DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35, 37, and 101

[Docket Nos. RM11–24–000 and AD10–13–000]

Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Notice of Proposed Rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to revise certain aspects of its current market-based rate regulations, ancillary services requirements under the *pro forma* open-access transmission tariff (OATT), and accounting and reporting requirements. Specifically, the Commission proposes to revise its *Avista Corp.*[1] policy governing the sale of ancillary services at market-based rates to public utility transmission providers and reflect such reforms in Parts 35 and 37 of the Commission's regulations. The Commission also proposes to require each public utility transmission provider to include provisions in its OATT explaining how it will determine Regulation and Frequency Response reserve requirements in a manner that takes into account the speed and accuracy of resources used. Finally, the Commission proposes to revise the accounting and reporting requirements under its Uniform System of Accounts for public utilities and licensees and its forms, statements, and reports, contained in FERC Form No. 1, Annual Report of Major Electric Utilities, Licensees and Others, FERC Form No. 1–F, Annual Report for Nonmajor Public Utilities and Licensees, and FERC Form No. 3–Q, Quarterly Financial Report of Electric Utilities, Licensees, and Natural Gas Companies, to better account for and report transactions associated with the use of energy storage devices in public utility operations.

DATES: Comments are due 60 days after publication in the **Federal Register**.

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

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

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

FOR FURTHER INFORMATION CONTACT: Rahim Amerkhail (Technical Information), Federal Energy Regulatory Commission, Office of Energy Policy and Innovation, 888 First Street NE., Washington, DC 20426, (202) 502–8266; Christopher Handy (Accounting Information), Federal Energy Regulatory Commission, Office of Enforcement, 888 First Street NE., Washington, DC 20426, (202) 502–6496; Lina Naik (Legal Information), Federal Energy Regulatory Commission, Office of the General Counsel, 888 First Street NE., Washington, DC 20426, (202) 502–8882; Eric Winterbauer (Legal Information), Federal Energy Regulatory Commission, Office of the General Counsel, 888 First Street NE., Washington, DC 20426, (202) 502–8329.

SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,245

Notice of Proposed Rulemaking

(June 22, 2012)

1. In this Notice of Proposed Rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) seeks comment on a package of related proposals developed by the Commission based on comments received in response to a Notice of Inquiry (NOI)[2] issued in this proceeding on June 16, 2011. As the Commission noted in the NOI, there is growing interest in rate flexibility by both purchasers and sellers of ancillary services. A variety of resources are poised to provide ancillary services but may be frustrated from doing so by certain aspects of the Commission's market-based rate policies. At the same time, transmission customers and sellers alike are seeking greater transparency with regard to reserve requirements for ancillary services, with a particular focus on Regulation and Frequency Response. As the Commission has considered ways to foster transparency and competition in ancillary services markets, issues also have arisen related to accounting for and reporting of sales from energy storage devices that, if left unresolved, could impair the ability of these resources to participate in markets for ancillary services and other services subject to the Commission's jurisdiction.

2. The NOI explored these topics by seeking comment on existing restrictions on third-party provision of ancillary services, irrespective of the technologies used for such provision. The NOI also questioned whether the various cost-based compensation methods for Regulation and Frequency Response service that exist in regions outside of the current organized markets could be adjusted to address the same speed and accuracy issues identified in the proceeding that led to the issuance of Order No. 755.[3] Finally, the NOI sought comment on the adequacy of current accounting and reporting requirements as they pertain to the oversight of the provision of jurisdictional services from energy storage devices.

3. Based on the comments received in response to the NOI, the Commission proposes to revise certain aspects of its market-based rate regulations, ancillary services requirements under the *pro forma* open-access transmission tariff (OATT), and accounting and reporting requirements. Specifically, the Commission proposes to revise its *Avista Corp.* policy governing the sale of ancillary services at market-based rates to public utility transmission providers and reflect such reforms in Parts 35 and 37 of the Commission's regulations.[4] The Commission also proposes to require each public utility transmission provider to include provisions in its OATT explaining how it will determine Regulation and Frequency Response service reserve requirements in a manner that takes into account the speed and accuracy of resources used. Finally, the Commission proposes to revise certain accounting and reporting requirements under its Uniform System of Accounts for public utilities and licensees (USofA)[5] and its forms, statements, and reports, contained in FERC Form No. 1 (Form No. 1), Annual Report of Major Electric Utilities, Licensees and Others,[6] FERC Form No.

[1] *See Avista Corp.,* 87 FERC ¶ 61,223 (*Avista*), *order on reh'g,* 89 FERC ¶ 61,136 (1999).

[2] *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies,* 135 FERC ¶ 61,240 (2011) (NOI).

[3] *Frequency Regulation Compensation in the Organized Wholesale Power Markets,* Order No. 755, FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied,* Order No. 755–A, 138 FERC ¶ 61,123 (2012).

[4] *See Avista Corp.,* 87 FERC ¶ 61,223 (*Avista*), *order on reh'g,* 89 FERC ¶ 61,136 (1999) (*Avista Rehearing Order*).

[5] *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* 18 CFR part 101 (2011).

[6] 18 CFR 141.1 (2011).

1–F (Form No. 1–F), Annual Report for Nonmajor Public Utilities and Licensees,[7] and FERC Form No. 3–Q (Form No. 3–Q), Quarterly Financial Report of Electric Utilities, Licensees, and Natural Gas Companies,[8] to better account for and report transactions associated with energy storage devices used in public utility operations. The Commission seeks comment on these proposed reforms.

I. Background

4. The Commission has initiated numerous actions over the last several decades to foster the development of competitive wholesale energy markets by ensuring non-discriminatory access and comparable treatment of resources in jurisdictional wholesale markets.[9] With regard to ancillary services, the Commission in Order No. 888 [10] contemplated that third parties (i.e., parties other than a transmission provider supplying ancillary services pursuant to its OATT obligation) could provide ancillary services on other than a cost-of-service basis if such pricing was supported, on a case-by-case basis, by analyses that demonstrated that the seller lacks market power in the relevant product market.[11] Later, in *Ocean Vista Power Generation, L.L.C.,*[12] the Commission provided guidance regarding such analyses, explaining that as a general matter a study of ancillary services markets should address the nature and characteristics of each ancillary service, as well as the nature and characteristics of generation capable of supplying each service, and that the study should develop market shares for each service.

5. The Commission subsequently acknowledged in *Avista* [13] that data limitations can impair the ability of sellers to perform a market power study for ancillary services consistent with the requirements of *Ocean Vista.* The Commission therefore adopted a policy allowing third-party ancillary service providers that could not perform a market power study to sell certain ancillary services [14] at market-based rates with certain restrictions.[15] In so doing, the Commission reasoned that the backstop of cost-based ancillary services from transmission providers, in effect, limits the price at which customers are willing to buy ancillary services, thus ensuring that the third party sellers' rates would remain just and reasonable even without a showing of lack of market power. However, the Commission found that this backstop failed to provide adequate mitigation of potential third-party market power in three situations: (1) Sales to an RTO or an ISO, which has no ability to self-supply ancillary services but instead depends on third parties;[16] (2) to address affiliate abuse concerns, sales to a traditional, franchised public utility affiliated with the third-party supplier, or sales where the underlying transmission service is on the system of the public utility affiliated with the third-party supplier; and (3) sales to a public utility that is purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers.[17]

6. The Commission's focus in this proceeding is on the third situation above. The concern in this situation has been that if third parties who had not been shown to lack market power were permitted to sell to public utilities seeking to meet their OATT ancillary service obligations, the public utility's ability to recover such purchase costs in OATT rates might lead it to agree to above-market purchases, which would then be incorporated into the public utility's OATT ancillary service rate and gradually increase that rate. This increase in turn would reduce the ability of the cost-based OATT rate to serve as an alternative to the third-party market based rate, and thus undermine the mitigation measure that the Commission relied upon in *Avista* to enable relaxation of the requirement for a market power analysis.[18] In summary, under existing Commission regulation and policy, a third-party supplier may sell certain ancillary services at market-based rates without showing a lack of market power except under the three circumstances identified above.

7. Over a decade has passed since the Commission first developed the *Avista* restrictions. During this time, potential changes to the *Avista* restrictions have been considered by the Commission on several occasions. In the rulemaking proceeding leading to the issuance of Order No. 697, the Commission sought comment on whether to modify or revise the *Avista* policy and, if so, how.[19] The Commission ultimately

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[7] 18 CFR 141.2 (2011).

[8] 18 CFR 141.400 (2011).

[9] *See, e.g., Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,781 (1996), *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York* v. *FERC,* 535 U.S. 1 (2002); *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, FERC Stats. & Regs. ¶ 31,252, *clarified,* 121 FERC ¶ 61,260 (2007), *order on reh'g,* Order No. 697–A, FERC Stats. & Regs. ¶ 31,268, *clarified,* 124 FERC ¶ 61,055, *order on reh'g,* Order No. 697–B, FERC Stats. & Regs. ¶ 31,285 (2008), *order on reh'g,* Order No. 697–C, FERC Stats. & Regs. ¶ 31,291 (2009), *order on reh'g,* Order No. 697–D, FERC Stats. & Regs. ¶ 31,305 (2010), *aff'd sub nom. Montana Consumer Counsel* v. *FERC,* 659 F.3d 910 (9th Cir. 2011); *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228 (2009), *order on reh'g,* Order No. 890–D, 129 FERC ¶ 61,126 (2009); *Wholesale Competition in Regions with Organized Electric Markets,* Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *order on reh'g,* Order No. 719–A, FERC Stats. & Regs. ¶ 31,292 (2009), *order on reh'g,* Order No. 719–B, 129 FERC ¶ 61,252 (2009).

[10] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,781.

[11] Order No. 888 required six Ancillary Services to be included in the OATT: (1) Scheduling, System Control and Dispatch; (2) Reactive Supply and Voltage Control from Generation Sources; (3) Regulation and Frequency Response; (4) Energy Imbalance; (5) Operating Reserve—Spinning; and (6) Operating Reserve—Supplemental. Order No. 890 later added a seventh OATT ancillary service: Generator Imbalance. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 85.

[12] 82 FERC ¶ 61,114, at 61,406–07 (1998) (*Ocean Vista*).

[13] *Avista,* 87 FERC at 61,882.

[14] These ancillary services included: Regulation and Frequency Response, Energy Imbalance, Operating Reserve—Spinning, and Operating Reserve—Supplemental. The Commission did not extend this *Avista* policy to Reactive Supply and Voltage Control from Generation Sources service, which means that third parties wishing to sell this ancillary service at market-based rates would remain subject to the pre-*Avista* market power screen requirement. The Commission also did not extend the *Avista* policy to Scheduling, System Control and Dispatch service. However, because only balancing area operators can provide this ancillary service, it does not lend itself to competitive supply.

[15] One of the restrictions imposed in *Avista* was an obligation for sellers to establish an Internet-based Web site for providing information about and transacting ancillary services and on-going reports to the Commission detailing their activities in the ancillary services markets. *See Avista,* 87 FERC at 61,883. In Order No. 697, the Commission concluded that subsequent implementation of electric quarterly report (EQR) filing requirements justified eliminating these requirements under the *Avista* policy.

[16] Subsequently, as the Commission recognized in Order No. 697, most RTOs and ISOs developed formal ancillary service markets, thus rendering this component of the *Avista* policy largely superfluous. *See* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at n.1194 and P 1069.

[17] *Avista,* 87 FERC ¶ 61,223 at n.12.

[18] *See Avista Rehearing Order,* 89 FERC at 61,391–92 (stating that the Commission is ''able to grant blanket authority for flexible pricing only because the price charged by the third-party supplier is disciplined by the obligation of the transmission provider to offer these services under cost-based rates. This discipline would be thwarted if the transmission provider could substitute purchases under non-cost-based rates for its mandatory service obligation.'')

[19] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 1052.

retained its policy of not allowing sales of ancillary services by a third-party supplier in the three situations identified above, but noted its openness to considering requests for market-based rate authorization to make such sales on a case-by-case basis.[20] Such a request was submitted by WSPP in 2011. Based on the facts in that instance, the Commission rejected WSPP's request as it related to market-based sales by a third-party supplier to satisfy the purchasing transmission provider's own OATT requirements to offer ancillary services to its customers. However, the Commission noted that it was open to new approaches in the evaluation of proposals for sales of ancillary services at market-based rates and encouraged parties to submit proposals that address the Commission's concerns.[21]

8. In its ongoing effort to foster the development of competitive markets, including those for ancillary services, the Commission has continued to evaluate its *Avista* policy, in particular the restriction on the sale of ancillary services by third-parties to a public utility that is purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers. As the Commission considered potential revisions to the *Avista* policy, the Commission also has evaluated the extent to which other policies may impair development of ancillary services markets in light of a growing need for ancillary services to support grid functions in the face of potential changes in the portfolio of generation resources, entry of new technologies seeking to provide the service, and the growing interest of sellers and transmission providers to have flexibility in meeting ancillary services needs.[22]

9. This evaluation led the Commission to issue an NOI in this proceeding to seek comment on whether revising this aspect of the *Avista* restriction would be appropriate, either by implementing alternative methods of proving a lack of market power or alternative methods of mitigating any potential market power. The NOI also sought comment on cost-based compensation methods for Regulation and Frequency Response service, as well as accounting and reporting requirements as they pertain to oversight of the provision of jurisdictional services from energy storage devices.

10. Based on the comments received, the Commission includes in this NOPR a package of proposals to facilitate the development of competitive markets for ancillary services, increase transparency for Regulation and Frequency Response reserve requirements, and better account for and report transactions associated with energy storage devices used in public utility operations. The Commission describes each of these proposals in detail below.

II. Discussion

A. The Avista Policy

11. As noted above, the Commission's *Avista* policy authorizes the sale of certain ancillary services at market-based rates without showing a lack of market power except under specified circumstances. As relevant here, a third-party may not sell ancillary services at market-based rates to a public utility that is purchasing ancillary services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers. In order to overcome this restriction, a potential seller must provide a market power study demonstrating a lack of market power for the particular ancillary service in the particular geographic market. However, commenters in response to the NOI note that certain information needed to perform such a market power study is not currently available, effectively precluding them from the opportunity to make such a showing.[23] Whether due to this or other limitations, the effect of the *Avista* policy is to categorically prohibit sales of ancillary services to public utility transmission providers outside of the RTO and ISO markets.[24]

12. Some commenters suggest that the current analyses used to evaluate a seller's ability to exercise horizontal market power in the sale of energy and capacity remain sufficient to address market power in ancillary services as well.[25] Other commenters contend that alternative mitigation measures would be appropriate for sellers unable to perform a market power analysis, such as the use of price caps based on the purchasing utility's cost-based OATT ancillary services rates or the use of competitive solicitations.[26] The Commission believes that these suggestions may have merit and has developed potential reforms to the *Avista* policy to provide greater flexibility to sellers while protecting buyers from the exercise of market power that could lead to unjust and unreasonable or unduly discriminatory or preferential rates. These proposals are discussed further below.

1. Use of Market Power Analyses

13. The Commission analyzes horizontal market power[27] for sales of energy and capacity using two indicative screens, the wholesale market share screen and the pivotal supplier screen, to identify sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority.[28] The wholesale market share screen measures whether a seller has a dominant position in the relevant geographic market in terms of the number of megawatts of uncommitted capacity owned or controlled by the seller, as compared to the uncommitted capacity of the entire market.[29] A seller whose share of the relevant market is less than 20 percent during all seasons passes the wholesale market share screen.[30] The pivotal supplier screen evaluates the seller's potential to exercise horizontal market power based on the seller's uncommitted capacity at the time of annual peak demand in the relevant market.[31] A seller satisfies the pivotal supplier screen if its uncommitted capacity is less than the net uncommitted supply in the relevant market.[32]

14. Passing both the wholesale market share screen and the pivotal supplier screen creates a rebuttable presumption that the seller does not possess horizontal market power; failing either screen creates a rebuttable presumption that the seller possesses horizontal market power.[33] A seller that fails one

[20] *Id.* P 1061.

[21] *WSPP, Inc.,* 134 FERC ¶ 61,169 (2011).

[22] *See, e.g., Integration of Variable Energy Resources,* Order No. 755, FERC Stats. & Regs. ¶ 32,664 (2010); and *Demand Response Compensation in Organized Wholesale Energy Markets,* Order No. 745, 76 FR 16658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011).

[23] WSPP Comments at 7–10, ENBALA Comments at 2–3, California Storage Alliance Comments at 5–6, and ESA Comments at 8.

[24] As noted above, most RTOs and ISOs have developed formal ancillary service markets, allowing for the sale of ancillary services at market-based rates in those regions.

[25] PPL Companies Comments at 3, EPSA Comments at 5–6, and Portland General Comments at 3–4, Shell Energy Comments at 13–16, Powerex Comments at 38–40, and WSPP Comments at 11–12. While several commenters also support the idea of developing less challenging analyses for measuring ancillary service market power, none provides any concrete proposals. *See, e.g.,* California PUC Comments at 5.

[26] *See, e.g.,* Southern California Edison Comments at 5–6 and WSPP Comments at 16.

[27] 18 CFR 35.37(b) (2011).

[28] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 13, 62. *See also* 18 CFR § 35.37(b), (c)(1) (2011).

[29] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 43.

[30] *Id.* PP 43–44, 80, 89.

[31] 18 CFR 35.37(c)(1) (2011).

[32] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 42.

[33] 18 CFR 35.37(c)(1) (2011).

of the screens may present evidence, such as a delivered price test (DPT), to rebut the presumption of horizontal market power.[34] In the alternative, a seller may accept the presumption of horizontal market power and adopt some form of cost-based mitigation.[35]

15. Three of the key components of the analysis of horizontal market power are the definition of products, the determination of appropriate geographic scope of the relevant market for each product, and the identification of the uncommitted generation supply within the relevant geographic market. In Order No. 697, the Commission adopted a default relevant geographic market for sales of energy and capacity.[36] In particular, the Commission will generally use a seller's balancing authority area plus first-tier markets, or the RTO/ISO market as applicable, as the default relevant geographic market. However, where the Commission has made a specific finding that there is a submarket within an RTO, that submarket becomes the default relevant geographic market for sellers located within the submarket for purposes of the market-based rate analysis. The Commission also provided guidance as to the factors the Commission will consider in evaluating whether, in a particular case, to adopt an alternative larger or smaller geographic market instead of relying on the default geographic market. A necessary condition that must be satisfied to justify an alternative market is a demonstration regarding whether there are frequently binding transmission constraints during historical peak seasons examined in the screens and at other competitive significant times that prevent competing supply from reaching customers within the proposed alternative geographic market.[37]

16. For sales of energy and capacity, the product definitions are well understood, the relevant geographic market is generally the default market described above, and the uncommitted generation supply is generally identified as all such supply located within the seller's balancing authority area plus potential uncommitted imports as determined largely by available transmission capacity in the form of simultaneous import limits.[38] In contrast, defining the product, determining the relevant geographic market, and identifying uncommitted competing resources can be more complex for ancillary services. To date the Commission has not received an acceptable market power analysis for the sale of ancillary services at market-based rates outside of RTO/ISO markets. As noted above, certain commenters in response to the NOI contend that the information necessary to perform a market power analysis outside of RTO/ISO markets is not currently available.[39] Certain other commenters argue that the current analyses used to evaluate a seller's ability to exercise market power in the sale of energy and capacity are sufficient to address market power in ancillary services as well.[40]

17. Much of the difficulty in acquiring ancillary service-specific data is related to identifying specific resources that are physically capable of providing certain ancillary services. For instance, Schedule 6 Operating Reserve—Supplemental may be provided by generating units that are online but partially unloaded, by quick-start generating units that are offline or by interruptible load or other non-generation resources capable of providing this service.[41] The associated reliability standards definitions indicate that Operating Reserves—Supplemental must be fully available to serve load within the Disturbance Recovery Period, which by default is 15 minutes after a reportable disturbance.[42] Information related to the amount of capacity able to start within 15 minutes and information related to the quantity of load that is interruptible within 15 minutes may not be readily available. In addition, the extent to which a public utility decides to provide this service from partially loaded units is a decision that public utilities make on a day-to-day basis and is dictated in part by the amount of headroom available from the units that are committed and dispatched to serve and follow load. Information related to this kind of decision making is inherently difficult to obtain. This inability to obtain needed information coupled with the fact that certain ancillary services, as detailed further below, have geographic and other limitations gives rise to our interest in considering reforms based on the characteristics of the ancillary service to be provided.

a. Reliance on Existing Indicative Screens

18. In light of these issues associated with market power analyses for specific ancillary services, and the comments asserting that the existing market power analyses for sales of energy and capacity may be sufficient for ancillary services as well, the Commission has considered whether passing the existing market-based rate screens described above should create a rebuttable presumption that the seller lacks horizontal market power for ancillary services. As discussed below, the Commission believes that this may be the case for the two imbalance ancillary services (Energy Imbalance and Generator Imbalance), but that alternative definitions of the relevant geographic market and alternative assumptions for identifying potential competing resources within the relevant geographic market may be needed in order to apply the existing indicative screens to other ancillary services.

19. Units capable of providing Energy Imbalance and Generator Imbalance do not appear to require any different technical equipment or suffer from any different geographical limitations compared to units that provide energy or capacity. As one commenter argues, any available unit in a given geographic market would appear to be capable of providing energy that helps address imbalances in that market.[43] The Commission notes that this position is consistent with the Commission's

[34] 18 CFR 35.37(c)(2) (2011). For purposes of rebutting the presumption of horizontal market power, sellers may use the results of the DPT to perform pivotal supplier and market share analyses and market concentration analyses using the Herfindahl-Hirschman Index (HHI). The HHI is a widely accepted measure of market concentration, calculated by squaring the market share of each firm competing in the market and summing the results. The Commission has stated that a showing of an HHI less than 2,500 in the relevant market for all season/load periods for sellers that have also shown that they are not pivotal and do not possess a market share of 20 percent or greater in any of the season/load periods would constitute a showing of a lack of horizontal market power, absent compelling contrary evidence from intervenors. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 111.

[35] 18 CFR 35.37(c)(3) (2011).

[36] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 15.

[37] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 268.

[38] Studies of Simultaneous Transmission Import Limits (SIL) quantify a study area's simultaneous import capability from its aggregated first-tier area. SIL studies are used as a basis for calculating import capability to serve load in the relevant geographic market when performing market power analyses.

[39] WSPP Comments at 7–10; ENBALA Comments at 2–3; California Storage Alliance Comments at 5–6; and, ESA Comments at 8. Several of these commenters request that new reporting requirements be imposed to facilitate sellers' ability to perform market power analyses for ancillary services markets.

[40] PPL Companies Comments at 3, EPSA Comments at 5–6, and Portland General Comments at 3–4, Shell Energy Comments at 13–16, Powerex Comments at 38–40, and WSPP Comments at 11–12.

[41] *See, e.g.,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261, *Pro Forma* OATT at Schedule 6, Operating Reserve—Supplemental Reserve Service.

[42] *See, e.g.,* NERC Reliability Standard BAL–002–1, Disturbance Control Performance at R4.2, available at *http://www.nerc.com/files/BAL-002-1.pdf.*

[43] Shell Energy Comments at 12.

decision in Order No. 890–A to base cost-based imbalance charges in the OATT on the incremental cost of the last 10 MW dispatched by the transmission provider for any purpose, without imposing any requirement that this last 10 MW be based on resources with any particular capabilities.[44] To the extent that there are no unique technical requirements or limitations that apply to the provision of Energy Imbalance or Generator Imbalance, it would follow that the market-based rate screens for energy and capacity would consider the same set of units as a market power analysis designed for those two ancillary services.

20. Accordingly, the Commission proposes to revise its regulations governing market-based rate authorizations to provide that sellers passing existing market-based rate analyses in a given geographic market should be granted a rebuttable presumption that they lack horizontal market power for sales of Energy Imbalance and Generator Imbalance ancillary services in that market. Specifically, section 35.37 of the Commission's regulations would be revised to state that a seller would have a rebuttable presumption it lacks market power with respect to sales of energy, capacity, energy imbalance service, and generator imbalance service if the seller passes the pivotal supplier analysis based on annual peak demand of the relevant market and a market share analysis applied on a seasonal basis. The Commission preliminarily concludes that expanding the rebuttable presumption adopted in Order No. 697 for energy and capacity to include Energy Imbalance and Generator Imbalance provides adequate protection that market-based rates charged by public utilities will be just and reasonable and not unduly discriminatory or preferential. The Commission notes that this proposal would not constitute a revision to the *Avista* policy. Rather, this proposal merely finds that the existing market power screens can be applied to analysis of market power for Energy Imbalance and Generator Imbalance. As a result, sellers who pass the existing market power screens would not be subject to the sales restrictions otherwise required under the *Avista* policy. The Commission seeks comment on this proposal, including the proposed revisions to part 35.37(c)(1) of our regulations, and its application to Energy Imbalance and Generator Imbalance services. Comments may address, among other things, any unique technical requirements or limitations that might apply to the provision of the ancillary imbalance services, and the Commission's proposal to extend the rebuttable presumption to imbalance services.

21. There appear to be significant technical requirements or limitations that apply to the provision of ancillary services other than Energy Imbalance and Generator Imbalance such that the existing market-based rate screen may not be adequate to capture the potential horizontal market power of sellers of these other ancillary services. Technical considerations may limit the units capable of providing Reactive Supply and Voltage Control, Regulation and Frequency Response, Operating Reserve-Spinning, and Operating Reserve-Supplemental services as compared to the broader set of units capable of providing energy or capacity potentially requiring the identification of a different geographic market than the default geographic market used to conduct market power analyses for sales of energy and capacity and a change to the assumptions used to identify potential competing resources within that market. For example, the size of the relevant geographic market for a particular ancillary service may be subject to change based on system conditions and the need to meet applicable reliability criteria. The balancing authority may at times be able to procure ancillary services on a system-wide basis, whereas at other times factors may require the balancing authority to procure ancillary services on a zonal or even more location-specific basis. Further, not every facility that has the capability to provide energy will have the capability to provide every ancillary service. Also, the procurement may involve commercially sensitive internal decision-making that determines what proportion of a unit's total capability will be dedicated to a particular ancillary service instead of energy and capacity.

22. With regard to Operating Reserve—Spinning and Operating Reserve—Supplemental, the Commission recognizes that resources used to provide these services are maintained to convert to energy if needed, as with imbalance services. However, minimum ramp rate requirements and stringent minimum start-up rates for off-line resources used for supplemental reserves apply to the provision of Operating Reserve—Spinning and Operating Reserve—Supplemental. For on-line resources, not all types of units may be capable of extended periods of operation below their fully loaded set point, or such operation may be prohibitively uneconomic.

23. With regard to Reactive Supply and Voltage Control, technical and geographic considerations generally limit the units capable of providing this ancillary service as compared with the broader set of units capable of providing energy or capacity. In order to provide Reactive Supply and Voltage Control service, conventional synchronous generators must be able to vary the voltage level of their electrical output. Not all synchronous generators may choose to operate in a way that provides Reactive Supply and Voltage Control service. Similarly, non-traditional asynchronous resources require some other power electronic controls in order to provide this ancillary service, and not all owners of asynchronous resources choose to install the needed controls. Further, non-generation resources may be technically capable of providing this ancillary service with appropriate controls, but they may not all choose to install the needed controls. Finally, as recognized in numerous venues and proceedings including Order No. 888, losses of reactive power during transmission may be significantly greater than losses incurred in delivering real power, meaning that reactive power must often be supplied from local resources.[45] Therefore, the appropriate relevant geographic market for Reactive Supply and Voltage Control service could be smaller than the default geographic market discussed above and even within that reduced geographic market, not all resources may be capable of competing to provide this particular ancillary service. Moreover, conventional resources generally require Automatic Generation Control (AGC) equipment in order to provide Regulation and Frequency Response service, while non-traditional resources require power electronic controls that perform like AGC. Not all units have AGC or power electronic controls that perform like AGC. Therefore, a different set of competing resources might need to be identified within the default geographic market for Regulation and Frequency Response service.

24. The Commission seeks comments on whether the technical requirements

[44] *See* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 309.

[45] FERC, *Principles for Efficient and Reliable Reactive Power Supply and Consumption,* Docket No. AD05–1–000, at 18 (2005), *available at http://www.ferc.gov/EventCalendar/Files/20050310144430–02–04–05-reactive-power.pdf.* (''Reactive power is difficult to transport. At high loadings, relative losses of reactive power on transmission lines are often significantly greater than relative real power losses * * * Losses in transmission lead to the expression that reactive power does not travel well.'').

for Operating Reserve—Spinning, Operating Reserve—Supplemental, Reactive Supply and Voltage Control, and Regulation and Frequency Response would necessitate a market power analysis based on a different geographic market or different set of resources as compared to those analyzed to determine market power for sales of energy and capacity. If so, we seek comment on how the relevant geographic market can be identified and how potentially competing resources with the needed characteristics can be identified within the relevant geographic market. Finally, we seek comment on whether the limited reporting requirement and optional market power screen, discussed further below, could be applicable for assessing the market power of potential sellers of these ancillary services.

b. Optional Market Power Screen

25. Several commenters to the NOI support the idea of developing alternative analyses for measuring market power for ancillary services,[46] while others propose that new reporting requirements be imposed to facilitate sellers' ability to perform market power analyses for ancillary services markets.[47] Upon review of these comments, the Commission proposes a limited new reporting requirement that would provide potential sellers of ancillary services[48] with the information needed to develop market power analyses using an optional market power screen solely applicable to ancillary services. Specifically, the Commission proposes to require each public utility transmission provider to publicly post on its OASIS information as to the aggregate amount (MW or MVAR, as applicable) of each ancillary service that it has historically required, including any geographic limitations it may face in meeting such ancillary service requirements.[49] For example, a hypothetical transmission provider may report that it has historically maintained 100 MW of Regulation and Frequency Response reserves for its balancing area and 100 MVAR of Reactive Supply and Voltage Control in each of two submarkets within its balancing authority area.

26. The optional market power screen for an ancillary service would then compare the amount of capacity in MWs (or, as applicable, MVARs) that a potential seller can dedicate to providing the ancillary service in the relevant geographic market with the buyer's reported aggregate requirement for that ancillary service, taking into account any reported historical locational requirements (e.g., locational requirements due to such things as binding transmission constraints or the geographic limitations of Reactive Supply). Using this optional market power screen, sellers whose available capacity is no more than 20 percent of the relevant reported aggregate requirement for an ancillary service would then receive a rebuttable presumption that they lack horizontal market power for the ancillary service in question.

27. The Commission recognizes that this approach would be an alternative to the Commission's historical approach to conducting market power analyses, though we believe it is consistent with the principles by which we developed our market power analyses. Moreover, this approach would be limited solely to market power analyses of ancillary services and would be permitted because of the lack of publicly-available information on the potential supply of various ancillary services in a given geographic market. In *Ocean Vista* the Commission explained that as a general matter, a study of ancillary service markets should address the nature and characteristics of each ancillary service, as well as the nature and characteristics of generators capable of supplying each service, and the study should develop market shares for each service.[50] Of particular relevance here, the Commission stated that the market power analysis for ancillary services markets should identify the relevant geographic market, which could include all potential sellers of the product from whom the buyer could obtain the service, taking into account relevant factors which may include the other sellers' locations, the physical capability of the delivery system and the cost of such delivery, and important technical characteristics of the sellers facilities.[51]

28. The proposed approach discussed above is consistent with these principles. Identification of the aggregate requirement for each ancillary service within the balancing authority area serves as a proxy for the identification of the amount and location of resources that may be technically capable of providing the requisite service in the relevant geographic market, without requiring resource-specific information for resources currently providing the service. The Commission has allowed use of proxies for various inputs to the indicative screens to simplify or streamline the analyses,[52] and in particular has stated that a seller, where appropriate, can make certain simplifying assumptions, such as performing the indicative screens assuming that the relevant market has no import capability (this was modified in later orders to mean no competing imports) or treating the host balancing authority area utility as the only other competitor.[53] Essentially, the proposed proxy would treat the resources used historically by the host balancing authority area utility as the only other competing resources for purposes of market share analysis. This proxy would take into account the nature and characteristics of each ancillary service, as well as the nature and characteristics of resources capable of supplying each service and any limitations such as deliverability that have historically affected designation of resources to provide the ancillary service. The proposed approach would allow potential third party sellers to compare their ancillary service capacity to the capacity that has historically been needed to provide the service as shown by the relevant transmission provider's OASIS posting of ancillary service

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[46] *See, e.g.,* California PUC Comments at 5.

[47] *See, e.g.,* NGSA comments at 5 and EPSA comments at 3–4.

[48] The Commission envisions this optional screen being available as a voluntary alternative to the type of market power analyses described in *Ocean Vista.* The Commission also envisions permitting this optional screen to be used solely in connection with sales of Operating Reserve-Spinning, Operating Reserve-Supplemental, Reactive Supply and Voltage Control, and Regulation and Frequency Response services. Further, if our earlier proposal regarding application of the existing screens to Energy and Generator Imbalance services is not ultimately finalized, then we would envision permitting the application of this optional screen to those ancillary services as well.

[49] This requirement would parallel the existing requirement for a seller that owns, operates or controls transmission to conduct simultaneous transmission import capability studies for its home control area and each of its directly-interconnected first-tier control areas in order to facilitate market power analyses by all sellers in the relevant market. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 346. The Commission's existing requirements and policies with regard to submission of historical data would apply. Therefore, any concerns as to possible manipulation of this data should be ameliorated.

[50] *Id.* P 1048.

[51] *Id.*

[52] For example, the Commission has allowed wind generating facilities that lack five years of operational data to use a five-year average regional wind capacity factor based on data reported by the Energy Information Administration to de-rate their capacity. *See Golden Spread Electric Cooperative, Inc.,* 138 FERC ¶ 61,208 (2012). Additionally, in Order No. 697, the Commission stated that it will allow the capacity of energy-limited facilities to be set equal to their five-year average historical capacity factor. Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 344. The Commission also stated that it is willing to consider proxy amounts for simultaneous transmission import limits. *Id.* P 381.

[53] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 321.

requirements, and calculate a market share on that basis.

29. The Commission preliminarily concludes that this approach will foster transparency and competition in the provision of ancillary services by providing information for ancillary service sellers to perform the market power analyses required by the Commission's rules while continuing to provide protection for customers from the potential exercise of market power. As with the expansion of the rebuttable presumption for energy and capacity to include Energy Imbalance and Generator Imbalance proposed above, the optional power market screen for ancillary services proposed here would not constitute a revision to the *Avista* policy. Rather, it merely would provide another means of demonstrating a lack of market power in sales of ancillary services. As a result, sellers who pass this optional market power screen would not be subject to the sales restrictions otherwise required under the *Avista* policy.

30. The Commission seeks comment on whether the proposed limited OASIS reporting requirement combined with the opportunity to use an optional market power screen for ancillary services, as described above and in proposed new parts 37.6(k) and 35.37(c)(5) respectively of our regulations, will provide adequate protection that market-based rates charged by public utilities will be just and reasonable and not unduly discriminatory or preferential. The Commission also requests that commenters address the use of the optional screen for Energy and Generator Imbalance ancillary services given the Commission's proposal above that sellers passing existing market-based rate analyses in a given geographic market should be granted a rebuttable presumption that they lack horizontal market power for sales of Energy Imbalance and Generator Imbalance ancillary services in that market. Additionally, the Commission requests comments on the appropriate level of detail to include in the proposed reporting requirement. The Commission is aware that balancing areas determine reserve requirements in different ways; for example, some may have static reserve requirements updated once a year, while others specify reserve requirements as a percentage of load, meaning that their reserve amounts can change throughout a year. The Commission does not at this time intend to change how balancing areas determine their reserve amounts. Rather, we wish the proposed OASIS reporting requirement to adequately capture whatever method the balancing area employs and be detailed enough to support the proposed optional market power screen. For example, if ancillary service reserve requirements change periodically throughout a year, should the associated OASIS posting show the different amounts of reserve procurement with their associated time periods or should the OASIS posting show a single average reserve procurement amount for the year? The Commission also asks for comments on whether the optional market power screen should only be implemented on an experimental basis until the Commission has more experience with the evolution of ancillary service markets and in reviewing the quality of optional market power screens.

2. Alternative Cost-Based Mitigation

31. The NOI also sought comment on alternative mitigation measures to the prohibition adopted in *Avista* with regard to sales to a public utility that is purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers. In particular, the Commission sought comment on the possibility of relying on an explicit price cap based on the purchasing utility's cost-based OATT ancillary service rates or the use of competitive solicitations. Based on a review of the resulting comments, the Commission seeks further comment regarding whether the specific alternative cost-based mitigation measures described below that would allow third-party sales to a public utility without showing a lack of market power are adequate to ensure that rates charged by third parties for Regulation and Frequency Response, Operating Reserve-Spinning, or Operating Reserve-Supplemental service will be just and reasonable and not unduly discriminatory or preferential. In addition, while the *Avista* policy did not apply to Reactive Supply and Voltage Control service, the Commission seeks comment on whether third-party sales of Reactive Supply and Voltage Control service to a public utility to satisfy its own OATT obligations should be permitted under one of the price cap options discussed below.

32. Specifically, the Commission proposes to permit sellers unable or unwilling to perform the market power study for ancillary services to propose price caps at or below which sales of Regulation and Frequency Response, Reactive Supply and Voltage Control, Operating Reserve-Spinning, or Operating Reserve-Supplemental service would be allowed where the purchasing entity is a public utility purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers. Such a price cap would be based on one of the two possible OATT ancillary service rate caps discussed below and, as in *Avista,* we propose that sales under these price caps would only be permitted in geographic markets where the seller has been granted market-based rate authority for sales of energy and capacity. Alternatively, a seller unable to perform a market power study for ancillary services could rely on competitive solicitations meeting certain minimum requirements in order to make sales in geographic markets where the seller has been granted market-based rate authority for sales of energy and capacity.

a. Use of Price Caps

33. As noted above, the Commission in the NOI explored the idea of using price caps based on the purchasing utility's OATT rates to serve as an alternative mitigation to the *Avista* policy. Use of price caps or other proxies is not unprecedented. For example, the Commission has long permitted cost-of-service sellers to propose cost-justified ceiling rates to allow the seller to respond quickly to market opportunities by discounting below the approved ceiling.[54] In many respects the cost-based ceiling rate umbrella tariffs of decades past may have helped begin the development of bilateral markets for energy and capacity, and we believe the development of bilateral markets for ancillary services today may similarly benefit from the availability of appropriate price cap options. Below we propose two options for comment.

34. First, third parties would be permitted to sell to a public utility buyer at rates not to exceed the buying public utility transmission provider's existing OATT rate for the same ancillary service. The Commission anticipates that this option should be relatively non-controversial to implement as the buyer's OATT ancillary service rates will have already been found to be just and reasonable. However, we recognize that in some situations this type of price cap may do

[54] *See, e.g., Central Maine Power Company,* 56 FERC ¶ 61,200, at 61,818–19 (1991) (''We are aware of the argument that, due to the need to respond quickly to market changes and opportunities for coordination, in some cases transactions must begin before the utility has a chance to file the rate reflecting the transaction with the Commission. While this argument has some merit, we note that many utilities have managed to avoid this problem by having tariffs on file that permit transactions to be negotiated *subject to a cap of 100-percent contribution to fixed costs.''* (emphasis added)).

little to signal a buyer's interest in the procurement of ancillary services or reflect the actual practices in a region, which may include pooling or sharing of reserves. Rather, a policy that relies on the rate of a single buyer may serve as a disincentive to the entry of additional resources to provide ancillary services and ultimately undermine the goal we are trying to achieve of providing sellers some flexibility while ensuring just and reasonable rates. The Commission also appreciates that an individual buyer's OATT ancillary service rates may be higher or lower than the cost of new entry and that they do not necessarily signal whether investment is needed to provide the service.

35. Notwithstanding these potential limitations of relying on a cap at the buying public utility transmission provider's OATT ancillary service rate, the Commission believes that such a cap could provide a means of mitigating the potential market power of sellers unable to perform a market power analysis. Furthermore, a price cap based on the buyer's OATT ancillary service rate may best match the geographic limitations of an ancillary service like Reactive Supply and Voltage Control, and may provide the simplest route to expanded supply at just and reasonable rates for service areas that require more Reactive Supply and Voltage Control. The Commission seeks comment on whether this cost-based cap would provide an effective alternative to imposition of the *Avista* restriction for mitigating potential market power. The Commission also seeks comment on whether this type of cap would induce the provision of ancillary services, particularly from parties who believe that this cap would be beneficial to their efforts to buy or sell specific ancillary services, such as Reactive Supply and Voltage Control. We also seek comment on whether the Commission should require additional transparency provisions to accompany such a cap beyond electric quarterly reports. These provisions may include the transmission provider posting its need for ancillary services and any seller responses.

36. Under the second option, third parties could propose to sell a given ancillary service to a public utility buyer at rates not to exceed the highest public utility transmission provider OATT rate within the relevant geographic market for physical trading of the ancillary service in question. Under this type of regional price cap, the seller (or group of sellers) would be required to file with the Commission a proposal that defines the scope of a contiguous geographic region that both encompasses the service territory(ies) of the public utility transmission provider whose OATT ancillary service rate will form the basis for the price cap, and within which trading of the ancillary service in question is physically possible. Using the highest OATT ancillary service rate as a price cap for a predefined market area with the characteristics above may address some of the potential limitations of a price cap based on an individual public utility transmission provider OATT identified above. Additionally, it may be a more reasonable approximation of the cost of new entry within a market where physical trading of the ancillary service in question is possible.

37. Such a regional price cap proposal could be proposed for any contiguous trading area within which the filer or filers propose to make physical trades of ancillary services. The Commission anticipates that this trading area often may include the seller's home balancing authority area plus first-tier balancing authority areas and possibly additional areas where transmission capacity is available. However, the Commission is concerned that sellers could seek to define regions that are unrealistically broad in order to access a high OATT ancillary service rate from outside their region that may not be appropriate elsewhere. To prevent this type of distortion, the Commission proposes to require price cap sellers to show that the ancillary services in question can be physically traded throughout the region they propose for a given ancillary service price cap. Such a showing would need to take into account the technical characteristics of the ancillary service in question in order to demonstrate the physical ability to trade in the proposed market area. For example, because of their different characteristics, a contiguous geographic region within which it is physically possible to trade Operating Reserve-Spinning is likely to be much greater than any contiguous geographic region within which it is physically possible to trade Reactive Supply and Voltage Control. We seek comment on the types of information available to make such a showing.

38. Also, because different sellers proposing to sell the same ancillary service could conceivably propose different but overlapping trading regions, which might result in multiple regional price caps applying to sales in the overlapping areas, the Commission seeks comment on whether this type of overlap should be permitted. If not, the Commission seeks comment on ways to prevent such overlap in the definition of trading regions. In a similar vein, the Commission also recognizes the possibility that some sellers may propose a regional price cap for a given trading area, while other sellers in the same trading area may propose to sell to specific buying public utilities under the other price cap option discussed above; a price cap set at the buying public utility's relevant OATT ancillary service rate. The Commission seeks comment on whether this type of overlap should be permitted and, if not, on ways it could be prevented.

39. As discussed earlier, the Commission recognizes that the single-public utility price cap option may best match the geographic limitations associated with Reactive Supply and Voltage Control service. Should the Commission, as a result, exclude Reactive Supply and Voltage Control from the list of ancillary services eligible for a regional price cap proposal, meaning that Reactive Supply and Voltage Control could only be sold under a price cap based on the buying public utility's OATT rate for Reactive Supply and Voltage Control?

40. The Commission proposes to amend its regulations at part 35.38 to provide that either of the OATT-based price caps described above can be proposed as mitigation of potential horizontal market power in ancillary services for those sellers who fail or forego relevant, properly defined market power screens for the ancillary service in question. The Commission preliminarily concludes that either cap could serve as an alternative method of ensuring just and reasonable rates for ancillary services that would, unlike the *Avista* mitigation scheme, permit willing buyers and sellers of ancillary services to transact, and thus provide a means of increasing the supply of needed ancillary services in a timely and cost-effective manner. The Commission seeks comment on its proposal, including whether these price caps will provide an effective mitigation measure as an alternative to imposition of the *Avista* restriction, and how the Commission should address the other questions described above.

b. Competitive Solicitations

41. The NOI also sought comment regarding whether transmission providers' use of open and transparent competitive solicitations could facilitate the provision of ancillary services and ensure just and reasonable rates. The Commission sought comment regarding whether a standardized competitive solicitation process could be developed for particular regions or markets.

42. While commenters are generally supportive of the use of competitive solicitations, some contend that competitive solicitations should not be the only option for mitigating market power concerns because past solicitations for ancillary services have not always produced enough interest to ensure a competitive outcome, and this may continue to be the case for some time to come.[55] WSPP also argues that competitive solicitations are probably impractical for short-notice transactions that would commence within a month or less.[56] However, others appear to suggest that the Commission mandate that all ancillary services be procured through competitive solicitations.[57]

43. The comments on this issue indicate that competitive solicitations may not be appropriate for all transactions and may not be sufficient to mitigate potential market power in the sale of ancillary services in every circumstance. However, this does not mean that competitive solicitations should not be available as an option for mitigating potential market power concerns. The Commission proposes to allow applicants to engage in sales to a public utility that is purchasing ancillary services to satisfy its OATT requirements to offer ancillary services to its own customers where the sale is made pursuant to a competitive solicitation that meets the following requirements.

44. Specifically, the Commission has stated that the following four guidelines help determine if a competitive solicitation process satisfies the principle that no affiliate should receive undue preference during any stage of a request for proposals: (1) Transparency: the competitive solicitation process should be open and fair; (2) definition: the product or products sought through the competitive solicitation should be precisely defined; (3) evaluation: evaluation criteria should be standardized and applied equally to all bids and bidders; and (4) oversight: an independent third-party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection.[58]

45. While the Commission originally issued these guidelines for the purpose of preventing undue affiliate preference, we believe they are also applicable in the context of using competitive solicitations to help mitigate the potential exercise of horizontal market power by sellers of ancillary services. However, even if a solicitation process meets all of these guidelines, it may still fail to attract sufficient numbers of sellers to properly discipline resulting market prices. Accordingly, for purposes of a mitigation proposal applicable to market-based sales of ancillary services, the Commission proposes to require entities filing such a proposal to demonstrate to the Commission that the solicitation attracted sufficient seller interest to properly discipline market prices. This showing would be required in addition to the four criteria listed above. The Commission believes that all of these requirements in combination will protect against horizontal market power and thereby ensure just and reasonable rates. We seek comment on this proposal and encourage commenters to develop ideas for ways in which competitive solicitations can be structured to accommodate near-term transactions.

46. Consistent with the discussion above, the Commission proposes to amend section 35.38 of its regulations to provide the opportunity for public utilities seeking waiver of the *Avista* restriction to rely on competitive solicitations meeting the Commission's requirements for transparency, definition, evaluation, oversight, and adequate seller interest.

B. Resource Speed and Accuracy in Determination of Regulation and Frequency Response Reserve Requirements

47. In addition to exploring potential changes to the Commission's requirements for market-based rate authority discussed above, the NOI also sought comment on whether the various cost-based compensation methods for Regulation and Frequency Response service that exist in regions outside of the current organized markets could be adjusted to address the issues identified in the proceeding that led to the issuance of Order No. 755.[59] In that proceeding, the Commission required changes to compensation mechanisms for Regulation and Frequency Response service in the RTO and ISO markets to ensure that all resources providing service are compensated in a just and reasonable and not unduly discriminatory manner. While acknowledging that the specific reforms ultimately adopted in Order No. 755 would not apply outside of RTOs and ISOs, the NOI questioned whether the underlying goal of better valuing the benefits of faster, more accurate provision of Regulation and Frequency Response service could be achievable in other ways outside of RTOs and ISOs.

48. Specifically, the NOI sought comment on: (1) How a cost-based cap for Regulation and Frequency Response service in the WSPP Agreement[60] could be structured to reflect an individual resource's performance; (2) whether transmission customers that self-supply Regulation and Frequency Response service could be permitted to determine the amount of capacity they procure based on the third-party resource's performance capability; and (3) any other way to extend the goals of the Frequency Regulation Compensation NOPR,[61] which ultimately resulted in Order No. 755, outside of the ISOs and RTOs.

49. Most of the more concrete NOI comments on this issue focus on the second question above: whether transmission customers that self-supply Regulation and Frequency Response

[55] Bonneville Comments at 8–9.

[56] WSPP Comments at 21–22.

[57] ESA Comments at 11–12, PPL Companies Comments at 9, IID Comments at 15, and CAREBS Comments at 6.

[58] *See, e.g., Allegheny Energy Supply Co. LLC,* 108 FERC ¶ 61,082 (2004).

[59] Order No. 755, FERC Stats. & Regs. ¶ 31,324 at P 68 (''faster-responding resources have the potential to lower frequency regulation capacity requirements, thereby improving market efficiencies'').

[60] The WSPP Agreement was initially accepted by the Commission on a non-experimental basis in 1991, and provided for flexible pricing for coordination sales and transmission services. *See Western Sys. Power Pool,* 55 FERC ¶ 61,099, *order on reh'g,* 55 FERC ¶ 61,495 (1991), *aff'd in relevant part and remanded in part sub nom. Environmental Action and Consumer Federation of America* v. *FERC,* 996 F.2d 401, 302 U.S. App. D.C. 135 (D.C. Cir. 1992), *order on remand,* 66 FERC ¶ 61,201 (1994). Prior to 1991, the WSPP Agreement was used for three years on an experimental basis. *See Pacific Gas and Electric Co.,* 50 FERC ¶ 61,339 (1990) (extending the initial two-year period of the WSPP Agreement for an additional year). The WSPP Agreement as it exists today permits sellers of electric energy to charge either an uncapped market-based rate (for public utility sellers, they must have obtained separate market-based rate authorization from the Commission to do this), or an ''up to'' cost-based ceiling rate. For sellers without market-based rate authority, the cost-based rate under the WSPP Agreement consists of an individual seller's forecasted incremental cost plus an ''up to'' demand charge based on the average fixed costs of a subset of the original parties to the WSPP Agreement, so long as the seller can justify the use of this charge based on its own fixed costs. Otherwise, the seller must file a separate stand-alone rate schedule that is cost-justified based on the individual seller's own costs. *See Western Sys. Power Pool,* 122 FERC ¶ 61,139 (2008) (finding that it is not just and reasonable to allow a seller to use the WSPP-wide ''up to'' demand charge as a ceiling rate in markets where the seller does not have market-based rate authority unless such a seller can cost-justify the use of the ''up to'' demand charge based on its own fixed costs). Currently, there are over 300 parties to the WSPP Agreement located throughout the United States and Canada, including private, public and governmental entities, financial institutions and aggregators, and wholesale and retail customers.

[61] *Frequency Regulation Compensation in the Organized Wholesale Power Markets,* FERC Stats. & Regs. ¶ 32,672 (2011) (Frequency Regulation Compensation NOPR). Order No. 755 had not yet issued at the time of the NOI in this proceeding.

service could be permitted to determine the amount of capacity they procure based on the third-party resource's performance capability.[62] Some commenters suggest that customers choosing to self-supply Regulation and Frequency Response service from faster-acting resources should be allowed to self-supply a lower volume of regulation capacity.[63] Powerex suggests that each balancing authority be required to maintain well-defined criteria under which a transmission customer self-providing ancillary service reserves can adjust the level of reserves based on the ramping capability of the resources it uses.[64] Bonneville states that, in such circumstances, the balancing authority should make the determination as to the appropriate level of capacity procurement, not the customer itself.[65]

50. Under the existing requirements of the *pro forma* OATT, each public utility transmission provider is required to provide its transmission customers with the option of self-supplying certain ancillary services, including Regulation and Frequency Response service.[66] This self-supply option has been clear since Order No. 888 and, therefore, public utility transmission providers must be prepared to provide self-supply requirements on request from a transmission customer. However, the Commission to date has not addressed the extent to which such requirements should reflect the characteristics of particular resources being used to provide Regulation and Frequency Response service.

51. The Commission proposes to require that each public utility transmission provider submit provisions for inclusion in its OATT that take into account the speed and accuracy of regulation resources in determining its Regulation and Frequency Response reserve requirements.[67] These provisions must include a description of how the public utility transmission provider would make adjustments to the capacity requirement when a customer opts to self-supply its requirements, including through purchases from third-parties, using resources with speed and accuracy characteristics that differ from the set of resources otherwise being used for Regulation and Frequency Response. This description could include the set of resources the public utility transmission provider uses to provide Regulation and Frequency Response service, indicating the capacity typically set aside from each resource and the ramp rate associated with each resource. The description needs to provide enough detail to allow an entity wishing to self-supply to compare the resources it proposed to use to the resources the public utility transmission provider is using to provide Regulation and Frequency Response service. Presumably, this adjustment could be in either direction: down if the customer self-supplies with faster or more accurate resources or up if it uses slower or less accurate resources.

52. The Commission preliminarily finds that accounting for speed and accuracy in a public utility transmission provider's determination of Regulation and Frequency Response reserve requirements is necessary to address the potential for undue discrimination against customers choosing to self-supply their Regulation and Frequency Response needs, including through purchases from third-parties. The Commission is concerned that a public utility transmission provider could engage in undue discrimination by requiring such customers to procure a different amount of regulation reserves than the particular speed and accuracy characteristics of the resources in question justify. Accordingly, the Commission proposes to amend its regulations at part 35.28 to require that public utility transmission providers amend their OATTs at Schedule 3 (Regulation and Frequency Response Service) to explain how they will take into account the speed and accuracy of regulation resources in determining Regulation and Frequency Response reserve requirements. The Commission acknowledges that each public utility transmission provider has unique needs related to Regulation and Frequency Response reserve requirements and, accordingly, may account for speed and accuracy in different ways. Therefore, the Commission does not at this time seek to mandate a particular methodology but instead expects that it would evaluate each proposed determination relevant to Regulation and Frequency Response reserve requirements on a case-specific basis.

53. The Commission seeks comment on this proposal, including comment on how speed and accuracy can be taken into account in the determination of Regulation and Frequency Response reserve requirements, and the Commission's preliminary conclusion that requiring transparency in the determination of Regulation and Frequency Response reserve requirements will help prevent undue discrimination in the form of public utility transmission providers requiring self-supplying customers to procure a different amount of regulation reserves than the particular speed and accuracy characteristics of the resources in question justify.

54. Further, in consideration of the comments regarding the ability of a customer to self-supply ancillary services, we take this opportunity to remind public utility transmission providers that they are already required to post on their public Web sites all rules, standards, and practices, to the extent they exist, that relate to transmission service. This includes the provision of ancillary services which are necessary to the provision of transmission service. As such, the obligation is clear and we see no need at this time to propose reforms.[68]

C. Accounting and Reporting for Energy Storage Operations

55. Finally, the NOI also asked about the Commission's accounting and reporting requirements for energy storage operations. Comments were sought on what changes, if any, should be made to the Commission's accounting and reporting regulations to provide for energy storage services, assets and operations. Comments were received from public utilities, industry associations, government agencies, and others. As noted in the NOI, the accounting regulations currently found in the USofA and the related reporting

[62] *See, e.g.,* Bonneville Comments at 9–10, California Storage Alliance Comments at 14–19, ESA Comments at 27–28, Powerex Comments, Appendix A at 8, and A123 Comments at 2–4. Other comments included WSPP's suggestion that a rate cap proposal could use the two-part rate design described in the Frequency Regulation NOPR, but WSPP does not provide any details regarding how such a rate design could be structured. WSPP Comments at 26–27.

[63] California Storage Alliance Comments at 14–17; ESA Comments at 27–28.

[64] Powerex Comments, Appendix A at 8.

[65] Bonneville Comments at 10.

[66] *See, e.g.,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,716; *pro forma* OATT, Original Sheet Nos. 20–21 and Schedule 3, Original Sheet No. 113.

[67] The Commission acknowledges that each balancing authority is responsible for determining its reserve requirements in order to comply with relevant NERC reliability standards, and that sometimes an individual OATT transmission provider may be its own balancing authority and other times it may be part of a larger balancing authority. The Commission also notes that a new standard, BAL–003–1 (Frequency Response and Frequency Bias Setting), is currently under development by NERC stakeholders and may assign a frequency response obligation to each balancing authority or reserve sharing group and require each balancing authority or reserve sharing group to use an appropriate frequency bias setting in its ACE equation and to achieve an adequate annual frequency response measure. While frequency response is distinguished from frequency regulation by the manner in which it is controlled (*see, e.g.,* Order No. 755, FERC Stats. & Regs. ¶ 31,324 at n.5), this standard may also be relevant to a balancing authority's determination of its overall reserve requirements.

[68] 139 FERC ¶ 61,246.

requirements were developed to capture financial and operational information along traditional primary business functions—production, transmission, and distribution of electric energy.[69] Further, as also noted, energy storage assets can have operating characteristics of each of these functions and some may be capable of performing multiple functions simultaneously.[70] Accordingly, entities using energy storage assets may seek multiple methods of cost recovery for their investments in and use of a single energy storage asset to provide various utility services.[71]

56. Numerous comments were received regarding the need for updating the USofA and Form Nos. 1 and 1–F for the accounting and reporting of public utilities. Most commenters are supportive of making amendments to accommodate energy storage transactions. However, some commenters indicate that the Commission's current accounting and reporting requirements sufficiently accommodate these types of transactions.

57. In general, commenters that support amending the current accounting and reporting requirements indicate that the operating nature of energy storage assets is different from typical electric plant assets. These commenters indicate that energy storage assets can be used to serve multiple purposes—production, transmission, or distribution—whereas traditional electric plant assets only serve one purpose. Consequently, they explain that this difference in capabilities can mandate, in certain cases, that the energy storage assets be accounted for differently than traditional electric plant assets. These commenters indicate that changes to the accounting and reporting requirements are needed to address concerns about the potential for cross-subsidization and double or over-recovery of costs in instances where an energy storage asset is simultaneously included in cost-based and market-based rates. Most of these commenters recommend specific accounting and reporting amendments that could assist with protecting against these concerns and certain other commenters in this group expressed that the concern existed but offered no recommendations. For example, Electricity Consumers did not propose specific accounting changes; however, it indicates that it supports accounting treatments that could enhance cost transparency to protect against double-recovery of costs.[72]

58. Several commenters recommend that the Commission create a new energy storage functional classification with associated plant and operation and maintenance (O&M) expense accounts for energy storage assets and operations. TAPS states that because the functional use of a given energy storage facility may change over time and may not fit neatly into any one existing functional category, and because energy storage facility costs may come to be recovered through storage-specific rate schedules, the only transparent and administratively efficient way to account for energy storage plant costs is by adding new accounts to the USofA.[73] TAPS contends that the overall objective of any changes should be to support either effective cost-based regulation of jurisdictional services provided using energy storage resources, or effective market power monitoring and mitigation.[74] APPA agrees with TAPS' comments.[75]

59. The Public Interest Organizations state that a separate asset class may prove the best way to provide full and comparable treatment for energy storage facilities.[76] NGK/TI argues that a new functional classification is needed because energy storage assets are functionally distinct from traditional production, transmission, and distribution assets and energy storage functions cross-cut these traditional functions.[77]

60. Other commenters recommend that the Commission create new plant and O&M expense accounts within the existing functional classifications of production, transmission, and distribution rather than creating a new functional classification specifically for energy storage. FirstEnergy states that new energy storage technologies may provide transmission, distribution, or production services, and the current USofA adequately provides for facilities and activities that provide these functions. However, FirstEnergy states that the USofA does not provide the necessary accounting transparency for new storage technologies. FirstEnergy recommends that the Commission establish new accounts within the currently established functions to provide additional accounting transparency and detail regarding the plant costs and O&M expenses of energy storage facilities that serve these functions.[78] FirstEnergy states that the accounting should strive for transparency by identifying each type of asset with the primary function it serves and aligning the expenses associated with the asset with the revenues it provides. SDG&E contends that energy storage assets should be classified in the existing classifications as production, transmission, or distribution as determined by the owner of the assets and consistent with the jurisdictional nature of the service that the energy storage device provides.[79]

61. Commenters opposed to amending the current accounting and reporting requirements generally argue that the existing requirements adequately accommodate energy storage technologies. CAREBS asserts that the Commission's goal should be to use, where possible, existing accounting methods rather than invent new ones. SolarReserve argues that because many sales of ancillary services would be made under sellers' market-based rate authority, the sellers would have waivers of the accounting and reporting requirements at issue here.[80] Thus, in SolarReserve's opinion, there is no need to amend the Commission's accounting and reporting requirements.

62. California Storage Alliance and ESA indicate that if the Commission decides against creating new energy storage plant accounts and instead proposes to use existing plant accounts to account for energy storage resources, there would need to be changes to existing plant accounts to better capture energy storage plant costs. In this instance, California Storage Alliance and ESA recommend that the Commission revise the instructions of current plant accounts to explicitly include energy storage resources.[81]

63. Responding to concerns about the potential for cross-subsidization in instances where an energy storage resource simultaneously provides multiple services under cost-based and market-based cost recovery mechanisms, EEI reasons that the Commission's current policies can address concerns of cross-subsidization. EEI states that a jurisdictional entity should separately account for services sold under cost-based rates and those that are sold under market-based rates to prevent unfair market advantages through subsidization.[82] Further, EEI

[69] NOI, 135 FERC ¶ 61,240 at P 25.

[70] *Id.*

[71] *Id.*

[72] Electricity Consumers Comments at 8.

[73] TAPS Comments at 13.

[74] *Id.* at 12.

[75] APPA Comments at 7.

[76] Public Interest Organizations Comments at 12.

[77] NGK/TI Comments at 10.

[78] FirstEnergy Comments at 5.

[79] SDG&E Comments at 4.

[80] SolarReserve Comments at 5.

[81] California Storage Alliance Comments at 29; and ESA Comments at 36.

[82] EEI Comments at 10.

states that if an energy storage device is providing a transmission service then it should be accounted for based on its primary use when it was initially placed in service.[83] California PUC makes a similar argument indicating that the energy storage device should be accounted for based on its intended use within a project.

64. EEI and other commenters also argue that energy storage technologies are in an early stage of the technology and that the Commission should wait before implementing new accounting or reporting requirements for energy storage assets. California PUC asserts that due to the complexity of the technologies and their multiple potential uses, to avoid disruption of the existing functional classification system the Commission should use a case-by-case exception approach to determine the appropriate classification.[84]

1. Proposed Accounting Requirements

65. While the Commission's accounting and reporting requirements associated with the USofA do not dictate the ratemaking decisions of this Commission or State Commissions, these accounting and reporting requirements nevertheless support the rate oversight needs of both this Commission and State Commissions. Accordingly, the Commission strives to ensure that its accounting and reporting requirements keep pace with the evolution of the electric industry. As the industry has evolved, the Commission has relied on its accounting and reporting requirements applicable to existing public utilities[85] (i.e., principally investor-owned utilities) to obtain information about an entity's financial condition and results of operations. This information is important in developing and monitoring rates, making policy decisions, compliance and enforcement initiatives, and informing the Commission and the public about the activities of entities that are subject to these accounting and reporting requirements.[86]

66. The Commission has required public utilities to continue to prepare their financial statements in accordance with the accounting requirements of the USofA, as it can accommodate most transactions and events affecting these entities. Under the Commission's accounting and reporting requirements, public utilities must record and classify electric plant assets in the prescribed primary plant accounts based on the purpose served or use of the asset to produce, transmit, or distribute electric energy. In addition, public utilities must also record and classify O&M expenses related to such plant assets based on the specific activity the efforts support. The electric plant assets and related O&M expenses must be reported in annual and quarterly Form Nos. 1, 1–F, and 3–Q reports that are maintained in accordance with the accounting requirements of the USofA.

67. As stated in the NOI, the roles of traditional production, transmission, and distribution assets are generally well understood and each has established method(s) of accounting and reporting; however, the same is not necessarily true of energy storage assets which can operate in ways that resemble production, transmission, and/or distribution.[87] Moreover, it may be possible for some energy storage assets to provide some combination of production, transmission, and distribution services simultaneously. Accordingly, public utilities using energy storage assets may seek multiple methods of cost recovery for their investments in, and use of, the assets to provide various utility services.[88] Consequently, due to the potential to use certain energy storage technologies to provide multiple services and the possibility that a public utility could simultaneously recover costs under both cost-based and market-based rates, the Commission sought comment in the NOI on whether current accounting and reporting requirements for activities and costs for the operation of energy storage resources provide sufficient transparency.

68. After analyzing all comments received and considering the Commission's informational needs, the Commission has determined that the current accounting and reporting requirements do not provide sufficiently transparent information on the activities and costs of new energy storage operations. Consequently, the Commission proposes to amend the USofA and Form Nos. 1, 1–F, and 3–Q to provide financial and operational information on energy storage assets.

69. The Commission proposes to add new electric plant and O&M expense accounts to record the installed cost and operating and maintenance cost of energy storage assets and a new account to record the cost of power purchased for use in energy storage operations. In addition, the Commission proposes to amend the Form Nos. 1, and 1–F to include the new accounts and amended schedules to report statistical and operational information on energy storage operations. Further, the Commission proposes to amend a schedule of the Form No. 3–Q to include the proposed new account to record the cost of power purchased for use in energy storage operations. The Commission seeks comment on these proposed amendments, including whether the proposed changes will provide sufficiently transparent information on the activities and costs of new energy storage operations.

70. Numerous commenters responding to the NOI indicate that the Commission's current accounting and reporting requirements for new energy storage assets are not sufficiently transparent. Many of these commenters suggest that the Commission address this matter by either creating new plant and O&M expense accounts to specifically account for energy storage assets and operations in the existing functional classifications of production, transmission, and distribution, or creating a new separate functional classification for energy storage operations and new associated energy storage plant and O&M expense accounts. While both options would satisfy the Commission's and the public's need for detailed and transparent financial and operation information on public utilities' use of energy storage resources to provide jurisdictional services, the latter option is unnecessary because the existing functional classifications can adequately support energy storage operations. Furthermore, creating a new functional classification does not provide additional benefits compared to creating new accounts within existing classifications. Our proposed amendments to the Form Nos. 1 and 1–F would require utilities with energy storage operations to report detailed financial and operation information on energy storage assets and activities in new schedules for all functions.[89] Thus, using existing functional classifications provides the same level of transparency as would creating a new functional class.

71. Moreover, the Commission understands that the energy storage industry continues to evolve, and as some commenters observe, the use of energy storage resources in large-scale

[83] *Id.*

[84] California PUC Comments at 7.

[85] The term "public utility" means any person who owns or operates facilities subject to the jurisdiction of the Commission under the Federal Power Act. 18 CFR part 101 (2011) (Definition No. 29).

[86] Applicants for market-based rate authority that do not sell under cost-based rates frequently seek and typically are granted waiver of many or all of these requirements.

[87] NOI, 135 FERC ¶ 61,240 at P 25.

[88] *Id.*

[89] See, discussion of proposed amendments to Form Nos. 1 and 1–F at PP 101–106.

public utility operations is at an early stage of development. However, commenters recommending that the Commission wait until the industry is more mature before imposing any accounting and reporting requirements for energy storage assets and operations disregard the current need for certainty in the accounting and reporting treatment for energy storage resources and operations. Uniform, transparent and consistent reporting of information on energy storage operations by public utilities is essential, especially by those seeking to recover costs of energy storage services in cost-based rates. This need for information is heightened by the chance that public utilities could seek to simultaneously recover service costs under cost-based and market-based rate mechanisms using a single energy storage asset.[90]

72. Transparency improvements achieved through revisions to the existing accounting and reporting requirements will enhance the Commission's and other form users' ability to make a meaningful assessment of a utility's cost of service and rates. Further, this will enable the Commission and others to better monitor for cross-subsidization. The overarching purpose of these proposed accounting and reporting amendments is to provide useful financial and operational information to regulatory agencies and other users of public utilities' financial statements by establishing uniform accounting and reporting requirements for energy storage assets and operations.

73. The Commission endeavors to achieve a balance between the benefits of revising its accounting and reporting regulations and the imposition of any additional burden on utilities. Information that would be reported for energy storage assets and operations differs little from other data public utilities maintain under the USofA. If a utility owns and operates these energy storage assets, reporting information on them in the proposed accounts and FERC form schedules should not be burdensome. Requiring utilities to classify and account for energy storage assets and operations under existing functional classifications rather than a new one addresses the Commission's and the public's need for detailed and transparent information and lessens the implementation burden on public utilities and licensees subject to Commission accounting and reporting requirements.

74. SolarReserve argues that the accounting and reporting requirements should not be amended because many sales of ancillary services would be made under the sellers' market-based rate authority. This argument is unconvincing. While public utilities using energy storage resources that are granted market-based rate authority by the Commission may seek waivers of the accounting and reporting requirements at issue here, there are instances when public utilities may not seek or fail to be granted waiver of the requirements. Additionally, previously granted waivers may be rescinded where a seller is found to have market power (or where the seller accepts a presumption of market power) and the seller proposes cost-based rate mitigation or the Commission imposes cost-based rate mitigation. Also, public utilities seeking to only recover storage costs under cost-based rates will be subject to these accounting and reporting requirements.

75. Furthermore, in instances where public utilities seek to simultaneously recover costs under cost-based and market-based rates, the Commission proposes that the entities be required to account for and report their operations in accordance with the Commission's accounting and reporting requirements to facilitate development and monitoring of the cost-based portion of the rates. In addition, we propose that public utilities currently providing jurisdictional services and recovering costs of the services under market-based rates that have been granted waiver of the accounting and reporting requirements that seek recovery of a portion of service costs under cost-based rates, be required to forego the previously issued waiver and account for and report all cost and operational information to the Commission in accordance with its accounting and reporting requirements. In this instance, public utilities would be required to account for and report costs sought to be recovered on a cost-based and market-based basis. We seek comment on these proposals. Also, we seek comment on whether there should be a percentage of cost recovery threshold[91] or other determining factor that triggers the accounting and reporting obligations in this situation, or should any instance of multiple cost recovery, regardless of the percentage of a utility's total costs, trigger the accounting and reporting obligations. If a percentage threshold should apply, we seek comment with supporting rationale on what would be an appropriate threshold percentage.

76. Except as discussed above, the proposed amendments to the accounting and reporting regulations are not intended to affect the Commission's policy on market-based rate authority as provided in Order No. 697 or its historical practice of granting waiver of the accounting and reporting regulations of 18 CFR parts 41, 101, and 141 to certain entities with market-based rate authority. In Order No. 697, the Commission concluded that the costs of complying with the USofA requirements and, specifically Parts 41, 101, and 141 of the Commission's regulations, outweigh any incremental benefits of such compliance where the seller only transacts at market-based rates.[92] These proposed accounting and reporting rules do not change that conclusion. However, the Commission notes that entities authorized to make market-based rate sales, irrespective of accounting or other waivers, must file electric quarterly transaction reports regarding their transactions pursuant to Order No. 2001.[93]

77. At this time, the proposed accounting and reporting rules do not impose additional accounting or reporting requirements for hydroelectric pumped storage plant. The existing accounting and reporting standards use subaccounts for pumped storage under the functional classification of production, which is the only Commission-approved jurisdictional use of pumped storage to date. While the Commission has no basis to believe it is impossible to use large-scale pumped storage technologies to perform transmission or distribution functions as well, to date, no pumped storage developer has successfully demonstrated such a non-''production'' use to the Commission. This stands in contrast to the track record for smaller-scale energy storage technologies, where one battery developer has successfully

[90] The Commission has not to date received any proposals from public utilities that simultaneously seek to recover costs under cost-based and market-based rate mechanisms using a single energy storage asset, but the Commission remains open to innovative solutions and will evaluate proposals on a case-by-case basis.

[91] For example, a public utility with 90 percent of its service costs recovered under market-based rates and the remaining 10 percent recovered under cost-based rates.

[92] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 985.

[93] *Revised Public Utility Filing Requirements,* Order No. 2001, FERC Stats. & Regs. ¶ 31,127 (2002), *reh'g denied,* Order 2001–A, 100 FERC ¶ 61,074 (2002), *reh'g denied,* Order No. 2001–B, 100 FERC ¶ 61,342 (2002), *order directing filings,* Order No. 2001–C, 101 FERC ¶ 61,314 (2002), *order directing filings,* Order No. 2001–D, 102 FERC ¶ 61,334, *order refining filing requirements,* Order No. 2001–E, 105 FERC ¶ 61,352 (2003), *clarified,* Order No. 2001–F, 106 FERC ¶ 61,060 (2004), *order on reh'g,* Order No. 2001–G, 120 FERC ¶ 61,270 (2007), *order on reh'g,* Order No. 2001–H, 121 FERC ¶ 61,289 (2007), *order revising filing requirements,* Order No. 2001–I, FERC Stats. & Regs. ¶ 31,282 (2008).

supported a non-production, transmission use for its project.[94] The Commission remains open to future additions of pumped storage subaccounts to the transmission and distribution functions if appropriate, but at this time the Commission believes that the assets and operations of this pumped storage equipment are sufficiently accounted for by the existing FERC accounts and schedules of the Form Nos. 1, 1–F and 3–Q.[95]

a. Electric Plant Accounts

78. The existing primary plant accounts do not explicitly provide for recording the original cost of energy storage assets. This can lead to inconsistent accounting and reporting for these assets by utilities subject to the accounting and reporting requirements, making it difficult for the Commission and others to determine costs related to energy storage assets for cost-of-service rate purposes. In addition, the lack of transparency affects interested parties' and including the Commission's ability to monitor these companies operations to prevent and discourage cross-subsidization between cost-based and market-based activities.

79. To provide more transparency for the costs of energy storage assets, as well as to address the possibility of inconsistent accounting and reporting, we propose creating a new electric plant account and amending two existing electric plant accounts to record the installed cost of energy storage equipment owned by public utilities and licensees. Specifically, we propose a new account within the production functional classification and amending existing accounts within the transmission and distribution functional classifications.

80. The proposed plant account would be Account 348, Energy Storage Equipment—Production, and the accounts we propose to amend are existing Account 351, [Reserved], and Account 363, Storage Battery Equipment. Account 351 is a reserve account and is not currently being used. The Commission proposes to rename Account 351 as Energy Storage Equipment—Transmission. The current instructions of Account 363 provides for the inclusion of the cost of storage battery equipment used for the purpose of supplying electricity to meet emergency or peak demands. The Commission proposes to amend the instructions of Account 363 to expand the type of energy storage assets that can be recorded in the account and to recognize the unique operating characteristics of energy storage assets, which may provide services other than only supplying electricity.[96] In addition, we also propose to rename Account 363 as Energy Storage Equipment—Distribution.

81. The Commission proposes that the instructions to the accounts provide for recording the cost of installed energy storage assets based on the function or purpose the equipment serves. Further, we propose that in instances where an energy storage asset is used to perform more than one function or purpose, the cost of the asset shall be allocated among production, transmission, and distribution plant based on the services provided by the asset and the allocation of the asset's cost through cost based rates approved by a relevant regulatory agency, federal or state. For example, if a relevant State Commission under its own retail rate-setting authority approves the recovery of 25 percent of the cost installed of the storage device through the distribution component of retail rates, then we would expect 25 percent of the cost installed of the asset to be allocated to distribution plant for accounting and reporting purposes and we would expect distribution-related O&M and other accounting and reporting entries to likewise match relevant decisions made in the State Commission rate proceeding. If other portions of the cost installed are also approved for inclusion in cost-based rates at either a state or federal level, then the relevant decisions in those state or federal proceedings would apply to accounting and reporting entries as well. The Commission seeks comments on these aspects of our proposal.

82. Additionally, the Commission proposes that the original cost of an energy storage asset and other amounts associated with the original cost of the asset (*e.g.,* accumulated depreciation expenses and accumulated deferred income taxes) initially allocated to specific FERC accounts and later reallocated to other FERC accounts based on services provided by the asset and cost recovery be accounted for in accordance with Electric Plant Instruction No. 12, Transfers of Property.[97] Accordingly, we propose that if the costs of an energy storage asset are included in the development of cost-based rates, then the same allocation of costs the primary rate-setting body used for rate development will also be used to allocate the original cost of the energy storage asset among the various functions for accounting and reporting purposes. The Commission seeks comment on these proposals, including the accounting for the transfer of costs associated with an energy storage asset from one functional classification to another. Finally, we propose that the cost of energy storage assets be charged to depreciation expense using the depreciation rates developed for each function.

83. Since some energy storage equipment may perform multiple functions on the grid, we propose that public utilities be required to maintain records identifying the types of functions each individual energy storage asset supports and performs.

84. Additionally, the Commission proposes that costs to install energy storage equipment, along with power purchased or internally generated to energize the equipment to prepare it for service, be capitalized as a component cost of the equipment on the first installation only. This includes costs associated with power purchased and internally generated to test the equipment in preparation for utility service prior to it becoming ready for or placed in service.[98] Further, we propose that earnings resulting from revenue received or earned for energy storage operations during test runs be credited to the cost of construction of the project.[99]

85. Certain energy storage assets are capable of being moved from one location to another. These mobile assets are suitable for a wide range of applications, including emergency power and reliability, among other uses. Labor, materials and other costs are associated with moving these energy storage assets from one location to another location, resetting and preparing them to provide service, and purchasing or self-generating power to reenergize the assets. We propose that any costs incurred to remove, relocate, reset or reenergize an energy storage asset after it was first placed into utility service would not be chargeable to the energy storage equipment accounts as a cost component of the energy storage asset. Instead, the Commission proposes that such costs be accounted for as a

[94] *See Western Grid Development, LLC,* 130 FERC ¶ 61,056, *reh'g denied,* 133 FERC ¶ 61,029 (2010) (*Western Grid*).

[95] *See* FERC Account Nos. 330–337 and 535–545.1, 18 CFR part 101 (2011); and Form Nos. 1, 1–F, and 3–Q, 18 CFR part 141 (2011).

[96] For example, as a distribution resource recorded in the account the asset could assist with voltage regulation which may require it to absorb electricity rather than only supply it at times.

[97] 18 CFR part 101 (2011).

[98] *See* Electric Plant Instruction No. 9(D), Equipment, 18 CFR part 101 (2011).

[99] *See, e.g.,* Electric Plant Instruction No. 3(A)(18), Earnings and Expenses During Construction, 18 CFR Part 101 (2011).

production, transmission, or distribution expense based on the services provided by the energy storage asset and recovery of the asset's cost through rates, in the accounts that follow.[100]

86. The Commission proposes requiring that expenses other than power expenses for removing, relocating or resetting energy storage plant serving a production function be charged to Account 548.1, Operation of Energy Storage Equipment, and Account 553.1, Maintenance of Energy Storage Equipment. We propose requiring that expenses other than power expenses for removing, relocating or resetting energy storage plant serving a transmission function be charged to Account 562.1, Operation of Energy Storage Equipment, and Account, 570.1, Maintenance of Energy Storage Equipment. Also, we propose requiring that expenses other than power expenses for removing, relocating or resetting energy storage plant serving a distribution function be charged to Account 582.1, Operation of Energy Storage Equipment, and Account 592.2, Maintenance of Energy Storage Equipment.

87. Finally, the Commission proposes that costs incurred to purchase or internally generate power to reenergize an energy storage asset after it was first put into service be charged as a current operating cost in the appropriate expense accounts for recording such costs, including the proposed purchased power account discussed below. The Commission seeks comment on its proposals regarding electric plant accounts and whether the proposed changes adequately provide for recording the cost of new energy storage technologies and the development of cost of service rates.

b. Power Purchased and Fuel Supply Expense Accounts

88. To provide some electrical services, energy storage devices may need to maintain a particular state of charge, or as in the case of compressed air facilities, may need to maintain some minimum pressure. To maintain the desired state of charge or pressure some companies may be required to purchase power in retail or wholesale markets to energize their energy storage devices and other companies may internally generate power. In the NOI, the Commission asked about the accounting for the cost of power, fuel and other direct costs incurred in energy storage operations. Specifically, the Commission asked about accounting for the cost of (1) power purchased and stored for resale; (2) power purchased that will not be resold but instead consumed in operations during the provisioning of services; (3) power purchased to sustain a state of charge; (4) power purchased to initially attain a state of charge; and (5) fuel or other direct costs incurred to internally generate power.[101]

89. California Storage Alliance and ESA recommend that a new expense account entitled ''Power Purchased for Storage Operations'' be created to account for items 1–3 above. They indicate that the account could also be used to account for item 4 if the costs are expensed as incurred; otherwise, they recommend that the costs be capitalized in the total cost of the storage resource.[102] California Storage Alliance states that a benefit of having a separate account for power purchased for energy storage operations is that energy storage operating costs, which are organized on a plant level, can be distinguished from traditional utility power purchases and exchanges of electricity, which are organized on a company level.

90. As stated above, the Commission proposes that item 4 and 5 costs of power purchased or internally generated to initially attain a state of charge in preparation for service prior to the equipment being ready for or placed in service be capitalized as a component cost of the equipment. Additionally, we propose that item 5 costs incurred later be expensed as incurred and accounted for as an expense of the accounting period. Regarding items 1–3, the Commission agrees with California Storage Alliance that there is a benefit to having the cost of power purchased for energy storage operations reported separate from other power purchases. This accounting is expected to enhance the transparency of reported cost, which is consistent with the goals of this proposed rulemaking. However, we do not agree with California Storage Alliance's recommendation that power purchased for energy storage operations be accounted for and reported at the individual plant level.

91. California Storage Alliance did not discuss this idea in any detail. It is not clear that information is needed to be reported at the individual plant level for rate development, transparency, or any other purposes. Consequently, rather than proposing that power purchased for energy storage operations be accounted for at the individual plant level, the Commission proposes that the cost of power purchased for energy storage operations be accounted for at the company level in new Account 555.1, Power Purchased for Storage Operations. In that case, companies with multiple energy storage plant assets will record the costs of all power purchased for energy storage operations in one account similar to the procedures used to account for power purchased for other purposes that are currently recorded in Account 555, Purchased Power. However, we also propose that companies maintain records of costs associated with operation of a particular energy storage asset as required by 18 CFR part 125.

92. Further, the Commission proposes that the instructions to Account 555.1 shall be the same as those of Account 555 with an additional instruction requiring the cost of power purchased and consumed or lost in energy storage operations during the provisioning of services be recorded in the new account.[103]

93. In regards to item 5 above, California Storage Alliance and ESA recommend that the cost of fuel incurred to internally generate power for use in energy storage operations be recorded in a new account entitled ''Storage Fuel'' and other direct costs incurred in such operations be recorded in new accounts entitled ''Operation of Electric Storage Equipment'' and ''Maintenance of Electric Storage Equipment.'' [104] California Storage Alliance and ESA do not explain the benefit of recording the cost of fuel for this purpose in a new account. While this accounting may enhance transparency to some extent, existing fuel accounts can adequately support recording the costs of fuel used in energy storage operations.

94. Generating companies currently account for fuel costs in FERC accounts by the method of production (i.e., steam, nuclear, hydraulic, or other). Recording fuel cost to a new storage fuel account would require these companies to calculate the amount of their total fuel costs to be allocated to energy storage operations. This data may best be reported in a new or existing schedule of the Form Nos. 1 and 1–F rather than in a new storage fuel account. California Storage Alliance and ESA's

[100] These proposed energy storage O&M expense accounts are discussed in more detail below at section 1(c).

[101] NOI, 135 FERC ¶ 61,240 at PP 38–44.

[102] California Storage Alliance Comments at 32–34; ESA Comments at 39–41.

[103] For example, purchased power may be consumed or lost during the conversion process where electric energy is received from the grid, stored as another form of energy and later transmitted to the grid as electric energy.

[104] California Storage Alliance Comments at 34 and 37; ESA Comments at 41 and 45.

recommended O&M expense accounts are discussed in the next section.

c. Operation and Maintenance Expense Accounts

95. As previously indicated there are O&M expenses related to the use of these energy storage assets to provide utility services and there are no existing O&M expense accounts in the USofA specifically dedicated to accounting for the cost of energy storage operations. EEI comments that, as it relates to the transmission function, the current O&M expense accounts would adequately provide for recording expenses associated with operation and maintenance of energy storage assets.[105] The Commission agrees that there are some existing O&M expense accounts that can adequately support energy storage-related operation and maintenance activities. We also believe current O&M expense accounts for the production and distribution functions can provide for recording some energy storage-related expenses. However, the operations and maintenance of certain energy storage assets may differ from conventional assets.[106] Further, some existing O&M expense accounts may not be well suited to record the cost of certain activities associated with energy storage operations.[107] To the extent that there are activities and associated costs of energy storage operations that are not specifically provided for in the existing O&M expense accounts, there is a need for accounts to report the costs.

96. California Storage Alliance and ESA recommended that all energy storage-related O&M expense costs be recorded in new accounts entitled ''Operation of Electric Storage Equipment'' and ''Maintenance of Electric Storage Equipment.'' However, aggregating all of the O&M costs for energy storage into two accounts reduces the transparency of the amounts reported, which is contrary to the purpose of the rulemaking. Further, because certain costs of energy storage operations can be adequately accounted for in the existing O&M expense accounts the costs should be reported there in accordance with the instructions of the accounts. Consequently, the Commission proposes that companies record energy storage-related O&M expenses in the existing O&M expense accounts according to the nature of the expense to the extent that the account adequately supports recording of the cost.

97. For energy storage-related O&M expenses that are not specifically provided for in the existing O&M expense accounts the Commission proposes that such costs be recorded in Account 548.1, Operation of Energy Storage Equipment, and Account 553.1, Maintenance of Energy Storage Equipment, for energy storage plant classified as production; Account 562.1, Operation of Energy Storage Equipment, and Account 570.1, Maintenance of Energy Storage Equipment, for energy storage plant classified as transmission; and Account 582.1, Operation of Energy Storage Equipment, and Account 592.2, Maintenance of Energy Storage Equipment, for energy storage plant classified as distribution.

98. The Commission proposes that the instructions of the accounts provide for the inclusion of the cost of labor, materials used and expenses incurred in the operation and maintenance, as appropriate, of energy storage equipment, to the extent that the costs are not appropriately recorded in other O&M expense accounts. Furthermore, we propose that Accounts 592, Maintenance of Station Equipment (Major only), and 592.1, Maintenance of Structures and Equipment (Nonmajor only), be revised such that the accounts do not include O&M expenses related to energy storage operations. Additionally, we propose that the instructions of these accounts be revised to remove the reference to Account 363. The Commission seeks comment on its proposal, including whether the operations of certain energy storage assets differ enough from conventional assets or maintenance activities to require the proposed revisions.

d. No New Revenue Accounts

99. In the NOI, the Commission asked whether new revenue accounts should be created or existing revenue accounts used to account for revenue associated with energy storage operations. The Commission also asked whether all revenues for energy storage operations should be recorded in a single revenue account: Account 456, Other Electric Revenues. Most commenters oppose recording all revenues associated with energy storage operations in a single account because it would not provide sufficient transparency as to the relation of the revenue to a particular service provided. Some commenters argue that new revenue accounts were needed to account for revenues generated using energy storage assets.[108] These commenters generally argue that the existing revenue accounts do not provide sufficient transparency. However, commenters opposed to creating new revenue accounts argue that production, transmission, and distribution services currently have adequate revenue accounts, and energy storage technologies will simply comprise a component of those services. These commenters contend that revenue derived from the use of energy storage assets will originate from the same type of activities associated with revenue derived from the use of traditional utility assets.[109] They argue that the type of resource used to provide the service does not change the accounting for the associated revenue.

100. The Commission agrees with commenters who contend that the existing revenue accounts sufficiently provide for accounting for revenue associated with using energy storage assets. We also agree that revenues associated with the use of energy storage assets will originate from the same type of activities associated with revenue derived from the use of traditional utility assets. The current revenue accounts provide for recording revenue based on sales of electricity and other products and services by type of customer, product, or service. Revenue derived from the operation of energy storage assets will originate from one or more of these items. Commenters recommending new accounts have not identified new revenue streams that may require different accounting. As such, the Commission does not propose new revenue accounts for energy storage. Companies using energy storage assets to provide utility service must record revenues associated with use of the assets in existing revenue accounts in accordance with the instructions of the accounts, as appropriate.

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[105] EEI Comments at 12. EEI indicated that in instances where energy storage assets provide a transmission function, the following O&M accounts associated with transmission can be used: Accounts 560, 561.5, 561.8, 562–564, 566–576.

[106] For example, the procedures and practices involving repair of a flywheel that serves a transmission function may not be the same as the procedures and practices involving repair of a transmission line.

[107] For example, certain O&M expenses for generator equipment used in storage operations that serves a transmission function are not well suited for recording in existing transmission O&M expense accounts. Such expenses are the type of expenses that would typically be incurred in production operations; however, because the generator equipment serves a transmission function, the nature of the expense is not production. In such cases, the O&M expenses for generator equipment should be recorded as a transmission expense using the appropriate energy storage equipment transmission O&M expense account.

[108] *See, e.g.,* TAPS Comments at 17–18; BrightSource Comments at 7; and Viridity Comments at 4.

[109] *See, e.g.,* California Storage Alliance Comments at 34; ESA Comments at 42; and FirstEnergy Comments at 5.

2. Proposed New and Amended Form Nos. 1, 1–F, and 3–Q Schedules

101. The Form Nos. 1, 1–F, and 3–Q have schedules that include a basic set of financial statements: Comparative Balance Sheet, Statement of Income and Retained Earnings, Statement of Cash Flows, and the Statement of Comprehensive Income and Hedging Activities. Supporting schedules with supplementary information are filed, including revenues and the related quantities of products sold or transported; account balances for O&M expenses; selected plant cost and operational data; and other information. The Form No. 1 provides schedule pages 408–409, Pumped Storage Generating Plant Statistics (Large Plants), and pages 410–411, Generating Plant Statistics (Small Plants) to report, among other items, operational information on pumped storage plants. These are the only schedules that provide for reporting information on energy storage and these schedules do not provide for reporting information on new types of energy storage assets such as batteries and flywheels, or allow any possibility of treating pumped storage plants as anything other than generating assets.

102. Several commenters responded to the NOI's inquiry about whether the Form Nos. 1 and 1–F should be amended to capture data on energy storage assets and operations. Commenters recommend that certain existing schedules be revised to include energy storage assets and a new schedule be created to report operational and statistical data on the assets.[110] The primary difference among the recommendations is the amount of detail proposed for inclusion in the new schedule.

103. Some commenters recommend that the schedule include all input items that are included in the total amount of O&M expenses for an energy storage asset, similar to how O&M expenses and plant information are currently required to be reported in schedule pages 408–409 of the Form No. 1.[111] In contrast, other commenters propose that the information be presented at a higher, aggregated, level with only total operation and total maintenance expense for energy storage operations reported in the schedule. The Form No. 1 provides schedule pages 408–409 for reporting detailed plant and O&M expense information on generating plants that are considered ''large'' and less detailed plant and cost information on generating plants that are considered ''small'' in schedule pages 410–411, Generating Plant Statistics (Small Plants). According to the instructions of these schedules, the specific schedule a utility must use to report its plant statistics and certain associated costs is determined by the installed capacity of the unit. Generating units with 10,000 kilowatts or more of installed capacity will generally report this information in schedule pages 408–409.[112] While this kilowatt threshold may be an appropriate measure of information reporting requirements for traditional generating plants, it may not be appropriate for new energy storage assets that in many instances will be rated below 10,000 kilowatts. Consequently, the Commission seeks comment on what would be an appropriate kilowatt threshold for requiring utilities to report more detailed plant and cost information for energy storage plant.

104. The Commission proposes to add two new schedules to the Form Nos. 1 and 1–F to report statistical and cost data on energy storage plant. One schedule will require more detailed information than the other to lessen the reporting burden on companies with small energy storage operations. We preliminarily propose that 10,000 kilowatts be the threshold for determining whether a filer reports more detailed information in proposed schedule pages 414–417, Energy Storage Operations (Large Plants), or less detailed information in proposed schedule pages 419–421, Energy Storage Operations (Small Plants). We propose that the following information be reported on pages 414–417 in the proposed schedule: (1) Megawatts (MW) purchased, MW delivered to the grid to support production, transmission, or distribution operations, MW lost during conversion and discharge of energy, and MW sold; (2) Account No. 555.1, Power Purchased for Storage Operations; (3) cost of fuel used in energy storage operations; (4) revenue from the sale of stored energy by revenue account; (5) other energy storage-related cost incurred; (6) cost of energy storage plant recorded in Accounts 101, 103, 106, and 107 by actual or expected functional classification; (7) operation and maintenance expenses associated with each function; and (8) name and location of energy storage plant, by project, and functional classification.

105. Additionally, we propose that the following information be reported on pages 419–421 in the proposed schedule: (1) Cost of plant; (2) operation expenses excluding fuel; (3) maintenance expenses; (4) cost of fuel used in energy storage operations; (5) Account No. 555.1, Power Purchased for Storage Operations; (6) other energy storage-related cost incurred; and (7) name and location of energy storage plant, by project, and functional classification.

106. Finally, we propose to amend several schedules of the Form Nos. 1 and 1–F to include the proposed energy storage plant, purchased power and O&M expense accounts discussed above, and schedule page 397, Amounts Included in ISO/RTO Settlement Statements, of the Form No. 3–Q to include the proposed purchased power account.[113] The Commission seeks public comment on each of the proposals discussed above, including whether the proposed changes will provide sufficiently transparent information on the activities and costs of new energy storage assets and operations.

III. Information Collection Statement

107. The collections of information below for this proposed rule have been submitted to the Office of Management and Budget (OMB) for review under Section 3507(d) of the Paperwork Reduction Act of 1995.[114] OMB's regulations require approval of certain information collection requirements imposed by agency rule.[115] The Commission solicits comments on its need for this information, whether the information will have practical utility, the accuracy of burden and cost estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

Burden Estimate and Information Collection Costs: The additional estimated annual public reporting burdens and costs for the requirements in this proposed rule are as follows.

[110] *See, e.g.,* California Storage Alliance Comments at 41; ESA Comments at 49; and TAPS Comments at 16.

[111] *See, e.g.,* California Storage Alliance Comments at 39–42; and ESA Comments at 47–50.

[112] The 10,000 kW threshold is currently applied to gas-turbine, internal combustion, nuclear, and conventional hydro and pumped storage plants. There is a separate 25,000 kW threshold for steam plants (e.g., coal, oil).

[113] *See* Appendix B Proposed Amendments to Form Nos. 1, 1–F and 3–Q.

[114] *See* 44 U.S.C. 3507(d).

[115] 5 CFR 1320.11 (2011).

[116] The Form No. 3–Q estimate is one hour since the information is already collected and will only require a minor separation of costs.

[117] The burden in Year 1 is 1,320 hrs. The average annualized burden over Years 1–3 is 440 hr. (1,320/3).

Data collection	Number of respondents (a)	Change in the number of hours per filing (b)	Filings per respondent per year (c)	Change in the total annual hours for this collection (a × b × c=d)	Estimated annual cost (at $120/hr.) (d × $120/hr.) ($)
Form No. 1	210	6	1	1,260	151,200
Form No. 1–F	5	6	1	30	3,600
Form No. 3–Q	213	[116] 1	3	639	76,680
FERC–917 [includes 18 CFR 35.28 pro forma open-access transmission tariff (OATT)].	132	10	1	440 averaged over Years 1–3 [1320 in Year 1].	[117] 52,800
FERC–717 [includes OASIS & posting data on self-supply ancillary services].	176	2	1	352	42,240
FERC–919 [includes '20 percent screen'].	155	7	1	1,085	130,200
Total				3,806 (averaged over Years 1–3)	456,720

Titles: FERC Form No. 1, ''Annual Report of Major Electric Utilities, Licensees, and Others;'' FERC Form No. 1–F, ''Annual Report for Nonmajor Public Utilities and Licensees;'' FERC Form No. 3–Q, ''Quarterly Financial Report of Electric Utilities, Licensees and Natural Gas Companies;'' FERC–917, ''Non-discriminatory Open Access Transmission Tariff,'' FERC–717, ''Standards for Business Practices and Communication Protocols for Public Utilities,'' and FERC–919, ''Electric Rate Schedule Filings: Market Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities.''

Action: Proposed revisions to information collections.

OMB Control Nos.: 1902–0021 (FERC Form No. 1); 1902–0029 (FERC Form No. 1–F); 1902–0205 (FERC Form No. 3–Q); 1902–0233 (FERC–917), 1902–0173 (FERC–717); and 1902–0234 (FERC–919).

Respondents: Public utilities, FERC licensees, and public utility transmission providers.

Frequency of responses: Annually (FERC Form Nos. 1 and 1–F); quarterly (FERC Form No. 3–Q); and as needed (FERC–917, FERC–717, and FERC–919).

Necessity of the Information: The proposed rule would amend the Commission's regulations to reflect changes occurring in the electric industry due to the availability of new energy storage technologies that can be used in the provision of large-scale utility operations. The addition of these plant accounts, and new and amended reporting forms, should enhance transparency and provide detailed information on transactions and events affecting public utilities and licensees that file reports with the Commission. Without specific instructions and accounts for recording and reporting the above transactions and events, inconsistent and incomplete accounting and reporting will likely result. With regard to FERC–917, FERC–919, and FERC–717 the proposed rule would provide increased transparency in the determination of Regulation and Frequency Response requirements, historical ancillary service information, and ancillary service capacity in order to ensure that rates for that service remain just, reasonable, and not unduly discriminatory.

Internal Review: The Commission has reviewed the requirements pertaining to the USofA and the reports it prescribes and determined that the proposed amendments are necessary because the Commission needs to establish uniform accounting and reporting requirements for the costs of utility assets and expenses incurred for providing services as part of a utility's operations. The Commission has reviewed the requirements associated with the OATT, OASIS, and market power analysis and determined they are necessary to increase transparency and ensure that rates remain just, reasonable, and not unduly discriminatory.

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

109. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], email: *DataClearance@ferc.gov,* Phone (202) 502–8663, fax: (202) 273–0873.

Comments on the collections of information and associated burden estimates in the proposed rule should be sent to the Commission in this docket and may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments to OMB should be submitted by email to: *oira_submission@omb.eop.gov.* Please refer to OMB Control Nos. 1902–0021 (FERC Form No. 1); 1902–0029 (FERC Form No. 1–F); 1902–0205 (FERC Form No. 3–Q); 1902–0233 (FERC–917), 1902–0173 (FERC–717); and 1902–0234 (FERC–919) and Docket Number RM11–24.

IV. Environmental Analysis

110. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[118] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classifications, and services.[119]

[118] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47,897 (Dec. 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[119] 18 CFR 380.4(a)(15) (2011).

V. Regulatory Flexibility Act

111. The Regulatory Flexibility Act of 1980 (RFA) [120] generally requires a description and analysis of proposed 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 Small Business Administration's (SBA's) Office of Size Standards develops the numerical definition of a small business.[121] 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 four million megawatt hours.[122] Most companies regulated by the Commission do not fall within the RFA's definition of a small entity.[123] The proposed rule applies exclusively to public utilities that own, control, or operate facilities for transmitting electric energy in interstate commerce and not electric utilities per se. Based on the filers of the annual FERC Form No. 1 and Form No. 1–F, as well as the number of companies that have obtained waivers, we estimate that 6.8 percent of the filers affected by this proposed rule are ''small.'' The Commission believes this rule will not have a significant economic impact on a substantial number of small entities, and therefore no regulatory flexibility analysis is required.

VI. Comment Procedures

112. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due 60 days after publication in the **Federal Register**. Comments must refer to Docket No. RM11–24–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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

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

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

VII. Document Availability

116. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington DC 20426.

117. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

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

List of Subjects in 18 CFR Parts 35, 37, and 101

Electric power rates; Electric utilities.

By direction of the Commission.
Commissioner Clark voting present.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission proposes to amend Parts 35, 37, and 101, 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. Amend § 35.28 by adding a new paragraph (c)(1)(viii) as follows.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c)(1)(viii) Each public utility's open access transmission tariff, at Schedule 3—Regulation and Frequency Response Service, must include provisions explaining how it will determine its Regulation and Frequency Response reserve requirements. These provisions must take into account speed and accuracy of regulation resources and include a description of how the public utility transmission provider would make adjustments to the capacity requirement when a customer opts to purchase from third-parties or self-supply its requirements using resources with speed and accuracy characteristics that differ from the set of resources otherwise being used for Regulation and Frequency Response Service.

* * * * *

3. Amend § 35.37 as follows:

a. Paragraph (c)(1) is revised.

b. New paragraph (c)(5) is added.

§ 35.37 Market power analysis required.

* * * * *

(c)(1) There will be a rebuttable presumption that a Seller lacks horizontal market power with respect to sales of energy, capacity, energy imbalance service, and generation imbalance service if it passes two indicative market power screens: a pivotal supplier analysis based on annual peak demand of the relevant market, and a market share analysis applied on a seasonal basis. There will be a rebuttable presumption that a seller possesses horizontal market power with respect to sales of energy, capacity, energy imbalance service, and generation imbalance service if it fails either screen.

* * * * *

(c)(5) There will be a rebuttable presumption that a Seller of Operating

[120] 5 U.S.C. 601–612.

[121] 13 CFR 121.101 (2011).

[122] 13 CFR 121.201, Sector 22, Utilities.

[123] *See* 5 U.S.C. 601(3) citing to section 3 of the Small Business Act, 15 U.S.C. 632. Section 3 of the Small Business Act defines a ''small-business concern'' as a business which is independently owned and operated and which is not dominant in its field of operation. The Small Business Size Standards component of the North American Industry Classification System defines a small electric utility as one that, including its affiliates, is primarily engaged in generation, transmission, and/or distribution of electric energy for sale and whose total electric output for the preceding fiscal years did not exceed 4 million MWh. 13 CFR 121.201 (2011).

Reserve—Spinning, Operating Reserve—Supplemental, Reactive Supply and Voltage Control, or Regulation and Frequency Response services lacks horizontal market power with respect to sales of the ancillary service in question if the amount of capacity in MWs (or, as applicable, MVARs) that it can dedicate to providing the ancillary service in the relevant geographic market, taking into account any reported historical locational requirements, is no more than 20 percent of the relevant reported aggregate requirement for that ancillary service as reported pursuant to § 37.6(k) of the Commission's Regulations.

* * * * *

4. Amend § 35.38 as follows:

a. Paragraph (a) is revised.

b. Paragraph (b) is revised.

c. New paragraph (c) is added.

§ 35.38 Mitigation.

(a) A Seller that has been found to have market power in generation or ancillary services, or that is presumed to have horizontal market power in generation or ancillary services by virtue of failing or foregoing the relevant market power screens, as described in 35.37(c), may adopt the default mitigation detailed in paragraph (b) of this section for sales of energy or capacity or paragraph (c) of this section for sales of ancillary services or may propose mitigation tailored to its own particular circumstances to eliminate its ability to exercise market power. Mitigation will apply only to the market(s) in which the Seller is found, or presumed, to have market power.

(b) Default mitigation for sales of energy or capacity consists of three distinct products:

* * * * *

(c) Default mitigation for sales of ancillary services consists of: (1) A cost-based cap based on the relevant OATT ancillary service rate of the purchasing public utility transmission operator; (2) a cost-based cap based on the highest relevant public utility OATT ancillary service rate in the proposed trading area; or (3) the results of a competitive solicitation that meets the Commission's requirements for transparency, definition, evaluation, oversight, and adequate seller interest to ensure competitiveness.

PART 37—OPEN ACCESS SAME-TIME INFORMATION SYSTEMS

5. The authority citation for Part 37 continues to read as follows:

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

6. Amend § 37.6 by adding a new paragraph (k) as follows.

§ 37.6 Information to be posted on the OASIS.

* * * * *

(k) *Posting data related to historical ancillary service requirements.* The Transmission Provider must post on OASIS information as to the aggregate amount (MW or MVAR, as applicable) of Operating Reserve—Spinning, Operating Reserve—Supplemental, Reactive Supply and Voltage Control, and Regulation and Frequency Response services that it has historically required in order to serve its long-term firm obligations, including any geographic limitations it may face in meeting such ancillary service requirements.

PART 101—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT

7. The authority citation for Part 101 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, 7651–7651o.

8. In Part 101, Electric Plant Chart of Accounts, Account 348 is added to the list:

Electric Plant Chart of Accounts

* * * * *

2. PRODUCTION PLANT

* * * * *

D. OTHER PRODUCTION

* * * * *

348 Energy Storage Equipment—Production

* * * * *

9. In Part 101, Electric Plant Accounts, Account 351, the name of the account is amended and instructions are added to read as follows:

Electric Plant Accounts

* * * * *

351 Energy Storage Equipment—Transmission

A. This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes. Where energy storage equipment can perform more than one function or purpose, the cost of the equipment shall be allocated among production, transmission, and distribution plant based on the services provided by the asset and the allocation of the asset's cost through rates approved by a relevant regulatory agency. Reallocation of the cost of equipment recorded in this account shall be in accordance with Electric Plant Instruction No. 12, Transfers of Property.

B. Labor costs and power purchase and generation costs incurred to install and energize the equipment are includible on the first installation only. The cost of removing, relocating and resetting energy storage equipment shall not be charged to this account but to Account 562.1, Operation of Energy Storage Equipment, and Account 570.1, Maintenance of Energy Storage Equipment, as appropriate.

C. The records supporting this account shall show, by months, the function(s) each energy storage asset supports or performs.

ITEMS

1. Batteries/Chemical
2. Compressed Air
3. Flywheels
4. Superconducting Magnetic Storage
5. Thermal

10. In Part 101, Electric Plant Accounts, Account 363, the name of the account and the instructions are amended and added to read as follows:

Electric Plant Accounts

* * * * *

363 Energy Storage Equipment—Distribution

A. This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes. Where energy storage equipment can perform more than one function or purpose, the cost of the equipment shall be allocated among production, transmission, and distribution plant based on the services provided by the asset and the allocation of the asset's cost through rates approved by a relevant regulatory agency. Reallocation of the cost of equipment recorded in this account shall be in accordance with Electric Plant Instruction No. 12, Transfers of Property.

B. Labor costs and power purchase and generation costs incurred to install and energize the equipment are includible on the first installation only. The cost of removing, relocating and resetting energy storage equipment shall not be charged to this account but to Account 582.1, Operation of Energy Storage Equipment, and Account 592.2, Maintenance of Energy Storage Equipment, as appropriate.

C. The records supporting this account shall show, by months, the function(s) each energy storage asset supports or performs.

ITEMS

1. Batteries/Chemical
2. Compressed Air
3. Flywheels
4. Superconducting Magnetic Storage
5. Thermal

11. In Part 101, Electric Plant Accounts, new primary plant account 348 is added to read as follows:

Electric Plant Accounts

* * * * *

348 Energy Storage Equipment—Production

A. This account shall include the cost installed of energy storage equipment used to store energy for load managing purposes. Where energy storage equipment can perform more than one function or purpose, the cost of the equipment shall be allocated among production, transmission, and distribution plant based on the services provided by the asset and the allocation of the asset's cost through rates approved by a relevant regulatory agency. Reallocation of the cost of equipment recorded in this account shall be in accordance with Electric Plant Instruction No. 12, Transfers of Property.

B. Labor costs and power purchase and generation costs incurred to install and energize the equipment are includible on the first installation only. The cost of removing, relocating and resetting energy storage equipment shall not be charged to this account but to Account 548.1, Operation of Energy Storage Equipment, and Account 553.1, Maintenance of Energy Storage Equipment, as appropriate.

C. The records supporting this account shall show, by months, the function(s) each energy storage asset supports or performs.

ITEMS

1. Batteries/Chemical
2. Compressed Air
3. Flywheels
4. Superconducting Magnetic Storage
5. Thermal

Note: The cost of pumped storage hydroelectric plant shall be charged to hydraulic production plant. These are examples of items includible in this account. This list is not exhaustive.

12. In Part 101, Operation and Maintenance Expense Chart of Accounts, Accounts 548.1, 553.1, 555.1, 562.1, 570.1, 582.1, and 592.2 are added to the list:

Operation and Maintenance Expense Chart of Accounts

* * * * *

1. POWER PRODUCTION EXPENSES

* * * * *

D. OTHER POWER GENERATION

* * * * *

Operation

* * * * *

548.1 Operation of Energy Storage Equipment

* * * * *

Maintenance

553.1 Maintenance of Energy Storage Equipment

* * * * *

E. OTHER POWER SUPPLY EXPENSES

* * * * *

555.1 Power Purchased for Storage Operations

* * * * *

2. TRANSMISSION EXPENSES

* * * * *

Operation

* * * * *

562.1 Operation of Energy Storage Equipment

* * * * *

Maintenance

* * * * *

570.1 Maintenance of Energy Storage Equipment

* * * * *

4. DISTRIBUTION EXPENSES

* * * * *

Operation

* * * * *

582.1 Operation of Energy Storage Equipment

* * * * *

Maintenance

* * * * *

592.2 Maintenance of Energy Storage Equipment

13. In Part 101, Operation and Maintenance Expense Accounts, new operation expense account 548.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

548.1 Operation of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the operation of energy storage equipment includible in Account 348, Energy Storage Equipment-Production, which are not specifically provided for or are readily assignable to other production operation expense accounts.

14. In Part 101, Operation and Maintenance Expense Accounts, new maintenance expense account 553.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

553.1 Maintenance of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of energy storage equipment includible in Account 348, Energy Storage Equipment-Production, which are not specifically provided for or are readily assignable to other production maintenance expense accounts.

15. In Part 101, Operation and Maintenance Expense Accounts, new power supply expense account 555.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

555.1 Power Purchased for Storage Operations

A. This account shall include the cost at point of receipt by the utility of electricity purchased for use in storage operations, including power purchased and consumed or lost in energy storage operations during the provision of services, including but not limited to energy purchased and stored for resale. It shall also include but not be limited to net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, and spinning reserve capacity. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balancing of debits and credits for energy, capacity, and possibly other factors. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.

B. The records supporting this account shall show, by months, the kilowatt hours and prices thereof under each purchase contract and the charges and credits under each exchange or power pooling contract.

16. In Part 101, Operation and Maintenance Expense Accounts, new operation expense account 562.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

562.1 Operation of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the operation of energy storage equipment includible in Account 351, Energy Storage Equipment-Transmission, which are not specifically provided for or are readily assignable to other transmission operation expense accounts.

17. In Part 101, Operation and Maintenance Expense Accounts, new maintenance expense account 570.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

570.1 Maintenance of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of energy storage equipment includible in Account 351, Energy Storage Equipment-Transmission, which are not specifically provided for or are readily assignable to other transmission maintenance expense accounts.

18. In Part 101, Operation and Maintenance Expense Accounts, new operation expense account 582.1 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

582.1 Operation of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the operation of energy storage equipment includible in Account 363, Energy Storage Equipment-Distribution, which are not specifically provided for or are readily assignable to other distribution operation expense accounts.

19. In Part 101, Operation and Maintenance Expense Accounts, new maintenance expense account 592.2 is added to read as follows:

Operation and Maintenance Expense Accounts

* * * * *

592.2 Maintenance of Energy Storage Equipment

This account shall include the cost of labor, materials used and expenses incurred in the maintenance of energy storage equipment includible in Account 363, Energy Storage Equipment-Distribution, which are not specifically provided for or are readily assignable to other distribution maintenance expense accounts.

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

Appendix A: List of Short Names of Commenters on the Federal Energy Regulatory Commission's Notice of Inquiry on Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies—Docket No. RM11–24–000, June 2011

Short Name or Acronym	Commenter
A123	A123 Systems, Inc.
AEP	American Electric Power Service Corporation.
AES Energy Storage	AES Energy Storage.
APPA	American Public Power Association.
Apparent Inc.	Apparent Inc.
Aquion Energy, Inc.	Aquion Energy, Inc.
AWEA	American Wind Energy Association.
Beacon Power Corporation	Beacon Power Corporation.
Bonneville	Bonneville Power Administration.
BrightSource	BrightSource Energy, Inc.
Business Council for Sustainable Energy	Business Council for Sustainable Energy.
California PUC	California Public Utilities Commission.
California Storage Alliance	California Energy Storage Alliance.
CAREBS	Coalition to Advance Renewable Energy Through Bulk Storage.
EEI	Edison Electric Institute.
Electricity Consumers	Electricity Consumers Resource Council.
ENBALA	Enbala Power Networks.
Environmental Defense Fund	Environmental Defense Fund.
EPSA	Electric Power Supply Association.
ESA	Electricity Storage Association.
FirstEnergy	The Cleveland Electric Illuminating Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Ohio Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, The Toledo Edison Company, Monongahela Power Company, The Potomac Edison Company, West Penn Power Company, FirstEnergy Solutions Corp., American Transmission Systems, Incorporated and Trans-Allegheny Interstate Line Company.
FriiPwr	FriiPwr USA.
Hydro Association	National Hydropower Association.
IID	Imperial Irrigation District.
Mark Lively	Mark B. Lively.
National Grid	National Grid USA.
National Park Service	National Park Service.
NaturEner	NaturEner USA, LLC.
NextStep	NextStep Electric, LLC.
NGK/TI	NGK Insulators, Ltd and Technology Insights.
NGSA	Natural Gas Supply Association.

APPENDIX A: LIST OF SHORT NAMES OF COMMENTERS ON THE FEDERAL ENERGY REGULATORY COMMISSION'S NOTICE OF INQUIRY ON THIRD-PARTY PROVISION OF ANCILLARY SERVICES; ACCOUNTING AND FINANCIAL REPORTING FOR NEW ELECTRIC STORAGE TECHNOLOGIES—DOCKET NO. RM11–24–000, JUNE 2011—Continued

Short Name or Acronym	Commenter
Northwest Group	Avista Corporation, Bonneville Power Administration, Chelan County PUD, Clark Public Utilities, Cowlitz County PUD, Idaho Power Company, NorthWestern Energy, PacifiCorp, Public Power Council, Public Utility District No. 2 of Grant County, and Puget Sound Energy, Inc.
Portland General	Portland General Electric Company.
Powerex	Powerex Corporation.
PPL Companies	PPL EnergyPlus, LLC and PPL Montana, LLC.
Prudent Energy	Prudent Energy Corporation.
Public Interest Organizations	Center for Rural Affairs, Clean Wisconsin, Climate + Energy Project, Conservation Law Foundation, Environment Northeast, Fresh Energy, Land Trust Alliance, Natural Resources Defense Council, Pace Energy and Climate Center, Project for Sustainable FERC Energy Policy, Sierra Club and Union of Concerned Scientists.
Riverbank	Riverbank Power Corporation.
Saft	Saft America, Inc.
SDG&E	San Diego Gas & Electric Company.
Shell Energy	Shell Energy North America (US), L.P.
Solar Energy Association	Solar Energy Industries Association.
SolarReserve	SolarReserve LLC.
Southern California Edison	Southern California Edison Company.
Starwood	Starwood Energy Group Global, LLC.
Steffes	Steffes Corporation.
TAPS	Transmission Access Policy Study Group.
Viridity	Viridity Energy Inc.
WADE/Wartsila	WADE USA and Wartsila North America.
WSPP	WSPP, Inc.
Xtreme	Xtreme Power.

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

Appendix B—New and Amended Form 1/1F/3Q Pages

BILLING CODE 6717–01–P

Name of Respondent	This Report is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none", "not applicable", or "NA", as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none", "not applicable", or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant and Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228-229	
24	Extraordinary Property Losses	230	
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none", "not applicable", or "NA", as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none", "not applicable", or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	
64	Pumped Storage Generating Plant Statistics	408-409	
65	Generating Plant Statistics Pages	410-411	
66	Energy Storage Operations (Large Plants)	414-416	
67	Energy Storage Operations (Small Plants)	419-420	

FERC FORM NO. 1 (REV. 12-12) **Page 3**
FERC FORM NO. 1-F (REV. 12-12)

Name of Respondent	This Report is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none", "not applicable", or "NA", as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none", "not applicable", or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
68	Transmission Line Statistics Pages	426-427	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
72	Stockholder's Reports – Check appropriate box: Two copies will be submitted. No annual report to stockholders is prepared.		

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Accounts (a)	Balance Beginning of Year (b)	Additions (c)
1	**1. INTANGIBLE PLANT**		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)		
6	**2. PRODUCTION PLANT**		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		
17	**B. Nuclear Production Plant**		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	**C. Hydraulic Production Plant**		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Miscellaneous Power Plant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	**D. Other Production Plant**		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	(348) Energy Storage Equipment - Production		
46	TOTAL Other Production Plant (Enter Total of lines 37 thru 45)		
47	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 46)		

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

Distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
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Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ______

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Accounts (a)	Balance Beginning of Year (b)	Additions (c)
48	**3. TRANSMISSION PLANT**		
49	(350) Land and Land Rights		
50	(351) Energy Storage Equipment - Transmission		
51	(352) Structures and Improvements		
52	(353) Station Equipment		
53	(354) Towers and Fixtures		
54	(355) Poles and Fixtures		
55	(356) Overhead Conductors and Devices		
56	(357) Underground Conduit		
57	(358) Underground Conductors and Devices		
58	(359) Roads and Trails		
59	(359.1) Asset Retirement Costs for Transmission Plant		
60	TOTAL Transmission Plant (Enter Total of lines 49 thru 59)		
61	**4. DISTRIBUTION PLANT**		
62	(360) Land and Land Rights		
63	(361) Structures and Improvements		
64	(362) Station Equipment		
65	(363) Energy Storage Equipment – Distribution		
66	(364) Poles, Towers, and Fixtures		
67	(365) Overhead Conductors and Devices		
68	(366) Underground Conduit		
69	(367) Underground Conductors and Devices		
70	(368) Line Transformers		
71	(369) Services		
72	(370) Meters		
73	(371) Installations on Customer Premises		
74	(372) Leased Property on Customer Premises		
75	(373) Street Lighting and Signal Systems		
76	(374) Asset Retirement Costs for Distribution Plant		
77	TOTAL Distribution Plant (Enter Total of lines 62 thru 76)		
78	**5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT**		
79	(380) Land and Land Rights		
80	(381) Structures and Improvements		
81	(382) Computer Hardware		
82	(383) Computer Software		
83	(384) Communication Equipment		
84	(385) Miscellaneous Regional Transmission and Market Operation Plant		
85	(386) Asset Retirement Costs for Regional Transmission and Market Operation Plant		
86	TOTAL Transmission and Market Operation Plant (Enter Total of lines 79 thru 85)		
87	**6. GENERAL PLANT**		
88	(389) Land and Land Rights		
89	(390) Structures and Improvements		
90	(391) Office Furniture and Equipment		
91	(392) Transportation Equipment		
92	(393) Stores Equipment		
93	(394) Tools, Shop and Garage Equipment		
94	(395) Laboratory Equipment		
95	(396) Power Operated Equipment		
96	(397) Communication Equipment		
97	(398) Miscellaneous Equipment		
98	SUBTOTAL (Enter Total of Lines 88 thru 97)		
99	(399) Other Intangible Property		
100	(399.1) Asset Retirement Costs for General Plant		
101	TOTAL General Plant (Enter Total of Lines 98, 99 and 100)		
102	TOTAL (Accounts 101 and 106)		
103	(102) Electric Plant Purchased (See Instruction 8)		
104	(Less) (102) Electric Plant Sold (See Instruction 8)		
105	(103) Experimental Plant Unclassified		
106	TOTAL Electric Plant in Service (Enter Total of lines 102 thru 1051)		

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
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Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	**1. POWER PRODUCTION EXPENSES**		
2	**A. Steam Power Generation**		
3	**Operation**		
4	(500) Operation Supervision and Engineering		
5	(501) Fuel		
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses		
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)		
14	**Maintenance**		
15	(510) Maintenance Supervision and Engineering		
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)		
21	TOTAL Power Production Expenses-Steam Power (Enter Total lines 13 & 20)		
22	**B. Nuclear Power Generation**		
23	**Operation**		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	**Maintenance**		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 & 40)		
42	**C. Hydraulic Power Generation**		
43	**Operation**		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
52	**Maintenance**		
53	(541) Maintenance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (Total of Lines 50 and 58)		

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ______

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

Line No.	Accounts (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	**D. Other Power Generation**		
61	**Operation**		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(548.1) Operation of Energy Storage Equipment		
66	(549) Miscellaneous Other Power Generation Expenses		
67	(550) Rents		
68	TOTAL Operation (Enter Total of lines 62 thru 67)		
69	**Maintenance**		
70	(551) Maintenance Supervision and Engineering		
71	(552) Maintenance of Structures		
72	(553) Maintenance of Generating and Electric Plant		
73	(553.1) Maintenance of Energy Storage Equipment		
74	(554) Maintenance of Miscellaneous Other Power Generation Plant		
75	TOTAL Maintenance (Enter Total of lines 70 thru 74)		
76	TOTAL Power Production Expenses-Other Power (Enter Total of lines 68 & 75)		
77	**E. Other Power Supply Expenses**		
78	(555) Purchased Power		
79	(555.1) Power Purchased for Storage Operations		
80	(556) System Control and Load Dispatching		
81	(557) Other Expenses		
82	TOTAL Other Power Supply Expenses (Enter Total of lines 78 thru 81)		
83	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 76 & 82)		
84	**2. TRANSMISSION EXPENSES**		
85	**Operation**		
86	(560) Operation Supervision and Engineering		
87	(561.1) Load Dispatch-Reliability		
88	(561.2) Load Dispatch-Monitor and Operate Transmission System		
89	(561.3) Load Dispatch-Transmission Service and Scheduling		
90	(561.4) Scheduling, System Control and Dispatch Services		
91	(561.5) Reliability, Planning and Standards Development		
92	(561.6) Transmission Service Studies		
93	(561.7) Generation Interconnection Studies		
94	(561.8) Reliability, Planning and Standards Development Services		
95	(562) Station Expenses		
96	(562.1) Operation of Energy Storage Equipment		
97	(563) Overhead Lines Expenses		
98	(564) Underground Lines Expenses		
99	(565) Transmission of Electricity by Others		
100	(566) Miscellaneous Transmission Expenses		
101	(567) Rents		
102	TOTAL Operation (Enter Total of lines 85 thru 101)		
103	**Maintenance**		
104	(568) Maintenance Supervision and Engineering		
105	(569) Maintenance of Structures		
106	(569.1) Maintenance of Computer Hardware		
107	(569.2) Maintenance of Computer Software		
108	(569.3) Maintenance of Communication Equipment		
109	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
110	(570) Maintenance of Station Equipment		
111	(570.1) Maintenance of Energy Storage Equipment		
112	(571) Maintenance of Overhead Lines		
113	(572) Maintenance of Underground Lines		
114	(573) Maintenance of Miscellaneous Transmission Plant		

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
115	TOTAL Maintenance (Enter Total of lines 104 thru 114)		
116	TOTAL Transmission Expenses (Enter Total of lines 102 and 115)		
117	**3. REGIONAL MARKET EXPENSES**		
118	**Operation**		
119	(575.1) Operation Supervision		
120	(575.2) Day-Ahead and Real-Time Market Facilitation		
121	(575.3) Transmission Rights Market Facilitation		
122	(575.4) Capacity Market Facilitation		
123	(575.5) Ancillary Services Market Facilitation		
124	(575.6) Market Monitoring and Compliance		
125	(575.7) Market Facilitation, Monitoring and Compliance Services		
126	(575.8) Rents		
127	Total Operation (Lines 119 thru 126)		
128	**Maintenance**		
129	(576.1) Maintenance of Structures and Improvements		
130	(576.2) Maintenance of Computer Hardware		
131	(576.3) Maintenance of Computer Software		
132	(576.4) Maintenance of Communication Equipment		
133	(576.5) Maintenance of Miscellaneous Market Operation Plant		
134	Total Maintenance (Lines 129 thru 133)		
135	TOTAL Regional Transmission and Market Operation Expenses (Enter Total of lines 127 and 134)		
136	**4. DISTRIBUTION EXPENSES**		
137	**Operation**		
138	(580) Operation Supervision and Engineering		
139	(581) Load Dispatching		
140	(582) Station Expenses		
141	(582.1) Operation of Energy Storage Equipment		
142	(583) Overhead Line Expenses		
143	(584) Underground Line Expenses		
144	(585) Street Lighting and Signal System Expenses		
145	(586) Meter Expenses		
146	(587) Customer Installations Expenses		
147	(588) Miscellaneous Expenses		
148	(589) Rents		
149	TOTAL Operation (Enter Total of lines 138 thru 148)		
150	**Maintenance**		
151	(590) Maintenance Supervision and Engineering		
152	(591) Maintenance of Structure		
153	(592) Maintenance of Station Equipment		
154	(592.2) Maintenance of Energy Storage Equipment		
155	(593) Maintenance of Overhead Lines		
156	(594) Maintenance of Underground Lines		
157	(595) Maintenance of Line Transformers		
158	(596) Maintenance of Street Lighting and Signal Systems		
159	(597) Maintenance of Meters		
160	(598) Maintenance of Miscellaneous Distribution Plant		
161	TOTAL Maintenance (Enter Total of lines 151 thru 160)		
162	TOTAL Distribution Expenses (Enter Total of lines 149 and 161)		

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year
163	**5. CUSTOMER ACCOUNTS EXPENSES**		
164	**Operation**		
165	(901) Supervision		
166	(902) Meter Reading Expenses		
167	(903) Customer Records and Collection Expenses		
168	(904) Uncollectible Accounts		
169	(905) Miscellaneous Customer Accounts Expenses		
170	TOTAL Customer Accounts Expenses (Total of lines 165 thru 169)		
171	**6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES**		
172	**Operation**		
173	(907) Supervision		
174	(908) Customer Assistance Expenses		
175	(909) Informational and Instructional Expenses		
176	(910) Miscellaneous Customer Service and Informational Expenses		
177	TOTAL Customer Service and Information. Expenses (Total lines 173 thru 176)		
178	**7. SALES EXPENSES**		
179	**Operation**		
180	(911) Supervision		
181	(912) Demonstrating and Selling Expenses		
182	(913) Advertising Expenses		
183	(916) Miscellaneous Sales Expenses		
184	TOTAL Sales Expenses (Enter Total of lines 180 thru 184)		
185	**8. ADMINISTRATIVE AND GENERAL EXPENSES**		
186	**Operation**		
187	(920) Administrative and General Salaries		
188	(921) Office Supplies and Expenses		
189	(Less) (922) Administrative Expenses Transferred-Credit		
190	(923) Outside Services Employed		
191	(924) Property Insurance		
192	(925) Injuries and Damages		
193	(926) Employee Pensions and Benefits		
194	(927) Franchise Requirements		
195	(928) Regulatory Commission Expenses		
196	(929) (Less) Duplicate Charges-Cr.		
197	(930.1) General Advertising Expenses		
198	(930.2) Miscellaneous General Expenses		
199	(931) Rents		
200	TOTAL Operation (Enter Total of lines 187 thru 199)		
201	**Maintenance**		
202	(935) Maintenance of General Plant		
203	TOTAL Administrative & General Expenses (Total of lines 199 and 201)		
204	TOTAL Electric Operation and Maintenance Expenses (Total of lines 83, 116, 135, 162, 170, 177, 184, and 203)		

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ELECTRIC PRODUCTION, OTHER POWER SUPPLY, TRANSMISSION, **REGIONAL MARKET,** AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional market, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter
1	**1. POWER PRODUCTION AND OTHER SUPPLY EXPENSES**	
2	Steam Power Generation - Operation (500-509)	
3	Steam Power Generation – Maintenance (510-515)	
4	Total Power Production Expenses - Steam Power	
5	Nuclear Power Generation – Operation (517-525)	
6	Nuclear Power Generation – Maintenance (528-532)	
7	Total Power Production Expenses - Nuclear Power	
8	Hydraulic Power Generation – Operation (535-540.1)	
9	Hydraulic Power Generation – Maintenance (541-545.1)	
10	Total Power Production Expenses - Hydraulic Power	
11	Other Power Generation – Operation (546-550.1)	
12	Other Power Generation – Maintenance (551-554.1)	
13	Total Power Production Expenses - Other Power	
14	**Other Power Supply Expenses**	
15	Purchased Power (555)	
16	(555.1) Power Purchased for Storage Operations	
17	System Control and Load Dispatching (556)	
18	Other Expenses (557)	
19	Total Other Power Supply Expenses (line 15-18)	
20	Total Power Production Expenses (Total of lines 4, 7, 10, 13 and 19)	
21	**2. TRANSMISSION EXPENSES**	
22	**Transmission Operation Expenses**	
23	(560) Operation Supervision and Engineering	
24	(561.1) Load Dispatch-Reliability	
25	(561.2) Load Dispatch-Monitor and Operate Transmission System	
26	(561.3) Load Dispatch-Transmission Service and Scheduling	
27	(561.4) Scheduling, System Control and Dispatch Services	
28	(561.5) Reliability, Planning and Standards Development	
29	(561.6) Transmission Service Studies	
30	(561.7) Generation Interconnection Studies	
31	(561.8) Reliability, Planning and Standards Development Services	
32	(562) Station Expenses	
33	(562.1) Operation of Energy Storage Equipment	
34	(563) Overhead Line Expenses	
35	(564) Underground Line Expenses	
36	(565) Transmission of Electricity by Others	
37	(566) Miscellaneous Transmission Expenses	
38	(567) Rents	
39	(567.1) Operation Supplies and Expenses (Non-Major)	
40	TOTAL Transmission Operation Expenses (Lines 23 – 39)	

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ______

ELECTRIC PRODUCTION, OTHER POWER SUPPLY, TRANSMISSION, **REGIONAL TRANSMISSION AND MARKET OPERATION,** AND DISTRIBUTION EXPENSES

Report Electric production, other power supply expenses, transmission, regional control and market operation, and distribution expenses through the reporting period.

Line No.	Account (a)	Year to Date Quarter
41	**Transmission Maintenance Expenses**	
42	(568) Maintenance Supervision and Engineering	
43	(569) Maintenance of Structures	
44	(569.1) Maintenance of Computer Hardware	
45	(569.2) Maintenance of Computer Software	
46	(569.3) Maintenance of Communication Equipment	
47	(569.4) Maintenance of Miscellaneous Regional Transmission Plant	
48	(570) Maintenance of Station Equipment	
49	(570.1) Maintenance of Energy Storage Equipment	
50	(571) Maintenance Overhead Lines	
51	(572) Maintenance of Underground Lines	
52	(573) Maintenance of Miscellaneous Transmission Plant	
53	(574) Maintenance of Transmission Plant	
54	TOTAL Transmission Maintenance Expenses (Lines 42 – 53)	
55	Total Transmission Expenses (Lines 40 and 54)	
56	**3. REGIONAL MARKET EXPENSES**	
57	**Regional Market Operation Expenses**	
58	(575.1) Operation Supervision	
59	(575.2) Day-Ahead and Real-Time Market Facilitation	
60	(575.3) Transmission Rights Market Facilitation	
61	(575.4) Capacity Market Facilitation	
62	(575.5) Ancillary Services Market Facilitation	
63	(575.6) Market Monitoring and Compliance	
64	(575.7) Market Facilitation, Monitoring and Compliance Services	
65	Regional Market Operation Expenses (Lines 58–64)	
66	**Regional Market Maintenance Expenses**	
67	(576.1) Maintenance of Structures and Improvements	
68	(576.2) Maintenance of Computer Hardware	
69	(576.3) Maintenance of Computer Software	
70	(576.4) Maintenance of Communication Equipment	
71	(576.5) Maintenance of Miscellaneous Market Operation Plant	
72	Regional Market Maintenance Expenses (Lines 67-71)	
73	TOTAL Regional Control and Market Operation Expenses (Lines 65 and 72)	
74	**4. DISTRIBUTION EXPENSES**	
75	Distribution Operation Expenses (580-589)	
76	Distribution Maintenance Expenses (590-598)	
77	Total Distribution Expenses (Lines 75 and 76)	
78	TOTAL (Lines 20, 55, 73, and 77)	

FERC FORM 3-Q (REV 12-12) **Page 324b**

Name of Respondent	This Report Is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

PURCHASED POWER (Accounts 555 and 555.1)
(Including Power Exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract
defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)		
					Average Monthly NCP Demand Total (e)	Average Monthly CP Demand (f)	MegaWatt Hours Purchased (Excluding for Energy Storage) (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
	Total						

Name of Respondent	This Report Is: (1) An Original (2) A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of Year/Qtr

PURCHASED POWER (Accounts 555 and 555.1) (Continued)
(Including Power Exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatt hours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatt hours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (n) totals to the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Purchases for Energy Storage on Page 401, line 11. The total amount in column (i) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased for Energy Storage (h)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Demand Charges ($) (k)	Energy Charges ($) (l)	Other Charges ($) (m)	Total (k+ l+m) of Settlement ($) (n)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, Account 555.1, Power Purchased for Storage Operations, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, Account 555, Purchased Power, or Account 555.1, Power Purchased for Storage Operations, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Purchases (Account 555.1)				
4	Net Sales (Account 447)				
5	Transmission Rights				
6	Ancillary Services				
7	Other Items (list separately)				
8					
9					
10					
11					
12					
13					
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42					
43					
44					
45	Total				

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ______

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY			DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use)			Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam			Requirements Sales for Resale (See Instruction 4, Page 311)	
4	Nuclear			Non-Requirements Sales for Resale (See Instruction 4, Page 311)	
5	Hydro-Conventional			Energy Furnished Without Charge	
6	Hydro=Pumped Storage			Energy Used by Company (Electric Department Only, Excluding Station Use)	
7	Other			Total Energy Losses	
8	Less Energy for Pumping			TOTAL (Enter Total of Lines 22 Through 27) MUST EQUAL LINE 20 UNDER SOURCES	
9	Net Generation (Enter Total of Lines 3 through 8)				
10	Purchases (other than for Energy Storage)				
11	Purchases for Energy Storage				
	Power Exchanges				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus Line 13)				
15	Transmission for Others (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Others (Line 16 minus line 17)				
19	Net Transmission for Others (Losses)				
20	TOTAL (Enter Total of Lines 9, 10, 11, 14, 18 and 19				

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ____

ENERGY STORAGE OPERATIONS (Large Plants)

1. Large Plants are plants of 10,000 KW or more.
2. In columns (a) (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report Megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.
4. In columns (e), (f) and (g) report MWHs delivered to the grid to support production, transmission and distribution. The amount reported in column (d) should include MWhs delivered/provided to a generator's own load requirements or used for the provision of ancillary services.
5. In columns (h), (i), and (j) report MWHs lost during conversion, storage and discharge of energy.
6. In column (k) report the MWHs sold.
7. In column (l), report revenues from energy storage operations. In a footnote, disclose the revenue accounts and revenue amounts related to the income generating activity.
8. In column (m), report the cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined. In columns (n) and (o), report fuel costs for storage operations associated with self-generated power included in Account 501 and other costs associated with self-generated power.
9. In columns (q), (r) and (s) report the total project plant costs including but not exclusive of land and land rights, structures and improvements, energy storage equipment, turbines, compressors, generators, switching and conversion equipment, lines and equipment whose primary purpose is to integrate or tie energy storage assets into the power grid, and any other costs associated with the energy storage project included in the property accounts listed. In addition, report the energy storage operation and maintenance expenses associated with each function.

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	MWHs (d)
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
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14				
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27				
28				
29				
30				
31				
32				
33				
34				
35	TOTAL			

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ____

ENERGY STORAGE OPERATIONS (Large Plants) (Continued)

	MWHs delivered to the grid to support			MWHs Lost During Conversion, Storage and Discharge of Energy			MWHs Sold (k)	Revenues from the Sale of Stored Energy (l)
Line No.	Production (e)	Transmission (f)	Distribution (g)	Production (h)	Transmission (i)	Distribution (j)		
1								
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Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ________

ENERGY STORAGE OPERATIONS (Large Plants) (Continued

Line No.	Power Purchased for Storage Operations (555.1) (Dollars) (m)	Fuel Costs from associated fuel accounts for Storage Operations Associated with Self-Generated Power (Dollars) (n)	Other Costs Associated with Self-Generated Power (Dollars) (o)	Project Costs included in (p)	Production (Dollars) (q)	Transmission (Dollars) (r)	Distribution (Dollars) (s)
1				Account 101			
2				Account 103			
3				Account 106			
4				Account 107			
5				Other			
6							
7							
8							
9				Total Project Costs			
10							
11							
12				Storage Operation and Maintenance Costs by Function (Dollars)			
13							
14							
15							
16							
17							
18							
19							
20				Operation Expenses			
21				Maintenance Expenses			
22							
23							
24							
25							
26							
27							
28							
29							
30				Total Operations and Maintenance Costs			

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ____

ENERGY STORAGE OPERATIONS (Small Plants)

1. Small Plants are plants less than 10,000 KW.
2 In columns (a), (b) and (c) report the name of the energy storage project, functional classification (Production, Transmission, Distribution), and location.
3. In column (d), report project plant cost including but not exclusive of land and land rights, structures and improvements, energy storage equipment and any other costs associated with the energy storage project.
4. In column (e), report operation expenses excluding fuel, (f), maintenance expenses, (g) fuel costs for storage operations and (h) cost of power purchased for storage operations and reported in Account 555.1, Power Purchased for Storage Operations. If power was purchased from an affiliated seller specify how the cost of the power was determined.
5. If any other expenses, report in column (i) and footnote the nature of the item(s).

Line No.	Name of the Energy Storage Project (a)	Functional Classification (b)	Location of the Project (c)	Project Cost (d)
1				
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5				
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10				
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35				
36	TOTAL			

Name of Respondent	This Report is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo., Da., Yr.)	Year/Period of Report End of ____

ENERGY STORAGE OPERATIONS (Small Plants)

	Plant Operating Expenses				
Line No.	Operations (Excluding Fuel used in Storage Operations) (e)	Maintenance (f)	Cost of fuel used in storage operations (g)	Account No. 555.1, Power Purchased for Storage Operations (h)	Other Expenses (i)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
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[FR Doc. 2012–15763 Filed 7–6–12; 8:45 am]

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