DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35 and 101

[Docket Nos. RM11–24–000 and AD10–13–000; Order No. 784]

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

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is revising its regulations to foster competition and transparency in ancillary services markets. The Commission is revising 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 is revising its regulations to reflect reforms to its Avista policy governing the sale of ancillary services at market-based rates to public utility transmission providers. The Commission is also requiring each public utility transmission provider to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made ''alternative comparable arrangements'' as required by the Schedule. The final rule also requires each public utility transmission provider to post certain Area Control Error data as described in the final rule. Finally, the Commission is revising 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: This rule is effective November 27, 2013.

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SUPPLEMENTARY INFORMATION:

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

Order No. 784

Final Rule

Issued July 18, 2013.

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1. The Federal Energy Regulatory Commission (Commission) is revising its regulations to enhance competition and transparency in ancillary services markets. The Commission is revising 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 is revising Part 35 of its regulations to reflect reforms to its *Avista Corp.*[1] policy governing the sale of ancillary services at market-based rates to public utility transmission providers. The Commission is also requiring each public utility transmission provider to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made ''alternative comparable arrangements'' as required

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

by the Schedule. Each public utility transmission provider is also required to post certain Area Control Error data on the open access same-time information system (OASIS). Finally, the Commission is revising the accounting and reporting requirements under its Uniform System of Accounts for public utilities and licensees (USofA) [2] and its forms, statements, and reports, contained in FERC Form No. 1 (Form No. 1), Annual Report of Major Electric Utilities, Licensees and Others,[3] FERC Form No. 1–F (Form No. 1–F), Annual Report for Nonmajor Public Utilities and Licensees,[4] and FERC Form No. 3–Q (Form No. 3–Q), Quarterly Financial Report of Electric Utilities, Licensees, and Natural Gas Companies,[5] to better account for and report transactions associated with the use of energy storage devices in public utility operations.

2. First, the Commission reforms the *Avista* policy governing sales of certain ancillary services to a public utility purchasing the ancillary service to satisfy its own OATT requirements to offer ancillary services to its own customers. As noted in the Notice of Proposed Rulemaking,[6] there is a growing need for ancillary services to support grid functions in the face of potential changes in the portfolio of generation resources and a growing interest of transmission providers to have flexibility in meeting ancillary services needs.[7] There is also interest in third-party provision of ancillary services and that interest may be unnecessarily frustrated by the *Avista* policy. Comments to the NOPR's proposal to reconsider the *Avista* restrictions generally supported these concepts. As such, and as discussed further below, we conclude that elements of our existing market-based rate regulations can be modified in a manner that continues to limit the exercise of market power, while also enhancing the ability of third parties to compete for the sale of certain ancillary services.

3. Second, we adopt reforms to provide greater transparency with regard to reserve requirements for Regulation and Frequency Response. Under the requirements of the *pro forma* OATT, transmission customers may either purchase Regulation and Frequency Response service at cost-based rates from the public utility transmission provider pursuant to its OATT or self-supply the service, including through purchases from third-parties.[8] With regard to the notion of self-supply, the *pro forma* OATT Schedule 3 merely states that the transmission customer must make alternative comparable arrangements to satisfy is Regulation and Frequency Response Service obligation. In particular, Schedule 3 provides no discussion of the meaning of the term ''comparable'' as it relates to reliance on resources with dispatch speed and accuracy characteristics that may differ from those used by the public utility transmission provider. Because the system must be operated reliably at all times, the customer may not decline the transmission provider's offer of ancillary services unless it demonstrates that it has acquired comparable services from another source.[9] In order to clarify the role of resource speed and accuracy in the determination of alternative comparable arrangements, in this Final Rule the Commission requires each public utility transmission provider to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made ''alternative comparable arrangements'' as required by the Schedule. This statement will also acknowledge that, upon request by the self-supplying customer, the public utility transmission provider will share with the customer its reasoning and any related data used to make the determination of whether the customer has made ''alternative comparable arrangements.'' To aid the transmission customer's ability to make an ''apples-to-apples'' comparison of regulation resources, the final rule also requires each public utility transmission provider to post on OASIS historical one-minute and ten-minute Area Control Error data as described in the final rule for the most recent calendar year, and update this posting once per year.

4. With this information, a transmission customer will be in a position to demonstrate to the public utility transmission provider that the resource(s) it selects for self-supply are comparable to those of the public utility transmission provider. As such, these reforms are necessary to address the potential for undue discrimination against transmission customers choosing to self-supply Regulation and Frequency Response, including through purchases from third-parties. Acknowledging the speed and accuracy of the resources used to provide this service will help to ensure that self-supply requirements of the public utility transmission provider do not unduly discriminate by requiring customers to procure a different amount of regulation reserves than the particular speed and accuracy characteristics of the resources in question justify (i.e., to be comparable, a customer self-supply arrangement that relies on slower, less accurate resources than those of the public utility transmission provider should probably involve a larger reserve requirement than would a purchase from the transmission provider, and vice versa). Moreover, as the Commission has previously stated, because most generation-based ancillary services can be provided by many of the generators connected to the transmission system, some customers may be able to provide or procure such services more economically than the transmission provider can.[10]

5. Finally, we adopt reforms to our accounting and reporting regulations to add new electric plant and operation and maintenance (O&M) expense accounts for energy storage devices. These reforms are necessary to accommodate the increasing availability of these new resources for use in public utility operations. These reforms are also necessary to ensure that the activities and costs of new energy

[2] *Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act,* 18 CFR Part 101 (2012).

[3] 18 CFR 141.1 (2012).

[4] 18 CFR 141.2 (2012).

[5] 18 CFR 141.400 (2012).

[6] *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies,* Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,690 (2012) (NOPR).

[7] *Integration of Variable Energy Resources,* Order No. 764, FERC Stats. & Regs. ¶ 32,331, *order on reh'g,* Order No. 764–A, 141 FERC ¶ 61,232 (2012); and *Demand Response Compensation in Organized Wholesale Energy Markets,* Order No. 745, FERC Stats. & Regs. ¶ 31,322, *order on reh'g,* Order No. 745–A, 137 FERC ¶ 61,215 (2011).

[8] *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 31,716 (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); *pro forma* OATT, Original Sheet Nos. 20–21 and Schedule 3, Original Sheet No. 113.

[9] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,716.

[10] *Id.* at 31,718. We note that customers could conceivably procure such services more economically either by paying much less per unit for a larger amount of slower, less accurate resources, or by paying somewhat more per unit for a smaller amount of faster, more accurate resources.

storage operations are sufficiently transparent to allow effective oversight.

Background

6. The Commission has taken numerous steps 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.[11] With regard to ancillary services, the Commission in Order No. 888 delineated two categories of ancillary services: Those that the transmission provider is required to provide to all of its basic transmission customers [12] and those that the transmission provider is only required to *offer* to provide to transmission customers serving load in the transmission provider's control area.[13] With respect to the second category the Commission reasoned that the transmission provider is not always uniquely qualified to provide the services and customers may be able to more cost-effectively self-supply them or procure them from other entities. The Commission 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.[14] Later, in *Ocean Vista Power Generation, L.L.C.,*[15] 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.

7. The Commission subsequently acknowledged in *Avista* [16] 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 at market-based rates with certain restrictions.[17] 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 a regional transmission organization (RTO) or an independent system operator (ISO), which has no ability to self-supply ancillary services but instead depends on third parties; [18] (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.[19] Therefore, the Commission's *Avista* policy has allowed third-party suppliers to sell certain ancillary services at market-based rates without showing a lack of market power, except under these three circumstances.

8. In its ongoing effort to enhance competitive markets as a means to ensure just and reasonable rates, including those for ancillary services, the Commission has continued to evaluate its *Avista* policy, including, with particular regard to this proceeding, 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. The Commission's concern has been to ensure that the cost-based OATT ancillary service rates of public utilities remain a viable backstop or alternative that transmission customers can rely upon instead of the market-based sales from third parties who have not been shown to lack market power. The Commission has reasoned that, if such third-party sellers were permitted to sell to public utilities seeking to meet their OATT ancillary service obligations, the public utility's ability to seek recovery of such purchase costs in OATT rates might lead to increases in those OATT ancillary service rates that may reflect the exercise of market power thus reducing the rates' ability to serve as an effective alternative to purchases from a third-party seller unable to show lack of market power. This would undermine the effectiveness of the mitigation measure that the Commission relied upon in *Avista* to relax the requirement for a market power analysis.[20]

9. However, as the record in this proceeding demonstrates, the restriction on sales of ancillary services at market-based rates to a public utility for purposes of satisfying its OATT requirements has proven to be an

[11] *See, e.g.,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,781; *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), *cert. denied sub nom. Pub. Citizen, Inc. v. FERC,* 133 S. Ct. 26 (2012); *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).

[12] The first category consists of Scheduling, System Control and Dispatch service and Reactive Supply and Voltage Control from Generation Sources service.

[13] The second category consists of Regulation and Frequency Response service, Energy Imbalance service, Operating Reserve-Spinning service, and Operating Reserve-Supplemental service. Order No. 890 later added an additional OATT ancillary service to this category: Generator Imbalance service. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 85.

[14] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,720–21.

[15] 82 FERC ¶ 61,114, at 61,406–07 (1998) (*Ocean Vista*).

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

[17] 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.

[18] 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.

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

[20] *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.'').

unreasonable barrier to entry, unnecessarily restricting access to potential suppliers. In the NOPR, the Commission proposed to address this problem by reforming the *Avista* restrictions, both by modifying the showing an entity must make to establish that it lacks market power and by establishing market power mitigation options in the absence of such a showing.

10. Building off the Commission's action in Order No. 755, which found that accounting for a given resource's speed and accuracy can help ensure just and reasonable rates and prevent against undue discrimination, in the NOPR, the Commission also proposed to require each public utility transmission provider to include provisions in its OATT explaining how it will determine regulation service reserve requirements for transmission customers, including those that choose to self-supply regulation service, in a manner that takes into account the speed and accuracy of resources used.

11. Finally, the Commission proposed to modify its accounting regulations to increase transparency for energy storage facilities. 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. 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.[21]

Discussion

The Avista Policy

12. 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 OATT 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. Based on the record before us, the Commission adopts a number of the reforms to the ancillary services pricing policy proposed in the NOPR and in some instances adopts a number of modifications to those reforms based on the comments received in response to the NOPR.

13. Specifically, this Final Rule allows a resource with market-based rate authority for sales of energy and capacity to sell imbalance services at market-based rates to a public utility transmission provider in the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service. In addition, upon consideration of the comments to the NOPR, this Final Rule also allows a resource with market-based rate authority for sales of energy and capacity to sell operating reserve services at market-based rates to a public utility transmission provider in the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service that supports the delivery of operating reserve resources from one balancing authority area to another. As a result, the only remaining limitation on third-party market-based sales of ancillary services is on sales of Reactive Supply and Voltage Control service and Regulation and Frequency Response service to a public utility that is purchasing ancillary services to satisfy its own OATT requirements absent a showing of lack of market power or adequate mitigation of potential market power. In that regard, third-party sales of Reactive Supply and Voltage Control service and Regulation and Frequency Response service to public utility transmission providers will be permitted at rates not to exceed the buying public utility transmission provider's OATT rate for the same service. Further, to the extent a transmission provider chooses to procure either Reactive Supply and Voltage Control service or Regulation and Frequency Response service through a competitive solicitation that meets the requirements of this Final Rule, third-party sellers of these services may sell at market-based rates.

14. While the record in this proceeding was insufficient for the Commission to relieve the restrictions for Reactive Supply and Voltage Control service and Regulation and Frequency Response service in the same manner as Imbalance and Operating reserves, we remain interested in exploring the technical, economic and market issues concerning the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service. As such, the Commission intends to gather further information regarding the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service in a separate, new proceeding.

15. Thus, while we decline to adopt some of the reforms proposed in the NOPR based on the record in this proceeding, we expect that this Final Rule substantially enhances the overall opportunities for third-parties to compete to make sales of ancillary services while continuing to limit the exercise of market power.

16. We will first discuss the market power analyses used to establish authority to sell at market-based rates, followed by a discussion of alternative cost-based mitigation in the event a market participant cannot show it lacks market power for a specific product or service.

Use of Market Power Analyses

17. The Commission analyzes horizontal market power[22] 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.[23] 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.[24] A seller whose share of the relevant market is less than 20 percent during all seasons passes the wholesale market share screen.[25] 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

[21] 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.

[22] 18 CFR 35.37(b) (2012).

[23] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at PP 13, 62. *See also* 18 CFR 35.37(b), (c)(1) (2012).

[24] Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 43. Uncommitted capacity is determined by adding the total nameplate or seasonal capacity of generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm sales. *Id.* P 38.

[25] *Id.* PP 43–44, 80, 89.

market.[26] A seller satisfies the pivotal supplier screen if its uncommitted capacity is less than the net uncommitted supply in the relevant market.[27]

18. 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 with respect to sales of energy or capacity; failing either screen creates a rebuttable presumption that the seller possesses horizontal market power for such sales.[28] A seller that fails one of the screens may present evidence, such as a delivered price test (DPT), to rebut the presumption of horizontal market power.[29] In the alternative, a seller may accept the presumption of horizontal market power and adopt some form of cost-based mitigation.[30]

19. 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.[31] In particular, the Commission will generally use a seller's balancing authority area plus first-tier markets,[32] or the RTO/ISO market as applicable, as the default relevant geographic market. 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.[33] Except in the circumstances set forth in *Avista,* entities seeking to sell ancillary services at market-based rates have been required to provide market power analyses that address the nature and characteristics of each ancillary service, as well as the nature and characteristics of generation capable of supplying each service.[34] This requirement was based on an assumption that such characteristics might differ from those related to sales of energy and capacity.

a. Reliance on Existing Indicative Screens

20. In the NOPR, the Commission analyzed whether passage of the existing market-based rate screens for sales of energy and capacity can adequately demonstrate lack of market power for sales of ancillary services, based on the relevant characteristics of resources capable of providing each ancillary service. Based on this analysis, the Commission proposed that only the two imbalance ancillary services (Energy Imbalance and Generator Imbalance), and no other ancillary services, could be encompassed by the existing market-based rate screens.[35] The Commission sought comment on both this analysis and the resulting proposal.[36]

21. As discussed in more detail below, commenters addressed both the Commission's ancillary service-by-ancillary service analysis of this issue, and the proposal to apply the existing market power screens to only the imbalance ancillary services.

i. Application to Imbalance Ancillary Services

Commission Proposal

22. In the NOPR, the Commission stated that resources 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 resources that provide energy or capacity. As a result, the Commission proposed that sellers passing existing market power analyses should be permitted to sell not only energy and capacity in the relevant geographic market(s), but also Energy Imbalance and Generator Imbalance services at market-based rates. The Commission sought comments on, among other things, any unique technical requirements or limitations that might apply to the provision of the imbalance ancillary services that might impact the Commission's proposal to find that passage of the existing market power screens also indicates a lack of market power for imbalance services.[37]

Comments

23. The majority of commenters support the Commission's proposal. AWEA, Beacon, California Storage Alliance, EEI, Electricity Consumers, EPSA, ESA, Iberdrola, Hydro Association, Public Interest Organizations, Powerex, Solar Energy Association, Shell Energy, Southern California Edison, and WSPP support the NOPR proposal to revise the Commission's 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.

24. ESA, Electricity Consumers, Beacon, and EEI, among others, agree that there are no special technical requirements or other limitations that apply to the provision of the Energy Imbalance or Generator Imbalance ancillary services.[38] Electricity Consumers and WSPP, among others, argue that the proposed revisions should reduce barriers to ancillary service providers and increase the supply of needed ancillary services. WSPP agrees that the proposal would enable additional sellers of balancing energy to transact with public utility transmission providers in both bilateral markets or a multi-lateral balancing market, and states that it would likely foster sales of balancing energy even outside of the transmission provider market. AWEA contends that the Commission's proposed reforms strike

[26] 18 CFR 35.37(c)(1) (2012).

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

[28] 18 CFR 35.37(c)(1) (2012).

[29] 18 CFR 35.37(c)(2) (2012). For purposes of rebutting the presumption of horizontal market power, sellers may use the results of the DPT to refine the default relevant geographic market used 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.

[30] 18 CFR 35.37(c)(3) (2012).

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

[32] First-tier markets are those markets directly interconnected to the seller's balancing authority area. *See, e.g.,* Order No. 697, FERC Stats. & Regs. ¶ 31,252 at P 232.

[33] 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.

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

[35] NOPR, FERC Stats. & Regs. ¶ 32,690 at PP 18–24.

[36] *Id.* P 24.

[37] *Id.* PP 19–20.

[38] ESA Comments at 6; Beacon Comments at 5; Electricity Consumers Comments at 3; and EEI Comments at 9.

the appropriate balance between reducing barriers to entry and protecting against market power.

25. WSPP and Powerex, with Iberdrola concurring by reference, urge the Commission to clarify that this proposal includes the capacity associated with balancing energy sales, not just the energy.[39] WSPP states that without the underlying capacity, sales of balancing energy could have no firmness and would be of little value in the market, in particular the bilateral market. Further, WSPP contends that the likely market for balancing energy would not differentiate energy and capacity products by OATT Schedules. Rather, sellers would sell ''flexible capacity'' capable of fulfilling multiple OATT Schedules and operators would look to flexible capacity to support various system stabilizing functions to which the OATT Schedules refer. Thus, WSPP contends that the market would be more efficient if the capacity and energy required to provide OATT services are not required to be unbundled when the natural market for supply would be a bundled ''flexible capacity'' product.[40]

26. Solar Energy Association states conceptual support for the proposal, but argues that sellers may have market power in certain ancillary services markets even if not in energy or capacity markets, and urges the Commission to police markets that are created due to the adoption of a rebuttable presumption of lack of market power.[41]

27. Two commenters express concern with the NOPR proposal. TAPS objects to the NOPR's preliminary finding that any available unit in a given geographic market is capable of providing energy that helps address imbalances in that market. TAPS contends that significant technical limitations limit the resources that can provide imbalance services absent special arrangements like pseudo-ties, and therefore the first tier resources included in the horizontal market power screen are not generally available to provide intra-hour imbalance service. TAPS asserts that Order No. 890–A supports this contention by allegedly finding ''that generation outside the control area can provide imbalance service when pseudo-tied and thus subject to within-area dispatch control.''[42] TAPS further states that outside organized markets, generators capable of providing imbalance service must have a special relationship with the control area operator in order to supply changing within-the-hour energy needs, without the constraints of hourly transmission scheduling requirements and that even the recently adopted 15-minute scheduling requirement is insufficient, especially when combined with the need to schedule 20 minutes in advance.[43]

28. TAPS asserts that, in non-RTO regions, imbalance service is typically provided by the energy associated with regulation and operating reserves, and thus resources capable of providing imbalance services would necessarily be subject to the same technical requirements as the NOPR described for regulation and operating reserves.[44] TAPS supports this assertion by claiming that Order No. 890 found that ''demand costs of providing imbalance service are already being provided under Schedule 3, 5, and 6 charges [i.e., Regulation and Frequency Response Service, Operating Reserve-Spinning Reserve Services, and Operating Reserve Supplemental Reserve Services].''[45]

29. TAPS further rejects the Commission's assertion in the NOPR that this proposal is consistent with the 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.[46] TAPS contends that the pricing of OATT imbalance service does not demonstrate the absence of the alleged restrictions described above on the supply of intra-hour energy that allows transmission providers to provide energy imbalance service.

30. Morgan Stanley contends that the existing market power screens are flawed even in their application to energy and capacity products and thus should not be applied to additional products. Morgan Stanley argues that the existing market power screens in some cases fail to assess the full import capability into a given geographic market, and thus the true market size. Morgan Stanley ultimately argues that a revised market power screen ''should include any transmission located outside of the relevant market area, but which is interconnected and over which there is transfer capacity.''[47] However, Morgan Stanley does not state opposition to the idea that a lack of market power in energy and capacity can justify an assumption of equivalent lack of market power in Energy Imbalance and Generator Imbalance services.

Commission Determination

31. The Commission will adopt its proposal with modification. The Commission will allow third-party sellers passing existing market power screens to sell Energy Imbalance and Generator Imbalance services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service.[48] The Commission continues to believe that there are no unique technical requirements or limitations that apply to a resource's provision of Energy Imbalance or Generator Imbalance services. However, the Commission agrees with TAPS that the delivery of Energy Imbalance and Generator Imbalance services may be limited by hourly transmission scheduling practices in place within certain regions and, as such, refines the NOPR proposal as discussed below.

32. Energy Imbalance and Generator Imbalance services are a subset of a broader set of ancillary services offered by a public utility transmission provider to manage system conditions and ensure reliable transmission service. Energy Imbalance and Generator Imbalance services involve the balancing of differences between scheduled and actual delivery of energy or output of generation over an hour.[49] In comparison, Regulation and Frequency Response service involves the matching of resources to load in a shorter timeframe, requiring automated dispatch at four- or five-second intervals.[50] As a result, resources used

[39] WSPP Comments at 6; and Powerex Comments at 9–10.

[40] WSPP Comments at 7.

[41] Solar Energy Association Comments at 4.

[42] TAPS Comments at 11–12.

[43] *Id.* at 11–13.

[44] *Id.* at 12–13.

[45] *Id.* at 12 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690).

[46] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 19 (citing Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 309).

[47] Morgan Stanley Comments at 2–5.

[48] We note that sales of Energy Imbalance and Generator Imbalance services to entities other than a public utility transmission provider remain authorized under *Avista.*

[49] *See pro forma* OATT, Schedules 4 and 9. Under the *pro forma* OATT, imbalances are calculated and charged on an hourly basis. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 722; Order No. 890–A, FERC Stats. & Regs. ¶ 61,297 at P 325 & n.117; *see also* Order No. 764, FERC Stats. & Regs. ¶ 32,331 at P 104. Energy Imbalance and Generator Imbalance services also may be self-supplied by a transmission customer.

[50] *See, e.g.,* Pro Forma OATT, Schedule 3 Regulation and Frequency Response Service—''Regulation and Frequency Response Service is

Continued

to provide Regulation and Frequency Response service must be capable of balancing moment-to-moment fluctuations, whereas resources used to provide Energy and Generator Imbalance can respond at longer time frames within the hour.

33. In practice, public utility transmission providers often have a portfolio of resources, some owned and some purchased from third-parties, from which they provide capacity, energy, and ancillary services. This portfolio typically includes resources with automatic generation control (AGC) equipment capable of handling both moment-by-moment frequency adjustments and longer duration imbalance needs, as well as other capacity and energy resources that may only be capable of addressing longer duration imbalance needs because they are not equipped with AGC. These longer duration resources may include block purchases from third parties that are dispatched or otherwise scheduled at varying timeframes. The relative amount of AGC-controlled and other resources used by a public utility transmission provider for intra-hour balancing will depend on the resources available and the public utility transmission provider's operating practices.

34. In the NOPR, the Commission did not separately discuss this range of resources and, instead, preliminarily concluded that there are no unique technical requirements or limitations that distinguish the resources capable of providing energy and capacity from those capable of providing imbalance services. The majority of commenters agree with the Commission's preliminary conclusion, arguing that the set of resources available to follow imbalances over an hour is the same set of resources capable of providing energy and capacity. However, TAPS disagrees, arguing that the set of resources capable of providing imbalance services must have a special relationship with the control area operator in order to supply changing within-the-hour energy needs.

35. We understand TAPS' argument to be that resources used to provide imbalance service must be able to respond to a dynamic four- or five-second signal, which might require special arrangements in order to permit imbalance sales outside of the resource's home balancing authority area such that even the ability to submit transmission schedules on a 15-minute basis would be insufficient to provide intra-hour imbalance energy.[51] We agree that some of the public utility transmission provider's energy imbalance needs are addressed by resources that manage the moment-by-moment difference between load and resources. We also agree that imbalance service would generally require deliveries on intervals shorter than the current hour. But we do not agree, as explained more fully below, that imbalance services require dynamic dispatch or more sophisticated delivery mechanisms than intra-hour transmission scheduling.

36. Under the *pro forma* OATT, imbalances are calculated on an hourly basis.[52] As a result, any energy deliveries within the hour can be used by a public utility transmission provider (or by a transmission customer) to manage imbalances across the hour. That is, energy deliveries within the hour can be included in the portfolio of resources used to follow imbalance trends across the hour, similar to a public utility transmission provider's decision to redispatch its own internal resources within the hour. While it is true, as TAPS states, that dynamically dispatched resources capable of providing regulation also would be capable of providing imbalance services, it does not follow that resources using intra-hour transmission schedules are incapable of providing imbalance services. As noted above, imbalance service can be provided from a collection of resources so long as they are deliverable within the hour.[53]

37. The question before the Commission here is whether the set of resources considered available to provide energy and capacity in a market power analysis is sufficiently similar to the set of resources capable of providing imbalance services. Based on the record before us in which numerous commenters agree that the resources are sufficiently similar and given that intra-hour transmission schedules are currently being offered by a number of public utility transmission providers, and must be offered by all public utility transmission providers under Order No. 764 on or before November 12, 2013,[54] the Commission finds it appropriate at this time to revise the *Avista* restriction to better reflect current operational realities.

38. With regard to TAPS' additional comments in support of its basic argument, as stated above, just because a public utility transmission provider may have chosen to rely on the energy associated with regulation or operating reserves to meet imbalances, it does not follow that those are the only resources capable of providing imbalance services. Moreover, TAPS' reference to a portion of a passage from Order No. 890 referring to demand costs of providing imbalance energy being recoverable through regulation (Schedule 3) and operating reserve (Schedules 5 and 6) services is not dispositive here. The rate mechanisms used by a public utility transmission provider to recover the cost of capacity associated with providing Energy Imbalance or Generator Imbalance service do not precisely reflect the technical capabilities of resources available to provide the imbalance services. There is no requirement, in past Commission pronouncements or otherwise, that imbalance services be provided only from resources capable of providing regulation or operating reserves. Indeed, TAPS criticizes the NOPR for asserting the Commission's proposal was consistent with the decision in Order No. 890–A to base cost-based imbalance charges 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.[55] We agree with TAPS that the pricing of OATT imbalance services does not necessarily determine the technical capabilities of resources available to provide those services and reject the NOPR's assertion in this regard. Similarly, we find that the pricing of regulation and operating reserve services, whether through Schedules 3, 5, 6 or some other mechanism (such as generator regulation service), do not necessarily determine the technical capabilities of resources available to provide imbalance services.

39. TAPS also cites Order No. 890–A as finding that generation outside a control area can provide imbalance

necessary to provide for the continuous balancing of resources (generation and interchange) with load . . . .''

[51] TAPS Comments at 13.

[52] *See* Order No. 890, FERC Stats. & Regs. at P 722, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 61,297 at P 325 & n.117; *see also* Order No. 764, FERC Stats. & Regs. ¶ 32,331 at P 104.

[53] The Commission acknowledges that energy purchases scheduled on an hourly basis might enable a public utility transmission provider to use other resources to provide imbalance or other ancillary services more efficiently or precisely. Such hourly sales of energy would not be an indirect sale of ancillary services within the meaning of *Avista.*

[54] In order to comply with Order No. 764, public utility transmission providers must allow transmission customers to modify existing schedules as well as create new transmission schedules at intervals not to exceed 15 minutes, on or before November 12, 2013. Order No. 764, FERC Stats. & Regs. ¶ 32,331 at P 91, *order on reh'g,* Order 764–A, 141 FERC ¶ 61,232.

[55] *See* NOPR, FERC Stats. & Regs. ¶ 32,690 at P 19 (citing Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 309).

service when pseudo-tied and thus subject to within-area dispatch.[56] The cited passage of Order No. 890–A, however, states that a pseudo-tie arrangement causes a control area to ''assum[e] responsibility for ensuring that the load is properly balanced moment-to-moment, for planning for the load, and for providing various other ancillary services including energy or generator balancing service.'' The Commission made no determination in that passage as to the universe of resources capable, or incapable, of providing imbalance services. Nevertheless, the Commission acknowledges that some public utility transmission providers may choose not to purchase imbalance service from resources that cannot also be dynamically dispatched. While that may inform the relative ability of a resource to find a buyer for its service, it does not define the set of resources from which imbalance services are available, which is the relevant question for market power analyses.

40. We also find the opposing arguments of Morgan Stanley to be beyond the scope of this proceeding. Morgan Stanley does not appear to object to the use of the same market power screens for energy, capacity and imbalance services. Rather, Morgan Stanley argues that the existing indicative screens should be reformulated to include greater transmission imports than are currently assumed. Arguments as to the make-up of the existing market power screens are beyond the scope of this proceeding. The question before us in this proceeding is whether the resources in a given geographic market capable of providing imbalance ancillary services are sufficiently similar to the resources capable of providing energy and capacity that the same market power analysis can apply to both sets of products. Moreover, the Commission already permits applicants to demonstrate that the relevant geographic market is larger or smaller than that default.[57]

41. Accordingly, this Final Rule establishes that sellers found to lack market power in a geographic market, and which are granted market-based rate authority to make sales of energy and capacity, will also be granted market-based rate authority for sales of Energy Imbalance and Generator Imbalance services to public utility transmission providers within the same balancing authority area, or to public utility transmission providers in different balancing authority areas, if those areas allow transmission customers to modify or create transmission schedules within the hour. Because, as explained above, such scheduling practices enable the delivery of within-hour imbalance services from one balancing authority area to another, their use ensures that the first-tier resources included in the existing market power screens can compete with resources in the home balancing authority area, and thus that the existing market power screens can be applied to imbalance services without modification. This finding applies both to sellers that currently have a market-based rate tariff on file and applicants seeking market-based rate authority. For administrative convenience, we make this change to the Commission's ancillary services pricing policy effective as of the effective date of this Final Rule (120 days after publication in the **Federal Register**), which will result in these changes becoming effective after November 12, 2013, the date by which all public utility transmission providers must offer intra-hour transmission scheduling. As noted above, we acknowledge that some transmission providers already offer intra-hour scheduling. However, rather than performing a transmission provider-by-transmission provider review of current scheduling practices in this rulemaking, the Commission will defer implementation of this change to our ancillary services pricing policy until after the effectiveness of the intra-hour scheduling requirements of Order No. 764, by which time all public utility transmission providers must offer intra-hour scheduling. Thus, as of the effective date, all sellers that have a market-based rate tariff on file as of that date may begin making third-party sales of Energy Imbalance and Generator Imbalance services at market-based rates to a public utility transmission provider that is purchasing Energy Imbalance and Generator Imbalance services to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers, without having to make a separate showing to the Commission.

42. In response to WSPP, we clarify that this authorization to undertake sales at market-based rates may include both the capacity and the energy associated with providing Energy Imbalance and Generator Imbalance services. Imbalance services are products designed to address differences between scheduled and actual deliveries and withdrawals of energy. As such, they can only be provided by ensuring the availability of capacity and then increasing or decreasing the energy output from that capacity as necessary to address these differences.[58]

ii. Application to Other Ancillary Services

Commission Proposal

43. In the NOPR, the Commission proposed to allow the existing market-based rate screens to be applied to Energy Imbalance and Generator Imbalance services, but sought comment on whether the characteristics of resources used to provide the other ancillary services 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.[59]

44. With regard to Operating Reserve-Spinning and Operating Reserve-Supplemental, the NOPR discussed the technical considerations, such as minimum ramp and start-up rates for off-line resources and the ability for extended operation below fully loaded set point for online resources, that seemed to indicate that fewer resources would be capable of providing these ancillary services as compared to the set of resources capable of providing energy or capacity. With regard to Reactive Supply and Voltage Control from Generation Sources, the NOPR discussed the technical and geographic considerations that generally limit the resources capable of providing this ancillary service as compared with the broader set of resources capable of providing energy or capacity. With regard to Regulation and Frequency Response, the Commission discussed the technical requirements, such as automatic generation control (AGC) equipment, that limit the set of resources capable of supplying this ancillary service.[60]

Comments

45. A number of commenters argue for application of the existing market power screens to Operating Reserve-Spinning and Operating Reserve-Supplemental.[61] EPSA argues that operating reserves are

[56] TAPS Comments at 12 (citing Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 631).

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

[58] *See, e.g.,* Order No. 764, FERC Stats. & Regs. ¶ 32,331 at P 240.

[59] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 24.

[60] *Id.* PP 22–23.

[61] EPSA Comments at 6, WSPP Comments at 8 (with Iberdrola supporting by reference), EEI Comments at 3 and 10, Western Group Comments at 3–4, Hydro Association Comments at 7, and Powerex Comments at 7 and 13.

merely derivatives of a resource's ability to generate energy.[62]

46. WSPP argues that the same considerations that led the Commission to believe that the rebuttable presumption should be extended to the imbalance ancillary services also apply to the operating reserve ancillary services. WSPP further asserts that all of these ancillary services are widely deliverable and that all generators capable of being redispatched to higher or lower set-points within a scheduling window are capable of providing these ancillary services.[63]

47. EEI argues that except for variable energy resources, essentially the same set of resources evaluated as competing supply under the existing market power screens possess the required technical capabilities to provide operating reserves.[64] Western Group makes a similar argument, asserting that products in Schedules 3, 5, and 6 (Regulation and Operating Reserves) share operational characteristics of Schedules 4 and 9 (Imbalance services).[65]

48. While Powerex agrees that resources capable of providing spinning and non-spinning reserves may be limited by response time requirements, Powerex argues that the existing market power screens nonetheless can be applied to operating reserve services.[66]

49. With respect to Regulation and Frequency Response, some commenters argue that passage of the existing market power screens indicates lack of market power for that service. For example, while EPSA agrees that the market power of sellers of Reactive Supply and Voltage Control service cannot be gauged by the existing market power screens due to significant technical and geographic impediments, it argues that Regulation and Frequency Response service is merely a derivative of a resource's ability to generate energy. Accordingly, EPSA argues that application of the existing market power screens to this ancillary service would be appropriate.[67]

50. Powerex agrees that the existing market power screens could be applied to Regulation and Frequency Response service. Powerex believes that technical improvements such as the dynamic scheduling system adopted by some users of the Western Interconnection facilitate widespread delivery of regulating reserves, thus overcoming any locational requirements for that service, while any technical impediments could be overcome because AGC or equivalent power electronic controls could be added by most market participants if the markets provide correct price signals.[68] WSPP similarly argues that, while not all generators have the AGC equipment needed to provide Regulation and Frequency Response service, installation of this capability is an economic decision and is not such an impediment that it should be treated as a market defining barrier to entry.[69]

51. FTC Staff urges the Commission to recognize that even though a particular resource may not currently have the ability to provide a given ancillary service due to lack of relevant equipment, if such equipment could be installed in a timely fashion in response to high prices, then such resource should be considered a potential competitor for purposes of market power analysis. Accordingly, FTC Staff suggests that the Commission revise its market power analysis to incorporate as existing market participants those potential entrants that are likely to enter a given ancillary service market (i.e., install needed equipment such as AGC) rapidly and profitably should market prices justify such entry.[70]

52. EEI argues that, before extending application of the existing market power screens to Regulation and Frequency Response, the Commission should separate this service into two separate ancillary services: primary frequency control and secondary frequency control. EEI argues that secondary frequency control, which it labels as Regulation, is a prime candidate to be extended the rebuttable presumption (i.e., to be subject to the existing market power screens).[71]

53. Two parties filed comments opposing the application of existing market power screens to non-imbalance ancillary services. Southern California Edison and TAPS state that they agree with the NOPR's reasoning as to why the existing market power screens cannot be applied to non-imbalance ancillary services.[72] Remaining commenters did not address the question of applying the existing market power screens to non-imbalance ancillary services.

Commission Determination

54. Upon consideration of the comments to the NOPR, and as discussed more fully below, the Commission will allow third-party sellers passing existing market power screens to sell Operating Reserve-Spinning and Operating Reserve-Supplemental services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if those areas have implemented intra-hour scheduling for transmission service that supports the delivery of operating reserve resources from one balancing authority area to another. Commenters have persuaded us that to the extent there are technical requirements and limitations associated with operating reserves, they do not materially distinguish resources capable of providing energy and capacity from those capable of providing operating reserves. As with the imbalance services, however, the Commission finds that the delivery of operating reserves from one balancing authority area to another may be limited by hourly scheduling practices in place within certain regions, which could impact the assumption in the existing market power screens that first-tier resources are able to compete with home balancing authority area resources. Therefore, the Commission will allow third-party sellers passing existing market power screens to sell these services to public utility transmission providers to the extent within-hour transmission service scheduling practices, including intra-hour transmission scheduling mandated by Order No. 764, support the delivery of operating reserves from one balancing authority area to another.

55. In contrast, the Commission affirms the preliminary finding in the NOPR that the set of resources capable of providing Regulation and Frequency Response service and Reactive Supply and Voltage Control service would differ significantly from the broader set of resources capable of supplying energy and capacity. Accordingly, the *Avista* restrictions will remain in place for sales of those services to public utility transmission providers at market-based rates. As noted below, the Commission will establish a new proceeding to further explore the technical, economic and market issues concerning the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service.

[62] EPSA Comments at 6.

[63] WSPP Comments at 8. Iberdrola supports these WSPP comments by reference.

[64] EEI Comments at 10.

[65] Western Group Comments at 3.

[66] Powerex Comments at 7 and 13.

[67] EPSA Comments at 6.

[68] Powerex Comments at 12.

[69] WSPP Comments at 8. Iberdrola supports these WSPP comments by reference.

[70] FTC Staff Comments at 6–8.

[71] EEI Comments at 10–11.

[72] Southern California Edison Comments at 1–2; and TAPS Comments at 9–10.

Operating Reserve Services

56. Operating Reserve-Spinning and Operating Reserve-Supplemental are products designed to serve load temporarily in the event of contingencies. As such, sellers must ensure the availability of capacity sufficient to address a contingency event and, if the contingency occurs, energy must be supplied from that capacity. While the NOPR preliminarily found that the operating reserve products appeared to require the availability of resources with relatively fast ramping capabilities, and in the case of off-line resources used for operating reserve-supplemental, relatively fast start-up capabilities as well,[73] comments to the NOPR argue otherwise.

57. Many comments to the NOPR make the case that the flexibility and response time requirements associated with operating reserve services are not so significant that the universe of resources that can provide these services is meaningfully different than the universe of resources used to assess energy and capacity market power. While traditional generation scheduling practices only require the resources that provide energy and capacity to be able to change output levels once an hour, the record in this proceeding indicates that most resources can change output levels on shorter time scales. In other words, most conventional resources can change output in response to contingency events on a time scale shorter than the typical hourly scheduling window, even if in the past they have only been selling hourly block energy and capacity. Therefore, the Commission will allow third-party sellers passing existing market power screens for energy and capacity for a given market to also sell Operating Reserves-Spinning and Operating Reserves-Supplemental services at market-based rates to a public utility transmission provider within the same balancing authority area, or to a public utility transmission provider in a different balancing authority area, if within-hour transmission scheduling practices in those areas support the delivery of operating reserves from one balancing authority area to another.[74]

58. We note that our approach for market-based sales of operating reserves differs slightly from the reforms adopted above for sales of imbalance services. We have found above that the existence of 15-minute scheduling in a region renders the set of resources capable of supplying imbalance services substantially similar to the set of resources capable of providing energy and capacity so that the same market power screens can be applied to both sets of services. This may not be the case in all circumstances for potential sellers of operating reserves and, therefore, we require such entities to explain in their market-based rate applications for such authority how the scheduling practices in their regions support the use of operating reserves. For example, while 15-minute scheduling might be sufficient for Operating Reserve-Supplemental because this service only requires designated resources to be available within a short period of time,[75] 15-minute scheduling by itself may not be sufficient for Operating Reserve-Spinning, which requires designated resources to be available immediately.[76] The Commission recognizes that unlike the imbalance services, operating reserve services are targeted only at addressing contingency events, and some regions such as WECC may have already developed within-hour capacity tagging and scheduling practices intended to support the use of operating reserves across multiple balancing authority areas.[77] These are the types of region-specific practices that sellers seeking authority to sell operating reserves to public utility transmission providers should describe in their market-based rate applications. Thus, as of the effective date of this Final Rule, both sellers that have a market-based rate tariff on file as of that date and applicants seeking new market-based rate authority must satisfactorily make the above showing and receive Commission authorization before making sales of Operating Reserve-Spinning and Operating Reserve-Supplemental to a public utility that is purchasing Operating Reserve-Spinning and Operating Reserve-Supplemental to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.

Regulation and Reactive Power Services

59. The Commission affirms the preliminary finding in the NOPR that the more stringent technical and geographic considerations associated with the regulation and reactive power ancillary services suggest that they are not simple combinations of basic energy and capacity products. Most commenters addressing this issue agree that the set of resources considered by the existing market power screens would differ too significantly from the set of resources that would be considered by market power analyses designed specifically for Reactive Supply and Voltage Control service.

60. While some commenters do argue that the existing market power screens are adequate for Regulation and Frequency Response service, we are not persuaded by their arguments on the record here. We continue to believe that significant technical requirements, such as the need for AGC equipment, limit the set of resources capable of supplying this ancillary service. While we agree in principle with FTC Staff's comments that potential competitors could be viewed as existing competitors for purposes of market power analysis if it is known that they can install needed equipment rapidly and profitably in response to appropriate price signals, the record does not conclusively support the notion that such equipment upgrades (e.g., to install AGC equipment in an existing generator) can be accomplished in such a manner. Although Powerex asserts that AGC or equivalent power electronic controls could be added by most market participants if the markets provide correct price signals, and WSPP asserts that the addition of AGC is an economic decision, we are not persuaded based on the limited information in the record before us. Also, the record indicates that third-party sellers of Regulation and Frequency Response service might need to enter into or facilitate special arrangements between neighboring balancing authorities, such as dynamic scheduling or pseudo-tie arrangements, in order to make sales outside of their home balancing authority area.

61. Accordingly, because the record before us does not support a modification at this time, the *Avista* restrictions will remain in place for sales of Regulation and Frequency Response and Reactive Supply and

[73] *See* NOPR, FERC Stats. & Regs. ¶ 32,690 at P 22.

[74] As with Energy Imbalance and Generator Imbalance services, we clarify that the authorization to undertake sales at market-based rates may include both the capacity and the energy associated with providing Operating Reserve-Spinning and Operating Reserve-Supplemental services.

[75] *See pro forma* OATT, Schedule 6 ''Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time.''

[76] *Id.* Schedule 5 ''Spinning Reserve Service is needed to serve load immediately in the event of a system contingency.''

[77] *See, e.g.,* WECC Regional Business Practice INT–018–WECC–RBP–0, Tagging Protocols, at WR5.1 and WR5.2, defining capacity e-tags for, respectively, spinning reserves and non-spinning reserves as ''product(s) that can be activated through the adjustment of a capacity e-tag.'' *Available at http://www.wecc.biz/library/Documentation%20Categorization%20Files/Forms/AllItems.aspx?RootFolder=%2flibrary%2fDocumentation%20Categorization%20Files%2fRegional%20Business%20Practices&FolderCTID=0x01200015E7900DB2E794468FDE06D520B95C07.*

Voltage Control services to a public utility transmission provider that is purchasing these ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers. However, the Commission intends to gather more information regarding this issue in a separate, new proceeding that will further explore the technical, economic and market issues concerning the provision of Reactive Supply and Voltage Control service and Regulation and Frequency Response service. Such proceeding will consider, among other things, the ease and cost-effectiveness of relevant equipment upgrades, the need for and availability of appropriate special arrangements such as dynamic scheduling or pseudo-tie arrangements, and other technical requirements for provision of Regulation and Frequency Response and Reactive Supply and Voltage Control services.

b. Optional Market Power Screen

Commission Proposal

62. In the NOPR, the Commission proposed a new optional market power screen solely applicable to ancillary services, together with a limited new reporting requirement that would provide potential sellers of ancillary services with the information needed to develop market power analyses using that optional market power screen.[78] Specifically, the optional market power screen for an ancillary service would 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 aggregate requirement for that ancillary service, taking into account any 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 aggregate requirement for an ancillary service would receive a rebuttable presumption that they lack horizontal market power for the ancillary service in question.

63. In order to provide sellers with information as to the buyer's aggregate requirement for an ancillary service, the Commission proposed to require each public utility transmission provider to publicly post on its OASIS 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. For example, a transmission provider may report that it has historically maintained 100 MW of Regulation and Frequency Response reserves for its balancing authority area and 100 MVAR of Reactive Supply and Voltage Control in each of two submarkets within its balancing authority area.

Comments

64. Some commenters support the optional market power screen on the basis that it provides a practical alternative to performing a traditional market power analysis, given the data constraints associated with the latter. WSPP, for example, states that the optional market power screen is a constructive response to the disconnection between regulatory market power study requirements and the incapability of market participants to perform those studies due to lack of data.[79] WSPP states that it strongly supports the Commission's proposal that public utility transmission providers be required to post the information needed for sellers to prepare the optional market power screen if the rebuttable presumption applicable to the imbalance ancillary service is not extended to all ancillary services.[80]

65. Public Interest Organizations argue that the optional screen is similar in intent to a *de minimis* capacity threshold and, as such, can remove the barrier of a burdensome market power analysis for smaller entities.[81] The Solar Energy Association asserts that the optional market power screen likely will broaden the number of participants in the markets for certain ancillary services.[82] Electricity Consumers similarly argues that the optional market power screen should reduce barriers to ancillary service providers and increase the supply of ancillary services in a timely and cost-effective manner.[83]

66. However, there was no consensus among the commenters supporting the proposed optional market power screen regarding the necessary granularity of the associated reporting requirement. Some commenters, such as WSPP and Shell Energy, argue that postings should reflect a transmission provider's annual peak requirements for ancillary services, rather than annual averages. WSPP argues that posting an annual average would tend to understate requirements for higher periods, thereby skewing screen results in the direction of violations.[84] Similarly, Shell Energy states that relying on annual peaks is preferable to annual averages because it better reflects the amounts that transmission providers need to procure. Shell Energy further argues that postings of annual peak values are preferable to postings of seasonal or quarterly values, which Shell Energy claims would be burdensome for transmission providers and suppliers.[85]

67. Conversely, the ESA, Beacon, and California Storage Alliance recommend that public utilities provide seasonal and time-of-day requirements (if any) for each ancillary service versus a single average annual amount and note that this is consistent with the type of data provided by RTOs/ISOs in the open wholesale markets.[86]

68. Some commenters oppose the optional market power screen, arguing that it would yield too many false positives because it does not measure a seller's ability to supply relative to the total potential supply of the overall market. EPSA, for example, argues that the optional screen would routinely result in false-positive indications of market power.[87] EPSA states that if the Commission decides to use a threshold test, it should compare the subject generator to total product capability, not merely the quantity demanded.[88] EEI similarly argues that the optional screen likely will result in many suppliers failing the 20 percent threshold.[89] EEI contends that there are alternatives that would refine the test to be more applicable and useful in promoting robust participation in competitive ancillary services markets in bilateral regions. EEI offers as an example requiring transmission providers to report on its OASIS in the aggregate its historical demand and its historical ability to supply the relevant ancillary services. EEI offers that if the Commission decides to pursue optional screen it should have a technical conference.[90]

69. Powerex claims that the optional market power screen does not appear workable in certain respects and is likely to result in too many false positives.[91] Powerex argues that establishing a test that is overly restrictive, and that a majority of sellers

[78] NOPR, FERC Stats. & Regs. ¶ 32,690 at PP 25–30.

[79] WSPP Comments at 12.

[80] *Id.* at 10.

[81] Public Interest Organizations Comments at 6.

[82] Solar Energy Association Comments at 5.

[83] Electricity Consumers Comments at 3.

[84] WSPP Comments at 11.

[85] Shell Energy Comments at 8.

[86] ESA Comments at 7; Beacon Comments at 6; and California Storage Alliance Comments at 4.

[87] EPSA Comments at 6.

[88] *Id.* at 7.

[89] EEI Comments at 16.

[90] EEI Comments at 15.

[91] Powerex Comments at 16.

will not be able to satisfy, will create a significant administrative burden that will continue to pose an obstacle to the development of competitive markets for ancillary services.[92] Powerex asserts that when using market shares as a metric of market power, the proper measurement is a seller's ability to supply relative to the total potential supply of the overall market.[93]

70. Morgan Stanley argues that the optional market power screen does not provide a complete picture of an entity's market power and that it is more relevant to compare the amount of supply a seller controls to the total supply available and the total market demand, than it is to compare it to a single buyer's requirements.[94] Morgan Stanley claims that a seller actually could have greater market power even if it only can serve a small portion of the buyer's aggregate requirements if the buyer has no other viable options for procuring the remaining portion of its ancillary service needs.[95]

71. Other commenters oppose the optional market power screen on the basis that its need and usefulness is unclear. For example, TAPS argues that the usefulness of the optional screen is uncertain, particularly given the acknowledged data limitations. TAPS further argues that one cannot be confident that the proxy would provide a meaningful screen for market power.[96]

72. The California PUC states that is sees no need for alternative methodologies and further argues that a 20 percent threshold is too high for ancillary services.[97] The Hydro Association also states that it does not see a need at this time for the Commission to develop alternative market screens.[98]

Commission Determination

73. The Commission will not adopt the optional market power screen for ancillary services as proposed in the NOPR. As suggested by EEI, ESPA and others, the fact that the proposed optional screen would not consider the full amount of competing supply available to a buyer likely means that the screen may result in so many false positive indications of potential market power that it would provide little benefit to the effort to foster competition in ancillary service markets.

74. The comments also indicate that establishing the reporting requirements associated with the optional market power screen would not be a trivial task, particularly given the lack of consensus regarding the granularity of information needed. The Commission believes that the costs of developing and imposing this new reporting requirement on transmission providers might not be justified, particularly in light of the other actions taken in this Final Rule. The need for the proposed optional screen, and its associated reporting requirement, is significantly reduced because this Final Rule, as explained above, will permit sellers to apply the existing market power screens to imbalance and operating reserve ancillary services. As such, the Commission has determined not to adopt the optional market power screen and its associated reporting requirement.

Alternative Mitigation

75. In the NOPR, the Commission proposed 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 transmission provider purchasing ancillary services to satisfy its OATT requirements to offer ancillary services to its own customers.[99] Such a price cap would have been based on one of the two possible OATT ancillary service rate caps discussed below and, as in *Avista,* the Commission proposed 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. In addition, 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.

Use of Price Caps

Commission Proposal

76. In the NOPR, the Commission proposed two cost-based mitigation measures as alternatives to the prohibition adopted in *Avista* with regard to sales to a public utility transmission provider that is purchasing ancillary services to meet its OATT requirements to offer ancillary services to its own customers. Sales of ancillary services at or below either alternative would be permitted. Under the first, third parties would be permitted to sell to a public utility transmission provider at rates not to exceed the buying public utility transmission provider's existing OATT rate for the same ancillary service. Under the second option, third parties could propose to sell a given ancillary service to a public utility transmission provider 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. The Commission proposed that the seller (or group of sellers) would 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.

Single OATT Rate Cap Option

Comments

77. There was a range of support for the establishment of a rate cap at the buyer's OATT rate for the same ancillary service. TAPS and Southern California Edison support this proposal outright as an option to enable ancillary service sales.[100] EEI states that while the Commission should primarily rely on existing market power analyses and screens to allow third-parties to sell certain ancillary services at market-based rates, cost-based mitigation measures are also appropriate in certain seller-specific circumstances. EEI states that these two alternative options should be included in any Final Rule. EEI contends that this flexibility should encourage an increased number of participating sellers in bilateral markets, provide options for transmission providers to meet obligations, create market efficiencies, and potentially lower prices.[101]

78. WSPP states that it supports inclusion of this option to enhance flexibility in the sale of ancillary services, but with reservations. WSPP's reservations essentially concern whether existing OATT ancillary services rates provide appropriate price signals. WSPP contends that because reserve sales are from the same units as energy sales, mitigation price caps that

[92] *Id.* at 17.

[93] *Id.* at 19.

[94] Morgan Stanley Comments at 6.

[95] *Id.* at 7.

[96] TAPS Comments at 14.

[97] California PUC Comments at 5–6.

[98] Hydro Association Comments at 8.

[99] NOPR, FERC Stats. & Regs. ¶ 32,690 at PP 33–40.

[100] TAPS Comments at 15–18 and Southern California Edison Comments at 6.

[101] EEI Comments at 18–19.

fail to take opportunity costs into account during peak periods are unduly low.[102] Separately, WSPP asks the Commission to clarify that for the single OATT rate cap there is no filing with the Commission as a prerequisite to the sale.[103] AWEA and Solar Energy Association either support the proposal or do not state opposition to it.[104] Iberdrola supports WSPP's and AWEA's comments by reference.[105] Electricity Consumers state that they do not object to the proposed alternatives provided that they are in fact promulgated as alternatives to the proposed revisions to the market power analysis.[106]

79. Although ESA, Beacon, and California Storage Alliance all support this proposal, they each argue that for this mitigation measure to be successful in fostering robust competitive markets, the Commission must ensure that cost-based schedules for ancillary services, in particular Regulation and Frequency Response, are compared on an ''apples-to-apples'' basis taking into account resource performance.[107]

80. Some commenters oppose this price cap proposal unless the cap can be raised in some way. For example, Shell Energy argues that a cap based on the buyer's OATT rate would not produce prices high enough to entice competitive supply. Instead, Shell Energy suggests establishment of a price cap set at 200 percent of the buyer's OATT rate for the ancillary service in question.[108] Similarly, EPSA asserts that cost-based price caps systematically fail to represent the true value of capacity products and will fail to allow a full range of economic tradeoffs in the bilateral markets. EPSA states support for the use of price caps as a last resort, and only if they reflect the seller's lost opportunity costs as represented by energy transactions during a recent historical period.[109] Powerex makes similar arguments, favoring the use of energy price indices to represent lost opportunity costs. Failing that, Powerex argues that a component for transmission costs for remote suppliers should be added to any OATT-based price cap.[110]

81. ENBALA argues that a cost-based cap limited to the buying utility's OATT rate might be too restrictive and lead the Commission to scrutinize more agreements than necessary, but ENBALA states that ''Reactive Supply and Voltage Control service should be excluded from the regional price cap, being priced by the buying utility's OATT rate to reflect the geographic limitations of the ancillary service.'' [111]

Commission Determination

82. As one option available to sellers, the Commission will permit market-based sales of Regulation and Frequency Response service and Reactive Supply and Voltage Control service to public utility transmission providers at rates not to exceed the buying public utility transmission provider's OATT rate for the same service.[112] We find that a price cap based on the buying public utility transmission provider's OATT rate for the same ancillary service would produce a just and reasonable rate, and do so in a manner that is administratively simple. As discussed in the NOPR,[113] because the buying public utility transmission provider's OATT ancillary service rates have already been found to be just and reasonable, it is reasonable to find that any third-party sales of the same ancillary service to that buyer at or below that buyer's own approved rates for that service would also be just and reasonable. Accordingly, we will not require sellers to make a separate showing as to the justness and reasonableness of such rates and will allow sellers to make third-party sales of such services at rates as discussed here as of the effective date of this Final Rule.

83. Allowing the sale of ancillary services below the purchasing public utility transmission provider's OATT rate is a reasonable extension of the mitigation measure relied upon by the *Avista* policy itself. As discussed earlier,[114] the *Avista* policy sought to protect buyers of third-party ancillary services from potential exercise of market power by ensuring that they would continue to have access to cost-based ancillary services from transmission providers, in effect limiting the price at which customers are willing to buy ancillary services from third-parties. The result of the *Avista* mitigation measure is an implicit soft cap on the price at which third-party ancillary services could be offered to non-transmission provider customers. The price cap proposal adopted here extends this concept to transmission providers by creating an explicit price cap at the same level.

84. While a few commenters opine that a cap based on the buyer's OATT rate would not produce prices high enough to entice competitive supply, the Commission finds that, given the reforms adopted elsewhere in this Final Rule, it is appropriate to take the more conservative step of adopting a price cap based on the buyer's OATT rate for sales of Regulation and Frequency Response service and Reactive Supply and Voltage Control service to public utility transmission providers. This measure can be implemented quickly and easily with few administrative burdens on either the Commission or the industry. Alternative proposals by commenters would require more complicated design, analysis, and oversight to ensure that they achieve just and reasonable rates.

85. With respect to the arguments of ESA, Beacon, and California Storage Alliance that for this mitigation measure to be successful, the Commission must ensure that cost-based schedules for ancillary services are compared on an ''apples-to-apples'' basis taking into account resource performance, the Commission addresses this issue below in sub-section B of this Final Rule.

Regional OATT Rate Cap Option

Comments

86. Some commenters, such as ESA, Beacon, and the California Storage Alliance, support the regional OATT rate cap option on the basis that it is a reasonable approximation of the cost of entry.[115] ENBALA also expresses support for a regional cost-based rate cap, arguing that it provides an adequate alternative to the current formal market power requirement.[116] EEI and Electricity Consumers also express support for a regional OATT rate cap but offer no specific recommendations.[117]

87. Southern California Edison states that it supports a cap based on the highest OATT rate within the geographic market as long as it is capped at the lesser of (a) the highest OATT rate in the market or (b) three times the median OATT rate in the relevant geographic market. Southern

[102] WSPP Comments at 15.

[103] *Id.* at 14.

[104] AWEA Comments at 3 and Solar Energy Association Comments at 6.

[105] Iberdrola Comments at 3.

[106] Electricity Consumers Comments at 4.

[107] ESA Comments at 8–10; Beacon Comments at 7–9; and California Storage Alliance Comments at 5–6.

[108] Shell Energy Comments at 8–9.

[109] EPSA Comments at 9–10.

[110] Powerex Comments at 25–29.

[111] ENBALA Comments at 2–4.

[112] We do not apply this mitigation option to the other OATT ancillary services because this Final Rule allows sales of those services at market-based rates for any seller that has market-based rate authority for energy and capacity.

[113] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 34.

[114] *See supra* P 7.

[115] ESA Comments at 10; California Storage Alliance Comments at 7; and Beacon Comments at 9.

[116] ENBALA Comments at 2.

[117] EEI Comments at 18–19; and Electricity Consumers Comments at 4.

California Edison explains that it proposes this modification to protect against having a small balancing authority area with an extremely high outlier rate setting the cap.[118]

88. Other commenters criticize the highest OATT rate cap proposal. Some parties, such as WSPP, EPSA, and Powerex, argue that setting caps based on cost-based rates would not allow sellers to recover foregone opportunity costs associated with energy sales and thus would fail to create any incentives for sellers to enter ancillary service markets. They argue that this is particularly true for short-term ancillary service sales, given that opportunity costs vary materially for hourly, daily, monthly, and seasonal periods, but these variations are not reflected in OATT rates and therefore would not be reflected in the cap.

89. For example, Powerex contends that any alternative price cap must be high enough to create economic incentives for potential sellers to forego other opportunities, namely, energy sales.[119] Powerex argues that setting price caps based on transmission providers' cost-based rates in many instances will not allow sellers to recover the foregone opportunity costs associated with energy sales and that this is particularly true for short-term ancillary service sales.[120] Powerex states that short-term energy prices in the CAISO and other Western markets are frequently several-fold higher than Northwest transmission providers' OATT rates for ancillary services.[121]

90. Similarly, EPSA argues that a price cap should include a seller's lost opportunity costs, represented by energy transactions during a recent historical period. EPSA states that it is critically important to include lost opportunity costs, in order to allow a generator to rationally choose between producing energy and not producing energy.[122]

91. WSPP asserts that the Commission's observation that the OATT rate could be indicative of the cost of new entry appears speculative. WSPP contends that a cost-based rate may reflect a fully or substantially depreciated unit, rather than the cost of new construction.[123] WSPP also argues that because reserve sales are made from the same resources as energy sales, mitigation price caps that fail to take opportunity costs into account during peak periods are unduly low.[124]

92. Other commenters raise concerns about setting the geographic boundaries for a regional OATT rate cap. Shell Energy asserts that identifying the region in which an ancillary service can be physically traded can be difficult and recommends that the Commission, rather than sellers, identify the relevant trading regions and post that information on the Commission's Web site.[125] TAPS argues that a regional price cap would invite gerrymandering and provide no assurance that the resulting cap is a more reasonable approximation of the cost of new entry.[126] TAPS argues that significant physical constraints limit the provision of ancillary services over a geographic area.[127] TAPS contends that the regional OATT rate cap proposal is not defensible as either a cost-based or market-based rate and is at odds with the physical limitations on the provision of ancillary services in non-RTO regions.[128] TAPS contends that another regional transmission provider's higher rate (i.e., the highest regional rate) does not bear any relationship to either a third-party supplier's or the purchasing transmission provider's cost of supply.[129]

Commission Determination

93. The Commission will not adopt the NOPR proposal that would allow sellers to propose a price cap equal to the highest OATT rate within a specified region. Based on the comments received, the Commission concludes that use of a regional OATT rate cap would be inadequate to ensure that third-party sellers' rates remain just and reasonable. In the NOPR, the Commission suggested that this mitigation proposal might be justified on a cost basis in that the highest regional rate may be a reasonable approximation of the cost of new entry into the region in question.[130] However, the record developed in this proceeding does not support such a conclusion at this time.

94. We also share commenters' concerns associated with defining appropriate regions for purposes of setting regional price caps. The Commission is concerned that sellers would have an incentive to ''gerrymander'' or ''cherry-pick'' regional definitions to ensure inclusion of a high-cost ancillary service provider. In light of the other actions taken in this Final Rule, the Commission believes it would not be productive to undertake the analyses necessary to establish seller-specific regions for various ancillary services.

Competitive Solicitations

Commission Proposal

95. The NOPR proposed 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 guidelines: (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; (4) oversight—an independent third-party should design the solicitation, administer bidding, and evaluate bids prior to the company's selection;[131] and (5) competitiveness—adequate seller interest to ensure competitiveness.

Comments

96. Commenters generally support the proposal to permit competitive solicitations as an alternative to performing a market power study.[132] EEI, for example, expresses support for competitive procurement as an option for long-term resource planning.[133] EPSA states that the Commission's proposed guidelines for competitive solicitations conform to general principles that EPSA has advocated for such processes.[134]

97. Some commenters object to certain aspects of the Commission's proposal. Most criticism is directed at the proposed requirement for independent third-party oversight of competitive solicitations. WSPP, for example, expresses support for competitive solicitations as a means of mitigating potential market power concerns but opposes the proposed oversight by an independent third party. WSPP argues that such oversight is unnecessary, and that the required filing

[118] Southern California Edison Comments at 6–7.
[119] Powerex Comments at 26.
[120] *Id.*
[121] *Id.* at 27.
[122] EPSA Comments at 9–10.
[123] WSPP Comments at 15.
[124] *Id.* at 15.
[125] Shell Energy Comments at 9.
[126] TAPS Comments at 22.
[127] *Id.* at 20.
[128] *Id.* at 2.
[129] *Id.* at 19.
[130] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 36.
[131] *See, e.g., Allegheny Energy Supply Co. LLC,* 108 FERC ¶ 61,082 (2004).
[132] EPSA Comments at 8–9; EEI Comments at 19–20; ESA Comments at 10–11; Beacon Comments at 9–11; California Storage Alliance Comments at 7; and ENBALA Comments at 4.
[133] EEI Comments at 19–20.
[134] EPSA Comments at 8–9.

is ample to demonstrate whether or not the solicitation yielded sufficient competition.[135] Shell Energy agrees that third-party oversight of competitive solicitations is unnecessary, arguing that this requirement would hinder short-term procurement of ancillary services and make the solicitation process unfeasible except for long-term transactions.[136]

98. However, Morgan Stanley contends that it is not clear that the Commission's competitive solicitation proposal would protect against market power. Morgan Stanley contends that a competitive solicitation only demonstrates lack of market power if it is robust enough to attract offers that, in aggregate, are significantly in excess of the quantity sought. Morgan Stanley states that it is not clear how a competitive solicitation could help buyers looking to purchase such services on a short-term basis, although it might for the long-term provision of ancillary services.[137]

Commission Determination

99. The Commission adopts the NOPR proposal to allow applicants to engage in market-based sales of ancillary services to a public utility that is purchasing ancillary services to satisfy its OATT requirements where the sale is made pursuant to a competitive solicitation that meets the requirements specified in the NOPR as numerated above, except as modified below. The Commission has relied on the use of competitive solicitations to mitigate affiliate abuse concerns when affiliates seek to enter into transactions pursuant to market-based rate authority.[138] In that context, the Commission has adopted guidelines for independent, third-party review of competitive solicitations. The requirements proposed for sales of ancillary services to public utility transmission providers are based on these guidelines, which the Commission concludes are reasonable to adopt here with one exception. Upon review of comments, we have decided to partially eliminate the requirement that an independent third-party design and administer the solicitation and evaluate bids prior to the company's selection.

100. As proposed, the independent third-party review requirement would apply to all competitive solicitations. However, the record does not support imposing a requirement for independent third-party review when none of the parties participating in a competitive solicitation is affiliated with the buying public utility transmission provider. If no affiliate of the buyer participates in the solicitation, there is no concern regarding preferential treatment and, therefore, no need for review by an independent third party. As commenters suggest, requiring an independent third-party reviewer could discourage the use of competitive solicitations as it would add to the cost and time needed to procure ancillary services. Some public utility buyers may have a short-term, unexpected need for ancillary services and therefore need to act quickly to fill this need. In such cases, the buyer itself will have to conduct the solicitation, with very limited time for independent review. The Commission therefore revises the NOPR proposal to require independent third-party review of competitive solicitations only when the buyer solicits offers from one or more of its affiliates.

101. However, the Commission emphasizes that any buyer seeking to procure ancillary services from unaffiliated sellers through a competitive solicitation will need to demonstrate compliance with the four other requirements: transparency, definition, evaluation, and competitiveness. In this regard, we reject Morgan Stanley's assertion that the competitiveness requirement can only be met where a solicitation attracts offers that, in aggregate, are significantly in excess of the quantity sought. We believe there may be multiple methods of demonstrating adequate competitiveness, and we will review such proposals on a case-by-case basis. This will help ensure that any ancillary services procured in this manner are purchased at a competitive market price. At the same time, these requirements will not hinder buyers' flexibility to design solicitations to meet their specific needs. This demonstration must be made through a filing under section 205 of the Federal Power Act, submitted by the seller to the Commission prior to commencement of service under the third-party ancillary service sales agreement that results from the competitive solicitation. To be specific, the third-party seller will need to submit both the actual sales agreement and a narrative description of how the buyer's competitive solicitation meets the requirements of this Final Rule. This narrative description will help demonstrate that exercise of market power was not a factor in the negotiation of the sales agreement, and therefore that the resulting rate is just and reasonable.

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

Commission Proposal

102. The Commission proposed in the NOPR 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. Among other things, this would allow customers choosing to self-supply this service with faster responding or more accurate resources to self-supply with a lower volume of regulation capacity, or vice versa. The Commission stated that it expects to evaluate each proposed determination of regulation reserve requirements on a case-by-case basis. It also stated that each description of how the public utility will adjust its regulation capacity requirement must provide enough detail that an entity wishing to self-supply may compare the resources it is considering using with the resources that the public utility is using. The Commission sought comment on how speed and accuracy should be taken into account.[139]

Comments

103. A majority of commenters[140] generally support the NOPR proposal to require each public utility transmission provider to 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. Electricity Consumers, Hydro Association, Morgan Stanley, California PUC, and EPSA highlight the benefits of increased transparency, to which EPSA adds that lack of transparency is an impediment to competitive compensation outside of ISOs/RTOs and contributes to a lack of a discernible market value for speed and accuracy. Other commenters, including Public Interest Organizations, Iberdrola, Morgan Stanley, and FTC Staff cite avoidance of undue discrimination, comparable treatment, and the potential that the NOPR proposal will encourage innovation and new entry, as reasons for

[135] WSPP Comments at 17–18.

[136] Shell Energy Comments at 10.

[137] Morgan Stanley Comments at 8–9.

[138] *See Boston Edison Co. Re: Edgar Electric Energy Co.,* 55 FERC ¶ 61,382 (1991); *Allegheny,* 108 FERC ¶ 61,082.

[139] NOPR, FERC Stats. & Regs. ¶ 32,690 at PP 47–54.

[140] These commenters include Beacon, California Storage Alliance, ESA, Hydro Association, Solar Energy Association, Public Interest Organizations, California PUC, AWEA, Morgan Stanley, EPSA, TAPS, FTC Staff, Electricity Consumers, and Iberdrola.

supporting the proposal. Solar Energy Association supports taking into account the speed and accuracy of regulation resources when establishing the rates that may be charged for those services, with faster and more accurate resources priced accordingly.[141]

104. Hydro Association supports the idea of ''pay for performance'' standards that recognize the difference between accurate fast-responding resources versus resources that ramp more slowly and respond less nimbly, and agrees with the Commission that a case-by-case evaluation of each proposed determination is more appropriate than imposing a mandatory methodology. Similarly, California PUC states that transparency should act as a deterrent against discrimination, but cautions that the Commission should avoid an overly prescriptive methodology that may dictate the amount of regulation resources that are needed.

105. Several other commenters, including Beacon, ESA, California Storage Alliance, and Morgan Stanley, encourage the Commission to require transmission providers to provide an explanation of how they set their regulation reserve requirements. ESA, Beacon, and California Storage Alliance propose five elements of an explanation that each transmission provider should be required to provide about how it sets its regulation reserve requirement,[142] as well as a list of specific information that each transmission provider should make available.[143] Morgan Stanley also urges the Commission to require public utility transmission providers to provide demonstrations of equivalent treatment for their own or their affiliate's requirements to ensure that there is no undue discrimination, and to establish a process for market participants to challenge and resolve the speed and accuracy assumptions and requirements that public utility transmission providers publish.[144] Beacon and ESA also state that ideally the Commission would require each utility to develop a conversion formula or chart that specifies how much capacity a transmission customer must self-supply given a certain ramp-rate and accuracy.

106. ESA, Beacon, Public Interest Organizations, California Storage Alliance, and AWEA advocate extending the requirement of accounting for speed and accuracy in regulation service to public utilities meeting their own needs, including via third-party suppliers, not simply to transmission customers choosing to self-supply.[145] AWEA argues that holding more reserves than needed may result in rates that are not just and reasonable.[146] ESA, Beacon, Public Interest Organizations, and California Storage Alliance state that third party sales to a public utility that is purchasing ancillary services to satisfy its own OATT requirements to offer ancillary services to its own customers represents the most significant potential market for sales of ancillary services in non-RTO/ISO regions. Public Interest Organizations agree, arguing that neither the current rules nor the NOPR encourage transmission providers to improve the speed and accuracy of their owned or contracted frequency regulation resources, and that allowing generators to be displaced from providing frequency regulation will enable them to operate at a more stable output, which also can lower energy market prices. Public Interest Organizations contend that the existing OATT Schedule 3 rate treatment is no longer adequate to incorporate emerging technologies, and encourage the Commission to require that OATT Schedule 3 rates incorporate Order No. 755's framework of an objective accuracy and performance determination, and that the amount of frequency regulation transmission customers are required to procure or self-supply takes into account the speed and accuracy capability of the ancillary service provider's technology.[147]

107. Parties that support extending the proposal to public utility transmission providers meeting their own needs also recommend that the Commission consider performance-based rate treatment for public utility investments and contracts with third-party ancillary service providers that allow the public utility to reduce the total capacity and cost of providing regulation service while maintaining the same level of reliability.[148] They argue that the potential benefits to ratepayers could justify allowing a performance-based incentive rate adder that public utility transmission providers could recover through rates, and that if the public utility can demonstrate that it will be able to reduce the total capacity and cost of providing regulation service and maintain the same degree of reliability, such treatment should result in public utilities improving the performance of their regulation fleet and in turn reducing expenses for frequency regulation, ultimately resulting in lower costs.

108. TAPS asks the Commission to state explicitly that the NOPR's proposal to account for the speed and accuracy of customer self-supplied regulating resources includes demand resources and to state that such a finding would be consistent with OATT Schedule 3 and Order No. 755.[149]

109. EEI opposes the NOPR proposal. It contends that it is premature to require each transmission provider to include provisions in its OATT explaining how it will determine Regulation and Frequency Response requirements, and requests that the Commission defer this proposal pending experience with secondary frequency control (i.e., regulation) in the ISOs and RTOs following the issuance of Order No. 755.[150] EEI requests that the Commission recognize the material differences between primary and secondary frequency control resources in the final rule. It argues that it is also premature to adopt requirements regarding primary frequency control, and recommends that the Commission encourage each balancing authority to continue investigating the role of various types of resources, and allow the industry to maintain its efforts to understand the relationship and interdependencies between primary and secondary frequency response.

110. EEI contends that the assumption that faster responding technologies are necessarily more efficient than traditional methods of frequency regulation has not been substantiated. EEI explains that industry is still exploring frequency response, including current and historical primary and secondary control response performance, and that for system reliability it is important to maintain a balanced portfolio of resources including inertial response, governor response, and secondary frequency control (or regulation response). It further explains that, although OATT Schedule 3 groups primary and secondary frequency control into a single service, the nature of these

[141] Solar Industry Association Comments at 3.

[142] The five elements are: (1) A description of the calculation; (2) the metric which is used to set the requirement; (3) the average performance of the existing Regulation assets; (4) the speed and accuracy of the units currently in place (including ramp-rate and accuracy); and (5) sufficient data for a third party to reproduce the results, including posting ACE data on its OASIS reporting. ESA Comments at 12–13; Beacon Comments at 12; and California Storage Alliance Comments at 6.

[143] Each entity proposes a bulleted list of nine items including generation capacity available to provide regulation, rates, costs, accuracy and CPS scores, and representative ACE data. ESA Comments at 13; and Beacon Comments at 12–13.

[144] Morgan Stanley Comments at 10.

[145] Beacon and Public Interest Organizations support ESA's comments regarding third party sales of regulation.

[146] AWEA Comments at 4.

[147] Public Interest Organizations Comments at 8.

[148] *See* comments of ESA, Beacon, Public Interest Organizations, and California Storage Alliance.

[149] TAPS Comments at 27.

[150] EEI Comments at 22–26.

services are distinct. With regard to secondary frequency control (regulation), EEI claims that the benefits from resources that ramp more quickly for purposes of secondary frequency control may be offset by a lack of capability to sustain that response, or to provide automatic primary frequency control.

Commission Determination

111. The Commission will adopt the NOPR proposal with modification. Rather than requiring OATT Schedule 3 to include a description of how resource speed and accuracy will be taken into account in determining Regulation and Frequency Response reserve requirements, we will require each public utility transmission provider to add to its OATT Schedule 3 a statement that it will take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service, including as it reviews whether a self-supplying customer has made ''alternative comparable arrangements'' as required by the Schedule. This statement will also acknowledge that, upon request by the self-supplying customer, the public utility transmission provider will share with the customer its reasoning and any related data used to make the determination of whether the customer has made ''alternative comparable arrangements.'' [151] To aid the transmission customer's ability to make an ''apples-to-apples'' comparison of regulation resources, the Commission will also amend Part 35 of its Regulations by adding a new section (k) to § 37.6,[152] to require each public utility transmission provider to post certain Area Control Error (ACE) data described further below. We find that these reforms are necessary to address the potential for undue discrimination in the provision of Regulation and Frequency Response, including in instances when a customer self-supplies this service using its own resources or purchases from a third-party. Acknowledging the speed and accuracy of the resources used to provide this service will help to ensure that an appropriate quantity of resources is utilized for self-supply, whether those resources are faster and more accurate or slower and less accurate than those used by the public utility transmission provider. The weight of comments support reform in this area, including arguments that such a reform will help foster innovation and the entry of newer resources into the market.

112. Under the current *pro forma* OATT, transmission customers considering using their own or third-party resources to self-supply regulation service are required to demonstrate to the public utility transmission provider that they have made ''alternative comparable arrangements.'' However, the *pro forma* OATT provides no further information as to how the determination of ''alternative comparable arrangements'' would be made. Moreover, the OATT contains no express obligation on the part of the transmission provider to consider the relative speed and accuracy of resources a customer might desire to use in self-supplying Regulation and Frequency Response service. A public utility transmission provider could require a customer seeking to self-supply regulation services to provide a volume of regulation reserves based on the characteristics of the resources used by the public utility transmission provider to provide regulation service, which may not be reflective of the characteristics of the customer's resources. This could under- or overstate regulation reserve requirements depending on the relative characteristics of the resources at issue. It also could impair the customer's ability to self-supply regulation requirements at the lowest possible cost.[153] The Commission finds that this lack of clarity as to the role of resource speed and accuracy in the determination of ''alternative comparable arrangements'' for regulation reserve requirements for self-supplying transmission customers must be addressed in order to limit opportunities for potential discrimination in the provision of regulation service by public utility transmission providers.

113. While the Commission initially proposed that each public utility transmission provider should amend its OATT to include a description of how regulation reserve requirement determinations would take into account speed and accuracy of resources, we believe the better course of action at this time is to place the obligation on the public utility transmission provider to take into account speed and accuracy without requiring it to develop detailed tariff language describing the specific process to be used. This will provide the public utility transmission provider with flexibility while also providing the customer with information. While a number of commenters suggested elements for what the public utility transmission provider should be required to provide, the clearest proposal in the comments related to this issue request that public utility transmission providers be required to provide current monthly and 12-month rolling average Control Performance Standard 1 (CPS1), Control Performance Standard 2 (CPS2) and Balancing Authority ACE Limit (BAAL) scores for Frequency Regulation.[154] However, by itself availability of such information would do nothing to explain how the public utility transmission provider determines regulation reserve amounts. Furthermore, while ACE information might help to characterize the speed and accuracy of the public utility transmission provider's own regulation resources, the Commission believes that using the relatively long duration of monthly and 12-month rolling ACE averages implicit in these scores may not provide information useful for measuring performance over a fraction of an hour, which is the relevant time frame for Regulation and Frequency Response service.

114. Accordingly, the Commission declines to impose a ''one size fits all'' approach to calculating regulation reserve requirements, consistent with the comments of Hydro Association and California PUC, and declines to require the inclusion of this process in Schedule 3. Rather, we require that Schedule 3 be amended to include a statement that the public utility transmission provider will take into account the speed and accuracy of regulation resources in determining reserve requirements for Regulation and Frequency Response service, including when reviewing whether a self-supplying customer has made ''alternative comparable arrangements.'' Self-supplying customers and their public utility transmission providers will then have a basis to study and negotiate appropriate arrangements case-by-case, very similar to how such

[151] *See* Appendix B for the revised Schedule 3 of the *pro forma* OATT provisions consistent with this Final Rule.

[152] This regulation will replace the like-numbered proposed regulation related to historical ancillary service requirements data posting from the NOPR that we decline to adopt in section II.A.1.b. of this Final Rule.

[153] For example, a self-supplying customer could save money either by relying on a smaller amount of high quality regulation resources at a slightly higher per-unit price or by relying on a larger amount of lower quality regulation resources at a much lower per-unit price. Provided that reliability is maintained, the transmission customer should have the ability to self-supply consistent with its preferences.

[154] CPS1 and CPS2 are described in NERC Reliability Standard BAL–001–0.1a—Real Power Balancing Control Performance. The BAAL criterion is expected to replace CPS2 in that Reliability Standard when it becomes effective, pending final approval by NERC and the Commission.

interactions take place under other processes such as the interconnection process.

115. That said, we agree with the comments of ESA, Beacon, and California Storage Alliance that transmission customers considering whether or not there would be any economic advantage to self-supply of Regulation and Frequency Response service requirements would need to be able to make an ''apples-to-apples'' comparison of their resources to those of their public utility transmission provider.[155] Doing so would require the transmission customer to know both the potential avoided cost of purchasing from its public utility transmission provider, and some measure of the speed and accuracy of the public utility transmission provider's Regulation resources. The first requirement is met through the rate filed in the public utility transmission provider's OATT Schedule 3. We believe the second requirement can only be met through a new OASIS posting requirement.

116. As noted earlier, the public utility transmission provider's CPS1, CPS2, and BAAL scores might address this need in concept, except that they currently reflect long-term averages that do not match the relevant time frame for Regulation and Frequency Response service. We believe the one-minute and ten-minute average ACE data collected by public utility transmission providers to produce the CPS1, CPS2, and BAAL scores would be more useful for this purpose because it does match the relevant time frame. Accordingly, in order to ensure a level of transparency adequate to support self-supply decision-making by transmission customers, we will require public utility transmission providers to post historical one-minute and ten-minute ACE data on OASIS. For this purpose, we find that historical data for the most recent calendar year, updated once per year, should meet the need. This information is already collected and provided to NERC, through balancing area operators and reliability coordinators, so there should be minimal incremental burden associated with posting it on OASIS.

117. The Commission's standard filing requirements, including opportunity for intervention and comment, address Morgan Stanley's request to establish a process for market participants to challenge and resolve speed and accuracy assumptions. For example, as is the case in interconnection agreement proceedings, the transmission service agreement that reflects an individually negotiated self-supply arrangement for Regulation and Frequency Response service can be filed by the public utility transmission provider unexecuted. This will leave the transmission customer free to protest relevant aspects of the public utility transmission provider's determination of whether the customer has made ''alternative comparable arrangements,'' including as those arrangements relate to the speed and accuracy of the customer's proposed Regulation resources.

118. With respect to Morgan Stanley's request that public utilities demonstrate equivalent treatment for their own or their affiliate's regulation requirements, we find that the increased transparency required by this Final Rule will accomplish this goal. The requirements adopted above apply to the public utility transmission provider's own regulation resources, in the sense that it must apply the same procedures for determining regulation reserve requirements to itself as it does to self-supplying customers.

119. With respect to the request of TAPS that the Commission state explicitly that the NOPR's proposal to account for the speed and accuracy of customer self-supplied regulating resources includes demand resources, we note that OATT Schedule 3, as amended by Order No. 890 makes clear that Regulation and Frequency Response service may be provided from non-generation resources capable of providing the service. Accordingly, a transmission provider's determination of regulation reserve requirements should take into account the speed and accuracy characteristics of the resources in question, whether they are generation-based or otherwise.

120. Turning to the various requests that the Commission step beyond the NOPR proposals, the Commission declines to require two-part pricing for regulation capacity and performance set forth in Order No. 755. We conclude that the requirements adopted above will allow customers and the Commission to ensure that the speed and accuracy of resources used for regulation reserves are properly taken into account in reserve level determinations within the context of the bilateral markets within which non-RTO/ISO public utility transmission providers operate. The Commission also declines commenter requests to provide incentive rate treatment for purchases of Regulation and Frequency Response service by public utility transmission providers to meet their OATT requirements. Commenters are not clear as to what mechanism they believe the Commission should use to require such treatment, and the Commission sees no reason to implement an incentives program in the context of ancillary services rate design.

121. With respect to EEI's comments regarding differences between primary frequency response and secondary frequency regulation, the Commission acknowledges these distinctions. Improving the transparency regarding the resources used to provide Regulation and Frequency Response service under OATT Schedule 3 does not alter the ability of any balancing authority to maintain adequate reserves to meet reliability requirements. The Commission thus sees no need to wait for the industry to better understand the relationship and interdependencies between primary and secondary frequency response prior to adopting the requirements of this final rule. The Commission will evaluate a public utility transmission provider's compliance proposal as part of the case-by-case review discussed above, which will provide the public utility transmission provider the opportunity to demonstrate how it establishes its regulation reserve requirements.

Accounting and Reporting for Energy Storage Operations

122. In the NOPR, the Commission proposed to revise certain accounting and reporting requirements under its USofA and its forms, statements, and reports contained in Form Nos. 1, 1–F, and 3–Q. The Commission stated that the revisions were needed so that entities subject to the Commission's accounting and reporting requirements could better account for and report transactions associated with energy storage devices used in public utility operations. Moreover, the Commission noted that 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 subject to the accounting and reporting requirements.

123. The Commission proposed that new electric plant and associated O&M expense accounts be created to provide for the recording of investment and O&M costs of energy storage assets. The Commission also proposed to create a new purchased power account to provide for recording the cost of power purchased for use in storage operations. In addition, the Commission proposed that new Form Nos. 1 and 1–F schedules be created and existing schedules in the forms and Form No. 3–

[155] ESA Comments at 8–10; Beacon Comments at 7–9; and California Storage Alliance Comments at 5–6.

Q be amended to report operational and statistical data on storage assets. Finally, the Commission inquired about whether entities seeking to recover costs of energy storage assets and operations simultaneously under cost-based and market-based rates should be required to forego previously granted accounting and reporting waivers associated with market-based rates, and if so, should the requirement to forego the waivers be subject to some percentage threshold based on a ratio of cost-based cost recovery to total cost to be recovered.

124. While most commenters support the Commission's proposal to revise the accounting and reporting requirements, there were several recommendations to make adjustments to the proposals and also requests for clarification of certain proposals. Only Solar Energy Association opposed the proposal, stating, without elaboration, that it believes it is premature to establish reporting requirements for energy storage.[156] In the NOPR, the Commission responded to similar arguments regarding maturity of the energy storage industry as it relates to the use of energy storage assets to provide public utility services, and found those arguments unconvincing.[157] The Commission explained that there is a need for certainty in the accounting and reporting treatment for energy storage assets and operations, especially in instances where utilities seek to recover costs of energy storage operations in cost-based rates. Solar Energy Association has not provided new information that we could consider on this issue, therefore we find Solar Energy Association's argument unconvincing.

1. Electric Plant Accounts

Commission Proposal

125. In the NOPR, the Commission stated that the existing primary plant accounts do not explicitly provide for recording the cost of energy storage assets. The Commission concluded that this could 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. The Commission also noted that the lack of transparency affects interested parties', including the Commission's, ability to monitor these utilities' operations to prevent and discourage cross-subsidization between cost-based and market-based activities. To address these issues, the Commission proposed to create electric plant accounts in the existing functional classifications—production, transmission, and distribution—for new energy storage assets.[158]

126. The Commission proposed that the installed costs of energy storage assets be recorded in the accounts based on the function or purpose the asset serves. On this basis, an asset that performs a single function will have its cost recorded in a single plant account. In instances where an energy storage asset is used to perform more than one function or purpose, the Commission proposed that the cost of the asset be allocated among the relevant energy storage plant accounts based on the functions performed by the asset and the allocation of the asset's costs through cost-based rates that are approved by a relevant regulatory agency, whether federal or state.[159]

Comments

127. In general, the commenters applaud the Commission's efforts to improve transparency and prevent double-recovery of energy storage-related costs. The proposal to require utilities to record the costs of single-function energy storage assets in a single plant account garnered widespread support. However, the proposal to require utilities to allocate the costs of multi-function energy storage assets to the relevant energy storage plant accounts based on the functions performed and approved rate recovery, received comments supporting and opposing the proposal. Commenters that agree with the proposal generally indicate that the accounting would provide necessary transparency of a utility's operations,[160] while commenters that oppose the proposal generally indicate that the accounting would place an undue administrative burden on utilities and is inconsistent with the Commission's existing accounting rules.[161]

128. Public Interest Organizations state that they support the development of requirements that can reveal the activities and costs of energy storage operations thorough greater transparency and detail. California PUC similarly states that in the event an energy storage developer intends to use a facility to perform multiple functions, the proposed accounting and reporting should provide transparency. NU Companies state that they support flexible rate treatment for energy storage assets and believe the proposed accounting will provide transparency required to guard against inappropriate cross subsidization of various services and double recovery cost.

129. In opposition to the proposal, SDG&E contends that while it generally agrees with the Commission's allocation ''concept'' to account for energy storage assets by functional category, i.e., production, transmission, and distribution, it is concerned that generally applicable financial tools may not be able to efficiently track or monitor up to three functional categories for one asset without increased and ongoing manual intervention.[162] SDG&E argues that it agrees that the initial allocation concept would capture expenses by each function as the Commission intends; however, if the utility subsequently changes its initial allocation in the future the proposed accounting would create an unnecessary administrative burden that if a mistake is made could result in costs of the asset being stranded. SDG&E contends that to ensure the asset is accounted for properly so that asset costs are not stranded, a utility would be required to continuously monitor the asset to make sure its initial allocation is consistent with the asset's actual usage. SDG&E acknowledges that the NOPR addresses this concern;[163] however, SDG&E asserts that there is a more straightforward approach that can be used to allocate the costs of a multi-function energy storage asset. SDG&E advocates, instead of using multiple plant accounts, that the cost of an energy storage asset be recorded in a single plant account and its cost allocated to the various functions it performs using current ratemaking methods.

130. Similar to SDG&E, Southern California Edison and EEI also complain of an increased administrative burden resulting from allocating an energy

[156] Solar Energy Association Comments at 7.

[157] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 71.

[158] Account 348, Energy Storage Equipment-Production; Account 351, Energy Storage Equipment—Transmission; and Account 363, Energy Storage Equipment—Distribution, respectively.

[159] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 81.

[160] Public Interest Organizations Comments at 9–10; California PUC Comments at 9; NU Companies Comments at 4; APPA Comments at 5; ESA Comments at 18–19; TAPS Comments at 28–29; and California Storage Association Comments at 11–12.

[161] Southern California Edison Comments at 8; SDG&E Comments at 2–3; and EEI Comments at 29–30.

[162] SDG&E Comments at 2–3.

[163] SDG&E cites to the NOPR proposal that a utility transfer reallocated cost of an energy storage asset in accordance with the instructions of Electric Plant Instruction No. 12, Transfers of Property, 18 CFR Part 101 (2012). *See* SDG&E Comments at 3–4 (citing to NOPR, FERC Stats. & Regs. ¶ 32,690 at P 82).

storage asset's cost across multiple plant accounts as proposed in the NOPR. Southern California Edison and EEI contend that it would be necessary to create multiple unique property records for an energy storage asset to allocate its costs across multiple functions. Southern California Edison and EEI argue that having multiple records for each asset would require significant manual intervention while providing little practical value.[164] Additionally, Southern California Edison and EEI assert, without providing any detail, that the NOPR proposal is inconsistent with the general principle that each asset should have a single record within an accounting system.[165] Southern California Edison and EEI contend that there is neither a precedent for creating multiple property records for a single asset, nor a precedent for creating a record for a partial asset. Further, EEI argues that to the extent the different functions the cost of an energy storage asset could be spread across are subject to different depreciation rates, a single asset with a unique, individual economic life would be depreciated over multiple periods.

131. EEI indicates that while it generally opposes the NOPR's proposed accounting, it believes that in some circumstances the proposal may be a practical alternative for companies desiring to use it.[166] Therefore, EEI advocates that utilities be afforded two options to account for energy storage assets that are used to perform multiple functions. EEI proposes that utilities be allowed to either: (1) Record the costs of multi-function storage asset costs as proposed in the NOPR or (2) record the costs of the assets in a single plant account based on the primary function of the asset and to allocate costs to specific functions performed through the ratemaking process. Moreover, EEI recommends that the Form Nos. 1, 1–F, and 3–Q be amended to provide for reporting the option each company uses. EEI contends that allowing both options will afford companies the ability to maintain accounting and reporting records in the most efficient manner while providing transparency via reporting and uniformity in the ratemaking process.

132. Southern California Edison supports EEI's option (2). Southern California Edison and EEI contend that the option (2) approach is consistent with the approach used for certain assets that provide both state-jurisdictional and FERC-jurisdictional functions.[167] Southern California Edison and EEI explain that the ratemaking process may include a formula or special study in order to appropriately allocate the costs across functions.

Commission Determination

133. SDG&E's, Southern California Edison's, and EEI's arguments that requiring utilities to allocate the costs of energy storage assets that perform multiple functions across the relevant energy storage plant accounts places an undue administrative burden on utilities are unpersuasive. These commenters generally argue that this perceived undue administrative burden results from a requirement that utilities maintain records that track the usage of energy storage assets and costs associated with such use. However, utilities would be required to maintain records with this information whether accounting for the costs of an asset in multiple accounts as proposed in the NOPR or accounting for the costs in a single account as proposed by SDG&E, Southern California Edison and EEI. For example, information on the allocation of the cost of an energy storage asset to a particular function will have to be maintained by utilities operating multi-function, multi-cost recovery energy storage assets, regardless of whether the information is required to be reported in the reporting forms as proposed in the NOPR or if the information is not reported in the forms yet is used in ratemaking determinations as proposed by SDG&E, EEI, and Southern California Edison. Because utilities with energy storage operations that recover any portion of costs on a cost-of-service basis will be required to maintain use and cost allocation information on the assets, requiring these utilities to implement the NOPR's accounting proposal does not result in an additional burden on utilities that could be considered unduly burdensome.

134. Moreover, SDG&E's argument that costs could possibly be stranded if a utility does not appropriately account for energy storage operations is also unconvincing. This possibility exists throughout the utility industry and is not uniquely attributable to utilities with energy storage operations. Administrative errors, such as errors in accounting, that lead to costs being stranded due to inadequate or insufficient internal controls over policies, practices, and procedures used to track costs associated with assets represent a risk for all utilities whether or not the utilities own energy storage assets. Risks of this nature are inherent to all utilities' operations. Utilities must maintain adequate, sufficient, and reliable internal controls to reduce the probability of this risk affecting operations.

135. As support for their argument that the NOPR's proposed accounting causes an undue administrative burden and that their advocated accounting avoids the burden, Southern California Edison and EEI contend that their proposal to record the costs of an energy storage asset in a single plant account could require utilities to implement a formula or special study to appropriately allocate the costs of the asset across multiple functions. However, this contention does not support their argument. A formula or special study would require utilities to maintain the same information on the functions performed by an energy storage asset and costs associated with such performance, as would be required by the NOPR's proposed accounting. Thus, a formula or special study would not avoid the administrative burden associated with accounting for energy storage assets and operations. Furthermore, Southern California Edison and EEI have not provided information to support a determination that the burden would be decreased by implementing their proposed accounting. Their proposal would result in less transparent reporting of information on energy storage operations as compared to the NOPR's proposed accounting.

136. While the commenters argue that the accounting proposal might require increased manual intervention to account for and report storage assets, it is not clear that such intervention, if any, results in an undue administrative burden. As the Commission observed in the NOPR, uniform, transparent, and consistent reporting of information on energy storage operations by utilities is essential, especially by those seeking to recover costs of energy storage services in cost-based rates.[168] We believe that adopting the NOPR's proposed accounting and reporting revisions will improve transparency.[169] The revisions will enhance the Commission's and other form users' ability to make a meaningful assessment of a utility's cost-of-service rates, and will provide for better monitoring for cross-subsidization. In instances where an energy storage asset performs multiple

[164] Southern California Edison Comments at 8; and EEI Comments at 30.

[165] Southern California Edison Comments at 8 and n 8 citing Definition No. 8 Paragraph (A)(5), Continuing Plant Inventory Record, 18 CFR Part 101 (2012); and EEI Comments at 30.

[166] EEI Comments at 29–31.

[167] Southern California Edison Comments at 8; and EEI Comments at 31–32.

[168] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 71.

[169] *Id.* P 72.

functions, it is imperative that costs associated with each function be transparent and allocable to the function performed so that cross-subsidization of costs can be prevented. SDG&E, EEI, and Southern California Edison have not provided information that would refute the Commission's determination in the NOPR that the accounting proposal is not overly burdensome.

137. EEI's recommendation that utilities be afforded two options to account for and report storage assets that provide multiple services and recover associated costs simultaneously under cost-based and market-based rate methods is not consistent with the intent of the NOPR's proposed accounting and reporting revisions. The NOPR proposed one method to account for energy storage assets performing multiple functions under multiple cost recovery mechanisms to ensure that utilities account for the assets on a uniform and consistent basis. EEI's proposal for two methods of accounting could result in similarly-situated utilities with energy storage assets reporting the same type of transaction differently. This would not provide the uniformity sought by the accounting and reporting proposals and could disrupt consistency, which would make it difficult to compare utilities with energy storage operations across the industry. In addition, adopting EEI's proposal to record the costs of the assets in a single account would reduce the transparency of information reported in the forms. This information is critical to the clarity and transparency needed to support a reasonable analysis of a utility's cost. Consequently, we will not adopt EEI's proposal.

138. Southern California Edison's assertion that the NOPR requirement adopted here is not consistent with Definition No. 8, Continuing Plant Inventory Record, is incorrect.[170] While the definition pre-dates the NOPR's accounting and reporting requirements, the definition is broad enough such that its premise is as relevant for energy storage assets as it is for conventional electric plant assets. The accounting and reporting proposals require utilities to maintain a detailed record of the descriptive operational and cost information associated with energy storage assets consistent with the provisions of Definition No. 8.

139. Further, Southern California Edison's and EEI's contentions that there is no precedent for creating multiple property records for a single or partial asset misconstrue the proposed accounting and reporting requirements. The accounting and reporting proposals we adopt here do not require utilities to maintain multiple records for a single or partial asset as Southern California Edison and EEI contend. Rather, the reforms maintain the existing requirement of Definition No. 8 that utilities maintain descriptive operational and cost information on each asset. Moreover, we do not consider allocating the cost of a single asset to multiple property accounts to be the same as creating multiple property records as though there were multiple assets. A utility can maintain information on a single energy storage asset with costs allocated to multiple plant accounts in a single record that provides descriptive operational and cost information on the asset. Additionally, in accordance with General Instruction No. 12, Records for Each Plant, utilities are required to maintain a record, by electric plant accounts, on the book costs of each plant owned.[171] The requirement to record the cost of a multi-function, multi-cost recovery energy storage asset to more than one plant account is consistent with this instruction.

140. EEI argues that if different depreciation rates are applied to a single energy storage asset in accordance with each function the asset performs the various allocated costs of the asset would be depreciated over multiple periods. EEI is correct that there is a possibility of this occurring if costs of a single asset were subjected to multiple differing depreciation rates. However, this has neither been the experience of this Commission nor do we expect that a utility's primary rate regulator would subject a single asset to multiple depreciation rates. Although the costs of an energy storage asset may be allocated across multiple plant accounts, we agree with EEI that the asset is a single unique asset with a single economic life. Thus, there should be a single depreciation rate applied to the asset that allocates in a systematic and rational manner the service value of the asset over its service life. To the extent possible, a utility should apply a single depreciation rate to an energy storage asset.

141. The reforms adopted here are designed to provide needed transparency, but also to reflect a fair balance between the need for information and the additional burden on the utility. We believe these accounting reforms for energy storage reflect this balance. Accordingly, Account 348, Energy Storage Equipment—Production, Account 351, Energy Storage Equipment—Transmission, and Account 363, Energy Storage Equipment—Distribution, as proposed in the NOPR are adopted in this Final Rule.

2. Power Purchased Account

Commission Proposal

142. In the NOPR, the Commission noted that 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, and that some companies may be required to purchase power to maintain a desired state of charge or pressure. Further, the Commission determined that the benefits of enhanced transparency, in this instance, resulting from having the cost of power purchased for energy storage operations reported separately from other power purchases, outweighs the associated burden of requiring the accounting. Therefore, the Commission proposed a new Account 555.1, Power Purchased for Storage Operations, to report 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; and (4) power purchased to initially attain a state of charge, with item 4 being capitalized as a component cost of initially constructing the asset.

Comments

143. Most commenters support the proposed accounting. For example, ESA and others state that the new account will enhance the transparency of reporting the operations of storage resources.[172] Hydro Association indicates that similar accounting should be established for the cost of power purchased for pumped storage operations to account for initial unit testing and commissioning.[173]

144. Hydro Association states, in particular, for closed-loop pumped storage projects, the first unit testing entails pumping or charging the upper reservoir. Hydro Association explains that at an early stage of development of a pumped storage project, the generating station is months away from being declared ''commercial'' and testing the station requires energy from the grid to initially attain a fully charged state (i.e., a full upper reservoir). Hydro Association argues that these initial

[170] 18 CFR Part 101 (2012).

[171] The instructions indicate that the term ''plant'' means each generating station and each transmission line or appropriate group of transmission lines. This term is also applicable to energy storage facilities. 18 CFR Part 101 (2012).

[172] ESA Comments at 21–22.

[173] Hydro Association Comments at 12–13.

charging costs should be capitalized. Further, Hydro Association contends that costs incurred to test the generating station should likewise be capitalized into the cost of the project. In contrast to Hydro Association's assertion that the existing accounting requirements for pumped storage operations are not sufficient, EEI argues that the existing requirements appropriately and transparently provide for pumped storage plants.[174]

Commission Determination

145. We will adopt the new Account 555.1, Power Purchased for Storage Operations, as proposed in the NOPR. The accounting reforms here requiring initial charging and testing costs to be capitalized seek to apply existing requirements for conventional electric plant, such as pumped storage plant, to new energy storage assets. The requirements do not seek to differentiate the accounting for new energy storage assets from pumped storage plant in this instance.

146. We disagree with Hydro Association's assertion that the existing accounting requirements for pumped storage operations are not sufficient. Contrary to Hydro Association's assertion, pumped storage is not prohibited, for accounting purposes, by the existing accounting rules and regulations from capitalizing costs incurred to initially bring a pumped storage facility into operation nor is it prohibited from capitalizing costs incurred to test pump storage facilities prior to commercial operation. Electric Plant Instruction No. 3, Components of Construction Cost, provides that expenses incidental to the construction of plant such as cost to initially attain a fully charged state to bring the plant into operation may be capitalized as a component cost of the plant.[175] Further, Electric Plant Instruction No. 9, Equipment, provides that the costs of plant shall include necessary costs of testing or running plant or parts thereof during the test period prior to the plant becoming ready for or being placed in service.[176] Consequently, we agree with EEI's statement that the existing accounting requirements for pumped storage are sufficient. The NOPR proposals for Account 555.1 are adopted in this Final Rule as proposed.

[174] EEI Comments at 27.

[175] 18 CFR Part 101 (2012).

[176] *Id.*

3. Operation and Maintenance Expense Accounts

Commission Proposal

147. In the NOPR, the Commission observed that there are O&M expenses related to the use of 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. Therefore, the Commission proposed new O&M expense accounts for energy storage-related O&M expenses that are not specifically provided for in the existing O&M expense accounts in the USofA and revision of certain existing O&M expense accounts. Specifically, the Commission proposed that energy storage expenses 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, to the extent that the existing O&M expense accounts do not adequately support recording of the cost.[177]

Comments

148. The commenters support the proposed O&M expense accounts. Most commenters state that the proposed accounts will provide sufficient transparency of energy storage-specific O&M expenses.[178]

Commission Determination

149. This Final Rule adopts the NOPR proposals for the O&M expense accounts with the exception that the account number for Account 582.1 will be changed to Account 584.1. The name and text of the account will remain as proposed in the NOPR.

150. In addition, the NOPR proposed that the text of Account 592, Maintenance of Station Equipment (Major only), and Account 592.1, Maintenance of Structures and Equipment (Nonmajor only), be revised such that the accounts do not provide for O&M expenses related to energy storage operations and also to remove the reference to Account 363.

[177] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 96.

[178] *See, e.g.,* ESA Comments at 22; Beacon Power Comments at 21–22; and California Storage Alliance Comments at 17.

Accordingly, the following text is struck from Accounts 592 and 592.1:

''and account 363, Storage Battery Equipment.''

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

Commission Proposal

151. In the NOPR, the Commission acknowledged that the existing schedules in the Form Nos. 1, 1–F, and 3–Q do not provide for reporting information on new types of energy storage assets such as batteries and flywheels.[179] Consequently, the Commission proposed to amend several schedules of the Form Nos. 1, 1–F, and 3–Q to include energy storage plant, purchased power, and O&M expense accounts.[180] In addition, the Commission proposed to add new schedule pages 414–416, Energy Storage Operations (Large Plants), and pages 419–420, Energy Storage Operations (Small Plants), to the Form Nos. 1 and 1–F to provide for reporting operational and statistical information on new types of energy storage assets.[181] The Commission proposed that filers with energy storage assets having a rated capacity of 10,000 kilowatts (KW) or more record the operations of the assets on schedule pages 414–416, and filers with energy storage assets with less than 10,000 KW of capacity record the operations on schedule pages 419–420. In addition, the Commission sought comment on whether 10,000 KW is an appropriate threshold for requiring utilities to report more detailed plant and cost information for energy storage plant.[182] The Commission noted that certain existing schedules in the Form No. 1 have a 10,000 KW threshold.[183] However, the Commission opined that this threshold may not be appropriate for new energy storage assets that in

[179] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 101.

[180] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 106; and Appendix B Proposed Amendments to Form Nos. 1, 1–F and 3–Q.

[181] The text of the NOPR indicated that the schedules pages were 414–417 and 419–421 for the respective Large and Small Plant schedules. However, the proposed schedules included in Appendix B of the NOPR used different page numbers. We clarify that the schedule page numbers are 414–416 and 419–420, for the respective Large and Small Plant schedules, as indicated in this Final Rule.

[182] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 103.

[183] *See* Form No. 1, schedule pages 408–409, Generating Plant Statistics (Large Plants) and schedule pages 410–411, Generating Plant Statistics (Small Plants). Schedule pages 408–409 require filers to report more detailed information for generating assets with a rated capacity of 10,000 KW or more than schedule pages 410–411, which require less detailed information for generating assets with a rated capacity of less than 10,000 KW.

many instances may be rated below 10,000 KW.

Comments

152. Most commenters support the NOPR's forms proposals, and a few commenters recommend revisions to the forms in addition to those proposed.[184] Consistent with its recommendation that the Commission implement two options to account for energy storage assets, EEI proposes that the forms provide for disclosing the specific option a utility is using to account for the assets.[185] However, because we are not adopting EEI's recommendation for two accounting options, its disclosure proposal is unnecessary as utilities will have one uniform method for accounting for energy storage assets.

153. Hydro Association contends that there are shortcomings in the way the Form No. 1 treats existing pumped storage plants, as they are now used, and it suggests modifications that it believes will improve reporting of information on the assets. Hydro Association recommends that the heading of Line 6 ''Plant Hours Connect to Load While Generating'' of schedule pages 408–409, Pumped Storage Generating Plant Statistics (Large Plants), in the Form No. 1 be changed to read ''Plant Hours Connect to Load.'' [186] Hydro Association reasons that the total hours a facility is synchronized and connected to the grid are important to identify. Hydro Association explains that a facility's effectiveness is based on its total utilization factor, which Hydro Association describes as the sum of hours generating, pumping, and condensing. Hydro Association asserts that this sum should be reported on Line 6 under its proposed heading. Alternatively, Hydro Association proffers that if further detail is needed, the heading of Line 6 can remain as is and two new line items can be added to the schedule to report pumping and condensing hours.

154. Further, Hydro Association also contends that Line 38, ''Expenses for KWh (line 37/9)'' incorrectly calculates the cost per kilowatt hour (KWh) of pumped storage operations.[187] Hydro Association asserts that the calculation should include energy generated and energy used for pumping operations. Hydro Association proposes that Line 38 be revised to read as ''Expenses for KWh (line 37/9+10).''

155. TAPS recommends revisions to new schedule pages 414–416, Energy Storage Operations (Large Plants).[188] TAPS observes that the instruction for column heading (l) refers to ''revenues from energy storage operations'' while the name of the column is ''Revenues from the Sale of Stored Energy.'' TAPS asserts that because revenues from energy storage operations can be garnered by means other than from energy sales, the name of the column should be revised to be consistent with the instructions of the column or additional columns should be created, with corresponding instructions, to report other types of revenues.

156. In regard to the 10,000 KW threshold, California Storage Alliance states that it believes 10,000 KW is an appropriate threshold for requiring a difference in the reporting requirements for the assets.[189] In contrast, Beacon and ESA recommend a higher threshold of 20,000 KW.[190] Beacon and ESA assert that this threshold would align with the Small Generator Interconnection threshold and the capacity value for many existing and planned energy storage assets.

Commission Determination

157. We generally agree with the premise of Hydro Association's contention that Line 6 of schedule pages 408–409 could benefit from additional detail. However, the cost of additional detail must be weighed against any associated benefit that could result. To this end, we strive to achieve a balance such that the cost of implementing new reporting requirements does not excessively exceed the benefits of implementation. A particularly important benefit to the Commission of additional detail is that it provides data necessary for the regulation and review of companies' operations. Hydro Association has neither explained how information on pumping and condensing hours is needed for the regulation and review of pumped storage operations nor has it explained how the information would be beneficial for other uses. Hydro Association indicates that this information will provide for a measure of a facility's effectiveness, however, it is not clear that the cost of requiring this information is on par with any perceived benefits or that the requirement would not be overly burdensome. Consequently, we will not adopt Hydro Association's proposal to include the sum of generating, condensing and pumping on Line 6, nor will we adopt its alternate proposal to add two new line items to the schedule.

158. With regard to Hydro Association's contention that Line 38 of schedule pages 408–409 incorrectly calculates the cost per KWh of pumped storage operations, this line is not intended to report this cost, rather it is intended to report the cost per KWh of energy generated and transmitted to the grid. Line 38 of the schedule includes a formula that requires filers to divide total production expenses reported on Line 37 by energy generated and transmitted to the grid reported on Line 9. Nevertheless, we recognize Hydro Association's underlying concern that, as a conforming change given the other accounting requirements in this Final Rule, the schedule should report this information, including the energy generated and energy used in pumping, as illustrated in the formula example submitted by Hydro Association—Line 37/9+10.

159. We agree that reporting this information on schedule pages 408–409 will help create a more accurate database for benchmarking and O&M cost studies, and this information also will assist interested parties', including the Commission's, review of the operations of pumped storage facilities across the industry. We note that the data inputs needed to perform the calculation are currently required to be reported on Lines 9, 10 and 37 of schedule pages 408–409, so this requirement is not wholly new and the burden on utilities to calculate and report the information specifically on schedule pages 408–409 is minimal. Accordingly, the item on Line 38 of schedule pages 408–409 is revised to read ''Expenses per KWh of Generation (line 37/line 9)'' and a new Line 39 is added which reads ''Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10)).''

160. TAPS asserts that revenues from energy storage operations can originate from activities other than energy sales, thus it recommends that proposed schedule pages 414–416 be revised to provide for other types of revenues. We agree that there are potentially other activities that energy storage operators can engage in to generate revenue. For example, as TAPS noted, an energy storage operator can conceivably earn revenues from the sale of storage capacity. While we are not aware of any instances where these types of storage capacity transactions have occurred, to ensure that the schedule provides

[184] *See, e.g.,* APPA Comments at 5; Beacon Comments at 22–23; California Storage Alliance Comments at 19; and ESA Comments at 23.

[185] EEI Comments at 5.

[186] Hydro Association Comments at 11.

[187] *Id.*

[188] TAPS Comments at 28–29.

[189] California Storage Alliance Comments at 19.

[190] Beacon Comments at 22; and ESA Comments at 22–23.

adequate flexibility to allow for the reporting of all revenues from energy storage operations we will revise the name of the column to read ''Revenues from Energy Storage Operations.'' We will not create additional columns to report the various types of revenue because the instructions to the schedule already require filers to disclose this information in a footnote.

161. Beacon and ESA recommend that the Commission align the threshold for detailed reporting in the new schedules with the existing 20,000 KW threshold established in Order No. 2006 for the interconnection of small generators.[191] To this end, Beacon and ESA propose a 20,000 KW threshold as opposed to the 10,000 KW proposed in the NOPR. However, the 20,000 KW threshold in Order No. 2006 was established notwithstanding the requirement that small generators having 10,000 KW or more but less than 20,000 KW that are subjected to the Commission's accounting and reporting requirements would be subjected to a higher reporting burden than companies with generators of less than 10,000 KW. In this instance, the Commission determined that while there is a need to further remove barriers to participation in energy markets by establishing terms and conditions under which public utilities must provide interconnection service, there is also a parallel need for detailed information on the activities and operations of companies using these assets in the provisioning of utility services. Thus, the Commission maintained its existing 10,000 KW threshold for these small generators.

162. Beacon and ESA have not provided information that supports a decreased reporting burden for energy storage assets over 10,000 KW as compared to the reporting burden of conventional assets that are currently subject to the 10,000 KW threshold. Nor has Beacon or ESA provided information that would support increasing the existing 10,000 KW threshold for conventional assets to maintain parity between those assets and energy storage assets. Their proposal may result in an unduly discriminatory reporting requirement for energy storage assets compared to conventional assets, therefore we will not adopt the recommended 20,000 KW reporting threshold.

163. We will adopt the NOPR's proposed 10,000 KW threshold as this amount is neither unduly conservative nor is it overly burdensome. As we indicated in the NOPR, information that would be reported for energy storage assets and operations differs little from other data public utilities maintain under the USofA.[192] 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.

164. Finally, we will amend schedule pages 2–4, 204–207, 320–323, 324a–324b, 326–327, 397, and 401a of the Form Nos. 1, 1–F, and 3–Q as proposed in the NOPR.[193] We note that these amendments include revising schedule page 401a, Electric Energy Account, of the Form No. 1 to change the title of line item 10 to ''Purchases (other than for Energy Storage)'' and add a new line item 11 ''Purchases for Energy Storage'' to provide for reporting power purchased for energy storage operations. These changes require an additional line item on Form No. 1 schedule page 401a to provide for reporting stored energy because total net sources of energy must equal total disposition of energy as instructed by the requirement on Line 30 of the schedule. Utilities with energy storage operations that have stored energy as of the reporting date of the form must report the amount by megawatt hour in the schedule so that total net sources of energy is equal to total disposition of energy reported. Accordingly, as a conforming change, a new line item titled ''Total Energy Stored'' will be added to schedule page 401a under the heading ''Disposition of Energy.''

5. Other Accounting and Reporting Issues

a. Existing Waivers of Accounting and Reporting Requirements

Commission Proposal

165. In the NOPR, the Commission proposed 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 and that seek recovery of a portion of service costs under cost-based rates, be required to forego the previously issued waivers and account for and report all cost and operational information to the Commission in accordance with its accounting and reporting requirements.[194] In addition, the Commission also inquired whether there should be a percentage of cost recovery threshold 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.

Comments

166. Most commenters agree with the proposal to rescind previously issued waivers and many of these commenters argue that there should not be a percentage threshold that triggers the requirement. California Storage Alliance states that rescinding the waivers will enhance transparency and facilitate development and monitoring of the cost-based portion of rates.[195] Further, California Storage Alliance states that there should not be a percentage threshold that triggers accounting and reporting requirements. California Storage Alliance, and others,[196] also recommend that in instances where a competitive solicitation process is used to determine recovery of the cost-based portion of rates, a public utility should not be required to forego any reporting and accounting waivers. In further describing their position, these commenters suggest that a particular ''storage asset may be capable of simultaneously providing two distinct functions, one traditionally cost-based use, and another generally market-based.'' They then posit the possibility of a public utility issuing a competitive solicitation solely for the ''cost-based use.'' Their comments then assert that the winning bidder would be obligated to provide the ''cost-based service'' and would be paid through a ''rate-based mechanism.''[197] We also received requests to clarify that the waivers will only be rescinded if energy storage is involved.[198]

Commission Determination

167. We will adopt the NOPR proposal requiring public utilities to forego previously issued accounting and reporting waivers in instances where the utility seeks to recover costs associated with operation of an energy storage asset simultaneously under market-based and

[191] *Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g,* Order No. 2006–A, FERC Stats. & Regs. ¶ 31,196 (2005), *order on clarification,* Order No. 2006–B, FERC Stats. & Regs. ¶ 31,221 (2006). This order originally set forth the terms and conditions under which public utilities must provide interconnection service to Small Generating Facilities of no more than 20,000 KW.

[192] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 73.

[193] NOPR, FERC Stats. & Regs. ¶ 32,690 at Appendix B Proposed Amendments to Form Nos. 1, 1–F, and 3–Q.

[194] *Id.* P 75.

[195] California Storage Alliance Comments at 10.

[196] California Storage Alliance Comments at 10–11; ESA Comments at 18; and Beacon Comments at 18.

[197] *Id.*

[198] Indicated Suppliers Comments at 6–11; EPSA Comments at 13; and EEI Comments at 33–34.

cost-based rate recovery mechanisms. We will not impose a percentage recovery threshold, therefore any cost-based recovery of the cost will trigger rescission of previously granted accounting and reporting waivers.

168. Regarding the comments of California Storage Alliance, ESA, and Beacon, the Commission clarifies that sellers under a competitive solicitation that meets the requirements of this Final Rule [199] will not be required to forego any prior accounting and reporting waivers. However, we feel it necessary to explain that the reason for this outcome differs from what these commenters seem to propose.

169. Their comments seem to indicate a belief that there are some products that are inherently cost-based and others that are inherently market-based, and that if a competitive solicitation were held for a cost-based product, the resulting rates would still be cost-based. We are not persuaded by these commenters' arguments that products should be classified as inherently cost-based or market-based. Some potential sellers of these products will qualify to sell them at market-based rates because they either lack market power in the relevant product market, or it has been adequately mitigated. Other sellers who do not qualify to make market-based sales, because they either have market power or cannot prove they lack it, will be limited to charging cost-based rates.

170. Under the competitive solicitation proposal at bar, proof that the competitive solicitation meets the requirements of this Final Rule will demonstrate that a seller qualifies to make market-based sales at the rates resulting from the solicitation, and thus can avoid having to justify those rates on a cost-of-service basis. Because such sellers will still only be making market-based sales, there is no reason to rescind the prior accounting and reporting waivers that were granted because they would only be making market-based rate sales. Cost-based sales of ancillary services have always been an option for third party sellers, and remain an option for them after issuance of this Final Rule. However, all of the requirements of cost-of-service regulation, such as the very accounting and reporting requirements at issue here, would apply to such sales. We also clarify that the requirement for a company to forego previously issued accounting and reporting waivers, in this instance, is only applicable when energy storage is involved. There may be other occasions when previously issued waivers may be rescinded however those occasions are outside the scope of this rulemaking.

[199] *See supra* PP 87–90.

b. Definition of Energy Storage Asset or Technology

171. EEI asks that the Commission clarify the definition of energy storage assets or technologies that are subject to these accounting and reporting requirements.[200] EEI proposes that the Commission define energy storage assets as ''commercially available technology that is capable of absorbing energy, storing energy, and subsequently releasing the energy to the electric system.'' [201] Further, EEI states that certain other energy storage assets should be exempted from the Final Rule, and thus the new accounts, if the function of the asset is so clearly related to activities properly reflected in existing accounts such that the asset is not designed to be used as an ''energy storage asset'' under the definition articulated in this Final Rule. EEI states, for example, that the following assets or technologies should be exempted:

Batteries used primarily in connection with the control and switching of electric energy produced and the protection of electric circuits and equipment that are recorded in the following existing FERC accounts:

Account 315, Accessory Electric Equipment
Account 324, Accessory Electric Equipment (Major Only)
Account 345, Accessory Electric Equipment

Batteries used in connection with controlling station equipment or for general station purposes that are recorded in the following existing FERC accounts:

Account 353, Station Equipment

Batteries used in connection with controlling station equipment or for general station purposes that are recorded in the following existing FERC accounts:

Account 362, Station Equipment

Compressed air systems used for pneumatic or air tools that are recorded in the following existing FERC accounts:

Account 316, Miscellaneous Power Plant Equipment
Account 325, Miscellaneous Power Plant Equipment (Major Only)
Account 346, Miscellaneous Power Plant Equipment

Commission Determination

172. We agree with EEI that there are certain assets that are excluded from the scope of this Final Rule, however, we will not adopt EEI's proposed definition for an energy storage asset or technology. The definition is too broad and could be interpreted to include storage-type technologies that are outside the scope of this Final Rule. As EEI indicated, the assets listed above are the type of assets that should be excluded. This list is not exhaustive; rather it is an example of the type of assets and activities served by those assets that are a baseline indicator of assets that are outside the scope of the accounting and reporting requirements adopted in this Final Rule. For the purposes of this Final Rule, an energy storage asset shall be defined as property that is interconnected to the electrical grid and is designed to receive electrical energy, to store such electrical energy as another energy form,[202] and to convert such energy back to electricity and deliver such electricity for sale, or to use such energy to provide reliability or economic benefits to the grid. The term may include hydroelectric pumped storage and compressed air energy storage, regenerative fuel cells, batteries, superconducting magnetic energy storage, flywheels, thermal energy storage systems, and hydrogen storage, or combination thereof, or any other technologies as the Commission may determine.[203]

[200] EEI Comments at 26–28.

[201] *Id.*

c. Incorporating Energy Storage Plant Accounts Into Existing Formula Rates

173. EEI requests that the Commission pre-authorize inclusion of the new energy storage plant and O&M expense accounts in existing formula rates without the need for separate, company-specific section 205 proceedings.[204] EEI contends that many jurisdictional utilities that own and operate energy storage technologies account for the assets in existing accounts that are incorporated in formula rates. EEI states that to the extent the new accounts require a revision to existing filed rates, the Commission should allow such changes to be filed in a compliance filing in this proceeding.

Commission Determination

174. We agree with EEI that utilities currently owning and operating these assets are using existing accounts and reporting schedules. Moreover, in many instances these accounts are incorporated in the companies' formula rate templates and costs reported in the accounts are through operation of the formula rate included in rate

[202] Electrical energy may be converted to and stored as several different forms of energy such as chemical, mechanical, and thermal energies.

[203] Although hydroelectric pumped storage is an energy storage technology in accordance with our definition, the accounting and reporting requirements of this rulemaking do not apply to the assets, notwithstanding the revisions to schedule pages 408–409. As we indicated previously, our existing accounting and reporting requirements for pumped storage sufficiently accommodate pumped storage assets and operations.

[204] EEI Comments at 32–33.

determinations. For some of these companies, transferring amounts from an existing plant account under a particular functional classification to a new energy storage plant account under the same functional classification may involve a relatively straight-forward transfer of cost. In this type of situation, a compliance filing will provide adequate transparency to allow interested parties, including the Commission, to review amounts being transferred from one account to another and also to establish the incorporation of the new energy storage plant and O&M expense accounts in the formula rate tariff. However, a compliance filing may not be suitable for all situations.

175. For example, in instances where a company intends on recording the costs of an energy storage asset to multiple plant accounts in accordance with a plan to support multiple functions using the asset, a compliance filing may not provide for an adequate review of the many variables involved that can impact the determination of the appropriate allocation of the cost and rates charged based on the allocation. Moreover, if a company intends on recovering capital and O&M costs of the asset simultaneously under cost-based and market-based rate recovery mechanisms, a compliance filing would not provide sufficient notice or review of the cost to be recovered under the two rate mechanisms. Consequently, because a compliance filing is not appropriate for all situations, we will limit approval of its use to companies that are transferring amounts from an existing plant account under a particular functional classification to a new energy storage plant account under the same functional classification. Transfers of the costs to other plant accounts after this initial compliance filing shall be subject to the requirements of Electric Plant Instruction No.12, Transfers of Property,[205] as proposed in the NOPR,[206] and the provisions of utilities' formula rate tariffs, as applicable. Utilities that do not qualify to use the compliance filing process must first receive approval from a relevant rate regulator to revise their existing formula rate tariffs to incorporate the new energy storage accounts.

d. Depreciation Rates for Energy Storage Assets

Commission Proposal

176. In the NOPR, the Commission proposed that the cost of energy storage assets be charged to depreciation expense using the depreciation rates developed for each function.[207]

Comments

177. Commenters generally support this proposal. For example, Beacon and ESA acknowledge support for the proposal.[208] EEI recommends that instead of requiring depreciation rates to be based on a utility's existing rate for a particular function, the Commission allow utilities to set initial depreciation rates for new energy storage battery equipment based on the manufacturer's estimated useful life, prior to the utilities receiving approval of new depreciation rates through a rate proceeding where new approved rates are ordered for these accounts.[209] EEI explains that the current life of storage batteries is expected to be approximately 10 to 15 years and it contends that this expected life can be substantially less than the life used to calculate the depreciation rate for the function the asset may be classified under.

Commission Determination

178. For accounting purposes, utilities are required to use percentage rates of depreciation that are based on a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.[210] Where composite depreciation rates are used, the rate should be based on the weighted average estimated useful lives of depreciable property comprising the composite group. Furthermore, estimated service lives of depreciable property must be supported by engineering, economic, or other depreciation studies.[211] To the extent that an energy storage asset, such as a battery, has an estimated useful service life that is supported by engineering, economic, or other studies of the manufacturer or utility, the depreciation rate derived from such study must result in a systematic and rational allocation of the asset's costs over the estimated service life. Therefore, for accounting purposes, utilities may set initial rates for new energy storage assets based on manufacturer or utility estimated service lives that are supported by engineering, economic or other studies. In addition, as we indicated above, utilities should use a single depreciation rate for an energy storage asset regardless the number of functions to which the costs of the asset are allocated.[212]

e. Jurisdictional Authority

179. The California PUC warns that the Commission's authority over the accounting and reporting for energy storage assets should not limit or infringe upon States' jurisdictional authority over the assets as the majority of the assets are likely to be financed pursuant to state jurisdictional procurement authority.[213]

Commission Determination

180. The accounting and reporting requirements of this rulemaking are not intended to limit or infringe upon States' jurisdictional authority. Pursuant to section 301(a) of the Federal Power Act (FPA), the Commission has authority to prescribe a system of accounts and rules and regulations that are applicable in principle to all licensees and public utilities subject to the Commission's accounting and reporting requirements.[214] The Commission may determine the accounts in which particular outlays and receipts will be entered, charged or credited. The amendments to the accounting and reporting requirements are in accordance with the authority bestowed upon the Commission under the FPA and as such do not preempt or affect any jurisdiction a State commission or other State authority may have under applicable State and Federal law or limit the authority of a State commission in accordance with State and Federal law.

f. Implementation Date

181. EEI requests clarification of the implementation date of the proposed accounting and reporting requirements. EEI states that it believes assets and related amounts recorded in other accounts under the existing accounting requirements should be reclassified to the new energy storage accounts provided the asset meets the definition of an energy storage asset.[215] However, EEI argues that it would not be beneficial or cost effective to require utilities to retroactively amend prior year reports to implement the requirements. Therefore, EEI recommends that the accounting and reporting requirements be effective prospectively only.

[205] 18 CFR Part 101 (2012).

[206] NOPR, FERC Stats. & Regs. ¶ 32,690 at P 82.

[207] *Id.*

[208] Beacon Comments at 19; and ESA Comments at 19.

[209] EEI Comments at 32.

[210] General Instruction No. 22, Depreciation Accounting, 18 CFR Part 101 (2012).

[211] *Id.*

[212] *See supra* P 128.

[213] California PUC Comments at 8.

[214] 16 U.S.C. 825(a).

[215] EEI Comments at 28–29.

Commission Determination

182. While we agree with EEI that it may not be cost effective to require utilities with energy storage assets to retroactively amend prior year reports to implement the accounting and reporting requirements of this Final Rule; we disagree with EEI's contention that it would not be beneficial to interested parties desiring more transparent reporting of the costs associated with energy storage operations. In these instances, the Commission must weigh the perceived cost of implementing a requirement against the expected benefits of implementation. Although requiring utilities with energy storage assets to retroactively implement the requirements would provide a more transparent historical record of these utilities energy storage operations, this information would not be necessary to provide oversight of these utilities energy storage operations going forward. Moreover, it is not clear that the benefits of retroactive implementation are sufficient to justify the cost. Consequently, we will not require utilities to retroactively implement the accounting and reporting requirements.

183. Utilities subject to the Commission's accounting and reporting requirements must implement the requirements as of January 1, 2013. Utilities are not required to adjust prior year, comparative information reported in 2013 Form Nos. 1 and 1–F that must be filed by April 18, 2014, nor are they required to adjust prior year, comparative information reported in 2013 Form No. 3–Q reports. However, a footnote disclosure must be provided describing any amounts transferred from an existing account to a new energy storage account.

184. Due to outdated software, discussed in more detail below, the adopted new and revised schedules of Form Nos. 1, 1–F and 3–Q will not be available for use as of the effective date of this Final Rule. Consequently, utilities with energy storage assets and those that acquire the assets at a later date must continue or begin, as appropriate, using the existing form schedules to report energy storage assets pending availability of the new and revised schedules. Furthermore, we direct the Chief Accountant to issue interim accounting and reporting guidance for utilities to report to the Commission the costs of energy storage operations contemplated in this Final Rule until the new and revised schedules are available.

185. Regarding the reporting software issues, the Commission's forms software applications are built with Visual FoxPro development tools and must be installed on a Windows-based computer. Microsoft, the Visual FoxPro vendor, announced in 2007 that it would no longer sell or issue new versions of Visual FoxPro and would provide support for it only through 2015. Also, over time, the Commission has found that it is difficult to update tables in the software to accommodate revisions to existing schedules and add new schedules to the forms because Visual FoxPro does not allow data tables to exceed two gigabytes. These data size limitations will soon restrict the Commission's ability to add data fields in the forms. These limitations make the forms software application outmoded, ineffective, and unsustainable.

186. Pursuant to Sections 141.1, 141.400, and 385.2011 of the Commission's Regulations,[216] Form Nos. 1 and 3–Q must be submitted using electronic media.[217] Due to technology changes that will render the current forms filing process outmoded, ineffective, and unsustainable, the Commission will discontinue the use of Commission-distributed software to file forms. Moreover, because of the software limitations, the new and revised form schedules will not be available to utilities with energy storage assets and those that acquire the assets later as of the effective date of this Final Rule. Consequently, due to the time lag between implementation of the accounting and reporting requirements adopted here and the availability of a filing platform that accommodates the Commission's reporting forms, utilities should submit their 2013 Form No. 1 and 2014 Form No. 3–Qs using the existing forms filing process until an updated filing platform is made available by the Commission. Commission staff will issue appropriate notices and hold technical conferences if necessary concerning changes to the filing process.[218]

D. Other Issues

187. Some commenters raised issues beyond the scope of the NOPR. WSPP argues that public utility participation in a competitive market for ancillary services is hindered by certain OATT requirements applicable to network transmission customers. Specifically, WSPP refers to the requirement that network resources be undesignated as such, and thus lose their firm network transmission service, when they are committed to third-party sales instead of network load obligations. WSPP points to timing mismatches between the operational needs of ancillary service use and the undesignation requirements of the OATT as the main source of this issue. It argues that the Commission previously acknowledged these issues in connection with contingency reserves under the Southwest Reserve Sharing Group.[219] WSPP argues that this undesignation requirement hinders robust participation from network transmission customers, including the transmission providers themselves, in ancillary service markets.

188. EEI makes similar arguments with respect to the network resource undesignation requirements, and asks that the Commission remain receptive to utility-specific requests for flexibility.[220]

189. Hydro Association and Public Interest Organizations argue that the Commission should develop policies that facilitate long-term contracts with energy storage owners. Hydro Association asserts that the Commission should solicit further input on policies that would allow RTO, ISO, and stand-alone transmission providers to enter into long-term contracts with energy storage owners.[221] Public Interest Organizations make similar arguments.[222]

190. Shell Energy suggests that the current distinction between Energy Imbalance and Generator Imbalance is unnecessary, and that the two services should be combined into a single product. Shell Energy cites similar definitions in the EQR Data Dictionary, and states that treating the two services as different products provides little benefit, creates unnecessary complexity and may result in confusion and regulatory uncertainty.[223]

191. Shell Energy also urges the Commission to recognize ''Balancing Reserves'' as a separate energy and capacity product used to firm variable energy resources. Shell Energy argues that such a product would be differentiated from ancillary services because, unlike ancillary services, it would not be limited to addressing

[216] 18 CFR 141.1, 141.400, and 385.2011 (2012), respectively.

[217] Form No. 1–F filers may also submit the reports electronically; however, the Commission's regulations do not explicitly require these filers to submit the reports electronically. *See* 18 CFR 141.2 (2012).

[218] Filers with energy storage assets and operations may be required to amend and refile their 2013 Form Nos. 1 and 1–F and 2014 Form No. 3–Q to report energy storage operation information in the schedules adopted in this final rule as a result of the anticipated new filing platform. However, these filers will not be required to amend and refile previously submitted 2013 Form No. 3–Qs.

[219] WSPP Comments at 19–21.

[220] EEI Comments 21–22.

[221] Hydro Association Comments at 4–6.

[222] Public Interest Organizations Comments at 11.

[223] Shell Energy Comments at 3–4.

contingencies. Shell Energy seeks clarification that such a product would not be considered an ancillary service, and thus would not be subject to the *Avista* restrictions. Rather it would be subject to a seller's existing authorization to sell energy and capacity at market-based rates.[224] EPSA makes similar arguments regarding the need for a new, non-contingency-related balancing reserves product.[225] While WSPP's comments do not specifically seek to identify a new product based on whether or not it can be used for issues other than contingencies, as do Shell Energy and EPSA, WSPP nevertheless makes certain similar arguments in part of its comments. WSPP asserts that sellers may not always wish to sell specific ancillary services, but rather may wish to sell ''flexible capacity'' products capable generally of fulfilling multiple OATT schedules. While its comments are not entirely clear on this point, WSPP could be interpreted to argue that the Commission should recognize flexible capacity as a product different from ancillary services.[226]

192. AWEA requests that the Commission explore the role that dynamic transfer capability, or lack thereof, plays in protecting against exertion of market power. AWEA argues that lack of dynamic transfer capability severely constrains competitive ancillary service markets in many parts of the country. AWEA suggests that the Commission could require transmission providers to analyze, inventory, and market dynamic scheduling capability on a non-discriminatory basis.[227]

193. Powerex argues that there may be certain locations where there is sufficient market liquidity such that a seller should be able to make ancillary service sales without performing a separate market power analysis. Powerex believes that these locations might be defined by some measure of market liquidity, or by a specific minimum number of potential sellers, and gives as examples the trading hubs of Mid-Columbia, California-Oregon Border, Palo Verde, Four Corners, and Mead. Powerex does not suggest specific liquidity metrics, but does have suggestions regarding the appropriate minimum number of potential suppliers. It suggests that third-party sales to a transmission provider could be deemed competitive any time there are: (1) At least three potential suppliers, each capable of providing 100 percent of the buyer's needs for the ancillary service in question; or (2) at least five potential suppliers, each capable of meeting a significant portion (e.g., at least 25 percent) of the buyer's need for the ancillary service in question.

Commission Determination

194. With respect to WSPP's request for more flexibility on the requirements for network resource undesignation, the Commission declines to consider such changes on a generic basis at this time. This undesignation requirement is intended to ensure that network transmission customers cannot inappropriately withhold firm transmission capacity from potential competitors. While WSPP is correct that the Commission has permitted limited deviations from this requirement in connection with established reserve sharing groups, we are not persuaded that a more general relaxation is justified. WSPP indicates in its comments that a public utility is unable to undesignate the network resource providing the energy associated with the provision of ancillary services because the unit providing the energy may differ from the unit providing the capacity. This suggests that the public utility will be using transmission service from a unit that is different from the unit for which transmission service has been reserved. Thus, WSPP is essentially asking the Commission to permit a public utility transmission provider to implicitly use firm point-to-point transmission service without reserving it or paying for it. The Commission has previously expressly prohibited this practice and nothing in the comments suggests that the Commission's concerns are no longer valid.[228] Further, participating in a reserve sharing group differs from making third-party market sales of ancillary services. A reserve sharing group essentially expands a public utility transmission provider's native load obligations to serving other load serving entities' native load in the event of a contingency with like protection in return. Permitting a public utility transmission provider to deliver energy associated with its reserve sharing group obligations without undesignating the resource providing the energy is an appropriate recognition of the network service elements of reserve sharing arrangements. On the other hand, market sales of ancillary services must be delivered using point-to-point transmission service.

195. With respect to the requests of Hydro Association and Public Interest Organizations to facilitate long-term contracting with energy storage owners, we see no basis for any additional action at this time. In bilateral markets, assuming that parties are able to avoid the *Avista* restrictions through use of one of the options provided in this rule, potential buyers including transmission owners and sellers are free to transact through contracts of whatever length they find mutually agreeable.

196. Shell Energy's suggestion that Energy Imbalance and Generator Imbalance services be combined into a single product is beyond the scope of this rulemaking, and Shell Energy's arguments in support of this idea do not rise to a level concrete enough to justify such an expansion at this time.

197. With respect to Shell Energy and EPSA's comments regarding recognition of non-contingency-related balancing reserves as separate from ancillary services, and WSPP's similar discussion of ''flexible capacity,'' we clarify that sales of energy and capacity at market-based rates are permissible, provided the buyer may not use the purchases to meet its OATT obligations to provide Regulation and Frequency Response or Reactive Supply and Voltage Control ancillary services.

198. AWEA's comments regarding dynamic transfer capability raise issues beyond the scope of this rulemaking, which have not been fully explored in this proceeding, and whose resolution is not necessary to the completion of this rulemaking. Accordingly, the Commission will not direct changes with respect to dynamic scheduling or dynamic transfer capability at this time.

199. Regarding Powerex's argument for development of a new market liquidity screen for ancillary service market power, we decline to attempt such development at this time. The record does not currently support either development of a generic market liquidity metric, or the particular minimum participant number thresholds proposed by Powerex. We remain open to a more detailed discussion of these ideas in the future if needed, but at this time will move forward with the rule changes contained elsewhere in this Final Rule, which we hope will reduce the need to develop alternative market power analyses.

III. Summary of Compliance and Implementation

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[224] Shell Energy Comments at 5–6.

[225] EPSA Comments at 10–11.

[226] WSPP Comments at 7.

[227] AWEA Comments at 3.

[228] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 834.

200. With respect to this Final Rule's reforms to the *Avista* policy governing sales of certain ancillary services to a public utility purchasing the ancillary service to satisfy its own OATT requirements to offer ancillary services to its own customers, sellers that have a market-based rate tariff on file should revise the provision concerning third-party sales of ancillary services, to the extent they have this provision in their tariffs, as follows: Third-party ancillary services: Seller offers [include all of the following that the seller is offering: Regulation and Frequency Response Service, Reactive Supply and Voltage Control Service, Energy and Generator Imbalance Service, Operating Reserve-Spinning ~~Reserves~~, and Operating Reserve-Supplemental ~~Reserves~~]. Sales will not include the following: (1) Sales to an RTO or an ISO, i.e., where that entity has no ability to self-supply ancillary services but instead depends on third parties; and (2) 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 open access transmission tariff requirements to offer ancillary services to its own customers~~. Sales of Operating Reserve-Spinning and Operating Reserve-Supplemental will not include sales 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, except where the Commission has granted authorization. Sales of Regulation and Frequency Response Service and Reactive Supply and Voltage Control Service will not include sales 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, except at rates not to exceed the buying public utility transmission provider's OATT rate for the same service or where the Commission has granted authorization.

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201. While the authorization is effective as of the date specified in this Final Rule, sellers should file this tariff revision the next time they make a market-based rate filing with the Commission. To the extent sellers do not currently have this provision in their tariff but wish to make third-party sales of ancillary services, they should include this revised provision in their tariff the next time they make a market-based rate filing with the Commission.

202. With regard to sales of Operating Reserves, as discussed above, both sellers that have a market-based rate tariff on file and applicants seeking new market-based rate authority must satisfactorily make the required showing and receive Commission authorization before making sales of Operating Reserve-Spinning and Operating Reserve-Supplemental to a public utility that is purchasing Operating Reserve-Spinning and Operating Reserve-Supplemental to satisfy its own open access transmission tariff requirements to offer ancillary services to its own customers.

203. With respect to the Final Rule's reforms to provide greater transparency with regard to reserve requirements for Regulation and Frequency Response, within 30 days from the effective date of this Final Rule, we require each public utility transmission provider to revise its OATT Schedule 3 consistent with the revised Schedule 3 in accordance with Appendix B to this Final Rule.

204. With respect to Final Rule's reforms to our accounting and reporting regulations, utilities subject to these requirements must implement the requirements as of January 1, 2013. Utilities are not required to adjust prior year, comparative information reported in 2013 Form Nos. 1 and 1–F that must be filed by April 18, 2014, nor are they required to adjust prior year, comparative information reported in 2013 Form No. 3–Q reports. However, a footnote disclosure must be provided describing any amounts transferred from an existing account to a new energy storage account.

205. Due to outdated software, discussed in more detail in the body of this Final Rule, the adopted new and revised schedules of Form Nos. 1, 1–F and 3–Q will not be available for use as of the effective date of this Final Rule. Consequently, utilities with energy storage assets and those that acquire the assets at a later date must continue or begin, as appropriate, using the existing form schedules to report energy storage assets pending availability of the new and revised schedules.

IV. Information Collection Statement

206. The following collections of information contained in this Final 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.[229] OMB's regulations require approval of certain information collection requirements imposed by agency rule.[230] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information if the collections of information do not display a valid OMB control number.

Burden Estimate: The additional estimated public reporting burdens and costs for the reporting requirements in this Final Rule are as follows.[231]

Data collection	Number of respondents (a)	Change in the number of hours per filing (averaging implementation over Yrs. 1–3) [232] (b) (hrs.)	Filings per respondent per year (c)	Change in the total annual hours for this collection (averaging implementation over Yrs. 1–3) (aXbXc=d) (hrs.)	Estimated annual cost (averaging implementation over Yrs. 1–3) (at $120/hr.) (dX$120/hr.) ($)
Form No. 1	210	7 [3 hrs. (one-time implementation in Year 1), plus 6 hrs. annually].	1	1,470	176,400
Form No. 1–F	5	7 [3 hrs. (one-time implementation in Year 1), plus 6 hrs. annually].	1	35	4,200
Form No. 3–Q	213	1	3	639	76,680
FERC–917 [includes one-time filing of Pro forma open-access transmission tariff (OATT) & data sharing] [233].	132	17.33 averaged over Years 1–3 [4 hrs. one-time in Yr. 1, plus an average recurring burden in Years 1–3 of 16 hrs.].	1	2,288 averaged over Years 1–3.	274,560 averaged over Years 1–3
FERC–516	no change	no change	no change	no change	no change

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

[230] 5 CFR 1320.11 (2012).

[231] In the NOPR, the Commission proposed changes to FERC–919 (related to the '20 percent screen'). The FERC–919 is not affected by the Final Rule. In addition, changes to FERC–516, which were not contained in the NOPR, are included in the Final Rule.

Data collection	Number of respondents (a)	Change in the number of hours per filing (averaging implementation over Yrs. 1–3) [232] (b) (hrs.)	Filings per respondent per year (c)	Change in the total annual hours for this collection (averaging implementation over Yrs. 1–3) (aXbXc=d) (hrs.)	Estimated annual cost (averaging implementation over Yrs. 1–3) (at $120/hr.) (dX$120/hr.) ($)
FERC–717 (OASIS posting under 18 CFR 37.6k).	176	1	1	176	9,889 [234]
Total				4,608 (averaged over Years 1–3).	$541,729 (averaged over Years 1–3)

In paragraph 96, the Commission is requiring that any third-party seller seeking to sell ancillary services to a public utility transmission provider through a competitive solicitation will need to demonstrate compliance with the competitive solicitation requirements of this rule, through a filing under section 205 of the Federal Power Act. This requirement for submittal in a section 205 filing would be made under FERC–516 (OMB Control No. 1902–0096). The filing would be submitted by the seller to the Commission prior to commencement of service under the third-party ancillary service sales agreement that results from the competitive solicitation. The filing will include both the actual sales agreement and a narrative description of how the buyer's competitive solicitation meets the requirements of this Final Rule. Meeting those requirements demonstrates the justness and reasonableness of the resulting rate. If the seller did not have this option to sell under the competitive solicitation, the seller could not use market-based rates and would have to either submit an application for cost-based rates under FERC–516 or an application seeking waiver of the *Avista* restrictions on a case-by-case basis.[235] The Commission believes that the burden associated with the new requirements is far less burden than a full cost-of-service rate filing and approximately the same burden as the burden associated with an *Avista* waiver filing. In addition, the numbers of respondents and filings are not expected to change significantly. Therefore, no changes are proposed to the burden or number of responses for FERC–516.

Title: 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–516, '' Electric Rate Schedules and Tariff Filings,'' and FERC–717, ''Open Access Same-Time Information System and Standards for Business Practices & Communication Protocols.''

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), 1902–0096 (FERC–516), and 1902–0173 (FERC–717).

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

Frequency of responses: Annually (FERC Form Nos. 1 and 1–F, and FERC–717); quarterly (FERC Form No. 3–Q); and as needed (FERC–917 and FERC–516).

Necessity of the Information: The final rule amends the Commission's regulations to reflect changes that are occurring in the electric industry due to the availability of new energy storage technologies that are being used in the provision of large-scale utility operations. These technologies are providing services that were typically provided by traditional single-purpose production, transmission and distribution resources. The addition of these new plant accounts and new and amended reporting forms are intended to enhance transparency and provide detailed information on transactions and events affecting public utilities and licensees that file reports with the Commission. The accounting regulations currently found in the USofA and related reporting requirements capture financial and operational information along traditional primary business functions but do not provide sufficient detailed information concerning energy storage operations, and in particular, the costs incurred by organizations using these resources to simultaneously provide multiple utility services with a single asset. The addition of these accounts is intended to improve the transparency, completeness and consistency of accounting practices for the cost of assets, the expenses incurred in providing services, along with revenues collected. Without specific instructions and accounts for recording and reporting the above transactions and events, inconsistent and incomplete accounting and reporting will result.

Internal Review: The Commission has reviewed the requirements pertaining to the USofA and to 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 the expenses incurred for providing services as part of its operations.

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

[232] For the Forms 1 and 1–F, the one-time implementation burden in Year 1 is estimated to be 3 hours per respondent. However, for the burden and cost estimates, we are averaging those additional 3 hours over Years 1–3, giving an average annual one-time implementation burden of 1 hour. That 1 hour is in addition to the normal annual filing burden of 6 hours each, giving an average annual estimate of 7 hours for Forms 1 and 1–F, for Years 1–3.

[233] This includes the one-time refiling of OATT Schedule 3 (estimated average of 4 hours per utility respondent), and if requested, the utility's sharing data and a narrative description with its self-supplying customer(s) (estimated average of 4 customer requests per utility respondent per year, taking 4 hours per request). The estimated annual burden per utility is

- Year 1: 4 hrs. (for one-time refiling) + (4 requests * 4 hrs.), giving an estimate of 20 hrs. per utility
- Years 2 and 3, each: 4 requests * 4 hrs., giving 16 hrs. per utility per year. When the one-time implementation burden (of 4 hours) is averaged over Years 1–3, the annual additional burden per utility is 17.33 hours.

[234] Based on the 2012 data from the Bureau of Labor Statistics at *http://bls.gov/oes/current/naics2_22.htm,* the hourly cost of salary plus benefits would be $56.19.

[235] *See, e.g., Powerex,* 125 FERC ¶ 61,179 (2008).

the burden estimates associated with the information collection requirements.

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 collection of information and the associated burden estimates in the 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), and 1902–0233 (FERC–917), 1902–0096 (FERC–516), and 1902–0173 (FERC–717) and Docket Number RM11–24.

Environmental Analysis

207. 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.[236] 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.[237]

VI. Regulatory Flexibility Act

208. The Regulatory Flexibility Act of 1980 (RFA)[238] generally requires a description and analysis of 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) Office of Size Standards develops the numerical definition of a small business.[239] 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.[240] The 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 2011 annual FERC Form No. 1 and Form No. 1–F, as well as the number of companies that have obtained waivers, we estimate that 44 entities (20 percent of the filers) affected by this proposed rule are ''small.'' For each of the 44 ''small'' entities, the Commission estimates an additional annual burden of only ten hours (seven hours for the annual Form 1 or Form 1–F (averaging implementation over years 1–3), plus one hour per quarter for the Form 3–Q). 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.

VII. Document Availability

209. 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.

210. 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.

211. 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.*

Effective Date and Congressional Notification. These regulations are effective November 27, 2013. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

List of Subjects

18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements

18 CFR Part 101

Electric power, Electric utilities, Uniform System of Accounts.

By direction of the Commission.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends Parts 35 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 § 35.37 by revising paragraph (c)(1) to read as follows:

§ 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, and generator imbalance services 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 lacks horizontal market power with respect to sales of operating reserve-spinning and operating reserve-supplemental services if the Seller passes these two indicative market power screens and demonstrates in its market-based rate application how the scheduling practices in its region

[236] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Regulations Preambles 1986–1990 ¶ 30,783 (1987).

[237] 18 CFR 380.4(a)(15) (2012).

[238] 5 U.S.C. 601–612.

[239] 13 CFR 121.101 (2011).

[240] 13 CFR 121.201, Sector 22, Utilities.

support the delivery of operating reserve resources from one balancing authority area to another. There will be a rebuttable presumption that a seller possesses horizontal market power with respect to sales of energy, capacity, energy imbalance, generator imbalance, operating reserve-spinning, and operating reserve-supplemental services if it fails either screen.

* * * * *

■ 3. Amend § 35.38 as follows:

■ a. Paragraph (a) is revised.

■ b. Paragraph (b) introductory text is revised.

■ c. Paragraph (c) is added.

The revisions and addition read as follows:

§ 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 consist of: (1) A cap based on the relevant OATT ancillary service rate of the purchasing transmission operator; or (2) the results of a competitive solicitation that meets the Commission's requirements for transparency, definition, evaluation, and competitiveness.

■ 4. Amend § 37.6 by adding paragraph (k) to read as follows:

§ 37.6 Information to be posted on the OASIS.

* * * * *

(k) *Posting of historical area control error data.* The Transmission Provider must post on OASIS historical one-minute and ten-minute area control error data for the most recent calendar year, and update this posting once per year.

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

■ 5. 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.

■ 6. In Part 101:

■ a. Under Electric Plant Chart of Accounts, Account 348 is added to the list;

■ b. Under Electric Plant Accounts, Account 351, the name of the account is revised and instructions are added;

■ c. Under Electric Plant Accounts, Account 363, the name of the account and the instructions are revised;

■ d. Under Electric Plant Accounts, primary plant account 348 is added;

■ e. Under Operation and Maintenance Expense Chart of Accounts, Accounts 548.1, 553.1, 555.1, 562.1, 570.1, 584.1, and 592.2 are added to the list;

■ f. Under Operation and Maintenance Expense Accounts, operation expense account 548.1 is added;

■ g. Under Operation and Maintenance Expense Accounts, maintenance expense account 553.1 is added;

■ h. Under Operation and Maintenance Expense Accounts, power supply expense account 555.1 is added;

■ i. Under Operation and Maintenance Expense Accounts, operation expense account 562.1 is added;

■ j. Under Operation and Maintenance Expense Accounts, maintenance expense account 570.1 is added;

■ k. Under Operation and Maintenance Expense Accounts, operation expense account 584.1 is added;

■ l. Under Operation and Maintenance Expense Accounts, maintenance expense account 592.2 is revised; and

■ m. Under Operation and Maintenance Expense Accounts, maintenance expense account 592.1 is revised;

The revisions and additions read as follows:

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

* * * * *

Electric Plant Chart of Accounts

* * * * *

2. Production Plant

* * * * *

D. Other Production

* * * * *

348 Energy Storage Equipment—Production

* * * * *

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 purposes, 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 purchased to 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

* * * * *

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 purchased to 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, 592.1, 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

* * * * *

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 purchased to 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 accounts 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.

* * * * *

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

* * * * *

584.1 Operation of Energy Storage Equipment

* * * * *

Maintenance

* * * * *

592.2 Maintenance of Energy Storage Equipment

* * * * *

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.

* * * * *

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.

* * * * *

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.

* * * * *

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.

*   *   *   *   *

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.

*   *   *   *   *

584.1 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.

*   *   *   *   *

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.

*   *   *   *   *

592 Maintenance of Station Equipment (Major Only)

This account shall include the cost of labor, materials used and expenses incurred in maintenance of plant, the book cost of which is includible in account 362, Station Equipment. (See operating expense instruction 2.)

*   *   *   *   *

592.1 Maintenance of Structures and Equipment (Nonmajor Only)

This account shall include the cost of labor, materials used and expenses incurred in maintenance of structures, the book cost of which is includible in account 361, Structures and Improvements, and account 362, Station Equipment. (See operating expense instruction 2.)

Note: The following appendix will not appear in the *Code of Federal Regulations.*

Appendix A: List of Short Names of Commenters on the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking on Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies—Docket No. RM11–24–000, June 2012

Short name or acronym	Commenter
APPA	American Public Power Association
AWEA	American Wind Energy Association
Beacon	Beacon Power Corporation
California PUC	California Public Utilities Commission
California Storage Alliance	California Energy Storage Alliance
EEI	Edison Electric Institute
Electricity Consumers	Electricity Consumers Resource Council
ENBALA	ENBALA Power Networks
EPSA	Electric Power Supply Association
ESA	Electricity Storage Association
FTC Staff	Staff of the Federal Trade Commission
Hydro Association	National Hydropower Association
Iberdrola	Iberdrola Renewables, LLC
Indicated Suppliers	Calpine Corporation, Dynegy Inc., Exelon Corporation, GenOn Energy, Inc., and Tenaska Energy, Inc.
Midwest ISO	Midwest Independent Transmission System Operator Inc.
Morgan Stanley	Morgan Stanley Capital Group Inc.
NAATBatt	National Alliance for Advanced Technology Batteries
New York ISO	New York Independent System Operator, Inc.
NU Companies	Northeast Utilities Service Company on behalf of Connecticut Light and Power Company, Western Massachusetts Electric Company, Public Service Company of New Hampshire, and NSTAR Electric Company
Powerex	Powerex 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
Public Power Council	Public Power Council
SDG&E	San Diego Gas & Electric Company
Shell Energy	Shell Energy North America (US), L.P.
Solar Energy Association	Solar Energy Industries Association
Southern California Edison	Southern California Edison Company
TAPS	Transmission Access Policy Study Group and Transmission Dependent Utility Systems
Western Group	Arizona Public Service, Avista Corporation, Bonneville Power Administration, Idaho Power Company, PacifiCorp, Portland General Electric, Xcel Energy Services, Puget Sound Energy, Inc., Seattle City Light, and Takoma Power
WSPP	WSPP, Inc.

Note: The following Appendix will not appear in the *Code of Federal Regulations.*

Appendix B: Pro Forma Open Access Transmission Tariff

The Commission amends Schedule 3, Regulation and Frequency Response Service of the *pro forma* OATT:

Schedule 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Control Area operator that performs this function for the Transmission Provider). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements. The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Note: The following Appendix will not appear in the *Code of Federal Regulations.*

BILLING CODE 6717–01–P

Appendix C – New and Amended Form 1/1F/3Q Pages.

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 and 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	

FERC FORM NO. 1 (REV. 12-12) **Page 2**
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)
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	

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) (Continued)

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)		

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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)

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)		

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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)

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	(583) Overhead Line Expenses		
142	(584) Underground Line Expenses		
143	(584.1) Operation of Energy Storage Equipment		
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	(592.1) Maintenance of Structures and Equipment		
155	(592.2) Maintenance of Energy Storage Equipment		
156	(593) Maintenance of Overhead Lines		
157	(594) Maintenance of Underground Lines		
158	(595) Maintenance of Line Transformers		
159	(596) Maintenance of Street Lighting and Signal Systems		
160	(597) Maintenance of Meters		
161	(598) Maintenance of Miscellaneous Distribution Plant		
162	TOTAL Maintenance (Enter Total of lines 151 thru 161)		
163	TOTAL Distribution Expenses (Enter Total of lines 149 and 162)		

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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 (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)
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	Power Purchased for Storage Operations (555.1)	
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 MARKET,** AND DISTRIBUTION EXPENSES(Continued)

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.

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)				
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9					
10					
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41					
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		22	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use)		23	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam		24	Requirements Sales for Resale (See Instruction 4, Page 311)	
4	Nuclear		25	Non-Requirements Sales for Resale (See Instruction 4, Page 311)	
5	Hydro-Conventional		26	Energy Furnished Without Charge	
6	Hydro=Pumped Storage		27	Energy Used by Company (Electric Department Only, Excluding Station Use)	
7	Other		28	Total Energy Losses	
8	Less Energy for Pumping		29	Total Energy Stored	
9	Net Generation (Enter Total of Lines 3 through 8)		30	TOTAL (Enter Total of Lines 23 Through 29) MUST EQUAL LINE 21 UNDER SOURCES	
10	Purchases (other than for Energy Storage)				
11	Purchases for Energy Storage				
12	Power Exchanges				
13	Received				
14	Delivered				
15	Net Exchanges (Line 12 minus Line 13)				
16	Transmission for Others (Wheeling)				
17	Received				
18	Delivered				
19	Net Transmission for Others (Line 16 minus line 17)				
20	Net Transmission for Others (Losses)				
21	TOTAL (Enter Total of Lines 9, 10, 11, 15, 19 and 20)				

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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 ________

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 KW or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give that which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use – KWh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) – KWh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Power Plant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / line 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power Generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc. Pumped Storage Plant	
35	Production Exp Before Pumping Exp (line 24 thru line 34)	
36	Pumping Expenses	
37	Total Production Exp (total line 35 and line 36)	
38	Expenses per KWh of Generation (line 37/ line 9)	
39	Expenses per KWh of Generation and Pumping (line 37/(line 9 + line 10))	

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

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
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			3
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			39

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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.

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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32				
33				
34				
35	TOTAL			

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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)

	MWHs delivered to the grid to support			MWHs Lost During Conversion, Storage and Discharge of Energy			MWHs Sold (k)	Revenues from Energy Storage Operations (l)
Line No.	Production (e)	Transmission (f)	Distribution (g)	Production (h)	Transmission (i)	Distribution (j)		
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4								
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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							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30				Total			

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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 (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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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)(Continued)

	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)
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