. However, our estimate in this section is based on information available in the EQR, which includes annual wholesale sales but not retail sales. If we were able to include retail sales, we believe that most investor-owned utilities that currently file EQRs make more than 4,000,000 annual wholesale and retail sales, and thus, would not be classified as small. Second, there are power marketers that often do not own or control generation or transmission, and may be affiliated with companies that are not primarily engaged in the sale of electric energy (such as financial institutions or hedge funds).[277] However, information regarding whether a power marketer is affiliated with a larger company is generally not included in an EQR filing, making it difficult to determine the number of small entities that are affiliated with a larger company, thereby leading to an inflated estimate of the number of companies affected by this Final Rule that are truly small.

191. Moreover, while the Final Rule adopts revisions to the existing EQR filing requirements, it does not create an entirely new reporting requirement for current EQR filers. Since 2001, the Commission has used the EQR filing requirement to meet its statutory obligation to have a public utility's rates on file.[278] The Commission also requires a company that has been granted market-based rate authority to file an EQR.[279] Thus, current EQR filers already have in place a system to capture and report EQR data, and will need to modify their systems rather than create an entirely new system. Any alternative means for meeting that obligation likely will entail greater burden than the electronic collection of transaction data that has been occurring in the EQR since 2002. In addition, we believe that the burden of complying decreases the smaller the filer is because it will have less information to report. Furthermore, we note that companies may request, on an individual basis, waiver from the EQR reporting requirements.[280] Thus, the Commission certifies that this Final Rule will not have a significant impact on a substantial number of small entities.

VI. Document Availability

192. 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 FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington DC 20426.

193. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document

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[271] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 486 FR 1750 (Jan. 22, 1988), FERC Stats. & Regs. ¶ 30,783 (1987).

[272] 18 CFR 380.4(a)(5).

[273] 5 U.S.C. 601–612.

[274] 13 CFR 121.101.

[275] 13 CFR 121.201, Sector 22, Utilities & n.1.

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

[277] Some of these such as Google, Occidental Chemical and ONEOK may not qualify as small in their primary area of business and are participating in the electric market as part of an overall corporate strategy.

[278] Order No. 2001, FERC Stats. & Regs. ¶ 31,127 at P 31.

[279] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 334.

[280] As stated in the NOPR, the Commission has granted requests for waiver of the EQR filing requirements. *See* NOPR, FERC Stats. & Regs. ¶ 32,676 at P 135, n.147 (citing *Bridger Valley Elect. Assoc., Inc.,* 101 FERC ¶ 61,146). Entities with a waiver will continue to have a waiver and will not need to file a new request for waiver.

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.

194. User assistance is available for eLibrary and the FERC's Web site during normal business hours from FERC 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*.

VII. Effective Date and Congressional Notification

195. These regulations are effective December 10, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects in 18 CFR Part 3

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

By the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends 18 CFR part 35, Chapter I, Title 18, *Code of Federal Regulations,* as follows.

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

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

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

■ 2. Section 35.10b is revised to read as follows:

§ 35.10b Electric Quarterly Reports.

Each public utility as well as each non-public utility with more than a *de minimis* market presence shall file an updated Electric Quarterly Report with the Commission covering all services it provides pursuant to this part, for each of the four calendar quarters of each year, in accordance with the following schedule: for the period from January 1 through March 31, file by April 30; for the period from April 1 through June 30, file by July 31; for the period July 1 through September 30, file by October 31; and for the period October 1 through December 31, file by January 31. Electric Quarterly Reports must be prepared in conformance with the Commission's software and guidance posted and available for downloading from the FERC Web site (*http://www.ferc.gov*).

(a) For purposes of this section, the term ''non-public utility'' means any market participant that is exempted from the Commission's jurisdiction under 16 U.S.C. 824(f).

The term does not include an entity that engages in purchases or sales of wholesale electric energy or transmission services within the Electric Reliability Council of Texas or any entity that engages solely in sales of wholesale electric energy or transmission services in the states of Alaska or Hawaii.

(b) For purposes of this section, the term ''*de minimis* market presence'' means any non-public utility that makes 4,000,000 megawatt hours or less of annual wholesale sales, based on the average annual sales for resale over the preceding three years as published by the Energy Information Administration's Form 861.

(c) For purposes of this section, the following wholesale sales made by a non-public utility with more than a *de minimis* market presence are excluded from the EQR filing requirement:

(1) Sales by a non-public utility, such as a cooperative or joint action agency, to its members; and

(2) Sales by a non-public utility under a long-term, cost-based agreement required to be made to certain customers under Federal or state statute.

■ 3. In § 35.41, paragraph (c) is revised to read as follows:

§ 35.41 Market behavior rules.

* * * * *

(c) *Price reporting.* To the extent a Seller engages in reporting of transactions to publishers of electric or natural gas price indices, Seller must provide accurate and factual information, and not knowingly submit false or misleading information or omit material information to any such publisher, by reporting its transactions in a manner consistent with the procedures set forth in the *Policy Statement on Natural Gas and Electric Price Indices,* issued by the Commission in Docket No. PL03–3–000, and any clarifications thereto. Seller must identify as part of its Electric Quarterly Report filing requirement in § 35.10b of this chapter the publishers of electricity and natural gas indices to which it reports its transactions. In addition, Seller must adhere to any other standards and requirements for price reporting as the Commission may order.

Note: Attachment A will not be published in the *Code of Federal Regulations.*

Attachment A: Revisions to the Data Dictionary Clean Version

Electric Quarterly Report Data Dictionary

Version 2.0 (issued July 19, 2012)

EQR DATA DICTIONARY—ID DATA

Field No. Old	Field No. New	Field	Required	Value	Definiiton
1	1	Filer Unique Identifier	✓	FR1	(Respondent)—An identifier (i.e., "FR1") used to designate a record containing Respondent identification information in a comma-delimited (csv) file that is imported into the EQR filing. Only one record with the FR1 identifier may be imported into an EQR for a given quarter.
1	1	Filer Unique Identifier	✓	FS# (where "#" is an integer).	(Seller)—An identifier (e.g., "FS1", "FS2") used to designate a record containing Seller identification information in a comma-delimited (csv) file that is imported into the EQR filing. One record for each seller company may be imported into an EQR for a given quarter.
1	1	Filer Unique Identifier	✓	FA1	(Agent)—An identifier (i.e., "FA1") used to designate a record containing Agent identification information in a comma-delimited (csv) file that is imported into the EQR filing. Only one record with the FA1 identifier may be imported into an EQR for a given quarter.

EQR DATA DICTIONARY—ID DATA—Continued

Field No. Old	Field No. New	Field	Required	Value	Definiiton
2	2	Company Name	✓	Unrestricted text (100 characters).	(Respondent)—The name of the company taking responsibility for complying with the Commission's regulations related to the EQR.
2	2	Company Name	✓	Unrestricted text (100 characters).	(Seller)—The name of the company that is authorized to make sales as indicated in the company's FERC tariff(s). This name may be the same as the Company Name of the Respondent.
2	2	Company Name	✓	Unrestricted text (100 characters).	(Agent)—The name of the entity completing the EQR filing. The Agent's Company Name need not be the name of the company under Commission jurisdiction.
3	X				
4	3	Contact Name	✓	Unrestricted text (50 characters).	(Respondent)—Name of the person at the Respondent's company taking responsibility for compliance with the Commission's EQR regulations.
4	3	Contact Name	✓	Unrestricted text (50 characters).	(Seller)—The name of the contact for the company authorized to make sales as indicated in the company's FERC tariff(s). This name may be the same as the Contact Name of the Respondent.
4	3	Contact Name	✓	Unrestricted text (50 characters).	(Agent)—Name of the contact for the Agent, usually the person who prepares the filing.
5	4	Contact Title	✓	Unrestricted text (50 characters).	Title of contact identified in Field Number 3.
6	5	Contact Address	✓	Unrestricted text	Street address for contact identified in Field Number 3.
7	6	Contact City	✓	Unrestricted text (30 characters).	City for the contact identified in Field Number 3.
8	7	Contact State	✓	Unrestricted text (2 characters).	Two character state or province abbreviations for the contact identified in Field Number 3.
9	8	Contact Zip	✓	Unrestricted text (10 characters).	Zip code for the contact identified in Field Number 3.
10	9	Contact Country Name.	✓	CA—Canada MX—Mexico US—United States UK—United Kingdom	Country (USA, Canada, Mexico, or United Kingdom) for contact address identified in Field Number 3.
11	10	Contact Phone	✓	Unrestricted text (20 characters).	Phone number of contact identified in Field Number 3.
12	11	Contact E-Mail	✓	Unrestricted text	Email address of contact identified in Field Number 3.
	12	Transactions Reported to Index Price Publisher(s).	✓	Y (Yes) N (No)	Filers should indicate whether they have reported their sales transactions to index price publisher(s). If they have, filers should indicate specifically which index publisher(s) in Field Number 72.
13	13	Filing Quarter	✓	YYYYMM	A six digit reference number used by the EQR software to indicate the quarter and year of the filing for the purpose of importing data from csv files. The first 4 numbers represent the year (e.g., 2007). The last 2 numbers represent the last month of the quarter (e.g., 03 = 1st quarter; 06 = 2nd quarter, 09 = 3rd quarter, 12 = 4th quarter).

EQR DATA DICTIONARY—CONTRACT DATA

Field No. Old	Field No. New	Field	Required	Value	Definition
14	14	Contract Unique ID	✓	An integer proceeded by the letter "C" (only used when importing contract data).	An identifier beginning with the letter "C" and followed by a number (e.g., "C1", "C2") used to designate a record containing contract information in a comma-delimited (csv) file that is imported into the EQR filing. One record for each contract product may be imported into an EQR for a given quarter.
15	15	Seller Company Name.	✓	Unrestricted text (100 characters).	The name of the company that is authorized to make sales as indicated in the company's FERC tariff(s). This name must match the name provided as a Seller's "Company Name" in Field Number 2 of the ID Data (Seller Data).
16	16	Customer Company Name.	✓	Unrestricted text (70 characters).	The name of the counterparty.
17	X				

EQR DATA DICTIONARY—CONTRACT DATA—Continued

Field No. Old	Field No. New	Field	Required	Value	Definition
18	17	Contract Affiliate	✓	Y (Yes) N (No)	The customer is an affiliate if it controls, is controlled by or is under common control with the seller. This includes a division that operates as a functional unit. A customer of a seller who is an Exempt Wholesale Generator may be defined as an affiliate under the Public Utility Holding Company Act and the FPA.
19	18	FERC Tariff Reference.	✓	Unrestricted text (60 characters).	The FERC tariff reference cites the document that specifies the terms and conditions under which a Seller is authorized to make transmission sales, power sales or sales of related jurisdictional services at cost-based rates or at market-based rates. If the sales are market-based, the tariff that is specified in the FERC order granting the Seller Market Based Rate Authority must be listed.
20	19	Contract Service Agreement ID.	✓	Unrestricted text (30 characters).	Unique identifier given to each service agreement that can be used by the filing company to produce the agreement, if requested. The identifier may be the number assigned by FERC for those service agreements that have been filed with and accepted by the Commission, or it may be generated as part of an internal identification system.
21	20	Contract Execution Date.	✓	YYYYMMDD	The date the contract was signed. If the parties signed on different dates, use the most recent date signed.
22	21	Commencement Date of Contract Terms.	✓	YYYYMMDD	The date the terms of the contract reported in fields 18, 23 and 25 through 45 (as defined in the data dictionary) became effective. If those terms became effective on multiple dates (i.e.: due to one or more amendments), the date to be reported in this field is the date the most recent amendment became effective. If the contract or the most recent reported amendment does not have an effective date, the date when service began pursuant to the contract or most recent reported amendment may be used. If the terms reported in fields 18, 23 and 25 through 45 have not been amended since January 1, 2009, the initial date the contract became effective (or absent an effective date the initial date when service began) may be used.
23	22	Contract Termination Date.	If specified in the contract.	YYYYMMDD	The date that the contract expires.
24	23	Actual Termination Date.	If contract terminated.	YYYYMMDD	The date the contract actually terminates.
25	24	Extension Provision Description.	✓	Unrestricted text	Description of terms that provide for the continuation of the contract.
26	25	Class Name	✓		See definitions of each class name below.
26	25	Class Name	✓	F—Firm	For transmission sales, a service or product that always has priority over non-firm service. For power sales, a service or product that is not interruptible for economic reasons.
26	25	Class Name	✓	NF—Non-firm	For transmission sales, a service that is reserved and/or scheduled on an as-available basis and is subject to curtailment or interruption at a lesser priority compared to Firm service. For an energy sale, a service or product for which delivery or receipt of the energy may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.
26	25	Class Name	✓	UP—Unit Power Sale.	Designates a dedicated sale of energy and capacity from one or more than one specified generation unit(s).
26	25	Class Name	✓	N/A—Not Applicable.	To be used only when the other available Class Names do not apply.
27	26	Term Name	✓	LT—Long Term ST—Short Term N/A—Not Applicable.	Contracts with durations of one year or greater are long-term. Contracts with shorter durations are short-term.
28	27	Increment Name	✓		See definitions for each increment below.
28	27	Increment Name	✓	H—Hourly	Terms of the contract (if specifically noted in the contract) set for up to 6 consecutive hours (≤ 6 consecutive hours).
28	27	Increment Name	✓	D—Daily	Terms of the contract (if specifically noted in the contract) set for more than 6 and up to 60 consecutive hours (>6 and ≤ 60 consecutive hours).
28	27	Increment Name	✓	W—Weekly	Terms of the contract (if specifically noted in the contract) set for over 60 consecutive hours and up to 168 consecutive hours (>60 and ≤ 168 consecutive hours).

EQR DATA DICTIONARY—CONTRACT DATA—Continued

Field No. Old	Field No. New	Field	Required	Value	Definition
28	27	Increment Name	✓	M—Monthly	Terms of the contract (if specifically noted in the contract) set for more than 168 consecutive hours up to, but not including, one year (>168 consecutive hours and < 1 year).
28	27	Increment Name	✓	Y—Yearly	Terms of the contract (if specifically noted in the contract) set for one year or more (≥ 1 year).
28	27	Increment Name	✓	N/A—Not Applicable.	Terms of the contract do not specify an increment.
29	28	Increment Peaking Name.	✓		See definitions for each increment peaking name below.
29	28	Increment Peaking Name.	✓	FP—Full Period	The product described may be sold during those hours designated as on-peak and off-peak in the NERC region of the point of delivery.
29	28	Increment Peaking Name.	✓	OP—Off-Peak	The product described may be sold only during those hours designated as off-peak in the NERC region of the point of delivery.
29	28	Increment Peaking Name.	✓	P—Peak	The product described may be sold only during those hours designated as on-peak in the NERC region of the point of delivery.
29	28	Increment Peaking Name.	✓	N/A—Not Applicable.	To be used only when the increment peaking name is not specified in the contract.
30	29	Product Type Name	✓		See definitions for each product type below.
30	29	Product Type Name	✓	CB—Cost Based	Energy or capacity sold under a FERC-approved cost-based rate tariff.
30	29	Product Type Name	✓	CR—Capacity Reassignment.	An agreement under which a transmission provider sells, assigns or transfers all or portion of its rights to an eligible customer.
30	29	Product Type Name	✓	MB—Market Based	Energy or capacity sold under the seller's FERC-approved market-based rate tariff.
30	29	Product Type Name	✓	T—Transmission	The product is sold under a FERC-approved transmission tariff.
30	29	Product Type Name	✓	Other	The product cannot be characterized by the other product type names.
31	30	Product Name	✓	See Product Name Table, Appendix A.	Description of product being offered.
32	31	Quantity	If specified in the contract.	Number with up to 4 decimals.	Quantity for the contract product identified.
33	32	Units	If specified in the contract.	See Units Table, Appendix E.	Measure stated in the contract for the product sold.
34	33	Rate	One of four rate fields (34, 35, 36, or 37) must be included.	Number with up to 4 decimals.	The charge for the product per unit as stated in the contract.
35	34	Rate Minimum	One of four rate fields (34, 35, 36, or 37) must be included.	Number with up to 4 decimals.	Minimum rate to be charged per the contract, if a range is specified.
36	35	Rate Maximum	One of four rate fields (34, 35, 36, or 37) must be included.	Number with up to 4 decimals.	Maximum rate to be charged per the contract, if a range is specified.
37	36	Rate Description	One of four rate fields (34, 35, 36, or 37) must be included.	Unrestricted text	Text description of rate. If the rate is currently available on the FERC website, a citation of the FERC Accession Number and the relevant FERC tariff including page number or section may be included instead of providing the entire rate algorithm. If the rate is not available on the FERC website, include the rate algorithm, if rate is calculated. If the algorithm would exceed the 150 character field limit, it may be provided in a descriptive summary (including bases and methods of calculations) with a detailed citation of the relevant FERC tariff including page number and section. If more than 150 characters are required, the contract product may be repeated in a subsequent line of data until the rate is adequately described.
38	37	Rate Units	If specified in the contract.	See Rate Units Table, Appendix F.	Measure stated in the contract for the product sold.

EQR DATA DICTIONARY—CONTRACT DATA—Continued

Field No. Old	Field No. New	Field	Required	Value	Definition
39	38	Point of Receipt Balancing Authority (PORBA).	If specified in the contract.	See Balancing Authority Table, Appendix B.	The registered NERC Balancing Authority (formerly called NERC Control Area) where service begins for a transmission or transmission-related jurisdictional sale. The Balancing Authority will be identified with the abbreviation used in OASIS applications. If receipt occurs at a trading hub specified in the EQR software, the term ''Hub'' should be used.
40	39	Point of Receipt Specific Location (PORSL).	If specified in the contract.	Unrestricted text (50 characters). If ''HUB'' is selected for PORCA, see Hub Table, Appendix C.	The specific location at which the product is received if designated in the contract. If receipt occurs at a trading hub, a standardized hub name must be used. If more points of receipt are listed in the contract than can fit into the 50 character space, a description of the collection of points may be used. 'Various,' alone, is unacceptable unless the contract itself uses that terminology.
41	40	Point of Delivery Balancing Authority (PODBA).	If specified in the contract.	See Balancing Authority Table, Appendix B.	The registered NERC Balancing Authority (formerly called NERC Control Area) where a jurisdictional product is delivered and/or service ends for a transmission or transmission-related jurisdictional sale. The Balancing Authority will be identified with the abbreviation used in OASIS applications. If delivery occurs at the interconnection of two control areas, the control area that the product is entering should be used. If delivery occurs at a trading hub specified in the EQR software, the term ''Hub'' should be used.
42	41	Point of Delivery Specific Location (PODSL).	If specified in the contract.	Unrestricted text (50 characters). If ''HUB'' is selected for PODCA, see Hub Table, Appendix C.	The specific location at which the product is delivered if designated in the contract. If receipt occurs at a trading hub, a standardized hub name must be used.
43	42	Begin Date	If specified in the contract.	YYYYMMDDHHMM	First date for the sale of the product at the rate specified.
44	43	End Date	If specified in the contract.	YYYYMMDDHHMM	Last date for the sale of the product at the rate specified.
45	X				

EQR DATA DICTIONARY—TRANSACTION DATA

Field No. Old	Field No. New	Field	Required	Value	Definition
46	44	Transaction Unique ID	✓	An integer proceeded by the letter ''T'' (only used when importing transaction data).	An identifier beginning with the letter ''T'' and followed by a number (e.g., ''T1'', ''T2'') used to designate a record containing transaction information in a comma-delimited (csv) file that is imported into the EQR filing. One record for each transaction record may be imported into an EQR for a given quarter. A new transaction record must be used every time a price changes in a sale.
47	45	Seller Company Name.	✓	Unrestricted text (100 Characters).	The name of the company that is authorized to make sales as indicated in the company's FERC tariff(s). This name must match the name provided as a Seller's ''Company Name'' in Field 2 of the ID Data (Seller Data).
48	46	Customer Company Name.	✓	Unrestricted text (70 Characters).	The name of the counterparty.
49	X				
50	47	FERC Tariff Reference.	✓	Unrestricted text (60 Characters).	The FERC tariff reference cites the document that specifies the terms and conditions under which a Seller is authorized to make transmission sales, power sales or sales of related jurisdictional services at cost-based rates or at market-based rates. If the sales are market-based, the tariff that is specified in the FERC order granting the Seller Market Based Rate Authority must be listed.

EQR DATA DICTIONARY—TRANSACTION DATA—Continued

Field No. Old	Field No. New	Field	Required	Value	Definition
51	48	Contract Service Agreement ID.	✓	Unrestricted text (30 Characters).	Unique identifier given to each service agreement that can be used by the filing company to produce the agreement, if requested. The identifier may be the number assigned by FERC for those service agreements that have been filed and approved by the Commission, or it may be generated as part of an internal identification system.
52	49	Transaction Unique Identifier.	✓	Unrestricted text (24 Characters).	Unique reference number assigned by the seller for each transaction.
53	50	Transaction Begin Date.	✓	YYYYMMDDHHMM (csv import). MMDDYYYYHHMM (manual entry).	First date and time the product is sold during the quarter.
54	51	Transaction End Date	✓	YYYYMMDDHHMM (csv import). MMDDYYYYHHMM (manual entry).	Last date and time the product is sold during the quarter.
	52	Trade Date	✓	YYYYMMDD (csv import). MMDDYYYY (manual entry).	The date upon which the parties made the legally binding agreement on the price of a transaction.
	53	Exchange/Brokerage Service.	....	See Exchange/Brokerage Service Table, Appendix H.	If a broker service is used to consummate or effectuate a transaction, the term ''Broker'' shall be selected from the Commission-provided list. If an exchange is used, the specific exchange that is used shall be selected from the Commission-provided list.
	54	Type of Rate	✓	....	See type of rate definitions below.
	54	Type of Rate	✓	Fixed	A fixed charge per unit of consumption.
	54	Type of Rate	✓	Formula	A calculation of a rate based upon a formula that does not contain an index component.
	54	Type of Rate	✓	Electric Index	A calculation of a rate based upon an index or a formula that contains an index component.
	54	Type of Rate	✓	RTO/ISO	A rate that is based on an RTO/ISO published price or formula that contains an RTO/ISO price component.
55	55	Time Zone	✓	See Time Zone Table, Appendix D.	The time zone in which the sales will be made under the contract.
56	56	Point of Delivery Balancing Authority (PODBA).	✓	See Balancing Authority Table, Appendix B.	The registered NERC Balancing Authority (formerly called NERC Control Area) abbreviation used in OASIS applications.
57	57	Point of Delivery Specific Location (PODSL).	✓	Unrestricted text (50 characters). If ''HUB'' is selected for PODBA, see Hub Table, Appendix C.	The specific location at which the product is delivered. If receipt occurs at a trading hub, a standardized hub name must be used.
58	58	Class Name	✓	....	See class name definitions below.
58	58	Class Name	✓	F—Firm	A sale, service or product that is not interruptible for economic reasons.
58	58	Class Name	✓	NF—Non-firm	A sale for which delivery or receipt of the energy may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.
58	58	Class Name	✓	UP—Unit Power Sale	Designates a dedicated sale of energy and capacity from one or more than one specified generation unit(s).
58	58	Class Name	✓	BA—Billing Adjustment.	Designates an incremental material change to one or more transactions due to a change in settlement results. ''BA'' may be used in a refiling after the next quarter's filing is due to reflect the receipt of new information. It may not be used to correct an inaccurate filing.
58	58	Class Name	✓	N/A—Not Applicable ..	To be used only when the other available class names do not apply.
59	59	Term Name	✓	LT—Long Term .... ST—Short Term N/A—. Not Applicable	Power sales transactions with durations of one year or greater are long-term. Transactions with shorter durations are short-term.
60	60	Increment Name	✓	....	See increment name definitions below.
60	60	Increment Name	✓	H—Hourly	Terms of the particular sale set for up to 6 consecutive hours (≤ 6 consecutive hours) Includes LMP based sales in ISO/RTO markets.
60	60	Increment Name	✓	D—Daily	Terms of the particular sale set for more than 6 and up to 60 consecutive hours (> 6 and ≤ 60 consecutive hours). Includes sales over a peak or off-peak block during a single day.

EQR DATA DICTIONARY—TRANSACTION DATA—Continued

Field No. Old	Field No. New	Field	Required	Value	Definition
60	60	Increment Name	✓	W—Weekly	Terms of the particular sale set for over 60 consecutive hours and up to 168 consecutive hours (> 60 and ≤ 168 consecutive hours). Includes sales for a full week and sales for peak and off-peak blocks over a particular week.
60	60	Increment Name	✓	M—Monthly	Terms of the particular sale set for set for more than 168 consecutive hours up to, but not including, one year (> 168 consecutive hours and < 1 year). Includes sales for full month or multi-week sales during a given month.
60	60	Increment Name	✓	Y—Yearly	Terms of the particular sale set for one year or more (≥ 1 year). Includes all long-term contracts with defined pricing terms (fixed-price, formula, or index).
60	60	Increment Name	✓	N/A—Not Applicable ..	To be used only when other available increment names do not apply.
61	61	Increment Peaking Name.	✓	....	See definitions for increment peaking below.
61	61	Increment Peaking Name.	✓	FP—Full Period	The product described was sold during Peak and Off-Peak hours.
61	61	Increment Peaking Name.	✓	OP—Off-Peak	The product described was sold only during those hours designated as off-peak in the NERC region of the point of delivery.
61	61	Increment Peaking Name.	✓	P—Peak	The product described was sold only during those hours designated as on-peak in the NERC region of the point of delivery.
61	61	Increment Peaking Name.	✓	N/A—Not Applicable ..	To be used only when the other available increment peaking names do not apply.
62	62	Product Name	✓	See Product Names Table, Appendix A.	Description of product being offered.
63	63	Transaction Quantity	✓	Number with up to 4 decimals.	The quantity of the product in this transaction.
64	64	Price	✓	Number with up to 6 decimals.	Actual price charged for the product per unit. The price reported cannot be averaged or otherwise aggregated
65	65	Rate Units	✓	See Rate Units Table, Appendix F.	Measure appropriate to the price of the product sold.
	66	Standardized Quantity	✓	Number with up to 4 decimals.	For product names energy, capacity, and booked out power only. Specify the quantity in MWh if the product is energy or booked out power and specify the quantity in MW if the product is capacity.
	67	Standardized Price	✓	Number with up to 6 decimals.	For product names energy, capacity, and booked out power only. Specify the price in $/MWh if the product is energy or booked out power and specify the price in $/MW-month if the product is capacity.
66	68	Total Transmission Charge.	✓	Number with up to 2 decimals.	Payments received for transmission services when explicitly identified.
67	69	Total Transaction Charge.	✓	Number with up to 2 decimals.	Transaction Quantity (Field 63) times Price (Field 64) plus Total Transmission Charge (Field 66).

EQR DATA DICTIONARY—INDEX REPORTING DATA

Field No. Old	Field No. New	Field	Required	Value	Definition
	70	Filer Unique Identifier	✓	FS# (where "#" is an integer).	The "FS" seller number from the ID Data table corresponding to the index reporting company.
	71	Seller Company Name.	✓	Unrestricted text (100 characters).	The name of the company that is authorized to make sales as indicated in the company's FERC tariff(s). This name must match the name provided as a Seller's "Company Name" in Field Number 2 of the ID Data (Seller Data).
	72	Index Price Publisher(s) To Which Sales Transactions Have Been Reported.	✓	If "Yes" is selected for Field 12, see Index Price Publisher, Appendix G.	The index price publisher(s) to which sales transactions have been reported.
	73	Transactions Reported.	✓	Unrestricted text (100 characters).	Description of the types of transactions reported to the index publisher identified in this record.

EQR DATA DICTIONARY—E-TAG DATA

Field No. Old	Field No. New	Field	Required	Value	Definition
	74	e-Tag ID	If an e-Tag ID was used to schedule the EQR transaction.	Unrestricted text (30 Characters).	The e-Tag ID contains: The Source Balancing Authority where the generation is located; The Purchasing-Selling Balancing Authority Entity Code; the e-Tag Code; and the Sink Balancing Authority.
	75	e-Tag Begin Date ..	If an e-Tag ID was used to schedule the EQR transaction.	YYYYMMDD (csv import). MMDDYYYY (manual entry).	The first date the transaction is scheduled using the e-Tag ID reported in Field Number 71. Begin Date must not be before the Transaction Begin Date specified in Field Number 51 and must be reported in the same time zone specified in Field Number 56.
	76	e-Tag End Date	If an e-Tag ID was used to schedule the EQR transaction.	YYYYMMDD (csv import). MMDDYYYY (manual entry).	The last date the transaction is scheduled using the e-Tag ID reported in Field Number 71. End Date must not be after the Transaction End Date specified in Field Number 52 and must be reported in the same time zone specified in Field Number 56.
	77	Transaction Unique Identifier.	If an e-Tag ID was used to schedule the EQR transaction.	Unrestricted text (24 Characters).	Unique reference number assigned by the seller for each transaction that must be the same as reported in Field Number 50.

EQR DATA DICTIONARY—APPENDIX A. PRODUCT NAMES

Product name	Contract product	Transaction product	Definition
BLACK START SERVICE	✓	✓	Service available after a system-wide blackout where a generator participates in system restoration activities without the availability of an outside electric supply (Ancillary Service).
BOOKED OUT POWER ...	....	✓	Energy or capacity contractually committed bilaterally for delivery but not actually delivered due to some offsetting or countervailing trade (Transaction only).
CAPACITY	✓	✓	A quantity of demand that is charged on a $/KW or $/MW basis.
CUSTOMER CHARGE	✓	✓	Fixed contractual charges assessed on a per customer basis that could include billing service.
DIRECT ASSIGNMENT FACILITIES CHARGE.	✓	....	Charges for facilities or portions of facilities that are constructed or used for the sole use/benefit of a particular customer.
EMERGENCY ENERGY ...	✓	....	Contractual provisions to supply energy or capacity to another entity during critical situations.
ENERGY	✓	✓	A quantity of electricity that is sold or transmitted over a period of time.
ENERGY IMBALANCE	✓	✓	Service provided when a difference occurs between the scheduled and the actual delivery of energy to a load obligation (Ancillary Service). For Contracts, reported if the contract provides for sale of the product. For Transactions, sales by third-party providers (i.e., non-transmission function) are reported.
EXCHANGE	✓	✓	Transaction whereby the receiver accepts delivery of energy for a supplier's account and returns energy at times, rates, and in amounts as mutually agreed if the receiver is not an RTO/ISO.
FUEL CHARGE	✓	✓	Charge based on the cost or amount of fuel used for generation.
GENERATOR IMBALANCE.	✓	✓	Service provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour (Ancillary Service). For Contracts, reported if the contract provides for sale of the product. For Transactions, sales by third-party providers (i.e., non-transmission function) are reported.
GRANDFATHERED BUNDLED.	✓	✓	Services provided for bundled transmission, ancillary services and energy under contracts effective prior to Order No. 888's OATTs.
INTERCONNECTION AGREEMENT.	✓	....	Contract that provides the terms and conditions for a generator, distribution system owner, transmission owner, transmission provider, or transmission system to physically connect to a transmission system or distribution system.
MEMBERSHIP AGREEMENT.	✓	....	Agreement to participate and be subject to rules of a system operator.
MUST RUN AGREEMENT	✓	....	An agreement that requires a unit to run.
NEGOTIATED–RATE TRANSMISSION.	✓	✓	Transmission performed under a negotiated rate contract (applies only to merchant transmission companies).
NETWORK	✓	....	Transmission service under contract providing network service.
NETWORK OPERATING AGREEMENT.	✓	....	An executed agreement that contains the terms and conditions under which a network customer operates its facilities and the technical and operational matters associated with the implementation of network integration transmission service.
OTHER	✓	✓	Product name not otherwise included.

EQR DATA DICTIONARY—APPENDIX A. PRODUCT NAMES—Continued

Product name	Contract product	Transaction product	Definition
POINT–TO–POINT AGREEMENT.	✓	....	Transmission service under contract between specified Points of Receipt and Delivery.
REACTIVE SUPPLY & VOLTAGE CONTROL.	✓	✓	Production or absorption of reactive power to maintain voltage levels on transmission systems (Ancillary Service).
REAL POWER TRANSMISSION LOSS.	✓	✓	The loss of energy, resulting from transporting power over a transmission system.
REASSIGNMENT AGREEMENT.	✓	....	Transmission capacity reassignment agreement.
REGULATION & FREQUENCY RESPONSE.	✓	✓	Service providing for continuous balancing of resources (generation and interchange) with load, and for maintaining scheduled interconnection frequency by committing on-line generation where output is raised or lowered and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load (Ancillary Service). For Contracts, reported if the contract provides for sale of the product. For Transactions, sales by third-party providers (i.e., non-transmission function) are reported.
REQUIREMENTS SERVICE.	✓	✓	Firm, load-following power supply necessary to serve a specified share of customer's aggregate load during the term of the agreement. Requirements service may include some or all of the energy, capacity and ancillary service products. (If the components of the requirements service are priced separately, they should be reported separately in the transactions tab.)
SCHEDULE SYSTEM CONTROL & DISPATCH.	✓	✓	Scheduling, confirming and implementing an interchange schedule with other Balancing Authorities, including intermediary Balancing Authorities providing transmission service, and ensuring operational security during the interchange transaction (Ancillary Service).
SPINNING RESERVE	✓	✓	Unloaded synchronized generating capacity that is immediately responsive to system frequency and that is capable of being loaded in a short time period or non-generation resources capable of providing this service (Ancillary Service). For Contracts, reported if the contract provides for sale of the product. For Transactions, sales by third-party providers (i.e., non-transmission function) are reported.
SUPPLEMENTAL RESERVE.	✓	✓	Service needed to serve load in the event of a system contingency, available with greater delay than SPINNING RESERVE. This service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load or other non-generation resources capable of providing this service (Ancillary Service). For Contracts, reported if the contract provides for sale of the product. For Transactions, sales by third-party providers (i.e., non-transmission function) are reported.
SYSTEM OPERATING AGREEMENTS.	✓	....	An executed agreement that contains the terms and conditions under which a system or network customer shall operate its facilities and the technical and operational matters associated with the implementation of network.
TOLLING ENERGY	✓	✓	Energy sold from a plant whereby the buyer provides fuel to a generator (seller) and receives power in return for pre-established fees.
TRANSMISSION OWNERS AGREEMENT.	✓	....	The agreement that establishes the terms and conditions under which a transmission owner transfers operational control over designated transmission facilities.
UPLIFT	✓	✓	A make-whole payment by an RTO/ISO to a utility.

EQR DATA DICTIONARY—APPENDIX B. BALANCING AUTHORITY

Balancing authority	Abbreviation	Outside US*
AESC, LLC—Wheatland CIN	AEWC	....
Alabama Electric Cooperative, Inc	AEC	....
Alberta Electric System Operator	AESO	✓
Alliant Energy Corporate Services, LLC—East	ALTE	....
Alliant Energy Corporate Services, LLC—West	ALTW	....
Ameren Transmission. Illinois	AMIL	....
Ameren Transmission. Missouri	AMMO	....
American Transmission Systems, Inc	FE	....
Aquila Networks—Kansas	WPEK	....
Aquila Networks—Missouri Public Service	MPS	....
Aquila Networks—West Plains Dispatch	WPEC	....
Arizona Public Service Company	AZPS	....
Associated Electric Cooperative, Inc	AECI	....
Avista Corp	AVA	....
Batesville Balancing Authority	BBA	....
BC Hydro T & D—Grid Operations	BCHA	✓
Big Rivers Electric Corp	BREC	....
Board of Public Utilities	KACY	....
Bonneville Power Administration Transmission	BPAT	....

EQR DATA DICTIONARY—APPENDIX B. BALANCING AUTHORITY—Continued

Balancing authority	Abbreviation	Outside US*
British Columbia Transmission Corporation	BCTC	✓
California Independent System Operator	CISO	
Carolina Power & Light Company—CPLW	CPLW	
Carolina Power and Light Company—East	CPLE	
Central and Southwest	CSWS	
Chelan County PUD	CHPD	
Cinergy Corporation	CIN	
City of Homestead	HST	
City of Independence P&L Dept.	INDN	
City of Tallahassee	TAL	
City Water Light & Power	CWLP	
City Utilities of Springfield	SPRM	
Cleco Power LLC	CLEC	
Columbia Water & Light	CWLD	
Comision Federal de Electricidad	CFE	✓
Comision Federal de Electricidad	CFEN	✓
Constellation Energy Control and Dispatch	GRIF	
Constellation Energy Control and Dispatch—Arkansas	PUPP	
Constellation Energy Control and Dispatch—City of Benton, AR	BUBA	
Constellation Energy Control and Dispatch—City of Ruston, LA	DERS	
Constellation Energy Control and Dispatch—Conway, Arkansas	CNWY	
Constellation Energy Control and Dispatch—Gila River	GRMA	
Constellation Energy Control and Dispatch—Glacier Wind Energy	GWA	
Constellation Energy Control and Dispatch—Harquehala	HGMA	
Constellation Energy Control and Dispatch—North Little Rock, AK	DENL	
Constellation Energy Control and Dispatch—Osceola Municipal Light	OMLP	
Constellation Energy Control and Dispatch—Plum Point	PLUM	
Constellation Energy Control and Dispatch—Red Mesa	REDM	
Constellation Energy Control and Dispatch—West Memphis, Arkansas	WMUC	
Dairyland Power Cooperative	DPC	
DECA, LLC—Arlington Valley	DEAA	
Duke Energy Corporation	DUK	
East Kentucky Power Cooperative, Inc	EKPC	
El Paso Electric	EPE	
Electric Energy, Inc.	EEI	
Empire District Electric Co., The	EDE	
Entergy	EES	
ERCOT ISO	ERCO	
Florida Municipal Power Pool	FMPP	
Florida Power & Light	FPL	
Florida Power Corporation	FPC	
Gainesville Regional Utilities	GVL	
Grand River Dam Authority	GRDA	
Grant County PUD No. 2	GCPD	
Great River Energy	GRE	
Great River Energy	GREC	
Great River Energy	GREN	
Great River Energy	GRES	
GridAmerica	GA	
Hoosier Energy	HE	
Hydro-Quebec, TransEnergie	HQT	✓
Idaho Power Company	IPCO	
Imperial Irrigation District	IID	
Indianapolis Power & Light Company	IPL	
ISO New England Inc	ISNE	
JEA	JEA	
Kansas City Power & Light, Co	KCPL	
Lafayette Utilities System	LAFA	
LG&E Energy Transmission Services	LGEE	
Lincoln Electric System	LES	
Los Angeles Department of Water and Power	LDWP	
Louisiana Energy & Power Authority	LEPA	
Louisiana Generating, LLC	LAGN	
Louisiana Generating, LLC—City of Conway	CWAY	
Louisiana Generating, LLC—City of West Memphis	WMU	
Louisiana Generating, LLC—North Little Rock	NLR	
Madison Gas and Electric Company	MGE	
Manitoba Hydro Electric Board, Transmission Services	MHEB	✓
Michigan Electric Coordinated System	MECS	
Michigan Electric Coordinated System—CONS	CONS	
Michigan Electric Coordinated System—DECO	DECO	
MidAmerican Energy Company	MEC	

EQR DATA DICTIONARY—APPENDIX B. BALANCING AUTHORITY—Continued

Balancing authority	Abbreviation	Outside US*
Midwest ISO	MISO	
Minnesota Power, Inc	MP	
Montana-Dakota Utilities Co	MDU	
Muscatine Power and Water	MPW	
Nebraska Public Power District	NPPD	
Nevada Power Company	NEVP	
New Brunswick System Operator	NBSO	✓
New Horizons Electric Cooperative	NHC1	
New York Independent System Operator	NYIS	
Northern Indiana Public Service Company	NIPS	
Northern States Power Company	NSP	
NorthWestern Energy	NWMT	
Ohio Valley Electric Corporation	OVEC	
Oklahoma Gas and Electric	OKGE	
Ontario—Independent Electricity System Operator	ONT	✓
OPPDCA/TP	OPPD	
Otter Tail Power Company	OTP	
P.U.D. No. 1 of Douglas County	DOPD	
PacifiCorp-East	PACE	
PacifiCorp-West	PACW	
PJM Interconnection	PJM	
Portland General Electric	PGE	
Public Service Company of Colorado	PSCO	
Public Service Company of New Mexico	PNM	
Puget Sound Energy Transmission	PSEI	
Reedy Creek Improvement District	RC	
Sacramento Municipal Utility District	SMUD	
Salt River Project	SRP	
Santee Cooper	SC	
SaskPower Grid Control Centre	SPC	✓
Seattle City Light	SCL	
Seminole Electric Cooperative	SEC	
Sierra Pacific Power Co.—Transmission	SPPC	
South Carolina Electric & Gas Company	SCEG	
South Mississippi Electric Power Association	SME	
South Mississippi Electric Power Association	SMEE	
Southeastern Power Administration—Hartwell	SEHA	
Southeastern Power Administration—Russell	SERU	
Southeastern Power Administration—Thurmond	SETH	
Southern Company Services, Inc	SOCO	
Southern Illinois Power Cooperative	SIPC	
Southern Indiana Gas & Electric Co	SIGE	
Southern Minnesota Municipal Power Agency	SMP	
Southwest Power Pool	SWPP	
Southwestern Power Administration	SPA	
Southwestern Public Service Company	SPS	
Sunflower Electric Power Corporation	SECI	
Tacoma Power	TPWR	
Tampa Electric Company	TEC	
Tennessee Valley Authority ESO	TVA	
Trading Hub	HUB	
TRANSLink Management Company	TLKN	
Tucson Electric Power Company	TEPC	
Turlock Irrigation District	TIDC	
Upper Peninsula Power Co	UPPC	
Utilities Commission, City of New Smyrna Beach	NSB	
Westar Energy—MoPEP Cities	MOWR	
Western Area Power Administration—Colorado-Missouri	WACM	
Western Area Power Administration—Lower Colorado	WALC	
Western Area Power Administration—Upper Great Plains East	WAUE	
Western Area Power Administration—Upper Great Plains West	WAUW	
Western Farmers Electric Cooperative	WFEC	
Western Resources dba Westar Energy	WR	
Wisconsin Energy Corporation	WEC	
Wisconsin Public Service Corporation	WPS	
Yadkin, Inc	YAD	

* Balancing authorities outside the United States may only be used in the Contract Data section to identify specified receipt/delivery points in jurisdictional transmission contracts.

EQR DATA DICTIONARY—APPENDIX C. HUB

HUB	Definition
ADHUB	The aggregated Locational Marginal Price (''LMP'') nodes defined by PJM Interconnection, LLC as the AEP/Dayton Hub.
AEPGenHub	The aggregated Locational Marginal Price (''LMP'') nodes defined by PJM Interconnection, LLC as the AEPGenHub.
COB	The set of delivery points along the California-Oregon commonly identified as and agreed to by the counterparties to constitute the COB Hub.
Cinergy (into)	The set of delivery points commonly identified as and agreed to by the counterparties to constitute delivery into the Cinergy balancing authority.
Cinergy Hub (MISO)	The aggregated Elemental Pricing nodes (''Epnodes'') defined by the Midwest Independent Transmission System Operator, Inc., as Cinergy Hub (MISO).
Entergy (into)	The set of delivery points commonly identified as and agreed to by the counterparties to constitute delivery into the Entergy balancing authority.
FE Hub	The aggregated Elemental Pricing nodes (''Epnodes'') defined by the Midwest Independent Transmission System Operator, Inc., as FE Hub (MISO).
Four Corners	The set of delivery points at the Four Corners power plant commonly identified as and agreed to by the counterparties to constitute the Four Corners Hub.
Illinois Hub (MISO)	The aggregated Elemental Pricing nodes (''Epnodes'') defined by the Midwest Independent Transmission System Operator, Inc., as Illinois Hub (MISO).
Mead	The set of delivery points at or near Hoover Dam commonly identified as and agreed to by the counterparties to constitute the Mead Hub.
Michigan Hub (MISO)	The aggregated Elemental Pricing nodes (''Epnodes'') defined by the Midwest Independent Transmission System Operator, Inc., as Michigan Hub (MISO).
Mid-Columbia (Mid-C)	The set of delivery points along the Columbia River commonly identified as and agreed to by the counterparties to constitute the Mid-Columbia Hub.
Minnesota Hub (MISO)	The aggregated Elemental Pricing nodes (''Epnodes'') defined by the Midwest Independent Transmission System Operator, Inc., as Minnesota Hub (MISO).
NEPOOL (Mass Hub)	The aggregated Locational Marginal Price (''LMP'') nodes defined by ISO New England Inc., as Mass Hub.
NIHUB	The aggregated Locational Marginal Price (''LMP'') nodes defined by PJM Interconnection, LLC as the Northern Illinois Hub.
NOB	The set of delivery points along the Nevada-Oregon border commonly identified as and agreed to by the counterparties to constitute the NOB Hub.
NP15	The set of delivery points north of Path 15 on the California transmission grid commonly identified as and agreed to by the counterparties to constitute the NP15 Hub.
NWMT	The set of delivery points commonly identified as and agreed to by the counterparties to constitute delivery into the Northwestern Energy Montana balancing authority.
PJM East Hub	The aggregated Locational Marginal Price nodes (''LMP'') defined by PJM Interconnection, LLC as the PJM East Hub.
PJM South Hub	The aggregated Locational Marginal Price (''LMP'') nodes defined by PJM Interconnection, LLC as the PJM South Hub.
PJM West Hub	The aggregated Locational Marginal Price (''LMP'') nodes defined by PJM Interconnection, LLC as the PJM Western Hub.
Palo Verde	The switch yard at the Palo Verde nuclear power station west of Phoenix in Arizona. Palo Verde Hub includes the Hassayampa switchyard 2 miles south of Palo Verde.
SOCO (into)	The set of delivery points commonly identified as and agreed to by the counterparties to constitute delivery into the Southern Company balancing authority.
SP15	The set of delivery points south of Path 15 on the California transmission grid commonly identified as and agreed to by the counterparties to constitute the SP15 Hub.
TVA (into)	The set of delivery points commonly identified as and agreed to by the counterparties to constitute delivery into the Tennessee Valley Authority balancing authority.
ZP26	The set of delivery points associated with Path 26 on the California transmission grid commonly identified as and agreed to by the counterparties to constitute the ZP26 Hub.

EQR DATA DICTIONARY—APPENDIX D. TIME ZONE

Time zone	Definition
AD	*Atlantic Daylight.*
AP	*Atlantic Prevailing.*
AS	*Atlantic Standard.*
CD	*Central Daylight.*
CP	*Central Prevailing.*
CS	*Central Standard.*
ED	*Eastern Daylight.*
EP	*Eastern Prevailing.*
ES	*Eastern Standard.*
MD	*Mountain Daylight.*
MP	*Mountain Prevailing.*
MS	*Mountain Standard.*
NA	*Not Applicable.*
PD	*Pacific Daylight.*
PP	*Pacific Prevailing.*
PS	*Pacific Standard.*
UT	*Universal Time.*

EQR DATA DICTIONARY—APPENDIX E. UNITS

Units	Definition
KV	*Kilovolt.*
KVA	*Kilovolt Amperes.*
KVR	*Kilovar.*
KW	*Kilowatt.*
KWH	*Kilowatt Hour.*
KW–DAY	*Kilowatt Day.*
KW–MO	*Kilowatt Month.*
KW–WK	*Kilowatt Week.*
KW–YR	*Kilowatt Year.*
MVAR–YR	*Megavar Year.*
MW	*Megawatt.*
MWH	*Megawatt Hour.*
MW–DAY	*Megawatt Day.*
MW–MO	*Megawatt Month.*
MW–WK	*Megawatt Week.*

EQR DATA DICTIONARY—APPENDIX E. UNITS—Continued

Units	Definition
MW–YR	*Megawatt Year.*
RKVA	*Reactive Kilovolt Amperes.*
FLAT RATE	*Flat Rate.*

EQR DATA DICTIONARY—APPENDIX F. RATE UNITS

Rate units	Definition
$/KV	*dollars per kilovolt.*
$/KVA	*dollars per kilovolt amperes.*
$/KVR	*dollars per kilovar.*
$/KW	*dollars per kilowatt.*
$/KWH	*dollars per kilowatt hour.*
$/KW–DAY	*dollars per kilowatt day.*
$/KW–MO	*dollars per kilowatt month.*
$/KW–WK	*dollars per kilowatt week.*
$/KW–YR	*dollars per kilowatt year.*
$/MW	*dollars per megawatt.*
$/MWH	*dollars per megawatt hour.*
$/MW–DAY	*dollars per megawatt day.*
$/MW–MO	*dollars per megawatt month.*
$/MW–WK	*dollars per megawatt week.*
$/MW–YR	*dollars per megawatt year.*
$/MVAR–YR	*dollars per megavar year.*
$/RKVA	*dollars per reactive kilovar amperes.*
CENTS	*cents.*
CENTS/KVR	*cents per kilovolt amperes.*
CENTS/KWH	*cents per kilowatt hour.*
FLAT RATE	*rate not specified in any other units.*

EQR DATA DICTIONARY—APPENDIX G. INDEX PRICE PUBLISHER

Index price publisher abbreviation	Index price publisher
AM	*Argus Media.*
EIG	*Energy Intelligence Group, Inc.*
IP	*Intelligence Press.*
P	*Platts.*
B	*Bloomberg.*
DJ	*Dow Jones.*
Pdx	*Powerdex.*
SNL	*SNL Energy.*

EQR DATA DICTIONARY—APPENDIX H. EXCHANGE/BROKER SERVICES

Exchange/brokerage service	Definition
BROKER	*A broker was used to consummate or effectuate the transaction.*
ICE	*Intercontinental Exchange .*
NYMEX	*New York Mercantile Exchange .*

Note: Attachment B will not be published in the *Code of Federal Regulations.*

Attachment B: List of Commenters on the NOPR

Short name or acronym	Commenter
Allegheny	Allegheny Electric Cooperative.
APPA	American Public Power Association.
Associated Electric Cooperative	Associated Electric Cooperative, Inc.
California DWR	California Department of Water Resources State Water Project.
Cities/M–S–R	City of Redding, California, City of Santa Clara, California, and M–S–R Public Power Agency.
DC Energy	DC Energy, LLC.
EDF Trading	EDF Trading North America, LLC.
EEI	Edison Electric Institute.
EPSA	Electric Power Supply Association.
Entergy	Entergy Services, Inc.
Financial Institutions Energy Group	Financial Institutions Energy Group.
Joint Commenters	American Public Power Associated; Edison Electric Institute; Large Public Power Council; and National Rural Electric Cooperative Association.
Joint Market Monitors	North American Market Monitors Joint Comments.
LPPC	Large Public Power Council.
MISO	Midwest Independent Transmission System Operator, Inc.
Northern California Power Agency	Northern California Power Agency.
NRECA	National Rural Electric Cooperative Association.
NYMPA/MEUA	New York Municipal Power Agency and Municipal Electric Utilities Association of New York.
Pacific Northwest IOUs	Avista Corporation; Portland General Electric Company; and Puget Sound Energy Company.
Pennsylvania Commission	Pennsylvania Public Utility Commission.
Powerex	Powerex Corporation.
PSEG Companies	PSEG Companies [281].
Public Systems	Connecticut Municipal Electric Energy Cooperative, Massachusetts Municipal Wholesale Electric Company, and New Hampshire Electric Cooperative, Inc.
Shell Energy	Shell Energy North America, L.P.
South Mississippi Electric	South Mississippi Electric Power Association.
Southwestern Power Association	Southwestern Power Administration.
TAPS	Transmission Access Policy Study Group.
Transmission Dependent Utility Systems.	Transmission Dependent Utility Systems.
Westar	Westar Energy, Inc.

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[281] Filed only a motion to intervene.