FEDERAL REGISTER

Vol. 77 Friday,
No. 135 July 13, 2012

Part II

Department of Energy

Federal Energy Regulatory Commission

18 CFR Part 35
Integration of Variable Energy Resources; Final Rule

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–11–000; Order No. 764]

Integration of Variable Energy Resources

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission is amending the *pro forma* Open Access Transmission Tariff to remove unduly discriminatory practices and to ensure just and reasonable rates for Commission-jurisdictional services. Specifically, this Final Rule removes barriers to the integration of variable energy resources by requiring each public utility transmission provider to: offer intra-hourly transmission scheduling; and, incorporate provisions into the *pro forma* Large Generator Interconnection Agreement requiring interconnection customers whose generating facilities are variable energy resources to provide meteorological and forced outage data to the public utility transmission provider for the purpose of power production forecasting.

DATES: *Effective Date:* This rule will become effective September 11, 2012.

FOR FURTHER INFORMATION CONTACT:

Jessica L. Cockrell (Technical Information), Office of Energy Policy and Innovation, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8190.

Andrea Hilliard (Legal Information), Office of General Counsel—Energy Markets, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8288.

SUPPLEMENTARY INFORMATION:

139 FERC ¶ 61,246

Department of Energy

Federal Energy Regulatory Commission

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

Issued June 22, 2012.

TABLE OF CONTENTS

I. Introduction

1. In this Final Rule, the Commission acts under section 206 of the Federal Power Act (FPA) to adopt reforms that will remove barriers to the integration of variable energy resources (VER)[1] and ensure that the rates, terms, and conditions for Commission-jurisdictional services provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential.[2] As the Commission noted in the Proposed Rule (75 FR 75336, December 2, 2010), VERs are making up an increasing percentage of new generating capacity being brought on-line.[3] This evolution in the Nation's generation fleet has caused the industry to reevaluate practices

[1] As defined in the Notice of Proposed Rulemaking, a Variable Energy Resource is a device for the production of electricity that is characterized by an energy source that: (1) Is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities. *See Integration of Variable Energy Resources Notice of Proposed Rulemaking,* FERC Stats. & Regs. ¶ 32,664, at P 64 (2010) (Proposed Rule).

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

[3] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 13.

developed at a time when virtually all generation on the system could be scheduled with relative precision and when only load exhibited significant degrees of within-hour variation. As part of this evaluation, the Commission initiated this rulemaking proceeding to consider its own rules and, based on the comments received, concludes that reforms are needed in order to ensure that transmission customers are not exposed to excessive or unduly discriminatory charges and that public utility transmission providers have the information needed to efficiently manage reserve-related costs.

2. Specifically, the Commission amends the *pro forma* Open Access Transmission Tariff (OATT) to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals. There is currently no requirement to provide transmission customers the opportunity to adjust their transmission schedules within the hour to reflect changes in generation output. As a result, transmission customers have no ability under the *pro forma* OATT to mitigate Schedule 9 generator imbalance charges in situations when the transmission customer knows or believes that generation output will change within the hour. This lack of ability to update transmission schedules within the hour can cause charges for Schedule 9 generator imbalance service to be unjust and unreasonable or unduly discriminatory. Accordingly, the Commission amends the *pro forma* OATT to correct this deficiency.

3. The Commission also amends the *pro forma* Large Generator Interconnection Agreement (LGIA) to require new interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider with which the customer is interconnected, where necessary for that public utility transmission provider to develop and deploy power production forecasting. Power production forecasts can provide public utility transmission providers with advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than through the deployment of reserve service, such as regulation reserves which can be more costly. This Final Rule facilitates a public utility transmission provider's use of power production forecasting by amending the *pro forma* LGIA to require new interconnection customers whose generating facilities are VERs to provide the underlying data necessary for public utility transmission providers to perform such forecasts accurately.

4. The Commission declines, however, to modify the *pro forma* OATT to include a new Schedule 10 governing generator regulation service as set forth in the Proposed Rule. The Commission intended for the proposed Schedule 10 to provide clarity to public utility transmission providers and transmission customers alike by setting forth a generic approach to the provision of generator regulation service. In response, numerous commenters urged the Commission not to adopt a standardized approach to generator regulation service, stressing that flexibility is needed in the design of capacity services needed to efficiently integrate VERs into the transmission system. The Commission agrees and, accordingly, will continue a case-by-case approach to evaluating proposed generator regulation service charges. To assist public utility transmission providers and their customers in the development and evaluation of such proposals, the Commission instead provides guidance in response to the comments submitted.

5. Taken together, the reforms adopted and guidance provided in this Final Rule are intended to address issues confronting public utility transmission providers and VERs and to allow for the more efficient utilization of transmission and generation resources to the benefit of all customers. This, in turn, fulfills our statutory obligation to ensure that Commission-jurisdictional services are provided at rates, terms, and conditions of service that are just and reasonable and not unduly discriminatory or preferential.

Background

6. In 1996, the Commission issued Order No. 888, which found that it was in the economic interest of public utility transmission providers to deny transmission service or to offer transmission service on a basis that is inferior to what they provide to themselves.[4] Concluding that unduly discriminatory and anticompetitive practices existed in the electric industry and that, absent Commission action, such practices would increase as competitive pressures in the industry grew, the Commission in Order No. 888 required all public utility transmission providers that own, control, or operate transmission facilities used in interstate commerce to have on file an open access, non-discriminatory transmission tariff that contains minimum terms and conditions of non-discriminatory service. As relevant here, the *pro forma* OATT contains terms for scheduling transmission service and the provision of ancillary services.

7. The Commission later turned its attention to the process by which large generators interconnect with the interstate transmission system. In Order No. 2003, the Commission concluded that there was a pressing need for a single set of procedures and a single, uniformly applicable interconnection agreement for large generator interconnections.[5] Accordingly, the Commission adopted standard procedures (the Large Generator Interconnection Procedures or LGIP) and a standard agreement (the LGIA) for the interconnection of generation resources greater than 20 MW.[6] These reforms were designed to minimize opportunities for undue discrimination and to expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.[7]

8. In Order No. 2003–A, the Commission explained that the interconnection requirements adopted in Order No. 2003 were based on the needs of traditional synchronous generators and that a different approach may be appropriate for generators relying on newer technology.[8] Therefore, Commission exempted wind resources from certain sections of the LGIA and added Appendix G to the LGIA, as a placeholder for the inclusion of interconnection standards specific to newer technologies.[9] Subsequently, in Orders Nos. 661 and 661–A, the Commission adopted a package of interconnection standards applicable to

[4] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,682 (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).

[5] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at P 11 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

[6] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146.

[7] *Id.*

[8] Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160 at P 407 & n.85.

[9] *Id.*

large wind generators for inclusion in Appendix G of the LGIA.[10]

9. In recognition of the evolving energy industry and in a further effort to remedy the potential for undue discrimination, the Commission returned to the *pro forma* OATT in Order No. 890 and implemented a series of changes to the requirements of open access transmission service.[11] Among other things, the Commission adopted a set of transmission planning principles,[12] created a new *pro forma* ancillary service schedule designed to address generator imbalances,[13] and instituted a new conditional firm transmission product.[14] With regard to imbalance charges, the Commission found that such charges should be designed to provide appropriate incentives to keep schedules accurate without being excessive and otherwise result in consistency in charges between and among energy and generator imbalances.[15] The Commission recognized that intermittent resources, such as VERs, cannot always accurately follow their schedules and that high penalties for imbalances will not lessen the incentive to deviate from their schedules. Accordingly, the Commission exempted intermittent resources from third-tier deviation band of imbalance penalties.[16]

10. Against this backdrop, the Commission in January 2010 issued a Notice of Inquiry in this proceeding to explore the extent to which barriers may exist that impede the reliable and efficient integration of VERs into the electric grid and whether reforms are needed to eliminate those barriers.[17] The Commission noted that the amount of VERs is rapidly increasing, reaching a point where such resources are becoming a significant component of the nation's energy supply portfolio.[18] In order to determine whether any rules, regulations, tariffs or industry practices within the Commission's jurisdiction hinder the reliable and efficient integration of VERs, the Commission sought comment on a range of subject areas: (1) Power production forecasting, including specific forecasting tools and data and reporting requirements; (2) scheduling practices, flexibility, and incentives for accurate scheduling of VERs; (3) forward market structure and reliability commitment processes; (4) balancing authority area coordination and/or consolidation; (5) suitability of reserve products and reforms necessary to encourage the efficient use of reserve products; (6) capacity market reforms; and (7) redispatch and curtailment practices necessary to accommodate VERs in real time.[19] The response from commenters was significant, with more than 135 entities submitting comments, many of which urged the Commission to undertake basic reforms in response to the increasing number of VERs being integrated into the system.

II. The Need for Reform

A. Commission Proposal

11. In light of the changes occurring within the electric industry, and based on comments submitted in response to the January 2010 Notice of Inquiry, the Commission issued the Proposed Rule to remedy operational and other challenges associated with VER integration that may be causing undue discrimination and increased costs ultimately borne by consumers. The Commission preliminarily found that the proposed set of reforms would eliminate operational procedures that have the *de facto* effect of imposing an undue burden on VERs. The Commission stated that the proposed reforms acknowledge that existing practices as well as the ancillary services used to manage system variability were developed at a time when virtually all generation on the system could be scheduled with relative precision and when only load exhibited significant degrees of within-hour variation. In proposing its reforms, the Commission sought to ensure that VERs are integrated into the transmission system in a coherent and cost-effective manner, consistent with open access principles.[20]

B. Comments

12. Commenters largely support initiation of a rulemaking proceeding to consider potential reforms to reduce discrimination and improve the efficiency of the transmission system.[21] Invenergy Wind, for example, states that the Proposed Rule reflects an important step forward in providing the regulatory foundation that will create an incentive for improvements in system operations and procurement practices necessary to support the addition of renewable resources to the nation's historical generation mix. BP Companies comment that it is important for the Commission to provide a level playing field for wind and solar-generated power.

13. Many commenters point to the importance of the Proposed Rule in removing market barriers to VER integration. NextEra comments that the instant proceeding is important because VERs have been developed in relatively modest amounts until recent years, and the existing market rules were designed to reflect the characteristics of more traditional generating resources (e.g., coal, natural gas and nuclear generation) rather than VERs. NextEra contends that existing rules were aimed at addressing the preferences and requirements of the resources and systems in the past, rather than to anticipate future changes. CEERT states that the Commission's initiative to remove market and operational barriers to VERs integration and eliminate undue discrimination against VERs is critical to making wholesale power markets more competitive and ensuring a sustainable energy future.

14. Iberdrola contends that this proceeding is the best opportunity available for the federal government to encourage the responsible development of renewable energy resources, and to avoid inadvertently stifling the growth

[10] *Interconnection for Wind Energy,* Order No. 661, FERC Stats. & Regs. ¶ 31,186, *order on reh'g,* Order No. 661–A, FERC Stats. & Regs. ¶ 31,198 (2005).

[11] *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 clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[12] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at PP 444–561. In June 2011, the Commission further amended the *pro forma* OATT to require, among other things, that each public utility transmission provider participate in a regional transmission planning process that produces a regional transmission plan and has a regional cost allocation method for the cost of new transmission facilities selected in a regional transmission plan for purposes of cost allocation. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 176 FR 49842 (Aug. 11 2011), FERC Stats. & Regs. ¶ 31,323 (2011).

[13] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at PP 663–72.

[14] *Id.* PP 911–15.

[15] *Id.* P 72.

[16] *Id.* P 665.

[17] *Integration of Variable Energy Resources Notice of Inquiry,* FERC Stats. & Regs. ¶ 35,563 (2010) (Notice of Inquiry).

[18] *Id.* P 2.

[19] *Id.* P 12.

[20] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 17.

[21] *E.g.,* ACSF; AEP; AWEA; Argonne National Lab; BP Companies; Business Council; California ISO; CMUA; CEERT; Center for Rural Affairs; Clean Line; CGC; Defenders of Wildlife; Dominion; EEI; Environmental Defense Fund; Exelon; First Wind; Iberdrola; Idaho Power; ITC Companies; ISO New England; Independent Power Producers Coalition—West; ISO/RTO Council; Invenergy Wind; Large Public Power Council; Massachusetts DPU; MidAmerican; Midwest ISO Transmission Owners; M–S–R Public Power Agency; National Grid; NaturEner; Oregon & New Mexico PUC; NextEra; NorthWestern; PNW Parties; PJM; Powerex; Public Interest Organizations; RenewElec; SMUD; San Diego Gas & Electric; SEIA; Southern California Edison; SWEA; Southwestern; Sunflower and Mid-Kansas; Tacoma Power; Vestas; Western Farmers; Western Grid; Xcel.

of renewable energy resources in an effort to protect the economic interests of incumbents. Similarly, NaturEner comments that the reforms are long overdue and should be implemented without further delay and in a manner requiring prompt compliance. This proceeding, NaturEner states, represents substantial progress towards the elimination of antiquated rules, requirements and processes, a significant reduction in duplication, unnecessary expenditures and inefficient allocation of resources, as well as an important step towards making the grid more robust, economical, and equitable.

15. Oregon & New Mexico PUC state that the Commission can play a valuable role in enabling the western electricity industry to reach state renewable energy goals at a reasonable cost to consumers by exercising its jurisdiction in these areas. Oregon & New Mexico PUC submit that the proposals in the Proposed Rule are an important step toward building the necessary foundation to integrate significant amounts of wind and solar in the West. Defenders of Wildlife similarly contend that by establishing a new rule which encourages VER integration, and long-term and much needed infrastructure investments can be made today to help spur the nation's growing renewable energy economy. ACSF states its strong support for Commission action to integrate VERs into a smarter, cleaner, and more flexible energy grid, whose principal design features should enable much more widespread investment and deployment of integrated and hybrid VER generation systems. ACSF states it is critical that the Commission exercise its authority to develop policies that send adequate economic signals that permit the country's most flexible, clean generation sources to provide complementary power for VERs.

C. Commission Determination

16. As noted above, the Commission initiated this proceeding through the issuance of a Notice of Inquiry to obtain information on barriers to the integration of VERs. The Commission sought to understand the challenges associated with the large-scale integration of VERs on the interstate transmission system and the extent to which existing operational practices may be imposing barriers to their integration. The Commission explained that the changing characteristics of the nation's generation portfolio compelled a fresh look at existing policies and practices, leading the Commission to seek comment on a range of issues.

17. Based on its review of comments to the Notice of Inquiry, the Commission focused in the Proposed Rule on a series of basic reforms regarding transmission scheduling, data reporting requirements, and charges for generator regulation service that can and should be implemented in the near term.[22] The Commission explained that, taken together, the Proposed Reforms were designed to address issues confronting public utility transmission providers and VERs and to allow for the more efficient utilization of transmission and generation resources to the benefit of all customers.[23] The Commission acknowledged that the proposed reforms focused on discrete operational protocols that were only a subset of the issues for which comment was sought in the Notice of Inquiry.[24] The Commission stated its belief that focusing on the particular set of reforms proposed would provide a reasonable foundation for public utility transmission providers seeking to manage system variability associated with increased numbers of VERs and that further study is required for many of the remaining issues raised in the Notice of Inquiry.[25]

18. The Commission received more than 1900 pages of initial and reply comments in response to the Proposed Rule. While differing in opinion on the merits of particular aspects of the Commission's proposal, commenters generally support the Commission's efforts to evaluate its rules through this rulemaking to explore further opportunities to reduce undue discrimination and reduce costs ultimately borne by consumers through more efficient use of the transmission system. Based on these comments, the Commission concludes that it is appropriate to act at this time to revise the transmission scheduling requirements of the *pro forma* OATT and incorporate data reporting requirements into the *pro forma* LGIA, as discussed in further detail later in this Final Rule.[26] As discussed throughout this Final Rule, these reforms are necessary to ensure that transmission customers are not exposed to excessive or unduly discriminatory charges for Schedule 9 generator imbalance service and to provide public utility transmission providers with information necessary to more efficiently manage reserve-related costs recovered from transmission customers through other ancillary services charges.

19. The Commission takes this action now recognizing that the composition of the electric generation portfolio continues to change. VERs are making up an increasing percentage of new generating capacity being brought on-line. New wind generating capacity accounted for 35 percent of all newly installed generating capacity from 2007–2010.[27] As of December 2011, nearly 12,000 MW of additional wind generating capacity has been brought online and another 8,320 MW of wind generating capacity is currently under construction.[28] Current projections indicate that this expansion will continue, with the Energy Information Agency forecasting that generation from wind power will nearly double between 2009 and 2035.[29] This recent and future growth is being facilitated by developments in state and federal public policies that encourage the expansion of VER generation.[30]

[22] Proposed Rule, FERC Stats. & Regs ¶ 32,664 at P 18.

[23] *Id.* P 19.

[24] *Id.* PP 23–24.

[25] *Id.* PP 12, 24.

[26] For the reasons discussed in Schedule 10 below, the Commission declines to standardize charges for generator regulation service through the adoption of a generic Schedule 10 to the *pro forma* OATT as suggested in the Proposed Rule.

[27] *See* American Wind Energy Association, *Wind Power Outlook 2011* (Apr. 2011), *available at http://www.awea.org/_cs_upload/learnabout/publications/reports/8546_1.pdf.*

[28] American Wind Energy Association, *U.S. Wind Industry Fourth Quarter 2011 Market Report* (Jan. 2012), *available at http://www.awea.org/learnabout/industry_stats/upload/4Q-2011-AWEA-Public-Market-Report_1-31.pdf.* In addition, the amount of new photovoltaic generating capacity in 2011 increased by 108 percent over 2010 amounts, adding 1,855 MW of PV and bringing the total solar generating capacity to more than 4,470 MW. Utility installations increased by 185 percent in 2011, far more than residential or commercial market segments. *See* Solar Energy Industries Ass'n, *US Solar Market Insight Report 2011 Year-in-Review Executive Summary* (Mar. 2012), *available at http://www.seia.org/galleries/pdf/SMI-YIR-2011-ES.pdf.*

[29] Annual Energy Outlook at 75, *available at http://www.eia.gov/forecasts/archive/aeo11/pdf/0383(2011).pdf.*

[30] For example, as of May 2011, 30 states and the District of Columbia have a renewable portfolio standard or goal. FERC, Div. of Energy Market Oversight, *Renewable Power and Energy Efficiency Market: Renewable Portfolio Standards* 1 (updated May 2011), *available at http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf).* In addition, the federal production tax credit, which has been in effect intermittently since the early 1990s, provides an inflation-adjusted credit for power produced from VERs and other renewable resources. 26 U.S.C. 45 (2007). In February 2009, the American Recovery and Reinvestment Act not only extended the production tax credit for a period of three additional years but also instituted an investment tax credit, which allows developers of certain renewable generation facilities to take a 30 percent cash grant in lieu of the production tax credit. American Recovery and Reinvestment Tax Act of 2009, Pub. L. 111–5, § 1101, 123 Stat. 115, 319–20 (2009). Other federal policies that provide incentives to renewable generation facilities include accelerated

Continued

20. As NERC has noted, higher levels of variable generation can alter the operation and characteristics of the bulk power system.[31] Increasing the relative amount of variable generation on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices and procedures, including the commitment of adequate reserves.[32] However, many of these operational protocols were developed for generation resources with a different set of characteristics. For example, the hourly scheduling protocols of the *pro forma* OATT reflect historical practices associated with operation of conventional generating resources that are relatively predictable and controllable when compared to VERs. Similarly, the interconnection requirements of Order No. 2003 were based on the needs of traditional synchronous generators, leading the Commission to revisit those requirements as applied to large wind generators in Order Nos. 661 and 661–A.

21. In Order No. 1000, the Commission recognized that changes in the generation mix influence the need for new transmission facilities and, as a result, Commission policies governing transmission planning and cost allocation.[33] The Commission concluded there that the increased focus on investment in new transmission projects made it critical to implement planning and cost allocation reforms to ensure that the transmission projects that come to fruition efficiently and cost-effectively meet regional needs. The Commission reaches a similar conclusion here. Changes in the generation mix and underlying public policies influencing investment in VER generation have accentuated the need to reform existing practices that unduly discriminate against VERs or otherwise impair the ability of public utility transmission providers and their customers to manage costs associated with VER integration effectively.

22. Specifically, we find that the adoption of intra-hour scheduling and data reporting to support power production forecasting will remedy undue discrimination and ensure just and reasonable rates through more efficient utilization of transmission and generation resources.[34] With regard to transmission scheduling practices, existing hourly scheduling protocols can expose transmission customers to excessive or unduly discriminatory generator imbalance charges. Generator imbalance charges are assessed to pay for the energy service the transmission provider must offer to account for deviations between a transmission customer's scheduled delivery of energy from a generator and the amount of energy actually generated, and also to provide an appropriate incentive for transmission customers to maintain accurate schedules. Under Schedule 9 of the *pro forma* OATT, there is no requirement to provide customers the opportunity to adjust their transmission schedules within the hour to reflect changes in generator output. As a result, transmission customers have no ability under the *pro forma* OATT to mitigate Schedule 9 generator imbalance charges in situations where the customer knows or believes that generation output will change within the hour. Implementation of intra-hour scheduling under this Final Rule will provide VERs and other transmission customers the flexibility to adjust their transmission schedules, thus limiting their exposure to imbalance charges. Over time, implementation of intra-hour scheduling also will allow public utility transmission providers to rely more on planned scheduling and dispatch procedures, and less on reserves, to maintain overall system balance.

23. With regard to data reporting to support power production forecasting, the lack of data reporting requirements can limit the ability of public utility transmission providers to develop and deploy power production forecasts in an effort to more efficiently manage operating costs associated with the integration of VERs interconnecting to their systems. Under the existing requirements of the *pro forma* LGIA, public utility transmission providers are permitted to request this information, but there is no obligation for interconnection customers whose generating facilities are VERs to provide it. Implementation of reporting requirements commensurate with the power production forecasting employed by the public utility transmission provider will allow for more accurate commitment or de-commitment of resources providing reserves, ensuring that reserve-related charges imposed on customers remain just and reasonable and not unduly discriminatory or preferential. While the Commission declines to adopt a *pro forma* generator regulation and frequency response service, we note that public utility transmission providers that decide to file with the Commission to impose such a charge should, as part of any filing, consider the affect of the reforms we adopt in this Final Rule when developing proposed reserve capacity costs and evaluating whether to require different transmission customers to purchase or otherwise account for different quantities of generator regulation reserves.

24. Although focused on discrete issues, the implementation of intra-hour scheduling and reporting requirements through this Final Rule will allow for the efficient utilization of transmission and generation resources as an increasing amount of VER generation is integrated into the system. This in turn will ensure that the rates, terms, and conditions for Commission-jurisdictional services provided by public utility transmission providers are just and reasonable and not unduly discriminatory. Our actions here are intended to build on, rather than undermine, existing efforts at the regional level to address VER integration. The Commission acknowledges that significant work has been done through industry initiatives seeking to craft regional solutions to the challenges associated with VER integration. For example, many public utility transmission providers in the Western Interconnection have implemented some form of transmission scheduling at 30-minute intervals.[35] The Commission is acting here to implement a minimum set of requirements for all public utility transmission providers and new interconnection customers whose generating facilities are VERs as necessary to facilitate the efficient integration of VERs. The Commission appreciates that these requirements go beyond some existing activities. The Commission nonetheless concludes that the reforms adopted herein are

depreciation of certain renewable generation facilities and loan guarantee programs.

[31] NERC, *Accommodating High Levels of Variable Generation* at 8, *available at http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf.*

[32] *Id.* at 59.

[33] Order No. 1000, 76 FR 49842, FERC Stats. & Regs. ¶ 31,323 at PP 45–46.

[34] In the Proposed Rule, the Commission also proposed to modify the *pro forma* OATT to include a new Schedule 10 governing generator regulation service. For the reasons discussed elsewhere in this Final Rule, the Commission declines to adopt that aspect of the Proposed Rule, instead providing guidance in response to comments submitted to assist public utility transmission providers and their customers in the development and evaluation of proposals on a case-by-case basis.

[35] *See, e.g., Ariz. Pub. Service Co.,* 137 FERC ¶ 61,023 (2011); *NorthWestern Corp.,* 136 FERC ¶ 61,119 (2011). We note that the Joint Initiative indicated in its comments at page 6 that its first step in offering 30-minute scheduling ''is intended to address unanticipated events, not to move to half-hour scheduling.'' In addition, based on business practices posted on OASIS, some transmission providers reserve the right to suspend 30-minute scheduling.

necessary to ensure that Commission-jurisdictional services are being provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential.

III. Legal Authority To Implement Proposed Reforms

A. Commission Proposal

25. In the Proposed Rule, the Commission preliminarily found that the practice of hourly scheduling, the lack of VER power production forecasting, and the lack of a clear mechanism to recover the cost of providing generator regulation service may be contributing to undue discrimination and unjust and unreasonable rates in light of the entry and increasing presence of VERs on the transmission grid. Thus, the Commission proposed the following three reforms that require public utility transmission providers to: (1) Amend the *pro forma* OATT to require intra-hourly transmission scheduling; (2) amend the *pro forma* LGIA to incorporate provisions requiring interconnection customers whose generating facilities are VERs to provide meteorological and operational data to public utility transmission providers for the purpose of improved power production forecasting; and (3) amend the *pro forma* OATT to add a generic ancillary service rate schedule, Schedule 10—Generator Regulation and Frequency Response Service, in which public utility transmission providers will offer to provide regulation service for transmission customers using transmission service to deliver energy from a generator located within a public utility transmission provider's balancing authority area.[36] The Commission preliminarily concluded that the proposed rules are necessary to ensure that rates for Commission-jurisdictional services are just and reasonable and to remedy undue discrimination in existing transmission system operations.[37]

B. Comments

26. Some commenters take issue with the Commission's authority to mandate the tariff amendments contained in the Proposed Rule. With regard to forecasting and 15-minute scheduling, EEI and Southern assert that the Proposed Rule does not articulate a sufficient basis for changing existing tariff-based scheduling requirements under section 206 of the FPA.[38] Specifically, EEI and Southern question whether the Commission is relying upon record findings to support these proposed requirements. EEI and Southern submit that sections 205 and 206 ''are simply parts of a single statutory scheme under which all rates are *established initially by the* [public utilities], by contract or otherwise. * * * Thus, FERC plays an essentially passive and reactive role under section 205.'' [39] EEI and Southern maintain that these types of decisions should be left to public utility transmission providers and RTOs and should be informed by regional conditions and not dictated on a generic basis.

27. In contrast, NextEra states that assertions that there is no record evidence not only ignore how current rules disadvantage VERs, but misunderstand the Commission's authority to promulgate rules of general applicability. NextEra points out that the Commission does not have to find that the tariffs or practices of every utility under its jurisdiction are unjust and unreasonable in order to proceed with a rulemaking. Rather, NextEra asserts that courts have confirmed that the Commission is not required to make individual findings when it exercises its statutory authority to promulgate a rule of general applicability.

28. Certain commenters also question the Commission's reliance in this proceeding on its authority to remedy undue discrimination.[40] Specifically, EEI and Southern take issue with the Commission's conclusion that procedures (such as hourly scheduling) applied uniformly to all transmission customers are unduly discriminatory under the FPA when those procedures arguably have a disparate impact on different types of transmission customers and/or place those customers at a competitive disadvantage in wholesale markets. EEI and Southern submit that the Commission and the DC Circuit have rejected the notion that facially-neutral technology and customer-blind transmission scheduling procedures are unduly discriminatory under section 205 of the FPA because of the effects or impacts of those requirements on different customer groups.[41] EEI asks the Commission to clarify that facially-neutral, technology- and customer-blind operational practices will not be deemed unduly discriminatory solely by virtue of disparate impact on dissimilar technologies or customers, and that the Proposed Rule is not intended as a departure from precedent in determining undue discrimination.

29. Similarly, Public Power Council questions the sufficiency of the Commission's evidence of undue discrimination against VERs. Public Power Council asserts that the Commission has not demonstrated that the costs of capacity charged to VERs were not incurred for the benefit of VERs, or would not have been incurred but for the needs of VERs, and that the costs of capacity were not prudently incurred. Public Power Council submits that the rules applicable to generation for the payment of balancing capacity costs are facially neutral, as VERs require more balancing capacity than non-variable resources. According to Public Power Council, if a load's characteristics required extraordinary amounts of balancing capacity, it seems unlikely that it or anyone else would complain that the rules should be changed to reduce costs. Thus, Public Power Council argues that a federal policy to promote renewable generation cannot be translated into an overriding mandate to prefer VERs.

30. ELCON asserts, with regard to 15-minute scheduling, forecasting, and Schedule 10 service, that the principle flaw in the Proposed Rule is its reliance on the supposition that operating practices favoring the dispatchability of resources are a form of ''preferential treatment,'' and therefore that non-dispatchable resources such as VERs are being discriminated against. ELCON explains that the proposals set forth in the Proposed Rule are costly measures that would apply preferentially to just one class of generation—VERs—seeking to address discrimination that does not actually exist.

31. Southern asserts that, in instances where a single rate is found to have disparate cost impacts upon dissimilar customers, such a result is only considered unduly discriminatory if such differences cannot be cost-

[36] Throughout this Final Rule the term Balancing Authority is used as defined by the North American Electric Reliability Cooperation (NERC). NERC, Glossary of Terms, available at *http://www.nerc.com/files/Glossary_of_Terms_2012January11.pdf.*

[37] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 23.

[38] EEI and Southern argue, for example, that the Commission must rely upon factual, record findings to support these proposed mandates. EEI (citing *National Fuels* v. *FERC,* 468 F.3d 831, 839–44 (D.C. Cir. 2006)); Southern (citing, e.g., *National Fuels,* 468 F.3d 831, 839–44).

[39] EEI (citing *Atlantic City* v. *FERC,* 295 F.3d 1,21 (D.C. Cir. 2002) (quoting *United Gas Pipe Line Co.* v. *Mobile Gas Serv. Corp.,* 350 U.S. 332341 (1956) and *City of Winnfield* v. *FERC,* 744 F.2d 871, 876 (D.C. Cir. 1984)); Southern (citing *Atlantic City* v. *FERC,* 295 F.3d 1,21 (D.C. Cir. 2002) (quoting *United Gas Pipe Line Co.* v. *Mobile Gas Serv. Corp,* 350 U.S. 332341 (1956) and *City of Winnfield* v. *FERC,* 744 F.2d 871, 876 (D.C. Cir. 1984)).

[40] *E.g.,* Southern; EEI.

[41] Southern (citing *Enron Power Marketing, Inc.* v. *FERC,* 296 F.3d 1148 (D.C. Cir. 2002) (*Enron*)); EEI (citing *Enron,* 296 F.3d 1148).

justified.[42] Southern argues that existing scheduling and imbalance practices are not unduly discriminatory against VERs. Southern explains that VER customers pay more energy imbalance charges than others because they impose more imbalance burdens and costs upon the system.[43] Similarly, ELCON maintains that the cost causation model of cost allocation results in greater economic efficiency by retaining a direct tie between the costs and the benefits of a given project. ELCON argues that in the instant case, there is no tie to the costs customers will be forced to bear.

32. Midwest ISO Transmission Owners contend that all generation resources should be treated on a comparable basis, and none should be subject to undue discrimination or receive an undue preference. Midwest ISO Transmission Owners state that in the Midwest ISO this will mean that VERs are subject to the same requirements as existing resources unless additional requirements are necessary to maintain reliability.[44] ELCON argues that the Commission should apply a principle of ''source neutrality,'' which it contends will create a level playing field for all alternative resources including demand response and combined heat and power. ELCON explains that, without the adoption of a resource planning paradigm based on source neutrality, almost any non-traditional resource may fall prey to undue discrimination with respect to transmission of electric energy and sales of electric energy for resale in interstate markets.

33. On the contrary, NextEra argues that most market rules are not oriented to aiding VERs, and may in fact present obstacles to VERs. NextEra states that, even in RTO markets, the fundamental principles around which markets are designed are day-ahead schedules, economic dispatch, and the impact of congestion. NextEra points out that none of these concepts are particularly applicable to VERs, which can have difficulty producing accurate day-ahead forecasts, are not truly dispatchable, and have limited ability to choose sites to reduce congestion. For example, NextEra contends that while nodal representation of generators may work best for dispatchable units, a system that was designed around non-dispatchable VERs could include features such as aggregation and scheduling from a portfolio of generators that might be staggered geographically, so as to reduce variability and forecasting errors and allow pooling of energy imbalances and deviations.

34. NextEra explains that when the Commission remedies unfair rules and practices, it is not doing so to create a preference for the type of entity that was being harmed, but rather to benefit the market and consumers. Thus, NextEra maintains that Commission action to provide greater flexibility, promote innovation or foster participation by new market entrants will ultimately benefit energy markets and consumers, even though the measure itself focuses on changes or incentives for one type of market participant.

35. Finally, with regard to meteorological forecasting in particular, Southern contends that such forecasting practices are beyond the scope of the Commission's authority. Southern states that courts have recognized that the Commission ''is a 'creature of statute,' having no constitutional or common law existence or authority, but only those authorities conferred upon it by Congress.'' [45] Southern contends that public utilities have long engaged in meteorological forecasting for load forecasting and dispatch purposes. Southern argues that there never has been an indication that such practices were within the scope of the Commission's jurisdiction, and the advent of VER generation has not added such forecasting to the scope of the Commission's authority.

C. Commission Determination

36. The Commission concludes that it has authority under section 206 of the FPA to adopt the reforms set forth in this Final Rule. Section 313(b) of the FPA makes Commission findings of fact conclusive if they are supported by substantial evidence.[46] When applied in a rulemaking context, ''the substantial evidence test is identical to the familiar arbitrary and capricious standard.'' [47] The Commission thus must show that a ''reasonable mind might accept'' that the evidentiary record here is ''adequate to support a conclusion,'' [48] that this Final Rule is needed to address barriers to the integration of VERs by remedying challenges that may be causing undue discrimination and increased costs ultimately borne by consumers. As explained below, the Commission has met its burden.

37. As discussed throughout this Final Rule, the reforms adopted in this proceeding are intended to ensure that rates for jurisdictional services remain both just and reasonable and are not unduly discriminatory or preferential. In this way, the reforms contained in this Final Rule build on the work of Order No. 890, in which the Commission made several reforms to the *pro forma* OATT, in part because of a recognition that the mix of generation resources on the system was changing and that not all generation resources were similarly situated.[49] Like the reforms instituted in Order No. 890, the reforms adopted herein are designed to remedy deficiencies in existing requirements that can cause the rates, terms, and conditions of jurisdictional services to become unjust and unreasonable or unduly discriminatory or preferential.

38. The basis for adopting changes to the *pro forma* OATT and *pro forma* LGIA is discussed in the sections below addressing reforms to transmission scheduling practices and the reporting of meteorological data. There the Commission concludes that changes to scheduling practices are necessary in order to ensure that charges for generator imbalance service under schedule 9 of the *pro forma* OATT and for generator regulation service, as relevant, are just and reasonable and not unduly discriminatory. The Commission also concludes that, without the reporting requirements adopted herein, the terms of the *pro forma* LGIA may impair the ability of public utility transmission providers to develop and deploy power production forecasting, which in turn can lead to rates for jurisdictional services that are unjust and unreasonable or unduly discriminatory.

39. The Commission concludes that we have the authority to make these determinations under applicable precedent, including *National Fuel.* In that case, the court found that the

[42] Southern (citing *Ala Elec. Coop.* v. *FERC,* 684 F.2d 20, 29 (D.C. Cir. 1982) (*Alabama Power*)).

[43] Southern further contends that VERs are not similarly situated to dispatchable generation for sheduling and imbalance purposes. *Id.* (citing *City of Vernon* v. *FERC,* 845 F.2d 1042, 1045–46 (D.C. Cir. 1988)).

[44] Midwest ISO Transmission Owners (referencing Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at PP 37, 45, 55 (stating that proposed reforms in intra-hour scheduling and power production forecasting can enhance reliability).

[45] Southern (citing *Cal. Indep. Sys. Operator Co.* v. *FERC,* 372 F.3d 395, 398 (D.C. Cir. 2004) (citing *Atlantic City Elec. Co.* v. *FERC,* 295 F.3d at 8)).

[46] 16 U.S.C. 825l(b).

[47] *Wisc. Gas Co.* v. *FERC,* 770 F.2d 1144, 1156 (1985); *see also Associated Gas Distrib.* v. *FERC,* 824 F.2d 981, at 1018 (D.C. Cir. 1987).

[48] *Dickenson* v. *Zurko,* 527 U.S. 150, 155 (1999).

[49] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 2 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 5. The Commission further recognized that intermittent resources, such as wind power, have a limited ability to control their output, and that this limitation supports tailoring certain requirements to the special circumstances presented by this type of resource. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 663 (requiring that generator imbalance provisions account for the special circumstances presented by intermittent generators).

Commission had not met the substantial evidence standard when it sought to extend its Standards of Conduct that regulate natural gas pipelines' interactions with their marketing affiliates to their interactions with their non-marketing affiliates. The court noted that it had previously upheld the Standards of Conduct as applied to marketing affiliates because the Commission had demonstrated both a theoretical threat, namely that pipelines could grant undue preferences to their marketing affiliates, and substantial record evidence that such abuse had actually occurred.[50] In considering the Commission's order extending the Standards to non-marketing affiliates, the court found that the Commission had cited a theoretical threat of undue preference, but had not cited a single example of actual abuse by non-marketing affiliates. It concluded that instead of providing evidence of a real problem with respect to non-marketing affiliates, the Commission had relied either on examples of abuse by marketing affiliates, and therefore already covered by the old Standards, or on comments from the rulemaking that merely reiterated a theoretical potential for abuse.[51] The court remanded the matter and noted that if the Commission chose to proceed with promulgating the new Standards, it would have to develop a factual record to support them. If the Commission decided instead to rely solely on a theoretical threat, it would need to show how this threat justified the costs that the Standards would create.[52]

40. Our actions in this Final Rule are consistent with the standards that the court set forth in *National Fuel.* We conclude that, in light of the increasing deployment of VERs on the nation's transmission system, the reforms adopted herein are necessary to correct operational practices that can limit the cost-effective integration of VERs into the transmission system consistent with open access principles. In other words, the problem that the Commission seeks to resolve represents a ''theoretical threat,'' in the words of the *National Fuel* decision, the features of which are discussed throughout the body of this Final Rule in the context of each of the reforms adopted herein. This threat is significant enough to justify the reforms imposed by this Final Rule. It is not one that can be addressed adequately or efficiently through the adjudication of individual complaints.[53] In the terminology of *National Fuel,* the remedy we adopt is justified sufficiently by the ''theoretical threat'' identified herein, even without ''record evidence of abuse.'' The actual experiences of problems cited in the record herein provide additional support for our action, but are not necessary to justify the remedy.

41. Citing *Enron,* Southern and EEI also argue that the Commission does not have the authority to remedy undue discrimination in situations where facially neutral operational practices result in a disparate impact on different market participants. The Commission disagrees. *Enron* involved an OATT Filing by a public utility (Entergy) in which the utility sought to require point-to-point transmission customers to designate specific sources and sinks for transmission service. The proposal also set forth what the utility would accept as a valid source or sink, prohibiting a generator (or generation-only control area) from being a sink, and prohibiting a load (or load-only control area) from being a source.[54] Customers objected to the proposal, arguing that the provision would not limit Entergy's ability to reserve capacity and schedule in and out of its control area because it had load and generation within its control area, but would prohibit similar transactions from customers operating control areas completely surrounded by Entergy that sought to set up transactions in and out of those control areas. The Commission evaluated Entergy's proposal under the applicable standard of review, i.e., whether the OATT Filing was consistent with or superior to the Order No. 888 *pro forma* OATT. The Commission accepted the proposal, and the United States Court of Appeals for the District of Columbia Circuit upheld the decision.[55]

42. We find that commenters' reliance on *Enron* is misplaced. In *Enron,* the Commission reviewed a tariff filing made under section 205 of the FPA to determine if it was consistent with or superior to the *pro forma* OATT. The scope of that analysis is not analogous to that of our inquiry in this proceeding, which is to determine if changes to the *pro forma* OATT and *pro forma* LGIA are necessary to ensure that rates for jurisdictional services remain just and reasonable and not unduly discriminatory. In any event, to the extent that *Enron* may be relevant to a rulemaking proceeding of general applicability, Southern and EEI appear to misunderstand the result in *Enron.* In that case, the court found that it was neither arbitrary nor capricious for the Commission to accept a tariff provision forbidding the designation of a generator-only control area as a sink and a load-only control area as a source as comparable to the *pro forma* OATT.[56] In addition to this holding, the court indicated that it was sufficient for the Commission to address comparability of an OATT (the applicable standard in that proceeding) ''on the basis of the terms and conditions offered to customers, not on the usefulness of those terms and conditions to a particular customer because of that customer's capacities and needs,'' noting also that the Commission found that the provision was not discriminatory.[57]

43. *Enron* did not, as Southern and EEI suggest, reject the notion that facially-neutral, technology- and customer-blind operational practices could be found to be unduly discriminatory because of the effects or impacts of those requirements on different customer groups. Instead, the relevant *Enron dicta* indicate that the Commission *could* sustain a determination that a tariff provision is comparable to the *pro forma* OATT where it offers the same terms and conditions to customers, notwithstanding a difference in how different customers will use or benefit from those tariff provisions.[58] However, nothing in *Enron* mandates that result.

44. Our conclusion that Southern and EEI erred in their interpretation of *Enron* is bolstered by other cases included in the comments of both parties. For example, Southern and EEI cite *Alabama Power* for the proposition that, in instances where a single rate is found to have disparate cost impacts on dissimilar customers, such a result is only considered unduly discriminatory if the differences cannot be cost justified.[59] In *Alabama Power,* the issue for the court was whether an application of the same rate to two groups of customers that were similar in many respects may nevertheless violate statutory prohibitions against unduly discriminatory rate schemes. That case involved rate filings by a utility that

[50] *National Fuel,* 468 F.3d at 840.

[51] *Id.* at 841.

[52] *Id.* at 844.

[53] Individual adjudications by their nature focus on discrete questions of a specific case. Rules setting forth general principles are necessary to ensure that adequate processes are in place.

[54] *Enron,* 296 F.3d at 1151.

[55] *Id.* at 1153–54.

[56] *Id.* at 1151–52.

[57] *Id.* at 1151. The court further found that the Commission adequately addressed charges that the provision would lead to discriminatory treatment by accepting the utility's commitment to apply the provision on a nondiscriminatory basis.

[58] *Id.*

[59] Southern (citing *Alabama Power,* 684 F.2d at 29); EEI (citing *Alabama Power,* 684 F.2d 20).

applied the same rate to two groups of wholesale service customers. One group alleged that this single rate represented a misallocation of costs, resulting in that group paying significantly more (and the other paying significantly less) than the costs for which its members were responsible. The court held that notwithstanding the fact that the same rate applied to both groups of customers, the Commission was obligated to evaluate whether the different costs imposed by those two groups rendered the use of a single rate unduly discriminatory.[60]

45. Southern argues that a finding in the Proposed Rule—that existing hourly transmission scheduling protocols expose transmission customers to ''excessive or unduly discriminatory generator imbalance charges''—may run afoul of *Alabama Power* because VER customers require greater amounts of imbalance service and therefore should be required to pay more in the way of imbalance charges.[61] Southern and EEI contend that, because VERs are not similarly situated to dispatchable generation for scheduling and imbalance purposes, existing scheduling and imbalance practices cannot be unduly discriminatory toward VERs.[62] Similarly, ELCON argues that the Proposed Rule would require all ratepayers to subsidize the integration of VERs despite not receiving any benefits, thereby violating cost causation principles.

46. As with commenters' reliance on *Enron,* we find that commenters' reliance on *Alabama Power* is misplaced. The Commission is not determining whether a single rate imposed on two groups of customers may unduly discriminate against one of those groups. Instead, the Commission is promulgating a generic rule that amends the scheduling requirements of the *pro forma* OATT to remedy practices throughout the industry that may be causing jurisdictional rates to be excessive or unduly preferential. Accordingly, the task before the Commission is not comparing the impact of a concrete rate proposal on distinct and readily identifiable customers or classes. Rather, the Commission is broadly evaluating whether the *pro forma* OATT contains the appropriate set of requirements to ensure that rates for all customers remain just and reasonable and not unduly discriminatory. As in Order No. 890, the Commission is acting in part to remedy OATT provisions that may allow public utility transmission providers to treat some customers in an unduly discriminatory manner. Such an endeavor necessarily requires the Commission to take notice of the general developments in the electric industry in deciding what generic reforms may be needed to ensure that the *pro forma* OATT does not unduly discriminate against any one class of customers.[63]

47. In Order No. 890, the Commission recognized that the mix of generation resources on the system was changing and that not all generation resources were similarly situated.[64] In response, the Commission instituted reforms that recognized the unique nature of intermittent resources, tailoring certain requirements to the special circumstances presented by this type of resource.[65] We again recognize that VERs, by definition,[66] are not similarly situated to conventional, dispatchable generators and that reforms to the *pro forma* OATT are necessary to ensure that these resources are treated in a fair and not unduly discriminatory manner. Simply because VERs are not similarly situated in all respects to conventional, dispatchable generators, it does not follow, as Southern and EEI assert, that existing *pro forma* OATT provisions that place a disproportionate burden on VERs are just and reasonable.[67] The more frequent scheduling intervals required by this Final Rule will enable VERs, as well as other generators, to schedule transmission service accurately based on forecasted energy output. This will mitigate VERs' exposure to imbalance charges, while at the same time giving public utility transmission providers a better understanding of expected energy flows on their systems.

48. The Commission does not need to make specific findings with respect to each affected entity so long as the agency's factual determinations are reasonable.[68] As further discussed herein, the Final Rule amends the *pro forma* OATT in ways that will limit uncertainty and provide additional control over scheduling, which should reduce imbalance charges for all customers. The proposed reforms will further benefit customers and the market as a whole by providing increased flexibility and encouraging innovation and participation by new market participants.[69] While the Commission commenced this proceeding as a response to the significantly increasing penetration of VERs into the nation's generation portfolio, the Commission's purpose is not to favor VERs over other forms of generation (or demand) resources. Quite the contrary, a primary goal of this proceeding is to remove obstacles that can have a discriminatory impact on the ability of VERs to compete in the marketplace and that can otherwise result in unjust and unreasonable rates for all market participants.[70]

49. Finally, in response to Southern, the Commission notes that it is not

[60] *Alabama Power,* 684 F.2d at 28–29.

[61] Southern (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 37).

[62] Both Southern and EEI cite additional authority for this point, i.e., that in order to demonstrate that it was unduly discriminated against, a party must show that it is similarly situated to another party receiving different treatment. *See* EEI (citing *Ark. Elec. Energy Consumers* v. *FERC,* 290 F.3d 362 (D.C. Cir. 2002) (''a rate is not 'unduly' preferential or 'unreasonably' '' discriminatory in violation of the FPA if disparate effect of transmission or sale of electric energy by the jurisdictional utility can justify the disparate effect'')); Southern (citing *City of Vernon* v. *FERC,* 845 F.2d 1042, 1045–46 (D.C. Cir. 1988) (''The Commission's opinion sets forth a two-part test for discriminatory treatment where different rates or services are offered, requiring a showing that the unequally treated customers are 'similarly situated,' and that the service sought is the 'same service' actually offered elsewhere.'') & n.2 (''FERC has typically relied on factors like these in defining a prima facie case of undue discrimination.''); *see,* e.g.,*Sacramento Mun. Util. Dist.* v. *FERC,* 474 F.3d 797, 802 (D.C. Cir. 2007) (''In order for PG&E's refusal to negotiate a successor agreement with [Sacramento Municipal Utility District (SMUD)] to constitute undue discrimination, SMUD must demonstrate it is similarly situated to Western.'').

[63] *See Transmission Access Policy Study Group* v. *FERC,* 225 F.3d 667 (D.C. Cir. 2000) (TAPS) (affirming Order No. 888 rulemaking based on general findings, rejecting utility arguments that FERC must have substantial evidence and make specific factual findings); *Wisc. Gas Co.* v. *FERC,* 770 F.2d 1144 (affirming that Commission need not make individual findings regarding each affected entity but can rely on a broader record in promulgating rule of general applicability); *Associated Gas Distrib.* v. *FERC,* 824 F.2d 981 (affirming that the Commission is not required to have empirical data for all the propositions upon which its order depended before promulgating a rule).

[64] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 5.

[65] *Id.* P 663 (requiring that generator imbalance provisions account for the special circumstances presented by intermittent generators).

[66] *See supra* note 1 (defining VER).

[67] *See Alabama Power,* 684 F.2d at 23–24 (''It matters little that the affected customer groups may be in most respects similarly situated—that is, that they may require similar types of service at similar (even if varying) voltage levels. If the costs of providing service to one group are different from the costs of serving the other, the two groups are in one important respect quite dissimilar.'').

[68] TAPS, 225 F.3d at 688 (citing *Wisc. Gas Co.* v. *FERC,* 770 F.2d at 1158).

[69] *Cf.* Order No. 679, *Promoting Transmission Investment through Pricing Reform,* Order No. 679, FERC Stats. & Regs. ¶ 31,222, at PP 131, 176, 224, *order on reh'g,* Order No. 679–A, FERC Stats. & Regs. ¶ 31,236, at P 77 (2006), *order on reh'g,* Order No. 679–B, 119 FERC ¶ 61,062 (2007). The Commission does not authorize these measures to provide a unilateral benefit to transmission owners but rather to encourage the development of needed transmission, which has broader benefits to the market and consumers.

[70] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 23.

asserting jurisdiction over the practice of power production forecasting in this Final Rule. Rather, the Commission is adopting changes to the *pro forma* LGIA to impose reporting requirements on interconnection customers whose generating facilities are VERs. As discussed in further detail later in this Final Rule, power production forecasting can be used by public utility transmission providers to significantly reduce operating costs associated with the integration of VERs interconnected to their systems.[71] However, the ability of public utility transmission providers to engage in power production forecasting may be limited without data from interconnected VERs. In order to facilitate a public utility transmission provider's use of power production forecasting to reduce its operating costs, the Commission is amending the requirements of the *pro forma* LGIA to impose a data reporting requirement as a condition of interconnection service for interconnection customers whose generating facilities are VERs.

50. The question then is whether the Commission has jurisdiction to condition the grant of interconnection service on the reporting of meteorological and outage data by interconnection customers whose generating facilities are VERs as a practice affecting rates subject to the Commission's jurisdiction under the FPA.[72] As the Commission explained in Order No. 2003, interconnection service is a component of open access transmission service, subject to the Commission's regulation under sections 205 and 206 of the FPA.[73] The reporting of meteorological and outage data by VER customers taking jurisdictional interconnection service has a direct affect on the ability of the public utility transmission provider to efficiently manage the VER integration through the development and deployment of power production forecasting. Failure to require the reporting of this data could limit the public utility transmission provider's ability to develop and deploy power production forecasts and, in turn, its attempts to efficiently commit or de-commit resources providing regulation reserves, potentially resulting in rates for reserve-related services that are unjust and unreasonable or unduly discriminatory. It is therefore reasonable for the Commission to conclude that it is within our jurisdiction to implement the data reporting requirements of this Final Rule as a condition of interconnection service.

IV. Proposed Reforms

A. Intra-Hour Scheduling

51. The first of the two reforms adopted in this Final Rule relates to the intervals at which transmission customers may submit transmission schedules under the *pro forma* OATT. As discussed below, the Commission amends the *pro forma* OATT to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals. The Commission concludes this change to existing operational practices is necessary in order to ensure that charges for generator imbalance service under Schedule 9 of the *pro forma* OATT and for generator regulation service, as relevant, are just and reasonable and not unduly discriminatory.

1. Intra-Hour Scheduling Requirement

a. Commission Proposal

52. In the Proposed Rule, the Commission preliminarily found that hourly transmission scheduling protocols are no longer just and reasonable and may be unduly discriminatory as the default scheduling time periods required by the *pro forma* OATT. Specifically, the Commission preliminarily found that existing hourly transmission scheduling protocols expose transmission customers to excessive or unduly discriminatory generator imbalance charges and are insufficient to provide system operators with the flexibility to manage their system effectively and efficiently. Therefore, the Commission proposed to amend sections 13.8 and 14.6 of the *pro forma* OATT to provide transmission customers the option to schedule transmission service on an intra-hour basis, at intervals of 15 minutes. The Commission noted that its proposed reform would allow for intra-hour scheduling adjustments and that it did not propose changes to the hourly transmission service reservation provided in the OATT.[74]

53. The Commission acknowledged in the Proposed Rule that a number of public utility transmission providers already have begun implementing intra-hour scheduling practices. The Commission stated that, while these individual reforms are important steps toward the efficient integration of VERs, it believed that it also is important to establish 15-minute scheduling periods as the default scheduling process. At the same time, the Commission acknowledged arguments that regional differences should be respected when developing an implementation process and that any Commission action should not negatively affect ongoing industry efforts. In that regard, the Commission sought comment on the best approach for implementing the proposed intra-hour scheduling reforms. The Commission recognized that an optimal implementation approach should support ongoing industry efforts and may consider regional differences, such as the amount of VERs present in that region. In proposing implementation approaches, the Commission encouraged commenters to consider any impacts on transmission customers scheduling across multiple systems and whether these impacts diminish the benefits of implementing intra-hour scheduling.[75]

54. To understand more fully the modifications that this proposed reform may require, the Commission sought comment on the specific hardware, software, and personnel changes that are necessary to implement intra-hour scheduling. The Commission further inquired as to whether there would be any additional impacts on relatively small public utility transmission providers, and how to best facilitate this reform for small public utility transmission providers.

b. Comments

i. Obligation to Offer Intra-Hour Scheduling

55. A number of commenters support the Commission's proposal to require public utility transmission providers to offer intra-hour scheduling,[76] although some seek clarifications or modifications of the proposal. Additionally, commenters disagree as to the appropriate period of time for submitting intra-hour schedules. These commenters generally agree that intra-hour scheduling would enable transmission customers to align transmission schedules with actual generation output more effectively, reduce the need for transmission providers to carry expensive operating

[71] *See infra* § IV.B.1 (Data Requirements).

[72] *See Cal. Indep. Sys. Oper.* v. *FERC,* 372 F.3d 395 (D.C. Cir. 2004).

[73] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at 12.

[74] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 39 & n.89.

[75] *Id.* PP 42–43.

[76] *E.g.,* A123; Alstom Grid; ACSF; Argonne National Lab; BP Energy; California ISO; CESA; CMUA; CEERT; Center for Rural Affairs; Clean Line; CGC; Defenders of Wildlife; Environmental Defense Fund; EPSA; Exelon; First Wind; FriiPwr; Independent Power Producers Coalition—West; Independent Energy Producers; ITC Companies; NextEra; NaturEner; Organization of Midwest ISO States; Oregon and New Mexico PUC; Public Interest Organizations; Powerex; SWEA; Tacoma Power; Tres Amigas; TVA; Vestas; Viridity Energy; Vote Solar; Western Grid; Xcel.

reserves, and provide for greater system flexibility by utilizing available resources in a more efficient manner.

56. For example, EPSA states that the option of 15-minute scheduling would expand the availability of flexible generation resources and demand response resources to provide additional liquidity and consistency in the market. Exelon argues that implementing intra-hour scheduling will reduce supply-side uncertainty, which should allow resources to be more optimally selected and allocated than otherwise would be the case. Powerex contends that shorter scheduling intervals would allow the use of more accurate forecasts that are closer to the operating time-frame. Joined by CEERT and others, Powerex argues that intra-hour scheduling would increase transmission system flexibility and efficiency, providing grid operators with more options for scheduling resources during each hour and decreasing the need for (and costs of) ancillary services needed for reliable integration of VERs.[77] The Center for Rural Affairs asserts that making intra-hour scheduling available is essential for public utility transmission providers and balancing authorities seeking to provide system balance with increasing generation from VERs.

57. While acknowledging that some stakeholders in this proceeding oppose the mandatory nature of the Commission's proposal, disagree about scheduling costs, and question the reliability impacts of the proposed reforms, Public Interest Organizations state that almost all stakeholders have acknowledged that intra-hour scheduling does improve scheduling accuracy and decrease the need for energy imbalance services. Public Interest Organizations, joined by Environmental Defense Fund and Argonne National Lab, contend that intra-hour scheduling, as compared to hourly scheduling protocols, allows for a more accurate prediction of the variable generation that can be delivered within the market interval, reducing the need to procure expensive regulation or energy imbalance services.[78] NaturEner agrees, arguing that shorter scheduling intervals would allow for more frequent generation adjustments, thus, decreasing the negative impacts on both the transmission system and the grid from frequent generation disruptions. Iberdrola similarly contends that moving toward smaller intra-hour scheduling intervals will provide incentives for more complete and efficient scheduling practices and eliminate other outdated and discriminatory operating practices.

58. California ISO states that continuing to require resources to match hourly transmission schedules would perpetuate inefficient and burdensome operational requirements. Tres Amigas contends that current scheduling practices have been associated with underutilized transmission assets and sub-optimal operating practices resulting in inefficient curtailment of generation. BP Energy asserts that 15-minute scheduling intervals will increase the ability of a transmission customer scheduling energy from a VER to manage the scheduled input and, therefore, its imbalance costs. Vestas notes that all generators, regardless of fuel type, will be able to track their schedules more closely with actual levels of production as a result of intra-hour scheduling. Vestas explains that, if a large fossil-fueled resource suffers an outage or derate within an hour, the ability to change its schedule earlier than the next clock hour can provide significant benefits to both the generator and the transmission system operator. Clean Line contends that intra-hour scheduling is likely to have benefits independent of variable generation integration, stating that sub-hourly variations in load could be managed in a more cost-effective manner. Also, A123 contends that shorter scheduling intervals will help OATT markets incorporate the benefits of high-ramp, limited energy resources like storage.[79]

59. However, other commenters oppose mandatory intra-hour scheduling, arguing generally that current scheduling practices are neither preferential nor unduly discriminatory.[80] For example, ELCON states that the Commission's proposals are costly measures that would apply preferentially to just one class of generation—VERs—in order to address discrimination that does not actually exist. Some commenters argue that further study of the need for intra-hour scheduling should be undertaken prior to mandating the practice. Several of these commenters assert that the Commission should not require the implementation of 15-minute intra-hour scheduling until certain impacts are better understood.[81] LADWP submits that intra-hour scheduling should not be implemented until it has been fully vetted and researched to assess operational capabilities and coordination.

60. Some commenters argue that the Commission's proposed reform may not lead to a reduction in aggregate reserve costs. These commenters contend that the implementation of intra-hour scheduling does not negate the inherent variability of VERs and, therefore, the cost of providing balancing services is merely shifted, rather than mitigated, by intra-hour scheduling.[82] For example, Avista explains that, while the host balancing authority will provide a reduced amount of balancing reserves within each scheduling period, a significant portion of this variability is being covered by the sink balancing authority or the load serving entity (LSE). Avista contends the sink balancing authority or LSE will incur increased balancing costs to follow the fluctuating VER schedule against a relatively more constant load, thereby shifting the cost of managing that variability as opposed to creating substantial cost savings through intra-hour scheduling. If the host balancing authority area and the sink balancing authority area are the same, Avista argues that no cost savings or reduction in reserves is accomplished by the proposed scheduling reforms. Iberdrola argues that implementing intra-hour scheduling absent a market for dispatchable resources to manage variability could potentially be more harmful than helpful to VER integration. Duke argues that, due to the inherent variability of VERs, more regulating reserves will be needed regardless of the scheduling interval. While operating experience may diminish the need for regulating reserves over time, Duke contends that the level of regulating reserves will ultimately be maintained at a higher level than required today. M–S–R Public Power Agency encourages the Commission to consider the effectiveness of reducing overall intermittency management obligations further before implementing an intra-hour scheduling reform.

61. With regard to the appropriate time interval for intra-hour scheduling, a number of commenters support the Commission's proposal to require public utility transmission providers to offer intra-hour scheduling at 15-minute intervals.[83] Many of these commenters

[77] *E.g.,* CEERT; Powerex; Public Interest Organizations; Vestas.

[78] *E.g.,* Argonne National Lab; Environmental Defense Fund; Public Interest Organizations.

[79] A ramp rate is the rate, expressed in megawatts per minute, that a resources changes its output. *See* NERC Glossary of Terms, available online at *http://www.nerc.com/files/Glossary_of_Terms.pdf.*

[80] *E.g.,* ELCON; Midwest ISO; NV Energy; Southern.

[81] *E.g.,* California PUC; LADWP; NorthWestern; NV Energy; Pacific Gas & Electric.

[82] *E.g.,* Avista; Bonneville Power; M–S–R Public Power Agency; Xcel.

[83] *E.g.,* A123; Alstom Grid; ACSF; Argonne National Lab; BP Companies; CESA; CEERT; Center for Rural Affairs; Clean Line; CGC; Defenders of

agree that a scheduling interval of 15-minutes or shorter provides a number of benefits such as lowering the costs related to integrating VERs into the market and operational benefits. Argonne National Lab states that requiring transmission providers to schedule resources with a frequency of at least every 15 minutes would provide benefits to all supply and demand resources in the power system, not only VERs. Several commenters argue that scheduling in 15-minute intervals would reduce imbalance charges through more accurate schedules.[84] EPSA notes that the proposed 15-minute scheduling interval is consistent with NERC recommendations for achieving greater flexibility while meeting relevant reliability requirements.[85] Exelon asserts that 15-minute scheduling is an industry best practice and that the Commission should set a deadline by which all transmission providers must conform.

62. Vestas acknowledges that a shortened scheduling interval must strike a balance between the benefits of increased certainty and reduced variability resulting from customers' ability to more closely match their schedules with their anticipated output and any increased complexity and technical issues that could result if the scheduling interval is too short. Vestas contends that a 15-minute scheduling window provides a reasonable compromise between the current hour and the even shorter 5-minute intervals utilized in certain RTO markets. Oregon & New Mexico PUC agree that as more wind and solar generation are integrated into the system, shorter intra-hour intervals will generate greater cost savings than longer intervals. Oregon & New Mexico PUC urge the Commission to adopt a minimum standard for transmission scheduling at 15-minute intervals to focus industry efforts on implementing a consistent standard rather than debating the appropriate interval.

63. Some commenters are concerned that the proposed 15-minute scheduling interval is too long.[86] While supportive of 15-minute scheduling as an interim step, several commenters recommend that the Commission require public utility transmission providers to move to shorter scheduling intervals.[87] RenewElec asserts that 15-minute scheduling may not be sufficient for the integration of large amounts of VERs. As an option for increasing flexibility without decreasing the 15-minute scheduling period, SEIA asks the Commission to clarify that generators may submit 15-minute schedules with different output levels at the beginning and end of the 15-minute period to reflect anticipated ramps to manage the variations in diurnal ramping of solar resources. Vote Solar echoes the concerns of SEIA with regard to solar diurnal ramping and argues for scheduling intervals more granular than 15-minutes to accommodate wide-area balancing. Vote Solar recommends that the Commission additionally require a 5-minute intertie scheduling interval. However, EEI cautions that if the Commission decides to move forward with the rule as proposed, the scheduling interval should be no less than 15 minutes as it may undermine the reliable operation of the system.

64. Other commenters argue that the proposed 15-minute scheduling interval is too short.[88] Several commenters recommend an initial 30-minute intra-hour scheduling interval to coincide with current regional initiatives or as a general first step.[89] Some commenters argue that the Commission should use the output of ongoing regional initiatives to determine whether a 15-minute scheduling interval is necessary, or whether another mechanism is the desired method to reduce VER integration costs.[90] EEI states that, if there is no demand for intra-hour scheduling, investments to implement 15-minute scheduling would be unnecessary. NorthWestern expresses uncertainty as to whether 15-minute scheduling would provide benefits greater than those achieved through 30-minute scheduling. Southern California Edison suggests that a 30-minute scheduling interval is sufficient as it can capture forecast error reductions, align with the commitment capabilities of most integrating resources, and reduce the need for additional administrative overhead. Iberdrola recommends that the Commission allow public utility transmission providers to provide intra-hour schedules at 30-minute intervals as an interim step to participation in an energy imbalance market.

65. Some commenters contend that a 15-minute scheduling interval does not support the standard 20-minute generator/scheduling ramp rate in the West.[91] Tacoma Power explains that continuing to use 20-minute ramps would create interface problems with the receipt of schedules on a 15-minute interval. Bonneville Power similarly argues that scheduling on a 15-minute interval would result in almost continuous ramping in a way that 30-minute scheduling does not, and that the resulting reduction in dynamic transfer capability could preclude implementation of other options for reducing VER integration costs. WestConnect asserts that this may result in a disparity in the accurate scheduling of VERs and the system operator's ability to efficiently integrate VERs under restricted ramping intervals.

66. Bonneville Power and Xcel request clarification that ''intra-hour scheduling adjustments'' include both adjustments to existing schedules and the submission of new schedules.[92] MidAmerican requests clarification as to whether intra-hour scheduling is intended to be available only within the current hour or also in future hours.

ii. Consistency in Scheduling Requirements

67. Commenters differ regarding whether the Commission should adopt a consistent intra-hour scheduling requirement for all transmission providers under the *pro forma* OATT. If the Commission decides to move forward with its proposal, EEI recommends that the Commission require a uniform, consistent scheduling interval throughout each interconnection. EEI contends that this will allow for the development of uniform and consistent intervals in reliability standards and business practices and also promote accuracy of results. A number of other commenters agree that consistent scheduling intervals are needed in order for intra-hour scheduling to occur across balancing authority areas.[93] For

Wildlife; Environmental Defense Fund; EPSA; Exelon; First Wind; Independent Energy Producers; ITC Companies; NaturEner; Organization of Midwest ISO States; Oregon & New Mexico PUC; Powerex; Public Interest Organizations; SWEA; Tres Amigas; Viridity Energy; Vote Solar; Western Grid; Xcel.

[84] *E.g.,* BP Energy; CEERT; CGC; Defenders of Wildlife; Duke; NextEra; Public Interest Organizations; SEIA; Vestas; Xcel.

[85] EPSA (citing NERC April 12, 2010 Response to NOI at 17–18).

[86] *E.g.,* Environmental Defense Fund; FriiPower; Independent Power Producers Coalition-West; RenewElec; SEIA; Vestas.

[87] *E.g.,* Environmental Defense Fund; Independent Power Producers Coalition-West; RenewElec.

[88] *E.g.,* LADWP; Montana PSC; NV Energy; Puget.

[89] *E.g.,* Bonneville Power; California ISO; California PUC; CMUA; Montana PSC; NorthWestern; NV Energy; Snohomish County PUD; Southern California Edison; WUTC.

[90] *E.g.,* Bonneville Power; California PUC; CMUA; FirstEnergy; NorthWestern; Snohomish County PUD; Southern California Edison.

[91] *E.g.,* LADWP; NorthWestern; PNW Parties; Tacoma Power; WestConnect.

[92] Bonneville Power; Xcel.

[93] *E.g.,* Argonne National Lab; EEI; Iberdrola; Independent Power Producers Coalition-West; NaturEner; NorthWestern; NRECA; Oregon & New Mexico PUC; Public Interest Organizations; Puget;

Continued

example, NorthWestern and Southern contend that, unless all public utility transmission providers within an interconnection are required to comply with the same intra-hour scheduling interval, intra-hour scheduling may erode a utility's ability to maintain reliability.

68. Public Interest Organizations agree that there is a need to apply consistent scheduling obligations across the country in order to avoid undue discrimination against VERs and argue that the benefits of 15-minute intra-hour scheduling will apply throughout the system, not just to VERs. If the Commission decides to allow for a public utility transmission provider to propose variations to 15-minute scheduling, Public Interest Organizations suggest that the entity be required to demonstrate why a variation is necessary and show that the proposed alternative will be equally effective or superior to the Commission's proposal. NextEra points out that the arguments favoring regional variations in scheduling requirements ignore the fact that many regions have no overall regional body or authority with sufficient ability to ensure consistency in resolving issues regarding VER integration. NextEra submits that the Commission has ultimate responsibility to ensure that market rules are just and reasonable, and that the Commission cannot delegate its responsibility to states, regions, or public utilities. Tres Amigas requests that the Commission clarify that intra-hour scheduling will apply to all generation scheduled on the bulk transmission system; inter- and intra-balancing authority transactions, and point-to-point, network, or native load service. Tres Amigas states that inconsistent transmission scheduling periods will lead to inefficient and/or discriminatory use of the transmission system.

69. Many commenters contend that the Commission should afford public utility transmission providers the flexibility to determine how best to implement intra-hour scheduling in their region. These commenters ask the Commission to acknowledge that region-specific scheduling practices may be appropriate in light of system circumstances and market designs.[94] Several of these commenters note that there are regional efforts and pilot programs underway that are aimed at efficiently managing the integration of VERs and providing an opportunity for intra-hour scheduling.[95] These commenters generally contend that the Commission should support and not undermine such regional initiatives. Examples of regional initiatives identified by commenters include the Joint Initiative,[96] the WECC Efficient Dispatch Toolkit,[97] and a pilot between Bonneville Power and the California ISO to evaluate the use of intra-hour scheduling on the California-Oregon Intertie.[98] Several commenters suggest that the Commission should conduct technical conferences to investigate the relative merits of these and alternative approaches prior to imposing a uniform national mandate.[99]

70. Some commenters express concern that a Commission mandate may detrimentally affect current regional efforts by diverting resources from or discouraging participation in voluntary regional initiatives by both jurisdictional and non-jurisdictional entities.[100] Bonneville Power and CMUA suggest that ongoing initiatives may provide the Commission with real-world data and alternative options to reach the Commission's stated goals. In order to support ongoing regional initiatives, Pacific Gas & Electric recommends that the Commission not implement 15-minute scheduling until regional initiatives have been given a reasonable amount of time to come to an end. Grant PUD argues that 20–30 minute scheduling intervals appear to be sufficient for the Northwest region of the country and that the Commission should allow this to be considered a "regional practice." [101] In addition, NRECA argues that the Commission should afford public utility transmission providers an opportunity to demonstrate that existing practices or practices under development are or will be consistent with or superior to the Commission's proposed reforms.

71. Some commenters stress the need for regional flexibility because, in their view, intra-hour scheduling may not be the right decision for everyone.[102] For example, LADWP asserts that the Proposed Rule is ill-timed, and that intra-hour scheduling may not be necessary in regions where the existing generation portfolio provides sufficient flexibility to integrate a fixed percentage of VER penetration reliably. Southwestern explains that, as a federal agency operating under a Congressional statutory mandate, the Administration may not be able to implement intra-hour scheduling as this may impact the purposes of the Corps projects such as flood control, hydropower, navigation, fish and wildlife, and recreation. If the Commission adopts the Proposed Rule, NRECA urges the Commission to permit public utility transmission providers to seek a waiver from implementing intra-hour scheduling until the entity receives a request to schedule intra-hour.

72. A number of commenters question the applicability of the proposed intra-hour scheduling requirements in regions with RTOs/ISOs, arguing that these markets already provide for system flexibility that is consistent with or superior to the intra-hour scheduling protocol proposed by the Commission.[103] Business Council suggests that the Commission should focus its attention on areas where rapid spot energy and ancillary service markets do not exist, particularly non-RTO/ISO areas that are experiencing significant renewable energy penetration. ISO/RTO Council asks the Commission to recognize that different regions currently provide varying levels of flexibility to VERs through different

Southern California Edison; Southern; and Tres Amigas.

[94] *E.g.*, Avista; Bonneville Power; California ISO; CMUA; California PUC; Detroit Edison; Dominion; EEI; FirstEnergy; Grant PUD; Idaho Power; Independent Power Producers Coalition-West; ISO/RTO Council; Midwest ISO; Montana PSC; National Grid; NorthWestern; NRECA; New York ISO; NV Energy; PJM; PNW Parties; Public Power Council; Puget; SMUD; Southern; Tacoma Power; WUTC; WestConnect.

[95] *E.g.*, Avista; Bonneville Power; Business Council; California ISO; California PUC; CESA; CMUA; EEI; Idaho Power; Joint Initiative; Montana PSC; National Grid; NorthWestern; NV Energy; PNW Parties; Puget; SMUD; WestConnect.

[96] The Joint Initiative is a consensual, collaborative effort within the Western Interconnection to develop high-value and cost-effective regional products, identified through a stakeholder process, for implementation by interested parties. It is jointly sponsored by Columbia Grid, Northern Tier Transmission Group, and WestConnect. Joint Initiative at 1–3. Step one of the Products and Services Strike Team intra-hour scheduling initiative began in July 2011 with the scheduling of transmission in half hour increments. Step two includes broader application of intra-hour scheduling and scheduling in finer increments (15 or 20 minutes) only after evaluation that this step is necessary.

[97] The WECC Efficient Dispatch Toolkit contains: (1) An enhanced curtailment calculator that will aid in managing flows across constrained paths; and (2) an energy imbalance market that will efficiently dispatch resources in response to imbalance.

[98] This pilot program is intended to facilitate the export of wind resources located in Bonneville Power's Balancing Authority into the California ISO. The pilot will use dynamic e-tagging and communication to facilitate intra-hour schedule changes, beginning with a 30-minute scheduling interval.

[99] *E.g.*, California ISO; Grays Harbor PUD; Pacific Gas & Electric; SMUD; Snohomish County PUD.

[100] *E.g.*, Avista; Bonneville Power; California PUC; EEI; Idaho Power; National Grid; NorthWestern; NRECA; NV Energy; PNW Parties.

[101] Grant PUD at 4.

[102] *E.g.*, ISO/RTO Council; NorthWestern; Pacific Gas & Electric; PNW Parties; Public Power Council; Puget.

[103] *E.g.*, AWEA; California ISO; California PUC; Detroit Edison; Iberdrola; ISO New England; Massachusetts DPU; Midwest ISO; PJM; Public Interest Organizations; RENEW; Sunflower and Mid-Kansas; Western Farmers.

systems and market mechanisms, suggesting that the Commission craft the Final Rule in a manner that allows transmission providers to work with their stakeholders to develop solutions that work for their region. FirstEnergy asserts that each RTO and ISO, through its stakeholder process, should be given the opportunity to evaluate the potential need for, and benefits and costs associated with, intra-hour scheduling. Sunflower and Mid-Kansas similarly argue that the Final Rule should recognize the differences between organized markets and not group them with non-RTO public utility transmission providers. Environmental Defense Fund asserts that, because some RTOs and/or balancing authorities have begun to implement regional scheduling reforms, the Commission should avoid imposing duplicative requirements or obstructing such efforts.

73. Some commenters suggest that the Commission clarify that its proposed intra-hour scheduling reforms apply only to RTOs and ISOs in the context of transactions between balancing authorities.[104] However, National Grid cautions the Commission against overly-prescriptive requirements for scheduling between regions and asks for clarification that public utility transmission providers are permitted to pursue other scheduling improvements for cross border transactions and inter-tie scheduling. National Grid notes that New York ISO and ISO New England are already working on solutions to improve interregional interchange scheduling. ISO/RTO Council states that accelerated scheduling changes may negatively affect RTO and ISO interchanges with non-market areas, as those smaller areas may be unable to keep up with an RTO or ISO scheduling within the hour.

74. Many commenters express concern regarding the potential for seams issues, particularly with transmission providers that are not subject to the Commission's ratemaking jurisdiction under sections 205 and 206 of the FPA.[105] Some commenters argue that, for a generator to submit a 15-minute schedule, all balancing authorities involved in the transmission chain must approve the tag or it will be rejected.[106] While the source balancing authority may approve the schedule, PNW Parties explain that the schedule may be denied in the adjacent balancing area if the same intra-hour scheduling procedures are not used, irrespective of the jurisdictional status of the transmission providers involved. Xcel suggests that, in areas where the balancing authority and transmission provider are separate entities, explicit guidance may be needed in order for a balancing authority to accept intra-hour schedules from a transmission provider. Xcel recommends that the Commission place responsibility on the balancing authority to approve intra-hour scheduling changes made in accordance with an approved tariff.

75. Additionally, these commenters question how beneficial intra-hour scheduling will be in the absence of consistent and compatible scheduling intervals among jurisdictional and non-jurisdictional entities.[107] Puget states that, while it has offered intra-hour scheduling since December 2009, its customers have scheduled few transactions due to the lack of conforming scheduling practices in neighboring non-jurisdictional utilities. If transmission customers are unable to schedule across seams at 15-minute intervals, Puget argues that jurisdictional utilities will receive little benefit from the required software, personnel and accounting changes needed to facilitate 15-minute scheduling. Idaho Power submits that seams issues created by different intervals in adjacent systems may ultimately lead to an increase in the costs of VER integration. WUTC asserts that for jurisdictional entities to implement intra-hour scheduling unilaterally would be economically unproductive and may disrupt reliability functions. Idaho Power and EEI similarly contend that seams issues may affect reliability.

76. EEI suggests that the Commission not require public utility transmission providers to provide intra-hour scheduling prior to an evaluation of the impacts on coordination between and among jurisdictional and non-jurisdictional entities. California ISO contends the parties in the West should continue with coordinated efforts to find reasonable solutions that can be implemented without placing an undue burden on neighboring parties. California PUC recommends that the Commission allow sufficient flexibility for public utility transmission providers to determine the most efficient way to support intra-hour scheduling across interties.

77. Snohomish County PUD and Grays Harbor PUD request that the Commission evaluate whether existing supply arrangements with Bonneville Power, referred to as ''slice'' contracts, allow for intra-hour scheduling before adopting the proposed requirements. Snohomish County PUD explains that these contracts allow customers to pay a fixed percentage of Bonneville Power's costs and, in turn, receive an equal percentage of output, thereby taking advantage of the flexibility of the federal system. However, Snohomish County PUD and Grays Harbor PUD state that these ''slice'' contracts limit customers to hourly scheduling. Snohomish County PUD is concerned that it and other similarly situated transmission providers may be unable to implement 15-minute scheduling. Snohomish County PUD contends that, as a result, it and others may have to acquire additional reserves in order to balance wind resources, in effect paying twice for the same capacity and scheduling flexibility. Snohomish County PUD asserts that this issue has already arisen in Bonneville Power's ongoing efforts to develop intra-hour scheduling at 30-minute intervals.

iii. Cost to Implement Intra-Hour Scheduling

78. A number of parties address the potential costs of implementing the Commission's proposed intra-hour scheduling requirement. Exelon states that there likely will be some development and ongoing administrative costs, such as modifying Open Access Same-Time Information System (OASIS) and interchange ramp software and additional staff to evaluate and confirm more frequent scheduling changes, but does not expect that such costs would be excessive. Tres Amigas contends that the incremental costs of providing intra-hour scheduling will be very modest. NaturEner argues that many transmission providers could implement intra-hour scheduling with existing staff and equipment but that, even if that is not the case, entities should be incentivized or required to automate or otherwise update their system as it would expedite the scheduling and transmission approval system. Independent Power Producers Coalition-West contends that increased automation and staffing would enhance the ability of a balancing authority to schedule at shorter intervals and achieve further integration of VERs.

79. Other commenters state that the cost of implementing intra-hour

[104] *E.g.*, AWEA; Iberdrola; Public Interest Organizations; and RENEW.

[105] *E.g.*, Avista; California ISO; Duke; EEI; Idaho Power; MidAmerican; NorthWestern; NV Energy; PNW Parties; Puget; Southern California Edison; Southern; Tres Amigas; WUTC.

[106] *E.g.*, PNW Parties; Puget; WUTC.

[107] *E.g.*, Avista; California ISO; Duke; EEI; Idaho Power; NorthWestern; NV Energy; PNW Parties; Puget; Southern California Edison; Southern; Tres Amigas; WUTC.

scheduling may be significant.[108] EEI and PNW Parties assert that intra-hour scheduling will affect many activities and systems, causing transmission providers in some regions to institute hardware, software, and personnel changes. For example, EEI and PNW Parties contend that changes will be required to numerous computer systems, such as energy management systems, scheduling applications, and automated checkout systems such as the WECC Interchange Tool, and also that certain practices not currently automated will have to be automated. EEI and PNW Parties note that staff would need to be trained on these new tools and additional staff would be required to process the expanded scheduling information being received. NRECA contends that the costs will be driven largely by software and personnel changes, rather than hardware investments, but that it is difficult to estimate with precision what software changes would be needed without knowing what measures NAESB will adopt in order to standardize the new scheduling regime.

80. NextEra explains that several steps will need to be taken in order to implement 15-minute scheduling but contends that the cost impacts are uncertain. NextEra provides that actions to implement intra-hour scheduling include potential modifications to both internal and external software packages. According to NextEra, these software programs, providing functions such as eTagging, accounting, and billing, will need to be harmonized across vendors. Additionally, NextEra contends that it is unclear whether existing systems would need to be replaced or modified, or whether functions currently being performed manually would need to be automated.

81. Some transmission providers estimate the level of investment and staffing changes that would be required to implement 15-minute scheduling on their system, although most discuss such estimates in the context of a broader range of activities that they believe may be intended or implicated by the implementation of 15-minute scheduling.[109] For example, Avista states that it would need to hire and train around-the-clock personnel at an estimated cost of $1.2 million per year to implement ''an approach that will allow for schedule adjustments *and* imbalance settlements in 15 minute periods.'' [110] MidAmerican estimates approximately $1.0 million in staff costs to implement ''similar intervals for balancing activities and interchange'' and, to the extent energy management and accounting systems must be changed, up to $2.0–2.3 million in infrastructure upgrades.[111] Bonneville Power also contends that it would need an additional 24x7 position, staffed by six full-time employees, to manage what it characterizes as the risks created by 15-minute scheduling, including the redesign of imbalance service and increased use of special protection schemes.

82. NRECA notes that the relative cost impact of implementing intra-hour scheduling will depend on a number of factors, such as the size of the system and how widely intra-hour scheduling is utilized. Although agreeing that the costs may be significant, NRECA states that costs are not expected to be extraordinary and can be mitigated through proper design and implementation. NRECA estimates implementation costs under a range of scenarios. Assuming hourly schedules at a 15-minute interval used only by VERs, NRECA anticipates the need for software modifications in the range of $50,000 per company, but notes that some of its members have incurred expenses in the range of $250,000 annually for software licensing and maintenance related to scheduling and energy accounting software upgrades. If hourly schedules at a 15-minute interval are widely used by transmission customers, NRECA estimates a minimum of one additional 24x7 shift, resulting in approximately $1.0 million of staffing costs, and potentially two 24x7 positions depending on the size of the transmission provider. Finally, if hourly schedules at a 15-minute interval are settled on a 15-minute basis, NRECA estimates an additional $250,000 to $300,000 for additional ''back room'' staff to settle 15-minute schedules, interchange and deviation accounts.

83. Bonneville Power contends that many of the short-term costs associated with 15-minute scheduling would not be incurred to implement scheduling on 30-minute intervals. Bonneville Power states that it is currently updating systems and work processes to implement 30-minute scheduling in association with regional initiatives and that it believes the changes, resources, and system impacts associated with the implementation of scheduling at a 30-minute interval will be relatively modest compared to what would be required to implement 15-minute scheduling. Bonneville Power asserts that the systems, transmission upgrades, and resources required to accommodate the increasingly dynamic movements of power across the interconnection under 15-minute scheduling would not be required under 30-minute scheduling. Tacoma Power argues that it will determine the level of automation needed for 30-minute scheduling based on the experience it gains during implementation of the Joint Initiative intra-hour program, but that implementation of 15-minute scheduling intervals as discussed in the Proposed Rule would require immediate automation of all the processes for Tacoma Power to have any market presence.

iv. Requests for Additional Requirements

84. Some commenters contend that transmission customers should be encouraged or required to submit intra-hour schedules, arguing that the Commission's objectives of lowering reserve costs can be reached only if intra-hour scheduling is utilized in a consistent and predictable manner.[112] Bonneville Power argues that mandatory intra-hour scheduling is necessary to achieve the reduction in reserve requirements of 80 percent cited in its 2008 study.[113] Idaho Power and PNW Parties contend that VERs generally have a strong financial incentive to maximize energy output and, therefore, may schedule for a full hour to maximize benefits regardless of the availability of 15-minute scheduling. WUTC recommends that the Commission couple the implementation of intra-hour scheduling with measures to mitigate over-scheduling by VERs, particularly when market conditions are favorable for over-scheduling.

85. Others recommend that the Commission provide incentives to use intra-hour scheduling by eliminating the exemption of VERs from third-tier generator imbalance penalties in Schedule 9 of the *pro forma* OATT, which they argue would no longer be just and reasonable given the

[108] *E.g.*, Avista; Bonneville Power; EEI; Grant PUD; MidAmerican; NRECA; NorthWestern; PNW Parties; Puget; Snohomish PUD; Southern California Edison; Southwestern; Tacoma Power; TVA.

[109] *E.g.*, Avista; Bonneville Power; Grant PUD; MidAmerican; NorthWestern; PNW Parties; Puget; Snohomish County PUD; Southwestern; Tacoma Power; TVA.

[110] Avista at 12, 14 (emphasis in original).

[111] MidAmerican at 14.

[112] *E.g.*, Bonneville Power; EEI; Idaho Power; MidAmerican; NorthWestern; Puget; PNW Parties; WUTC.

[113] Bonneville Power (citing Bart McManus, *Large Wind Integration Challenges and Solutions for Operations/System Reliability* (2008). Bonneville Power clarifies that, in the study, mandatory 10-minute scheduling on a 10-minute persistence basis reduced the reserve requirements in the BPA region by 80 percent. Bonneville Power also clarifies that this reduction only applies to the source Balancing Authority, not the sink Balancing Authority).

Commission's proposed reforms.[114] In addition to eliminating the exemption from third-tier generation imbalance penalties, MidAmerican suggests that an additional imbalance penalty tier be created for any transmission customer that consistently fails to adjust schedules on an intra-hour basis and creates significant variability. Avista recommends that the Commission allow transmission providers to impose appropriate penalties and recover the true costs of providing intra-hour schedules from VERs that continue to schedule on an hourly basis.

86. Several commenters argue that intra-hour scheduling may not achieve its intended benefits without additional reforms to augment intra-hour scheduling practices.[115] Some of these commenters assert that the Commission should allow a public utility transmission provider the flexibility to revise its energy imbalance settlement periods to align with any intra-hour scheduling interval.[116] Southern contends that this will allow a public utility transmission provider to offer appropriate incentives to customers to follow a given schedule and limit the potential for exposure to uncompensated risks.

87. However, Avista states that there are positives and negatives to either maintaining hourly settlement with intra-hour scheduling or modifying settlement intervals to coincide with intra-hour scheduling intervals. Avista asserts that conforming intra-hour schedules and imbalance settlement at 15-minute increments for all transmission schedules would result in alignment of scheduling and imbalance billing for all transactions and reduce gaming potential. Avista argues that the potential for gaming by transmission customers through the overcorrection of schedules in order to minimize imbalance charges may require a public utility transmission provider to carry regulation reserves in excess of what is needed. Midwest ISO agrees, citing a report from its Independent Market Monitor indicating that large changes in Net Scheduled Interchange caused by 15-minute intra-hour scheduling could lead to price volatility and negative operational impacts.[117] Avista and Midwest ISO further state that conforming imbalance settlement with intra-hour schedules may require substantial and potentially costly office system changes, additional operations staff, and other costs incurred through the communication, metering, and storage of all customer data at 15-minute increments.

88. Some commenters contend that intra-hour scheduling only governs the scheduling of flows on the transmission system and, by itself, does not necessarily affect the frequency with which generators are dispatched.[118] AWEA and Invenergy Wind agree that a transition to sub-hourly dispatch is the key for increasing the flexibility of the power system and for reducing the amount of reserves that must be held, which in turn will reduce costs for consumers and enable cost effective integration of VERs. Commenters recommend that the Commission require public utility transmission providers to implement a sub-hourly, real-time energy exchange that provides automated generation dispatch (such as an Efficient Dispatch Toolkit or the Energy Imbalance Market as adopted by the Southwest Power Pool and currently being studied in WECC). In AWEA's view, a market for sub-hourly energy would allow for netting of sub-hourly deviations and would provide price signals to incent greater sub-hourly flexibility.

89. AWEA acknowledges that changes to dispatch protocols and expansion of market options are being considered in regional efforts, but argues that progress is uncertain and unlikely to come to fruition in the near term. Iberdrola argues that intra-hour scheduling must be combined with intra-hour dispatch or market purchases to achieve the Commission's goals. Oregon and New Mexico PUC recommend that the Commission encourage reforms such as an Energy Imbalance Market or 15-minute calculations of available transmission capability (ATC) as a complement to intra-hour scheduling. However, Bonneville Power suggests distinguishing between intra-hour scheduling outside of a market region and intra-hour dispatch in an organized market, arguing that the costs and benefits of each may be dramatically different. Bonneville Power explains that the resources devoted to implementing 15-minute scheduling may be better used to pursue the development of an organized market with frequent dispatch intervals.

90. Some commenters assert that the Commission should consider changes to other aspects of electricity markets to facilitate intra-hour scheduling.[119] Invenergy Wind contends that consistent timeframes across all transmission and generation functions may lead to more efficient use of transmission capacity, regulation, and other ancillary services. American Clean Skies explains that the technology necessary to schedule transmission in 15-minute increments will also allow for scheduling reforms in the day-ahead market and the unit commitment process and, therefore, the Commission should require 15-minute scheduling reforms in these areas as well. However, PJM asserts that real-time control issues do not exist day-ahead and, therefore, the Commission need not consider reforms to the day-ahead market.

c. Commission Determination

91. The Commission concludes that it is appropriate to act at this time to adopt the scheduling reforms set forth in the Proposed Rule. Specifically, the Commission amends the *pro forma* OATT to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals. Our actions in this Final Rule will ensure that charges for generator imbalance service under Schedule 9 of the *pro forma* OATT and for other ancillary services through which reserve-related costs are recovered are just and reasonable and are not unduly discriminatory.[120]

92. As noted in the Proposed Rule, many *pro forma* OATT requirements, including hourly scheduling protocols, were developed at a time when virtually all generation on the system could be scheduled with relative precision.[121] As part of the Commission's regulatory responsibilities, we routinely review and, where appropriate, implement reforms to ensure the provision of service that remains just and reasonable and not unduly discriminatory. A similar review led the Commission in Order No. 890 to exempt VERs from the third-tier of generator imbalance penalties, given that VERs have a limited ability to accurately follow an hourly transmission schedule and, as a result, exposure to high imbalance penalties does not lessen their incentive to deviate from their schedule.[122] In this Final Rule, we take an additional step to allow transmission customers the flexibility to adjust their transmission

[114] *E.g.*, Avista; EEI; Idaho Power; MidAmerican; Puget; WUTC.

[115] *E.g.*, Avista; AWEA; RenewElec; Vote Solar.

[116] *E.g.*, EEI; Duke; Idaho Power; Southern.

[117] Midwest ISO (Potomac Economics, 2008 *State of the Market Report for the Midwest ISO,* Docket No. ZZ09–4–000 at 169 [141] (June 21, 2009)).

[118] *E.g.*, AWEA; CEERT; Invenergy Wind.

[119] *E.g.,* American Clean Skies; Invenergy Wind.

[120] In section IV.C (Generator Regulation Service Capacity) *infra,* the Commission acknowledges that a range of capacity services could be used by public utility transmission providers to recover reserve-related costs.

[121] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 38.

[122] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 665.

schedules, in advance of real-time, to reflect the variability of output in generation, more accurate power production forecasts to predict output, and other changes in load profiles and system conditions.

93. Specifically, the Commission affirms the preliminary finding in the Proposed Rule that existing hourly scheduling protocols expose transmission customers to excessive or unduly discriminatory generator imbalance charges.[123] Under Schedule 9 of the *pro forma* OATT, generator imbalance charges are assessed on deviations between generator output and a delivery schedule over a single hour.[124] There is no requirement to provide customers the opportunity to adjust their transmission schedules within the hour to reflect changes in generator output. As a result, transmission customers have no ability under the *pro forma* OATT to mitigate Schedule 9 generator imbalance charges in situations when the transmission customer knows or believes that generation output will change within the hour. The Commission concludes that this lack of ability to update transmission schedules within the hour can cause charges for Schedule 9 generator imbalance service to be unjust and unreasonable or unduly discriminatory. As a result of the intra-hour scheduling reforms of this Final Rule, the metric against which generator imbalances are measured will be more granular than under current hourly scheduling protocols.

94. The Commission expects that many types of entities, not only VERs, may benefit from the availability of intra-hour scheduling. Every transmission customer will have the ability to adjust its schedule at 15-minute intervals to reflect changing conditions. This includes, for example, transmission customers that experience a within-hour forced outage or transmission customers taking delivery from energy constrained resources (such as flow-limited hydro-electric generators, emission-limited thermal generators, and energy storage resources), even if using point-to-point transmission internal to the system. For example, we note that Entergy voluntarily adopted intra-hour transmission scheduling without the presence of substantial VERs in an effort to manage fluctuations in output from qualifying facilities on its system.[125] Based on this experience and the record in this proceeding, the Commission finds that intra-hour scheduling will provide a range of transmission customers with a necessary tool to mitigate exposure to Schedule 9 generator imbalance charges in light of changing conditions.

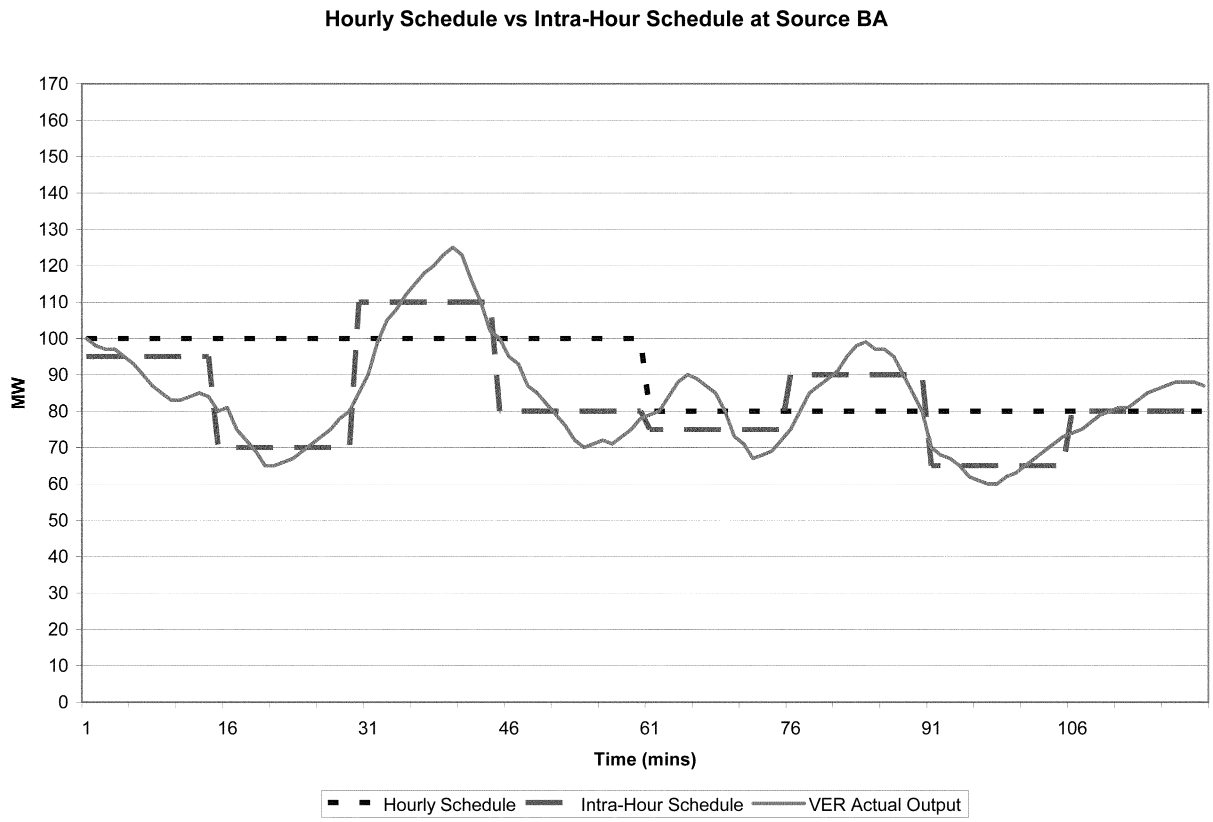
95. The Commission also finds that, over time, implementation of intra-hour scheduling will allow public utility transmission providers to rely more on planned scheduling and dispatch procedures, and less on reserves, to maintain overall system balance. Under hourly scheduling protocols, the source balancing authority for a transaction is required to honor its transmission schedule across an entire hour, requiring the source balancing authority to have sufficient reserves in place to manage imbalances within the hour, i.e., maintain consistent delivery of the scheduled amount of energy to the sink balancing authority over the hour. This includes reserves to respond to variations in generation output that are moment-to-moment as well as longer-term, but occurring within the hour, represented by the solid line in Figure 1.

[123] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 37.

[124] Imbalance charges are calculated by multiplying the quantity of imbalance by a set percentage of incremental or decremental costs defined in three deviation bands. These charges are netted on a monthy basis and settled financially at the end of each month. For example, any deviations greater than ± 7.5 percent (or 10 MW) of the scheduled transaction (applied hourly) will be settled at 125 percent of incremental costs or 75 percent of decremental costs. *See* OATT Schedule 9.

[125] *See Entergy Serv. Inc.,* 111 FERC ¶ 61,314 (2005).

Figure 1



96. By moving from hourly to 15-minute scheduling intervals, the amount of imbalance energy for which the source balancing authority is potentially responsible can be reduced, as reflected in Figure 1. This can lead to a corresponding reduction in the amount of capacity held to provide that energy and, in turn, lower reserve-related costs for the source balancing authority, and ultimately consumers. Therefore, the Commission also finds that implementation of intra-hour schedules is necessary in order to ensure that charges for ancillary services through which reserve-related costs are recovered are just and reasonable and not unduly discriminatory.[126]

97. For these reasons, the Commission adopts the proposal set forth in the Proposed Rule and directs public utility transmission providers, consistent with the compliance deadlines addressed below, to revise their OATTs to provide an opportunity for transmission customers to submit transmission schedules at 15-minute intervals. In response to Bonneville Power and Xcel, the Commission clarifies that this requirement is intended to allow transmission customers to both modify existing schedules as well as create new schedules, provided that the transmission customer has a transmission reservation in place.[127] The ability to create new transmission schedules within the hour will be particularly important to resources that may seek to provide intra-hour energy products, as discussed further below.

98. The Commission notes that most commenters support the practice of intra-hour scheduling, with disagreement focused primarily on the frequency of schedule adjustments and whether changes to existing scheduling should be paired with other reforms. Balancing the competing considerations raised by commenters, the Commission concludes that a 15-minute scheduling interval is appropriate and declines to impose additional reforms at this time. The Commission appreciates that implementation of other reforms, such as intra-hour imbalance settlement, an intra-hour transmission product, increasing the frequency of resource commitment through sub-hourly dispatch, or the formation of intra-hour imbalance markets, could yield additional benefits for public utility transmission providers and their customers. However, these additional reforms can have significant costs. The Commission's review of the record in this proceeding suggests that a more measured approach is appropriate to take at this time.[128]

99. The Commission acknowledges that implementation of intra-hour scheduling can result in a shift of responsibility for holding certain reserves away from the source balancing

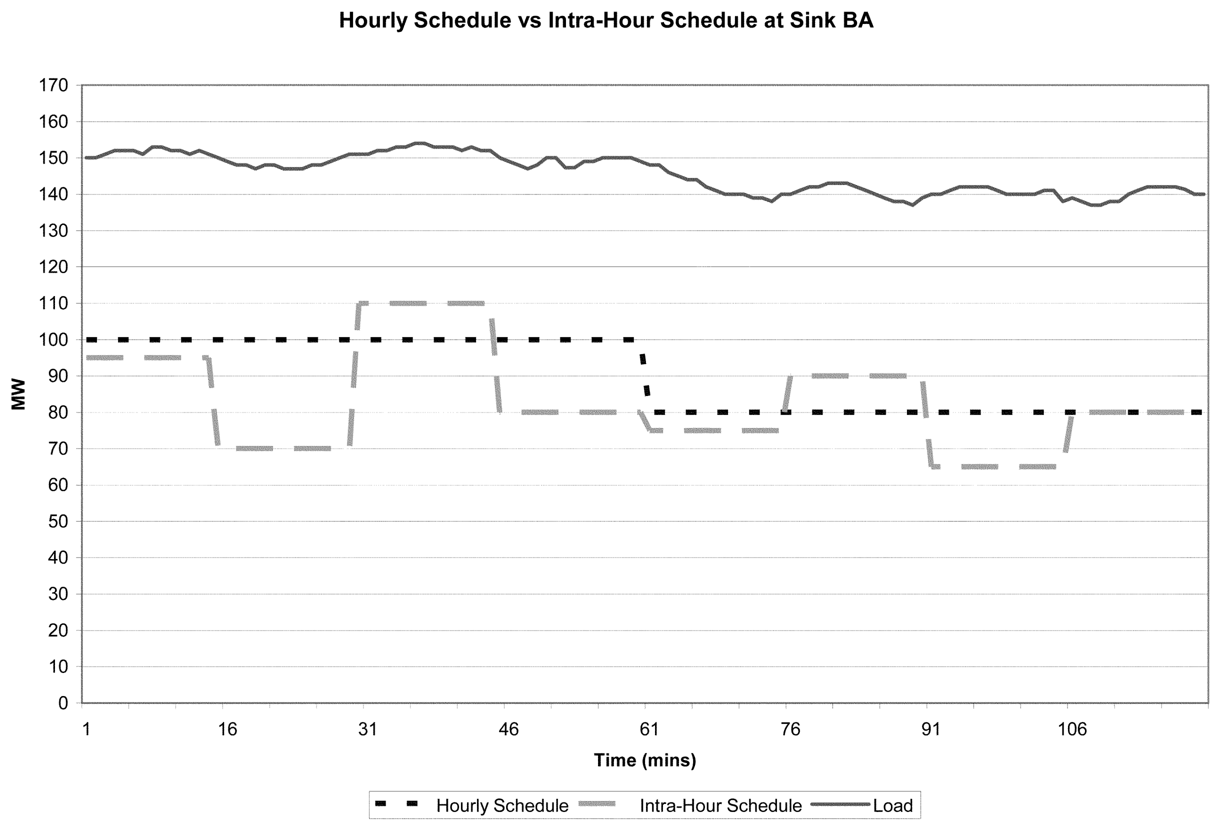
[126] One mechanism that could be used to recover reserve-related costs is generator regulation service. The Commission provides guidance regarding the development of generation regulation charges in section IV.C.2 (Mechanics of Generator Regulation Charge) *infra.* Among other things, public utility transmission providers should consider the extent to which transmission customers are using intra-hour scheduling in evaluating whether to require different transmission customers to provide or otherwise account for different quantities of generator regulation service.

[127] To be clear, this Final Rule does not alter the transmission products of the *pro forma* OATT and, therefore, implementation of intra-hour scheduling does not require (yet would not preclude) the intra-hour calculation of ATC or sale of transmission service.

[128] As noted below, public utility transmission providers will have an opportunity on compliance to demonstrate that alternative intra-hour scheduling proposals are consistent with or superior to the intra-hour scheduling requirements of this Final Rule. Such a proposal could include one or more of the additional reforms requested by commenters, such as the formation of intra-hour imbalance markets.

authority for export transactions.[129] As explained above, allowing for more granular transmission schedules can reduce the amount of variation in generation output for which the source balancing authority is responsible. The Commission appreciates that, from the sink balancing authority's perspective, scheduling at shorter intervals may result in the purchaser of energy having to manage more frequent changes in scheduled deliveries as compared to scheduling at hourly intervals. As indicated in Figure 2, a purchaser under existing hourly scheduling protocols receives a fixed quantity of energy over the hour from the source balancing authority, whereas use of 15-minute intervals could result in fluctuating deliveries across the hour.

Figure 2



To the extent the purchaser desires to continue receiving a constant delivery of energy across the hour, represented by the dotted line in Figure 2, it may be required to obtain that energy from the market.[130] The Commission concludes that this is an appropriate division of responsibility, as opposed to the current hourly system which places all responsibility for managing variations in generation output across the hour solely on the source balancing authority. Within the hour, the source balancing authority retains its responsibility of providing the energy needed for the VER to meet its schedule, while the purchaser takes on the responsibility of managing more frequent deliveries of scheduled energy.

100. By shifting responsibility for managing certain variations in generation output to the purchasing entity, purchasing entities will have greater incentive to manage changes in scheduled deliveries from 15-minute interval to 15-minute interval and the portfolio of resources that ultimately manage total VER variability will likely be more cost-effective than under current practices. Specifically, a portfolio of resources that respond over a range of time scales, from very fast to relatively slow, is lower cost than a portfolio that relies on resources designed to manage only the short-run variability of VERs.[131] For instance, portfolio cost savings could result from using a combination of expensive resources with automated generator control and less expensive resources that provide following service rather than using only resources with automated generator control. While the source balancing area could choose to manage VER variability with a portfolio of resources that respond over a range of time, it has little incentive to do so because any additional costs can be recovered from transmission customers. We expect use of a portfolio of resources to lower the overall cost of managing VER variability. The Commission anticipates that buyers and sellers also may respond by developing intra-hour balancing products. EPSA notes that the additional market liquidity created by the ability to schedule transmission intra-hourly can provide opportunities for existing resources to manage system

[129] *E.g.,* Xcel; Iberdrola.

[130] For example, sellers of VER energy could have existing contractual commitments to deliver at constant volumes over specified periods.

[131] *See e.g.,* J. Apt, *The Spectrum of Power from Wind Turbines.* Journal of Power Sources, Vol. 169, No. 2, at 369–374 (2007); cited at RenewElec comments at note 4.

variability by offering within-hour energy products. This is equally true for market participants seeking to maximize the value of their resources, or lower their purchased power costs, through intra-hour trading. As the liquidity of intra-hour energy products stabilizes, market participants also may begin to commit or otherwise acquire fewer reserves in advance, with the knowledge that they can purchase additional reserves on an as-needed basis from third parties. Requiring public utility transmission providers to offer intra-hour scheduling is a necessary predicate to facilitate these market opportunities.[132]

101. Notwithstanding broad support in comments for some version of intra-hour scheduling, as noted above, there was significant disagreement in the comments as to the appropriate time interval. Some commenters supported the 15-minute interval proposed by the Commission,[133] while others argued for either shorter (e.g., 5-minute) or longer (e.g., 30-minute) scheduling intervals.[134] In evaluating these comments, the Commission has balanced the competing interests of allowing transmission customers to more closely match schedules with anticipated generation output against not unduly burdening public utility transmission providers in implementing the intra-hour scheduling reform. The Commission concludes that adoption of a 15-minute scheduling interval for purposes of the *pro forma* OATT is reasonable. In its comments on the NOI, NERC states that the ideal scheduling increment would be between 5 and 15 minutes depending on system characteristics.[135] NERC reasoned that, while balancing authorities that schedule energy transactions on an hourly basis may have sufficient regulation resources to maintain the schedule for the hour, reducing scheduling intervals to ten minutes, for example, could make economically dispatchable generators in an adjacent balancing authority available to provide necessary ramping capability through an interconnection.[136] The Commission agrees and, as discussed above, anticipates that the availability of intra-hour scheduling at 15-minute intervals will facilitate the development of ramping products to manage variability in generation output more effectively. For these reasons we adopt 15-minute transmission scheduling as proposed.

102. In adopting a 15-minute transmission scheduling interval, we recognize that the cost of moving from hourly to 15-minute transmission scheduling could be substantial. Several transmission providers state that costs will depend heavily on the extent to which intra-hour scheduling is actually used by transmission customers, estimating staffing costs to be in the range of $1–2 million per year if widely used.[137] While these costs are not insignificant, greater use of intra-hour schedules means that more transmission customers are mitigating exposure to Schedule 9 generator imbalance charges and providing greater opportunities for public utility transmission providers to lower reserve-related costs. Commenters generally agree that the cost of implementing intra-hour scheduling will correlate to usage, with lower costs in those systems with fewer intra-hour schedules. In contrast, substantial use of intra-hour scheduling would affirm the usefulness of the option for transmission customers, justifying the added expense of processing a larger number of transmission schedules.

103. Many of the costs cited by commenters as being specific to 15-minute scheduling are related to the automation of systems used to process transmission schedules and verify cross-balancing authority aggregate schedules. The Commission notes that it is not mandating automation of scheduling practices, although we expect that each public utility transmission provider will consider whether automation of certain aspects of its system are necessary to implement scheduling at 15-minute intervals. To the extent a public utility transmission provider automates scheduling processes in response to increased scheduling activity, the Commission agrees with NaturEner and Independent Power Producers Coalition-West that automation of these processes represents a secondary benefit of our transmission scheduling reform. Several Commission staff audits have uncovered errors related to manual processing of transmission schedules.[138] These errors resulted in a transmission customer submitting a transmission schedule that resulted in a higher curtailment priority than the underlying transmission service reservation provided, allowed use of firm network service to deliver energy from resources that were not designated resources and allowed use of network transmission service to deliver a sale to a third party. As a result of these errors, the transmission customer may have gained access to transmission service that was not otherwise available, may have inappropriately gained additional protection from curtailment, and avoided payment for point-to-point transmission service. Increased automation of schedule process can reduce such errors and, in turn, ensure that the provision of transmission service is consistent with the *pro forma* OATT.

104. Some commenters raising concerns regarding the cost of implementing intra-hour scheduling imply that the proposed scheduling reforms would require changes in settlement procedures for imbalance service or the frequency of resource commitment through sub-hourly dispatch, which they state would require significant investments. For example, EEI and PNW Parties caution that these additional activities would affect computer systems, such as energy management and accounting systems.[139] MidAmerican estimates that upgrading such systems would cost $2.0–2.3 million. Other commenters, however, encourage the Commission to require intra-hour imbalance settlement and sub-hourly dispatch in order to align intra-hour scheduling with financial settlements and resource commitment. The Commission clarifies that the requirements of this Final Rule apply to scheduling practices, not imbalance settlement or sub-hourly dispatch. Public utility transmission providers may continue to calculate *pro forma* Schedule 9 generator imbalance charges on an hourly basis under the *pro forma*

[132] For example, the Joint Initiative has implemented an electronic platform to facilitate bilateral intra-hour transactions, the Intra-hour Transaction Accelerator Platform (I–TAP), also referred to as the WebExchange. *See http://www.columbiagrid.org/itap-overview.cfm.*

[133] *E.g.,* A123; Alstom Grid; ACSF; Argonne National Lab; BP Companies; CESA; CEERT; Center for Rural Affairs; Clean Line; CGC; Defenders of Wildlife; EPSA; Exelon; First Wind; Independent Energy Producers; NaturEner; Organization of Midwest ISO States; Oregon & New Mexico PUC; Powerex; Public Interest Organizations; SWEA; Tres Amigas; Viridity Energy; Western Grid; Xcel.

[134] *Compare* Environmental Defense Fund; FriiPower; Independent Power Producers Coalition-West; RenewElec; SEIA; Vestas; and Vote Solar (advocates of shorter) with Bonneville Power; California PUC; CMUA; Montana PSC; NorthWestern; Puget; Snohomish County PUD; Southern California Edison; WUTC (advocates of longer).

[135] NERC April 12, 2010 Response to NOI (NERC NOI Comments).

[136] NERC NOI Comments.

[137] *E.g.,* Avista; NRECA. To the extent intra-hour scheduling is not widely used by transmission customers, NRECA states its members likely could implement scheduling at 15-minute intervals with software modifications in the range of $50,000 per company, without additional staffing requirements.

[138] *E.g., Puget Sound Energy,* Docket No. PA07–1–000 at 25–27; *MidAmerican Energy Co.,* Audit Report, 112 FERC ¶ 61,346 at PP 30–34 (2005); and *Public Service Company of Colorado,* Docket No. PA05–1–000 at 9–11.

[139] *Eg.,* EEI; PNW Parties.

OATT and rely on hourly resource commitment practices.[140]

105. Notwithstanding the continued ability of public utility transmission providers to rely on hourly calculation of Schedule 9 generator imbalances, as a result of the intra-hour scheduling reforms of this Final Rule, the metric against which generator imbalances are measured will be more granular than under current hourly scheduling protocols. To the extent a public utility transmission provider believes that aligning the imbalance settlement with the intra-hour scheduling interval or implementing sub-hourly dispatch will result in more efficient operations, provide appropriate price signals to customers, or address other potential issues, it may seek any authorizations necessary from the Commission to do so under section 205 of the FPA.[141] Such proposals could be submitted contemporaneously with the compliance filing in response to this Final Rule or at such other time the public utility transmission provider believes appropriate.

106. Several commenters request that the Commission allow for regional variation in scheduling protocols.[142] In the Western Interconnection, many public utility transmission providers already have implemented some form of intra-hour scheduling at 30-minute intervals as part of an effort to enhance the operation of bilateral markets in the Western Interconnection.[143] Other tools recently implemented in the West include the I–TAP electronic platform to schedule energy and request transmission, the Dynamic Scheduling System to facilitate dynamic scheduling,[144] and the ACE Diversity Interchange Program to allow netting of momentary imbalances across participating balancing authority footprints.[145] Public utility transmission providers, state regulators, and others in the West are studying the impact of these recent initiatives, as well as the potential benefits and costs of pursuing additional market enhancements in the future, such as formation of an energy imbalance market. The Commission acknowledges that future market enhancements in addition to existing 30-minute scheduling practices and the above-referenced tools, might yield equivalent or greater benefits to transmission customers and public utility transmission providers when compared to reducing the scheduling interval from 30 to 15 minutes and therefore could be consistent with or superior to the Final Rule's intra-hour scheduling requirements.

107. The Commission therefore affirms the ability of public utility transmission providers to submit alternative proposals that are consistent with or superior to the intra-hour scheduling requirements of this Final Rule and are otherwise just and reasonable and not unduly discriminatory or preferential.[146] To make such a showing, a public utility transmission provider must demonstrate in its compliance filing how its proposal provides equivalent or greater opportunities for transmission customers to mitigate Schedule 9 generator imbalance charges, and for the public utility transmission provider to lower its reserve-related costs, when compared to implementation of the intra-hour scheduling requirements of this Final Rule under market practices currently in place within the region, including tools referenced above that already have been implemented in the West.[147] The public utility transmission provider must include in its compliance filing the tariff provisions necessary to implement its proposal, including the interval at which transmission customers may submit transmission schedules. The public utility transmission provider also must address how its proposed scheduling interval is consistent with other scheduling practices within its region. Finally, in recognition that implementation of intra-hour scheduling can result in a shift of responsibility for holding certain reserves away from the source balancing authority for export transactions, public utility transmission providers may consider the extent to which alternative proposals result in savings to transmission customers across multiple public utility transmission provider systems when making the demonstration required above.

108. Turning to other issues raised by commenters, the Commission is not convinced by arguments that the current exemption from third-tier generator imbalance penalties for intermittent resources should be eliminated to create an incentive for VERs to take advantage of the option to update transmission schedules every 15 minutes.[148] In Order No. 890, the Commission found intermittent generators cannot always accurately follow their schedules and that high penalties will not lessen the incentive to deviate from their schedules.[149] While the implementation of 15-minute scheduling provides an opportunity for VERs to better align transmission schedules with actual generation, the Commission continues to believe that third-tier generator imbalance penalties are unduly punitive for VERs given their relative inability to accurately follow schedules whether submitted on an hourly or 15-minute interval. The Commission concludes that the ability to avoid penalties in the first two tiers of generator imbalance charges will provide a sufficient incentive for VERs to adjust transmission schedules, to the extent they believe such adjustments will mitigate exposure to Schedule 9 generator imbalance charges. If a public utility transmission provider believes it necessary to address intentional deviations, it may propose revisions to Schedule 9 generator imbalance service pursuant to section 205 of the FPA.[150] Such proposals would need to demonstrate that VERs are not adjusting their transmission schedules despite their reasonable ability to foresee that

[140] *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.

[141] For example, PNW Parties and Idaho Power note that the financial incentives some transmission customers have to maximize output over an hour may in some instances counteract financial incentives to adjust transmission schedules on a 15-minute basis.

[142] *E.g.,* Avista; Bonneville Power; California ISO; CESA; CMUA; California PUC; Detroit Edison; EEI; FirstEnergy; Grant PUD; Idaho Power; Independent Power Producers Coalition-West; ISO/RTO Council; Midwest ISO; National Grid; Northwestern; NRECA; New York ISO; NV Energy; Pacific Gas & Electric; PJM; PNW Parties; Public Power Council; Puget; SMUD; Tacoma Power; WUTC; and WestConnect.

[143] *See e.g., Arizona Public Service Co.,* 137 FERC ¶ 61,023 (2011), *NorthWestern Corp.,* 136 FERC ¶ 61,119 (2011).

[144] *See* Joint Initiative.

[145] *See* NERC, *DRAFT Reliability Guideline: ACE Diversity Interchange* (June 2012), *available at http://www.nerc.com/docs/oc/rs/Draft%20ADI%20 Reliability%20Guideline%20-%20V1%20 060112.pdf.*

[146] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,770 (permitting public utility transmission providers to propose tariff modifications that are consistent with or superior to the requirements of the *pro forma* OATT).

[147] To the extent such an alternative proposal includes a commitment to develop and implement additional market enhancements in the future, the public utility transmission provider must provide in its compliance filing: A commitment by senior management to develop and implement the proposal; a description of collaborative efforts to date and timeline for future efforts in support of developing the proposal; and, the date by which the proposed market enhancement will be implemented.

[148] *E.g.,* Avista; EEI; Idaho Power; MidAmerican; Puget; WUTC.

[149] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 665.

[150] *Cf. id.* P 676 (noting the ability of public utility transmission providers to propose additional imbalance penalties for intentional deviations). Alternatively, the public utility transmission provider may propose alternative designs for other ancillary services rates to, for example, offer lower rates to those transmission customers committing to use intra-hour scheduling.

output will deviate significantly from existing transmission schedules.[151]

109. The Commission acknowledges comments made by some, particularly in the Pacific Northwest, asserting that the benefits of intra-hour scheduling will not be fully realized if non-jurisdictional entities do not adopt a consistent scheduling interval.[152] However, the Commission does not believe that limitations in our ratemaking jurisdiction over non-public utilities should stop us from moving ahead with reforms applicable to public utilities simply because the impact of those reforms might be more significant with participation by all entities. As explained above, requiring all public utility transmission providers to offer 15-minute transmission scheduling will enable public utility transmission providers and their customers to manage system variability more effectively. Therefore, the Commission is hopeful that non-jurisdictional transmission providers will voluntarily choose to implement 15-minute transmission scheduling in order to better manage variations in generation output. We understand that the existence of compatible business practices within a region is beneficial, and we encourage both jurisdictional and non-jurisdictional transmission providers to continue to coordinate and collaborate in order to maintain the continuity of the system and address issues as they arise. This includes collaboration in the development of any alternative compliance proposals developed by public utility transmission providers.

110. The Commission disagrees with comments by Southern and others that different scheduling intervals between jurisdictional and non-jurisdictional transmission providers may negatively affect reliability within an interconnection.[153] In the event a non-jurisdictional transmission provider only accepts hourly schedules, any attempt to submit an intra-hour schedule for delivery to the non-jurisdictional transmission provider would be rejected, as several commenters note.[154] This may lead to an inability to implement 15-minute scheduling fully and, in turn, could result in less effective management of system variability. However, the Commission does not believe that it would create any reliability challenges beyond those that exist today under hourly scheduling protocols. The Commission notes that voluntary efforts to implement intra-hour scheduling on 30-minute intervals in the Western Interconnection referenced above have not been uniformly applied, yet do not appear to have negatively affected reliability.

111. In response to concerns raised by Snohomish County PUD and Grays Harbor PUD regarding ''slice'' contracts with Bonneville Power, the Commission acknowledges that some existing power supply arrangements may not be flexible enough to take advantage of the benefits of intra-hour scheduling. Over time, the Commission anticipates that the market will respond to the availability of intra-hour scheduling through the development of new balancing products as well as modifications of existing arrangements where appropriate. However, in the case where the terms of an existing contract are inconsistent with intra-hour scheduling and cannot be modified, the Commission appreciates that the benefits of intra-hour scheduling may not be available with respect to that particular transaction.

112. In response to comments by WestConnect and NorthWestern that a 15-minute scheduling interval is inconsistent with the standard 20-minute generator ramp rate used in the West, we note that many of the Joint Initiative transmission providers—including members from WestConnect—have already implemented a 10-minute ramp rate to accommodate 30-minute transmission schedules. To the extent changes in ramping are necessary to support use of a 15-minute transmission schedules, it does not appear that such changes present a significant impediment for public utility transmission providers.

113. A number of commenters question the applicability of the intra-hour scheduling requirements to public utility transmission providers in RTO and ISO regions.[155] The Commission clarifies that the implementation of 15-minute transmission scheduling will only apply to intertie transactions in organized wholesale energy markets. The Commission finds that a consistent scheduling interval for transactions among all public utility transmission providers, including RTOs, is necessary in order to attain the benefits of intra-hour scheduling noted above. Additional reforms to other markets requested by commenters, such as adjustments to day-ahead markets, are beyond the scope of this rulemaking.

2. Implementation of Intra-Hour Scheduling

114. Commenters raise a number of additional issues related to how the intra-hour scheduling requirements adopted in this Final Rule should be implemented. The Commission addresses these issues below, including the following: (1) The appropriate notification period for submitting transmission schedules; (2) the recovery of costs associated with implementing intra-hour scheduling; (3) clarifications regarding the definition of transmission schedule, curtailment priorities, and calculations of ATC; (4) review of NERC reliability standards and NAESB business practices; and (5) other issues related to high voltage direct current (HVDC) transmission lines, dynamic scheduling, and the geographic location of resources used to provide reserves.

a. Notification Time for Submission of Transmission Schedule

i. Commission Proposal

115. In the Proposed Rule, the Commission proposed to allow all transmission customers the option of submitting intra-hour schedules up to 15 minutes before each scheduling interval.[156]

ii. Comments

116. Several commenters ask the Commission to retain the existing 20-minute notification time for submission of transmission schedules, arguing that schedules should be submitted no later than 20 minutes prior to the start of the schedule as required by NERC Reliability Standards INT–005, INT–006, INT–008, and NAESB WEQ–004 Appendix D.[157] Commenters contend that allowing only 15 minutes between schedule submission and start would not provide enough time for transmission operators to adequately evaluate, approve, and implement transmission schedules. ISO/RTO Council adds that changing to a 15-minute notice period will require

[151] The Commission notes that there is a relationship between a public utility transmission provider's potential need for alternative imbalance charge structures and the period used for imbalance settlements. Reinstating third-tier imbalance penalties in combination with shortened imbalance settlements would more likely punish VERs for variability that they cannot control, contrary to the exemption granted in Order No. 890 and affirmed here.

[152] *E.g.,* Avista; California ISO; Duke; Idaho Power; NorthWestern; NV Energy; PNW Parties; Puget; Southern California Edison; Southern; Tres Amigas.

[153] *E.g.,* EEI; Idaho Power; NorthWestern; Southern; Tacoma Power.

[154] *E.g.,* PNW Parties; Puget; WUTC.

[155] *E.g.,* AWEA; Iberdrola; ISO New England; Massachusetts DPU; PJM; Public Interest Organizations; RENEW; Sunflower and Mid-Kansas; Western Farmers.

[156] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 41.

[157] *E.g.,* Duke; EEI; Entergy; NRECA; PJM; Puget; Southern.

transmission operators to change their current systems and increase staff levels for processing transmission schedule requests. PJM comments that the 20-minute notification deadline is an established industry standard and that it should not be changed to 15 minutes.

117. Although not opposed to the Commission's proposal, NaturEner states that a shorter notification period would result in abbreviated response times for everyone in the scheduling process, including transmission customers. NaturEner asks the Commission to clarify that transmission providers have the discretion to accept schedule changes after the notification deadline. NaturEner contends that inclusion of such a clarification both supports the reform's underlying rationales and avoids any unnecessary future confusion regarding whether a balancing authority or transmission provider possesses such discretion.

iii. Commission Determination

118. The Commission will retain the existing 20-minute prior notification period for the submission of a transmission schedule and not adopt its proposal. The Commission agrees with commenters that the existing 20-minute prior notification period is needed to adequately evaluate, approve and implement transmission schedules. Accordingly, the Commission retains the existing notification period set forth in sections 13.8 and 14.6 of the *pro forma* OATT, which permits scheduling changes up to 20 minutes (or a reasonable time that is generally accepted in the region and is consistent and adhered to by the transmission provider) before the start of the next schedule change provided that the delivering party and receiving party also agree to the schedule modification. In response to NaturEner, the existing language of the *pro forma* OATT provides adequate flexibility for transmission providers to adopt alternative deadlines for accepting scheduling changes.

b. Recovery of Intra-Hour Scheduling Costs

i. Commission Proposal

119. In the Proposed Rule, the Commission proposed to allow public utility transmission providers to recover any costs incurred to implement the proposed intra-hour scheduling reform pursuant to Schedule 1 of a transmission provider's OATT.[158]

ii. Comments

120. Several commenters support the Commission's proposal, arguing that the benefits of intra-hour scheduling apply to more than VERs and, thus, costs relating to the implementation of intra-hour scheduling should be allocated to all transmission customers under Schedule 1 of the *pro forma* OATT.[159] For example, NextEra contends that intra-hour scheduling would provide long-term benefits for all customers through savings on reserve procurement. Public Interest Organizations agree, arguing that the initial costs of establishing 15-minute scheduling are an upfront investment that will yield exponential returns over time in the form of direct economic savings from increased grid efficiency and reliability, as well as energy security, greenhouse gas and other pollutant reductions, and job creation that accompanies increased renewable VER penetration. Center for Rural Affairs supports recovery of intra-hour scheduling costs to all beneficiaries through Schedule 1 in order to mitigate any challenge that this reform may present for small transmission providers, especially in rural communities with smaller areas of distribution. NaturEner points to the Joint Initiative as an example of allocating the hardware and software costs associated with implementation of intra-hour scheduling to all participants using the intra-hour scheduling system, i.e., the balancing authorities, transmission providers, and transmission customers. While Organization of Midwest ISO States supports the proposal, it asks that a clear showing of the costs incurred to implement intra-hour scheduling be required prior to allowing for recovery of those costs.

121. Other commenters disagree with the Commission's proposal to allow the costs associated with implementing intra-hour scheduling to be recovered through Schedule 1 and, instead, contend that such costs should be allocated to VERs and their customers.[160] These commenters argue that intra-hour scheduling will be predominantly used by and benefit VERs and their customers.[161] ELCON contends that traditional generation resources do not require intra-hour scheduling. In the Pacific Northwest, WUTC claims that intra-hour scheduling would be utilized almost exclusively by wind and other VERs, and not by thermal or hydropower resources. WUTC agrees that assignment of costs to those who cause them is essential to fair and just rates and to economic efficiency. Puget agrees that the only parties to benefit from 15-minute scheduling are VERs that are potentially able to reduce Schedule 9 generator imbalance charges by adjusting their schedules within the hour in response to changing wind conditions. Natural Gas argues that strict adherence to cost causation principles is central to ensuring that the proposals are limited to removing barriers and do not have the unintended consequence of subsidization and, ultimately, departure from the central precept of fuel neutrality.

122. Montana PSC states that traditional generation choosing to utilize intra-hour scheduling should be allocated a portion of implementation costs; however, absent this election VERs should be responsible for all costs related to development, operations, and maintenance of intra-hour scheduling.[162] NRECA similarly contends that, if transmission customers other than VERs make use of the new scheduling regime, it would be appropriate for those entities to share in the cost through Schedule 1 charges. Grant PUD argues that there is no guarantee that other resources may benefit from a shorter scheduling period and that some resources may actually incur costs to maintain 15-minute schedules, in which case they would pay twice for the shift to shorter schedules.

123. Avista asserts that allowing recovery through Schedule 1 will allocate costs not only to all transmission customers, but also to bundled retail native load customers. Avista argues that native load customers achieve no cost savings when a VER is located within a balancing authority area and is used to serve load within the same balancing area. Avista states that in this situation the native load customers bear all of the costs associated with following the output of the VER and do not need or benefit from intra-hour scheduling. Thus, Avista requests that none of the costs of implementing intra-hour scheduling be

[158] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 41.

[159] *E.g.,* Environmental Defense Fund; NextEra; Public Interest Organizations.

[160] *E.g.,* Avista; ELCON; Grant PUD; Montana PSC; Natural Gas; NorthWestern; NRECA; Puget; WUTC.

[161] *E.g.,* Avista; ELCON; Grant PUD; MidAmerican; NorthWestern; NRECA; Puget; WUTC.

[162] Similarly, NorthWestern asserts that unless intra-hour scheduling is made mandatory for all transmission customers, the VERs opting to use intra-hour scheduling should pay for the increased scheduling flexibility and the non VER customers should not be required to subsidize any particular generator type.

borne by a transmission provider's bundled retail native load customers.

124. Several of these commenters recommend that the Commission consider other mechanisms for recovering the costs of implementing intra-hour scheduling as opposed to a broad cost allocation scheme through Schedule 1.[163] For example, Avista asks the Commission to allow a transmission provider to directly assign the costs of implementing these reforms to the VER transmission customers that are the cause of such reforms through an appropriate charge included in either Schedule 1 or Schedule 10. NRECA argues that there is more than one method that a public utility transmission provider could use to recover costs and requests that the Commission provide public utility transmission providers the flexibility to choose the method that works best for each system and demonstrate a just and reasonable rate pursuant to section 205 of the FPA. NRECA also urges the Commission to include costs incurred to comply with any new Reliability Standards that ensue from the Final Rule.

iii. Commission Determination

125. The Commission adopts its proposal and allows public utility transmission providers to recover any costs incurred to implement the intra-hour scheduling reforms adopted in this Final Rule pursuant to Schedule 1 of the transmission provider's OATT. The Commission is not persuaded by commenters opposing the proposal that recovery of these costs through Schedule 1 will result in an overly broad assignment of costs. Such commenters argue that only a subset of transmission customers is likely to use intra-hour scheduling and that only those customers should bear the cost of implementing intra-hour scheduling reforms. The Commission disagrees. As discussed above, intra-hour scheduling provides all transmission customers with the tools needed to mitigate exposure to Schedule 9 generator imbalance charges in light of changing conditions.[164] Implementation of intra-hour scheduling is also necessary to the extent sellers wish to develop intra-hour energy products to maximize the value of available resources or to allow load serving entities to lower purchased power costs.[165] The Commission finds that these benefits will be spread broadly across customer classes.

126. Moreover, commenters opposing the Commission's proposal fail to reconcile their position with existing approaches used to recover scheduling-related costs under Schedule 1 of the *pro forma* OATT. Transmission providers do not currently parse scheduling costs into, for example, categories for network customers and point-to-point customers even though at times scheduling reforms have focused on one set of customers and not the other.[166] Rather, transmission customers as a whole have allocated the costs of scheduling-related activities through Schedule 1: Scheduling, System Control and Dispatch Service, and relevant allocations to retail native load have been made by public utility transmission providers. Commenters have failed to justify why the Commission should depart from this precedent during implementation of intra-hour scheduling practices.

127. In response to NRECA, the Commission's focus in this proceeding is on the implementation of intra-hour scheduling and, as relevant here, the recovery of scheduling-related implementation costs pursuant to Schedule 1 of the *pro forma* OATT. The Commission did not propose to address, and does not address here, recovery of other costs associated with compliance with NERC Reliability Standards.

c. Clarify Proposed Rule Language

i. Comments

128. Commenters ask the Commission to clarify what is intended by the terms schedule and scheduling interval. Southern and EEI state that the term ''schedule'' is not well defined throughout the electric industry and requests that the Commission clarify that ''schedule'' is equivalent to ''Interchange Transaction'' in the NERC Reliability Standards Glossary of Terms. TVA suggests that ''scheduling intervals'' coincide with the ''ramp start'' times as defined in the Timing Requirements tables of the NERC Reliability Standards INT–005–3, Interchange Authority Distributes Arranged Interchange; INT–006–3, Response to Interchange Authority; and INT–008–3, Interchange Authority Distributes Status. TVA contends that to view the term ''scheduling interval'' otherwise would deviate from NERC Reliability Standards and potentially have an adverse effect on assessment periods for reliability.

129. Bonneville Power requests that the Commission clarify the responsibilities of source and sink balancing authorities in regards to holding contingency reserves associated with scheduling of VER generation. Bonneville Power states that there is a debate regarding whether and when a source or sink balancing authority should deploy contingency reserves when a VER scheduling error exhausts the available balancing reserve capacity. Bonneville Power asks the Commission to clarify that a transmission provider can establish a base obligation to provide balancing reserve capacity to balance VERs and that the transmission provider can negotiate options for additional service beyond the base obligation with individual transmission customers.

130. A few commenters request clarification of the appropriate curtailment priority for intra-hour transmission schedules under the proposed reform.[167] Specifically, these commenters inquire as to whether a firm transmission reservation that is scheduled for less than the full hour would have priority over a non-firm hourly schedule. Bonneville Power and NRECA contend that submission of a firm intra-hour schedule should not necessarily result in the curtailment of lower priority hourly schedules. MidAmerican requests that the Commission clarify whether the submission of an intra-hour schedule by a transmission customer with firm transmission rights, after a competing intra-hour schedule from a transmission customer with only non-firm transmission rights, has curtailment priority.

131. Other commenters question how ATC calculations should be performed after implementation of intra-hour scheduling.[168] Public Interest Organizations state that current policy in the West does not allow ATC associated with transmission reservations that are not scheduled day-ahead to be used by other customers. Public Interest Organizations suggest that this policy may severely constrain or prohibit the effectiveness of intra-hour scheduling. In addition, Tacoma Power suggests that it may be appropriate to align ATC calculations with intra-hour scheduling intervals. Invenergy Wind asserts that the entire operational construct needs to shift from an hourly to a 15-minute basis in order to increase the efficiency of operating

[163] *E.g.,* Avista; Grant PUD; NRECA; Puget.

[164] *See supra* § IV.A.1 (Intra-Hour Scheduling Requirement).

[165] *Id.*

[166] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 770.

[167] *E.g.,* Bonneville Power; EEI; MidAmerican; NRECA.

[168] *E.g.,* Public Interest Organizations; Tacoma Power.

the transmission system and acquiring sufficient reserves in order to integrate VERs on a non-discriminatory basis. However, NorthWestern argues that continued use of hourly transmission service reservations would not be inconsistent with implementation of intra-hour transmission scheduling, stating that administering intra-hour transmission reservations would be difficult and costly.

132. Grant PUD makes reference to the Commission's use of the term ''reasonable control'' in the Proposed Rule, where the Commission states that it is unduly discriminatory to continue to require a resource to match an hourly schedule, especially when the output of the resource fluctuates beyond its reasonable control.[169] Grant PUD contends that what is reasonable depends on the current state of technology and requests that the Commission clarify that the definition of ''reasonable control'' is expected to improve over time.

ii. Commission Determination

133. In response to Southern and EEI, the Commission clarifies that the term ''schedule'' as used in this Final Rule is equivalent to its use in Schedule 9 of the OATT: ''* * * a delivery schedule from [a] generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area.'' [170] The procedures for submitting and revising a transmission schedule are delineated in sections 13.8 and 14.6 of the *pro forma* OATT, as changed by this Final Rule. Any transmission service schedule currently submitted pursuant to OATT sections 13.8 and 14.6 can therefore be modified or created in 15-minute intervals under this Final Rule.

134. In response to TVA, the Commission clarifies that the 15-minute scheduling interval will be treated the same as the current one-hour scheduling interval with respect to ramp start and stop times as defined in the Timing Requirements tables of NERC Reliability Standards INT–005–3, INT–006–3, and INT–008–3. As an example, in the Eastern Interconnection ramp start times will begin five minutes before the start of the 15-minute scheduling interval and end five minutes after the start of the 15-minute scheduling interval.

135. Regarding responsibilities for holding contingency reserves, the Commission did not propose any changes to existing rules regarding the use of contingency reserves in this proceeding. As Bonneville Power notes, there is ongoing debate in the industry regarding when and how contingency reserves may be used under NERC Reliability Standards. The Commission concludes it is appropriate, in the first instance, for stakeholders to address these questions through the NERC processes.[171]

136. The Commission also did not propose any changes to curtailment policies or ATC calculation. The Commission recognizes that transmission providers have flexibility under the *pro forma* OATT to award transmission service based on transmission capability that becomes available when firm transmission service is not scheduled by 10:00 a.m. the day prior to operation.[172] The Commission appreciates that, when a transmission provider makes service available under these circumstances, application of curtailment priorities and ATC calculation rules become more complicated. However, that is already the case under hourly transmission schedules. Therefore, the Commission did not propose any change to those practices to accommodate the possibility of intra-hour transmission schedules. All transmission schedules for firm service will continue to have curtailment priority over all transmission schedules for non-firm service [173] and transmission providers will continue to be required to follow existing rules governing the calculation of ATC.[174]

137. In response to the request from Grant PUD for clarification of the term ''reasonable control,'' the Commission explains that use of the term ''reasonable control'' is not intended to be a metric or a determining factor, but illustrative of the difficulty VERs experience when attempting to follow hourly schedules accurately. The Commission does not find it necessary to offer any further clarification.

d. NERC and NAESB Standards

i. Commission Proposal

138. In the Proposed Rule, the Commission noted that many commenters, in response to the NOI, claimed that shorter scheduling intervals may enhance reliability. The Commission therefore stated that it did not believe that an independent review of NERC Reliability Standards is necessary in order to propose implementation of intra-hour scheduling. However, the Commission sought comment on the issue to ensure that there is no inconsistency between relevant NERC standards and the proposed intra-hour scheduling tariff reform.[175]

ii. Comments

139. NERC states that certain entities currently offer 15-minute scheduling and that it is unaware of any conflicts with Reliability Standards. However, NERC asserts that wide spread use of intra-hour scheduling will likely require review and refinement of several existing Reliability Standards. Based on its preliminary review of Reliability Standards in coordination with industry stakeholders, NERC states that it does not believe there are any insurmountable hurdles that prevent industry from implementing 15-minute transmission scheduling. NERC explains that sufficient time must be allowed for Reliability Standards to be modified through the NERC Reliability Standards Committee prioritization process, but that transitioning to broad intra-hour scheduling flexibility is achievable in a reasonable timeframe.

140. Some commenters do not anticipate that a review of NERC Reliability Standards is necessary to ensure reliability upon the implementation of intra-hour scheduling.[176] NaturEner argues that an independent review of NERC standards may not be necessary, but if such a review occurs it should not delay implementation of intra-hour scheduling. Pacific Gas & Electric agrees that implementation of intra-hour scheduling can be achieved without a review of NERC standards, but recommends that NERC and other industry experts review and update current planning and operating criteria to ensure that balancing authorities have the necessary tools to flexibly balance

[169] Grant PUD (citing Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 39).

[170] OATT Schedule 9.

[171] The Commission addresses requests by Bonneville Power and others to limit the amount of capacity it must make available to transmission customers for generator regulation service under Schedule 10 in § IV.C.1 (Schedule 10—Generator Regulation and Frequency Response Service) below.

[172] The *pro forma* OATT states that ''[s]chedules for the Transmission Customers' Firm Point-To-Point Transmission Service must be submitted no later than 10:00 a.m. * * * of the day prior to commencement of such service.'' OATT Schedule 13.8.

[173] The *pro forma* OATT makes clear that ''(p)arties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff.'' OATT Schedule 14.5.

[174] In compliance with Order No. 890, public utility transmission providers have documented rules governing their calculation of ATC in Schedule C of their OATTs. *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 193.

[175] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 37.

[176] *E.g.,* NaturEner; Southern California Edison.

loads and resources with the advent of increased VER penetration.

141. Other commenters contend that review and modification of standards may be necessary, but not a prerequisite to implementation.[177] Southern and Xcel state that only modest, if any, changes would be needed to NERC Reliability Standards. Southern indicates that several standards may need to be reviewed and revised as they currently contemplate hourly intervals. Xcel contends that standards related to the maximum lead times required for entry and approval of a schedule may require changes. Xcel explains that the lead times for entry and approval of a tag may exceed the length of a scheduling interval, thus diminishing the usefulness of intra-hour scheduling. AEP and Duke Energy suggest that sensitivity studies should be performed by an industry forum or working group to determine the reliability impacts of the proposed scheduling changes on real-time system operations.

142. Several commenters argue that review and revision of NERC Reliability Standards, as well as NAESB business practice standards, may be necessary for the implementation of intra-hour scheduling at 15-minute intervals.[178] These commenters point out that many Reliability Standards and business practices are largely predicated on hourly scheduling intervals and govern transactions both internal to a particular balancing authority as well as across neighboring balancing authorities. Although most commenters did not identify specific changes to standards that would be necessary, some commenters suggest that NERC Reliability Standards related to some or all of the following areas be reviewed: Interchange Scheduling and Maintenance Coordination (INT), Resource and Demand Balancing (BAL), Emergency Preparedness and Operations (EOP), and Transmission Operations (TOP) standards.[179] Additionally, commenters indicate that reliability scheduling tools, such as the Interchange Distribution Calculator used in the Eastern Interconnection and the WebSAS system used in the Western Interconnection for scheduling, curtailment and ''check out'' processes may also require modification.[180]

143. NRECA cautions that any modifications to NERC standards should allow for the implementation of intra-hour scheduling but not mandate this practice. NRECA suggests that NERC be allowed to complete any updates to its standards associated with implementation of intra-hour scheduling prior to NAESB undertaking a review to ensure uniformity of approaches. NV Energy notes that, in order to schedule at 30 minute intervals or less, the protocols to effectuate such transactions must be agreed upon by all entities in WECC. Therefore, NV Energy requests that the Commission defer issuance of the Final Rule until the industry has had the opportunity to address NERC, WECC and NAESB standards issues.

144. PNW Parties state that the Joint Initiative participants found it necessary to review NERC and NAESB standards as part of their development of a 30-minute scheduling program, but did not identify in comments whether any changes to standards or business practices were needed. PNW Parties suggests, however, that applicable standards and business practices be reviewed and revised as necessary prior-to implementing more granular scheduling.

145. Some commenters within the VER industry request clarification and/or modification of NERC scheduling protocols to allow for a resource to be indentified as a ''sink.'' [181] These commenters claim that this is necessary because under the Commission's proposed reforms VERs will be transacting on an intra-hour basis in order to supplement their variable supply. Iberdrola explains that, in order to enter into bilateral transactions for balancing energy where a VER's 15-minute schedule is less than its hour-ahead schedule, the additional balancing energy purchased from a generator with excess energy would need to be tagged as the ''source'' and the VER would need to be tagged as the ''sink.'' Iberdrola claims that this is necessary because VERs will be transacting bilaterally in the sub-hourly timeframe in an effort to maintain the schedule that was entered prior to the operating hour. AWEA agrees, arguing that some of the benefits of intra-hour scheduling will not be realized without this additional clarification. In response to the potential concerns of transmission providers regarding generators being tagged as sinks, AWEA and Iberdrola argue that reliability concerns would only be present when the ultimate delivery point is unknown.[182] AWEA explains that the case presented by a VER transacting as a sink for intra-hour scheduling purposes is entirely different, as the ultimate delivery point is already known. In this case, AWEA points out that there is a schedule to deliver energy to a real load and explains that this schedule is delivering energy to the load which the VER is unable to serve. Therefore, AWEA and Iberdrola conclude that such scheduling practices do not present reliability concerns.

iii. Commission Determination

146. The Commission concludes that an independent review of NERC standards and NAESB business practices is not necessary prior to the implementation of intra-hour scheduling. As noted by NERC, several entities currently offer intra-hour scheduling without any apparent conflict with Reliability Standards. NERC comments that it does not believe there are any existing standards that prohibit industry from implementing intra-hour scheduling, and no commenters have pointed to specific NAESB business practices that prevent industry from implementing intra-hour scheduling. The Commission therefore concludes that it is not necessary to delay adoption of the intra-hour scheduling requirements of this Final Rule pending further review of NERC Reliability Standards and NAESB business practices. To the extent industry believes it is beneficial to refine one or more existing NERC Reliability Standards or NAESB business practices to reflect intra-hour scheduling, stakeholders can use existing processes to pursue such refinements.

147. With regard to the requests from AWEA and Iberdrola to allow a VER resource to be designated as a ''sink'' for purposes of transmission scheduling, rules for scheduling transmission segments are set forth in NAESB's Coordinate Interchange Standards,[183] which have been incorporated into the Commission's regulations by reference.[184] The Proposed Rule did not propose any changes to those rules and the Commission declines to interpret the application to any particular transactions in this generic rulemaking proceeding.

3. Other Issues

a. Comments

148. Several commenters question the application of intra-hour scheduling reforms to HVDC transmission lines. Clean Line states that HVDC

[177] *E.g.,* NERC; Pacific Gas & Electric.

[178] *E.g.,* Bonneville Power; Duke; EEI; MidAmerican; NRECA; PNW Parties; Southern.

[179] *E.g.,* Duke; EEI; NERC; NRECA; PNW Parties; Southern.

[180] *E.g.,* NERC; NRECA; Southern.

[181] *E.g.,* AWEA; Iberdrola.

[182] *E.g.,* AWEA; Iberdrola.

[183] NAESB WEQ–004, App. C, § 2 (Commercial Timing Table).

[184] *See* 18 CFR 38.2 (2011).

transmission lines can precisely control power and, thus, are typically expected to submit schedules to public utility transmission providers. Clean Line requests that HVDC transmission lines receive equal treatment and be allowed to submit intra-hour schedules on the same basis as generators. In contrast, ALLETE and Midwest ISO Transmission Owners both request that the Commission grant an exemption from 15-minute schedules for HVDC transmission lines. These commenters argue that 15-minute scheduling of HVDC transmission lines could lead to an increase in the duty on the load tap changers of HVDC converter transformers, potentially resulting in an increase in maintenance costs and an increased potential of transformer failure.

149. Bonneville Power raises questions regarding the impact of intra-hour scheduling on dynamic scheduling practices. Bonneville Power states that 15-minute scheduling will lead to increased ramping and inhibit the availability of dynamic transfer capability in areas where dynamic transfer capability is limited, such as the Bonneville Power system and other parts of the West. Bonneville Power contends that 30-minute scheduling relieves this problem and requests that the Commission gain a better understanding of the impacts that 15-minute scheduling will have on dynamic transfers. In contrast, First Wind requests that the Commission encourage dynamic transfers in addition to implementing intra-hour scheduling, suggesting that dynamic transfers can reduce regulation service requirements for transmission owners and transfer regulation requirements to purchasers of VER energy. First Wind also argues that intra-hour scheduling and dynamic transfers will allow for better tracking of real-time generation and reduce the need for ancillary services while increasing opportunities for flexible generation and demand response.

150. M–S–R Public Power Agency states that shortening the scheduling interval does not reduce the intermittency of the VERs themselves. M–S–R Public Power Agency offers that as a matter of physics a VER requires a back-up resource to ''balance'' its intermittency, irrespective of scheduling, adding that while a shorter scheduling interval may mitigate the number of megawatts needed to assure reliability, it will not mitigate the location or cost of back-up reserves. M–S–R Public Power Agency goes on to state that VER penetration levels of 20–25 percent start to exhaust the capability of even the most robust systems and that the proposed mitigation may be insufficient. M–S–R Public Power Agency explains that the raw energy of VERs must be converted to conditioned energy (traditional resources) at the source, and not shifted to other locations through mitigation, or there will be a degradation of services to all VERs within that system. M–S–R Public Power Agency states that intermittent resources require that the transmission owner have nearly infinite capability to provide backup resources; however, even the most robust balancing authority has limitations of how fast, how often, and when it can provide back up resources. M–S–R Public Power Agency offers that, with both the cost of transmission and reliability (back-up generation) challenges, VERs may be uneconomic. M–S–R Public Power Agency encourages the Commission to solicit input on this issue.

Commission Determination

151. All transmission customers that are currently eligible to submit hourly energy schedules will be eligible to participate in intra-hour scheduling, including HVDC lines that currently submit hourly energy schedules. To the extent a transmission provider believes an exemption is appropriate, it has the right to request a waiver of all or part of the OATT requirements as described in 18 CFR 35.28(d): ''A public utility subject to the requirements of this section and Order No. 889, FERC Stats. & Regs. ¶31,037 (Final Rule on Open Access Same-Time Information System and Standards of Conduct) may file a request for waiver of all or part of the requirements of this section, or Part 37 (Open Access Same-Time Information System and Standards of Conduct for Public Utilities), for good cause shown.'' Waiver requests will be evaluated in separate proceedings if and when they are submitted based on the facts and circumstances of each request.

152. With regard to the use of dynamic schedules, the Commission did not propose and is not adopting any change in policy with regard to dynamic scheduling. The Commission is not persuaded by arguments from Bonneville Power that 15-minute scheduling intervals will negatively affect dynamic transfer capability. However, the Commission acknowledges that a transmission provider's implementation of charges for generator regulation service, as discussed in the following section, may have the result of encouraging the use of dynamic scheduling to avoid such charges.

153. In response to M–S–R Public Power Agency, the Commission appreciates that the location of a particular resource can be relevant in determining whether it can be used to satisfy reserve obligations. That is, a public utility transmission provider providing ancillary services under the *pro forma* OATT, or a transmission customer self-supplying such ancillary services needs transmission capacity to ensure deliverability of a particular resource. Whether that is the case will be fact specific and we expect the transmission provider to take the appropriate steps to ensure such transmission capacity is available.

B. Data Reporting To Support Power Production Forecasting

154. The second of the two reforms adopted in this Final Rule relates to the submission of meteorological and forced outage data,[185] by new interconnection customers whose generating facilities are VERs, to the public utility transmission provider with which the customer is interconnected if the public utility transmission provider is doing power production forecasting. As discussed below, the Commission amends the *pro forma* LGIA to effectuate this data reporting requirement. The Commission concludes that, without these reporting requirements in place, the terms of the *pro forma* LGIA may impair the ability of public utility transmission providers to develop and deploy power production forecasting, which in turn can lead to rates for jurisdictional services that are unjust and unreasonable or unduly discriminatory.

1. Data Requirements

a. Commission Proposal

155. To facilitate the development and deployment of power production forecasting by public utility transmission providers, the Proposed Rule set forth revisions to the *pro forma* LGIA that would require interconnection customers whose generating facilities are VERs to provide certain meteorological and operational data to the public utility transmission provider with whom they are

[185] The Proposed Rule used the term ''operational data'' and specified forced outages as a particular type of operational data. To reflect the limited nature of data to be reported under this Final Rule more accurately, the Commission instead refers more specifically to ''forced outage data'' in our determinations here and accompanying revisions to the *pro forma* LGIA. We also note that Section 9.7.1 of the LGIA requires Transmission Providers and Interconnection Customers to coordinate and report planned outages. Within the context of this Final Rule, the Commission references the term ''forced outage'' as defined by NERC. *See NERC* Glossary of terms *available at http://www.nerc.com/files/Glossary_of_Terms.pdf*.

interconnected, if doing forecasting. The Commission proposed that such data would be transmitted from the interconnection customer to the public utility transmission provider at or near real-time. The Commission stated that this proposal built on existing Commission data-sharing requirements by outlining specific meteorological and operational data necessary to develop power production forecasts.[186]

156. With regard to the reporting of meteorological data, the Commission proposed revisions to the *pro forma* LGIA that would result in different types of meteorological information being provided by interconnection customers based on the type of VER they own and/or operate. The Commission proposed to require interconnection customers whose generating facilities are wind-based VERs to provide public utility transmission providers with site-specific meteorological data including, but not limited to, temperature, wind speed, wind direction, and atmospheric pressure. The Commission proposed to require interconnection customers whose generating facilities are solar-based VERs to provide public utility transmission providers with site-specific meteorological data including, but not limited to, temperature, atmospheric pressure, and cloud cover. The Commission recognized that different power production forecasts may require meteorological instruments to be located at hub height, up-wind of resources, or at ground level. However, the Commission refrained from proposing specific requirements in this respect and, instead, proposed to allow the public utility transmission provider and interconnection customers to negotiate these details taking into account the size and configuration of the VER facility, its characteristics, location, and importance in maintaining generation resource adequacy and transmission system reliability in its area. The Commission stated that resource-specific data requirements contained in individual LGIAs must be negotiated on a not unduly discriminatory basis.[187]

157. With respect to the reporting of operational data, the Commission proposed to revise the *pro forma* LGIA to require interconnection customers whose generating facilities are VERs to report to the public utility transmission provider any forced outages that reduce the generating capability of the resource by 1 MW or more for 15 minutes or more. The Commission noted that provision of VER outage data at this level of granularity would allow a public utility transmission provider to ascertain the extent to which current VER power production is a result of unit availability as opposed to changing weather conditions.[188] The Commission preliminarily found that having such information would eliminate a significant source of forecasting errors by ensuring that the public utility transmission provider has accurate information regarding the capacity actually available to produce electricity during the time-frame of the operational forecasts.[189]

158. The Commission sought comment on the extent to which the lists of basic meteorological and operational data articulated above may be inadequate or incomplete in achieving the stated power production forecasting goals.[190]

b. Comments

159. Commenters addressing the reporting of meteorological data generally support requiring the provision of data as necessary to enable public utility transmission providers to employ power production forecasts.[191] While disagreeing that public utility transmission providers should be responsible for power production forecasting, Montana PSC argues that, should the Commission impose forecasting requirements, public utility transmission providers should have access to all meteorological data that are site-specific to the VER, provided that the parties have a confidentiality agreement in place to protect proprietary information. BP Companies and First Wind request that the Commission clarify that the proposal is only relevant to instances in which the public utility transmission provider is developing and/or implementing VER power production forecasting.

160. Several commenters support the Commission's identification of certain categories of meteorological data to be provided by wind and solar resources.[192] For example, with regard to wind resources, Iberdrola agrees that wind speed, wind direction, temperature and pressure are all key atmospheric variables related to wind farm output and are the most important fields to measure. With regard to solar resources, NextEra, SEIA, and Xcel generally support the minimum categories of data identified in the Proposed Rule, but they suggest that the Commission revise the reference to cloud cover because it is ambiguous. Specifically, NextEra and SEIA recommend that the Commission require solar resources to report diffuse, direct, and global horizontal irradiance. NextEra adds that humidity should also be provided for a solar VER using concentrating thermal solar technology, while SEIA suggests that plane of array irradiance or direct normal radiation may also be necessary. These commenters note that irradiance is often a better measure because it actually drives energy production.

161. Commenters generally support the Commission's proposal to allow the public utility transmission provider and interconnection customer to negotiate additional meteorological and operational data reporting requirements.[193] Commenters identified a variety of additional meteorological and facility-specific data that may be useful in developing and deploying power production forecasts. These commenters generally note that regional differences may dictate additional data needs,[194] with several asking the Commission to acknowledge that additional data beyond that specifically identified in the Proposed Rule may be needed by a public utility transmission provider.[195]

162. Several commenters raise concerns regarding the Commission's discussion of the location of meteorological towers and other equipment necessary to record and report data to public utility transmission providers.[196] NextEra asks that the Commission refrain from allowing public utility transmission providers to require VERs to install multiple meteorological towers, arguing that data beyond what is available through one meteorological tower has little value for advanced power production forecasting methods. Invenergy similarly argues that a single meteorological tower per

[186] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at PP 60–61.

[187] *See id.* P 61.

[188] *See id.* P 62 (citing *Cal. Indep. Sys. Operator Corp.*, 131 FERC ¶ 61,087, at P 64 (2010)).

[189] *Id.* P 62.

[190] *Id.* P 63.

[191] *E.g.*, AWEA; Bonneville Power; California ISO; CEERT; Clean Line; California PUC; Exelon; First Wind; Iberdrola; Independent Energy Producers; Independent Power Producers Coalition-West; ISO/RTO Council; ISO New England; Large Public Power; Midwest ISO; Midwest ISO Transmission Owners; NaturEner; NextEra; NRECA; Pacific Gas & Electric; PJM; Powerex.

[192] *E.g.*, AWEA; Iberdrola; ISO New England; RENEW.

[193] *E.g.*, Bonneville Power; ISO New England; ISO/RTO Council; Large Public Power Council; Midwest ISO; NRECA; PNW Parties; RENEW; Xcel.

[194] *E.g.*, Bonneville Power; First Energy; ISO New England; ISO/RTO Council; NextEra; MidAmerican; Midwest ISO; Midwest ISO Transmission Owners; NorthWestern; NRECA; Pacific Gas & Electric; Xcel.

[195] *E.g.*, Bonneville Power; ISO New England; Midwest ISO; NextEra; NRECA.

[196] *E.g.*, AWEA; Invenergy; NextEra.

facility is usually sufficient for predicting plant output.

163. With regard to the frequency of reporting meteorological data, several commenters suggest that the frequency of data reporting should match the use of the data, which may not be at or near real-time.[197] For example, AWEA, Iberdrola, and NextEra state that second-by-second or minute-by-minute meteorological recordings yield minimal benefits for forecasting accuracy and could be costly and burdensome. AWEA and Clean Line suggest that a reasonable requirement for the frequency at which real-time meteorological and operational data is reported from a wind plant is 10 minutes or more. NorthWestern, however, states that it would be helpful to require each VER to update the forecasting data that it has provided to the public utility transmission provider when it provides a new energy schedule.

164. AWEA and Iberdrola also contend that distinctions should be made between the types of data that should be provided in real-time and the types of data that should be provided historically. These commenters state that archived time series data are crucial to statistical forecasting techniques and that this application is not done in real-time. AWEA and Iberdrola state that data needed for forecast training can be compiled into larger datasets and transmitted at less frequent intervals at a much lower cost. RenewElec and Bonneville Power generally agree that there is significant value in historical data recorded by VERs.

165. With regard to the operational data reporting requirements, some commenters urge the Commission to adopt the proposed requirement that VERs report to the public utility transmission provider any forced outages that reduce the generating capacity of a resource by 1 MW or more for 15 minutes or more.[198] For example, Bonneville Power states that having access to forced outage information will enable public utility transmission providers to determine whether forecast inaccuracy results from unit availability, changing weather conditions, or a combination of the two. Bonneville Power further states that without such information it will be difficult to verify forecasts and improve forecast accuracy. California ISO requests that the Commission not overturn its recent decision approving California ISO's 1 MW threshold for reporting a forced outage of an eligible intermittent resource. California ISO argues that outage reporting requirements that are less stringent than those proposed would increase the likelihood that the forecasting algorithm would accumulate inaccurate data.

166. Other commenters acknowledge that forced outage data are useful in developing power production forecasts, but disagree on the exact reporting requirements.[199] Some commenters contend that a 1 MW reporting threshold would pose an unnecessary burden on a wind plant owner/operator, yield minimal benefits for forecast accuracy, and pose compliance difficulties.[200] Instead of the proposed requirement, NaturEner recommends requiring that only planned outages of greater than 15 percent of the generator's capacity should be reported as soon as they are known by the generator. AWEA suggests that reporting apply only to forced outages that exceed 10 percent of the nameplate capacity of a plant, a requirement that AWEA states is similar to the one imposed on conventional generators. NextEra similarly asks that the outage reporting requirements be identical to those that apply to conventional resources. MidAmerican recommends that VER transmission customers be required to report forced outages lasting more than 24 hours and involving the lesser of either 20 MW or 50 percent of nameplate capacity. Xcel recommends that the Commission ask NERC to analyze and determine the appropriate threshold level for reporting VER outages to public utility transmission providers and balancing authorities.

167. SEIA contends that the forced outage reporting requirement may be appropriate for large solar photovoltaic generators, but not for concentrating solar plants that experience frequent changes in power output. SEIA states that, with respect to concentrating solar power-generating facilities, the Commission should consider a threshold for reporting such fluctuations based either on the total capacity of the facility or particular types of maintenance or repair activities that would result in an outage at a percentage of the facility.

168. Exelon asks the Commission to clarify what constitutes a forced outage for purposes of the requirement to report operational data, suggesting it should only include unanticipated outage events. NRECA notes that the Proposed Rule did not identify the frequency for reporting operational data to the public utility transmission provider. NRECA contends that the public utility transmission provider should be notified as soon as the VER is aware of an outage.

169. Several commenters recommend that the Commission provide regional flexibility with respect to the operational data reporting requirements.[201] For example, Iberdrola states that VER forced outage reporting requirements should be regional and: (1) Based on the penetration of VERs in the region; (2) based on the ability of the transmission provider to incorporate the data into power production forecasting from VERs that is in turn used for reliably operating the system; and (3) limited to an interval that enables the use of predictive outage reporting capability.

170. Some commenters argue that the Commission should acknowledge the importance of standardized regional reporting mechanisms when considering these proposed reforms.[202] For example, Midwest ISO notes that IEC Standard 61400–25 already exists to facilitate the exchange of information between individual wind turbines, their constituent components, wind power plants, area control, and other external systems. Midwest ISO suggests that use of a common format for communicating data between the VER and public utility transmission provider would promote the development of power production forecasting. However, Invenergy asks that the Commission make clear that public utility transmission providers are required to accept reasonable alternative means of data communication and not implement uniform standards that impose unnecessary costs on wind projects.

c. Commission Determination

171. The Commission adopts, as modified below, the proposed requirement that interconnection customers whose generating facilities are VERs provide meteorological and forced outage data to the public utility transmission provider with which the customer is interconnected, where necessary for that public utility transmission provider to develop and deploy power production forecasting. As discussed below, power production forecasting can be used by public utility transmission providers to operate their

[197] *E.g.,* AWEA; Clean Line; Iberdrola; NextEra; NaturEner; NorthWestern; Public Interest Organizations.

[198] *E.g.,* Bonneville Power; California ISO; NRECA.

[199] *E.g.,* AWEA; Exelon; NaturEner; SEIA; Xcel; MidAmerican; NextEra.

[200] *E.g.,* AWEA; Iberdrola; NaturEner; MidAmerican; PJM.

[201] *E.g.,* Iberdrola; ISO New England; Midwest ISO Transmission Owners; PJM; Southern California Edison.

[202] *E.g.,* Alstom; EEI; Midwest ISO.

systems and manage reserves more efficiently. To the extent a public utility transmission provider seeks to rely on power production forecasting, the Commission concludes it is appropriate to require new interconnection customers whose generating facilities are VERs to provide related data to the public utility transmission provider under the circumstances below. The Commission therefore directs public utility transmission providers to modify their *pro forma* LGIAs to effectuate the data reporting requirement.

172. As the Commission noted in the Proposed Rule, industry studies demonstrate the potential for significant benefits from the incorporation of power production forecasts into scheduling and unit commitment processes. In WECC alone, NREL estimated the use of VER power production forecasts has the potential to reduce operating costs by up to 14 percent or $5 billion per year.[203] NERC has similarly concluded that forecasting the output of variable generation is critical to bulk power system reliability in order to ensure that adequate resources are available for ancillary services and ramping requirements.[204] NERC has therefore recommended that forecasting techniques be incorporated into day-to-day operational planning and real-time operations routines/practices including unit commitment and dispatch.[205] The Commission notes that the benefits of power production forecasting can accrue across a variety of time frames, including the operating day, day-ahead, and seasonally.

173. However, power production forecasts are only as good as the data on which they rely. The ability of public utility transmission providers to use power production forecasting in the commitment and de-commitment of resources may be limited without adequate meteorological and forced outage data from VERs. The current lack of meteorological and forced outage data reporting requirements in the *pro forma* LGIA therefore may limit efforts by public utility transmission providers to more efficiently manage operating costs associated with the integration of VERs interconnecting to their systems. Under the existing requirements of the *pro forma* LGIA, public utility transmission providers are permitted to request this information, but there is no obligation for interconnection customers whose generating facilities are VERs to provide it. The Commission remedies this deficiency by adopting reporting requirements for new interconnection customers whose facilities are VERs, commensurate with the power production forecasting employed by the public utility transmission provider, to allow for more accurate commitment and de-commitment of resources providing reserves, ensuring that reserve-related charges imposed on customers remain just and reasonable and not unduly discriminatory or preferential. The Commission implements this requirement by requiring public utility transmission providers to modify their *pro forma* LGIAs to include the reporting requirements discussed below.

174. The reporting requirements adopted in this Final Rule are specifically designed to support the development and deployment of power production forecasting by public utility transmission providers. As a result, nothing in this Final Rule should be construed as creating an obligation for interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data in cases where the public utility transmission provider is not engaging in power production forecasting. The Commission recognizes that VER potential and penetration varies across public utility transmission provider systems and that, at this time, not all public utility transmission providers have sufficient levels of VERs to warrant engaging in power production forecasting. The Commission is nonetheless amending the *pro forma* LGIA to ensure that those public utility transmission providers seeking to develop and deploy power production forecasting in response to increasing VER penetration have adequate information to do so. To make the conditional nature of the reporting requirements clear, the Commission revises the proposed Article 8.4 of the *pro forma* LGIA to state that all requirements for meteorological and forced outage data must be consistent with the power production forecasting employed by the Transmission Provider, if any, to manage reserve commitments. The Commission believes that this strikes a reasonable balance between the requirement to provide the data and the public utility transmission provider's use of the data to manage reserve commitments more efficiently.

175. Turning to the particular reporting requirements imposed on interconnection customers whose generating facilities are VERs, the Commission affirms the approach set forth in the Proposed Rule allowing public utility transmission providers flexibility in identifying the specific meteorological and forced outage data to be reported. As proposed, Article 8.4 of the *pro forma* LGIA would specify certain categories of data to be provided by interconnection customers with VERs having wind or solar as the energy source, with the exact specifications of data to be provided taking into account the size and configuration of the VER, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. Some commenters generally support this approach, stating that the type of power production forecasting deployed by public utility transmission providers and the tools used to perform forecasts could vary widely, and therefore any reporting requirements associated with power production forecasting should be flexible.[206] This approach will provide public utility transmission providers the flexibility to negotiate, in the first instance, with interconnection customers whose generating facilities are VERs to identify the particular data to be reported by the customer.

176. The Commission finds that this flexible approach to establishing data reporting requirements will ensure that all reporting of meteorological and forced outage data corresponds with the power production forecasting being employed by the public utility transmission providers. To be clear, however, public utility transmission providers cannot unduly discriminate among interconnection customers with regard to data reporting requirements. By linking the requirement to provide meteorological and forced outage data to the use of these data by the public utility transmission provider in power production forecasting to manage reserve commitments, the Commission seeks to minimize opportunities for undue discrimination as well as needless burden on interconnection customers. At the same time, to the extent meteorological and forced outage data are needed for the public utility transmission provider to engage in power production forecasting, they must be provided by the interconnection customer, even if that means investment in additional equipment by the customer.[207] To the extent there are

[203] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 45 (citing National Renewable Energy Laboratory, *Western Wind and Solar Integration Study* ES–18 (2010), *available at http://www.nrel.gov/wind/systemsintegration/wwsis.html*).

[204] NERC, *Accommodating High Levels of Variable Generation* 54 (2009), *available at http://www.nerc.com/files/IVGTF_Report_041609.pdf*.

[205] *Id.* at 59.

[206] *E.g.,* Iberdrola; NextEra.

[207] The Commission acknowledges the concern of some commenters that the installation of multiple

Continued

concerns of discriminatory or unnecessary application of data reporting requirements, interconnection customers can request that the public utility transmission provider file with the Commission an unexecuted LGIA in order to resolve the disagreement.[208]

177. Notwithstanding the flexibility provided for party-specific negotiations of data reporting requirements, the record in this proceeding also confirms that some categories of meteorological data from VERs having wind or solar as the energy source will be relevant to most, if not all, power production forecasting deployed by a public utility transmission provider for these resources. Therefore, the Commission adopts the proposal to require certain categories of meteorological data from VERs having wind or solar as the energy source. Specifically, an interconnection customer with a VER having wind as the energy source must provide, at a minimum, site-specific meteorological data including: Temperature, wind speed, wind direction, and atmospheric pressure. An interconnection customer with a VER having solar as the energy source must provide, at a minimum, site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The exact specifications of data to be provided by the interconnection customer will remain subject to negotiation between the parties, which as noted above must take into account the size and configuration of the VER, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. It may also include additional meteorological data commensurate with the power production forecasting employed by the public utility transmission provider. As with other data reporting requirements, the public utility transmission provider may file an unexecuted LGIA pursuant to FPA section 205 seeking to demonstrate the necessity of requests for additional information if the parties cannot reach mutual agreement as to the specifications of data to be provided.[209]

178. By defining certain categories of data that must be provided, while leaving the exact specifications of data to negotiation between the interconnection customer and the public utility transmission provider, the Commission has sought to balance the competing interests of clarity and flexibility. The Commission appreciates that defining all data requirements with precision in this Final Rule might result in rules that are easier to implement. However, it also could lead to interconnection customers incurring costs to provide data at a level of granularity, for example, that is of no use to the public utility transmission provider given the type of power production forecasting deployed. By linking the reporting requirements to the data needs of the public utility transmission provider, the Commission seeks to facilitate the deployment of power production forecasting without unduly burdening the interconnection customer.

179. In the Proposed Rule, the Commission included ''cloud cover'' within the categories of data required of interconnection customers with a VER having solar as the energy source. The Commission agrees with commenters that the term ''cloud cover'' is imprecise and thus we modify Article 8.4 of the *pro forma* LGIA to refer to ''irradiance.'' However, the Commission declines to distinguish between types of irradiance and also declines to include ''humidity'' in the minimal categories of data. These additional characteristics may be more relevant for some types of facilities than others, so we leave to public utility transmission providers and their interconnection customers to identify the specifications of data relevant for reporting.

180. With regard to the frequency and timing of data reporting, the Commission modifies the Proposed Rule and allows public utility transmission providers and interconnection customers whose generating facilities are VERs to negotiate the frequency and timing of data submittals. The Proposed Rule would have required the reporting of data at or near real-time. In response, commenters such as AWEA and Iberdrola note that some power production forecasts use archived time series data that may be compiled and transmitted to public utility transmission providers at a significant costs savings when compared to the ongoing reporting of data at or near real-time, whereas NorthWestern suggests that data could be provided on a ten-minute or longer basis. Based on comments received, the Commission concludes it is more appropriate for the frequency and timing data submittals to be negotiated by the parties to ensure that the reporting of data is consistent with the type of power production forecasting being deployed by the public utility transmission provider. The Commission revises Article 8.4 of the *pro forma* LGIA accordingly.

181. In the Proposed Rule, the Commission sought to require the reporting of forced outages of 1 MW or more for 15 minutes or more. In response, commenters disagree as to the relevant level of granularity for outage data. Rather than establish a specific megawatt reporting threshold or frequency that could result in the reporting of data that are not used by the public utility transmission provider, the Commission concludes it is more appropriate for the public utility transmission provider and interconnection customer to negotiate the exact specifications of forced outage data to be provided, taking into account the size and configuration of the VER, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. As noted in the Proposed Rule, this will provide the flexibility necessary to ensure that the reporting of forced outage data is commensurate with the power production forecasting being employed by the public utility transmission provider, consistent with any regional practices that may exist. Therefore, the Commission modifies the Proposed Rule to align the reporting of forced outages with the power production forecasting being employed by the public utility transmission provider. The Commission also declines to adopt alternative minimum thresholds or pre-define forced outages for purposes of reporting requirements as requested by some commenters.

182. Some commenters request that the Commission standardize protocols for reporting meteorological or forced outage data required by this Final Rule. The Proposed Rule did not contain standard protocols for data reporting and, as a result, the merits of such a requirement have not been fully addressed in the record. Whether standardization of data communications would facilitate or hinder development of power production forecasting may implicate a variety of data and communications issues that would benefit from broad industry input through standards development processes such as those used by NAESB and other organizations.

d. LGIA

183. In order to effectuate the reporting requirements discussed above, the Proposed Rule set forth amendments to the *pro forma* LGIA adding a new section Article 8.4, *Provision of Data from a Variable Energy Resource.*

meteorological towers would increase costs for an interconnection customer. Whether data from a single meteorological tower is sufficient to support the power production forecasting deployed by the public utility transmission provider should be addressed as part of the negotiation of the LGIA.

[208] *See* 16 U.S.C. 824d (2006); 18 CFR 35.13 (2010).

[209] *Id.*

Consistent with the approach of Order Nos. 2003 and 661,[210] the Commission proposed not to require retroactive changes to LGIAs that are already in effect. However, the Commission sought comment as to whether this approach would prevent public utility transmission providers from effectively implementing power production forecasting.[211] The Commission also preliminarily found that the *pro forma* LGIA includes adequate confidentiality protections for sensitive data obtained from VERs.[212]

184. The Commission noted that it was proposing revisions only to interconnection customers whose generating facilities are VERs greater than 20 MW and, as a result, proposing revisions only to the *pro forma* LGIA and not the *pro forma* Small Generator Interconnection Agreement (SGIA). The Commission sought comment on whether the proposed reforms should also apply to interconnection customers whose generating facilities are VERs of 20 MW or less, so as to require revisions to the *pro forma* SGIA.

e. Comments

185. The Commission received a variety of comments on its proposal to not require retroactive changes to LGIAs that are in effect. NaturEner argues that without data from existing resources, power production forecasts would be less reliable or robust, resulting in artificially high required reserves and attendant expenses. AWEA, Clean Line, and Iberdrola state that they would not oppose requiring data from resources that have executed an LGIA, provided that the interconnection customers are only required to report data that are currently gathered by the VER. AWEA explains that data already are being collected by many wind plants deployed since 2005 and that many public utility transmission providers have already imposed reporting requirements. However, Southern MN Municipal asserts that the proposed reforms should not be extended to resources that have already executed an interconnection agreement. Bonneville Power asserts that Articles 9.3 and 9.4 of the LGIA give the transmission provider a unilateral right to update its instructions and operating protocols and procedures regardless of whether the proposed Article 8.4 is applied retroactively.

186. Midwest ISO Transmission Owners request that the Commission address the circumstances under which a VER with an existing interconnection agreement might become subject to the new power production forecasting requirement if it is applied prospectively. Midwest ISO Transmission Owners state that, at the very least, any increase in a facility's generating capacity or material modification that would necessitate a new LGIA should be sufficient to subject the VER generator to the new power production forecasting-related data requirements under the applicable tariff.

187. Some commenters suggest implementing reporting requirements for meteorological and forced outage data through the *pro forma* OATT in order to impose those requirements on existing resources or otherwise allow for changes in reporting requirements over time.[213] AWEA contends that, if the Commission determines to apply the reporting requirements to existing resources, it would be more appropriate to place the requirements in the *pro forma* OATT. Sunflower and Mid-Kansas agree, noting that the *pro forma* LGIA already requires parties to operate their facilities consistent with Applicable Laws and Regulations, including OATT requirements. Large Public Power argues that it is important that all VERs provide the operational information required by a transmission provider and, therefore, also recommends placing reporting requirements in the transmission tariff. Southern California Edison contends that placing reporting requirements in the *pro forma* OATT would allow greater flexibility in structuring agreements by referencing requirements in the California ISO Tariff, as they may change from time to time.

188. Other commenters ask the Commission to allow reporting requirements to be stated in market rules or business practices.[214] ISO New England requests that the Commission afford flexibility for public utility transmission providers to determine the mechanism by which to collect the required VER data. National Grid states that rather than requiring a proscriptive amendment of the *pro forma* LGIA, the Commission should require each region to work with its stakeholders to develop appropriate methods for forecasting the energy output from VERs. Pacific Gas & Electric requests that in its Final Rule the Commission provide latitude for the California ISO and other similarly-situated transmission providers to continue their existing programs for gathering relevant meteorological and operational data, and proposing incremental refinements to them, so long as they conform to the purposes of the Final Rule. Xcel similarly argues that the specific data requirements for individual public utility transmission providers should be identified through a business practice or other OASIS posting to allow adjustments due to changing system operating needs, improvements in meteorological forecasting technologies, or modifications in NERC reliability requirements.

189. With regard to the Commission's question as to whether the *pro forma* SGIA needs to be revised, many parties argue that the provision of data under the SGIA may be appropriate in some instances.[215] PJM and Snohomish County PUD note that the costs of reporting the proposed data to public utility transmission providers by small VERs could be higher than for larger resources. As such, they argue that the Commission should carefully consider these costs when applying reporting requirements. Several other commenters acknowledge difficulties associated with gathering data from resources subject to the SGIA, and propose a variety of thresholds to determine whether reporting requirements should apply to the resource.[216] For example, AWEA states that it makes sense to apply similar data reporting requirements to smaller-scale generators where it can be demonstrated that the data will be used for improving VER forecast accuracy and that the benefits exceed the cost of data collection. Others state that small resources should use alternative reporting requirements.[217] Southern California Edison recommends that the Commission consider an approach that aggregates individual site data from small generators in a geographic area, which reduces cost impacts to smaller projects.

190. Commenters contend that the public utility transmission provider should have the flexibility to identify and require data from small

[210] Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 120; Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 910.

[211] *See* Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 64.

[212] *Id.* P 60 (citing *Pro Forma* LGIA Article 22, which sets forth the confidentiality provisions applicable to data exchanged through the interconnection process).

[213] *E.g.,* AWEA; Large Public Power; Southern California Edison; Sunflower and Mid-Kansas.

[214] *E.g.,* California PUC; Dominion; ISO New England; National Grid; Pacific Gas & Electric.

[215] *E.g.,* California ISO; EEI; Duke; ISO New England; MidAmerican; NRECA; Pacific Gas & Electric; PNW Parties; Snohomish County PUD; Southern California Edison; Tacoma Power; Xcel.

[216] *E.g.,* AWEA; RenewElec; SEIA; Tacoma Power; Xcel.

[217] *E.g.,* Alstom Grid; RENEW.

generators.[218] For example, Bonneville Power argues that the Commission should require small VERs to provide meteorological and operational data according to the requirements established by their public utility transmission provider. These commenters generally agree that public utility transmission providers may have different forecasting needs, and that they require flexibility to address such issues. NextEra argues that there is no convincing reason to limit the forecasting requirement to resources larger than 20 MW, and that the impact of small VERs on system variability is the same as resources greater than 20 MW. Midwest ISO Transmission Owners note that the Midwest ISO *pro forma* Generator Interconnection Agreement (GIA) applies to all interconnection customers, regardless of size, and as a result any reporting requirements adopted in the GIA should apply to generators with a capacity of less than 20 MW. California PUC asks that the Commission make clear that public utility transmission providers are not prohibited from requesting meteorological and operational data from small VERs. Environmental Defense Fund states that the Commission should host a technical conference to examine issues arising from requiring small generators to contribute information to support power production forecasting.

191. Some commenters address other aspects of the Commission's proposal to amend the *pro forma* LGIA. AWEA questions the Commission's preliminary conclusion that the LGIA provides sufficient confidentiality protection for sensitive operational and meteorological data, stating that vendors providing forecasts to public utility transmission providers must not be allowed to use the data they collect for developing forecasts for the public utility transmission provider for any other purpose without express agreement. MidAmerican asks the Commission to clarify that there will not be any additional penalties for failure to provide accurate meteorological and operational data, other than the contractual remedies for breach already provided for in the *pro forma* LGIA. MidAmerican states that it recognizes that meteorological data are not always available if, for example, communication from a collecting device is interrupted. RenewElec recommends that the Commission set forth a data retention requirement in the new *pro forma* LGIA Article 8.4 that would require public utility transmission providers to maintain data collected from interconnection customers whose generating facilities are VERs for at least 10 years, facilitating follow-up studies to update power production forecasts.

f. Commission Determination

192. The Commission affirms the Proposed Rule and amends the *pro forma* LGIA to include a new Article 8.4 setting forth the reporting requirements adopted in this Final Rule. The Commission directs all public utility transmission providers to file a revised *pro forma* LGIA within 12 months of the effective date of this Final Rule reflecting the revisions adopted herein. As noted below, public utility transmission providers that have already implemented meteorological or forced outage reporting requirements may seek to demonstrate, on compliance, that these existing business practices and market rules adequately satisfy the requirements of this Final Rule.

193. As set forth in the Proposed Rule, Article 8.4 of the *pro forma* LGIA did not state where the meteorological and forced outage data reporting requirements would be specified in an LGIA. The Commission agrees with Bonneville Power that it is appropriate to state reporting requirements for meteorological and forced outage data in Appendix C, Interconnection Details, as this will allow the requirements to be changed from time to time. The Commission therefore revises proposed Article 8.4 to specify that reporting requirements for meteorological and forced outage data would be set forth in Appendix C, Interconnection Details, of an LGIA. A transmission provider with an executed LGIA that seeks reporting of such data may negotiate revisions to Appendix C related to such reporting requirements with the interconnection customer. To the extent the parties mutually agree on changes to Appendix C, such changes to Appendix C need not be submitted to the Commission for review. If the parties are unable to reach agreement on proposed modifications to Appendix C, however, these parties may invoke their rights, as relevant, to modify the LGIA under sections 205 or 206 of the FPA, as appropriate, and pursuant to Article 30.11 of the LGIA.

194. The Commission disagrees with commenters suggesting that flexibility provided by business practices or market rules makes them a superior alternative for implementing the meteorological and forced outage reporting requirements adopted in this Final Rule. The Commission has sought to address public utility transmission providers' need for flexibility by clarifying that reporting requirements are to be set forth in Appendix C to the LGIA, while also addressing interconnection customers' need for certainty in the obligations placed on them. The Commission appreciates that public utility transmission providers in some regions, including RTOs and ISOs, have already implemented meteorological or forced outage reporting under business practices and markets rules. Such public utility transmission providers may seek to demonstrate in their compliance filing how continued use of these existing business practices and market rules is adequate to satisfy the requirements of this Final Rule using the independent entity variation standard set forth in Order No. 2003, if relevant, or by demonstrating variations from the *pro forma* OATT are consistent with or superior to the requirements of this Final Rule.[219]

195. The Commission declines to modify existing LGIAs already in effect to include Article 8.4 of the *pro forma* LGIA as adopted in this Final Rule. The Commission acknowledges that, in some situations, there may be a sufficient amount of VERs already interconnected to the public utility transmission provider's system to make data from those resources useful or even necessary to properly implement power production forecasting. However, several considerations lead us to decline to modify every LGIA in effect on a generic basis. First the Commission believes retroactive changes to every LGIA in effect could be administratively burdensome to public utility transmission providers and interconnection customers, especially where the public utility transmission provider is not engaged in power production forecasting. Second, we note that nothing in the *pro forma* LGIA precludes the parties to an LGIA from mutually agreeing to revise the requirements set forth in Appendix C to reflect the reporting of meteorological and forced outage data. Indeed, we note that Article 9.4 of the *pro forma* LGIA recognizes that Appendix C will be modified to reflect changes to the interconnection customer's requirements as they may change from time to time. Finally, if the parties are unable to agree to modifications of Appendix C, we note that pursuant to Article 30.11 of the *pro forma* LGIA, the transmission provider has the right to make a unilateral filing to the Commission proposing to modify an

[218] *E.g.,* Bonneville Power; Idaho Power.

[219] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 9–10.

existing LGIA under section 205 of the FPA.

196. For similar reasons, the Commission declines suggestions to implement data reporting requirements through the *pro forma* OATT instead of the *pro forma* LGIA or to include the requirements in the *pro forma* SGIA. The effect of relying on the *pro forma* OATT would be to impose the data reporting requirements adopted in this Final Rule on existing interconnection customers retroactively, including those with resources under 20 MW that are subject to the *pro forma* SGIA. Like data from existing resources, data from small resources may be useful or necessary for power production forecasting, yet the record in this proceeding does not demonstrate that the need for data from small resources is so great as to outweigh the potential burden that reporting requirements could impose on smaller resources. Just as the *pro forma* LGIA provides an opportunity for public utility transmission providers to mutually agree with interconnection customers regarding reporting requirements, nothing in the *pro forma* SGIA precludes the transmission provider from negotiating with the owners and operators of small VERs to update their SGIAs to provide for the reporting of meteorological and forced outage data that are necessary for public utility transmission providers to employ power production forecasting. As with the *pro forma* LGIA, section 12.12 of the *pro forma* SGIA provides an opportunity for parties to an SGIA to bring any disagreement to the Commission for resolution.

197. In response to Midwest ISO Transmission Owners, the Commission notes that the extent to which a new LGIA is necessitated by a new Interconnection Request or Material Modification is governed by the *pro forma* LGIA and Commission precedent. To the extent a new LGIA is warranted, the VER interconnection customer would be subject to the relevant requirements of this Final Rule in effect at the time. Public utility transmission providers may seek to demonstrate in their compliance filings how continued use of existing tariffs, business practices and/or market rules is adequate to satisfy the requirements of this Final Rule using the independent entity variation standard set forth in Order No. 2003, if relevant, or by demonstrating variations from the *pro forma* OATT are consistent with or superior to the requirements of this Final Rule.[220]

198. With regard to AWEA's concern regarding the confidentiality of data, the Commission agrees that meteorological and forced outage data can be commercially sensitive, but concludes that the Article 22 of the *pro forma* LGIA provides adequate safeguards for reported data.[221] Any vendor providing forecasts to a public utility transmission provider would be an agent of the public utility transmission provider subject to the confidentiality obligations of the *pro forma* LGIA. With regard to MidAmerican's concern regarding penalties for failure to provide accurate meteorological and forced outage data, the Commission notes that the extent to which penalties beyond those set forth in the *pro forma* LGIA might be appropriate for failing to satisfy data reporting requirements will necessarily depend on the facts and circumstances surrounding each instance of failed reporting. The Commission appreciates that unforeseen circumstances may impair an interconnection customer's ability to report data and that the impact of failed reporting may in many instances be *de minimus.* However, it would not be appropriate for the Commission to conclude generically that in no circumstance would additional penalties beyond those remedies set forth in the *pro forma* LGIA be appropriate for failure to comply with the data reporting requirements of an executed LGIA.

199. Finally, the Commission declines to impose special retention requirements for reported meteorological and forced outage data as requested by RenewElec. The time period over which a public utility transmission provider would need to retain meteorological or forced outage data will be a function of the type of power production forecasting being employed by the public utility transmission provider.

2. Definition of VER

a. Commission Proposal

200. In the Proposed Rule, the Commission sought to modify the *pro forma* LGIA to include a new definition for Variable Energy Resource in Article 1. The proposed definition identified a Variable Energy Resource as a device for the production of electricity that is characterized by an energy source that: (1) Is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.[222] The Commission stated that it believed the proposed definition was consistent with NERC's characterization of variable generation.[223]

b. Comments

201. EEI supports the Commission's proposed definition without modification. California ISO supports the definition's focus on source of energy, but suggests that the phrase ''by an energy source that'' be replaced with ''by a fuel source that.'' California ISO states that this change would make clear that the three conditions that follow pertain to the fuel source and not the nature of the facility itself.

202. Other commenters disagree with the focus on the source of energy, arguing that a VER should be defined by reference to its operating characteristics, including the ability to control output.[224] BrightSource states that this would allow for comparison between facilities with different fuel sources on standard operational and reliability time-frames and also avoid confusion about types of plants that combine renewable and conventional fuel sources, such as solar-gas hybrids. Joined by SEIA, BrightSource argues that a plant able to maintain a high level of operational control comes close to fulfilling the operational characteristics of a non-VER generation and should be treated as such for purposes of the Proposed Rule's requirements. NextEra agrees, stating that some resources can control the variability of their facility by adjusting output through feathering blades, self-curtailment, or similar measures. SEIA suggests that the Commission consider alternative criteria that could provide a distinction between VERs with a high level of control and VERs without such controls, such as if actual production can remain within some statistical measure of forecast accuracy during its operating hours. MidAmerican similarly requests that the Commission adopt a definition based on physical electrical generation output characteristics rather than input attributes such as fuel type, suggesting that whether energy sources qualify as ''renewable'' varies among states that have developed their own renewable resource regulations.

[220] *See Id.* P 910.

[221] Article 22 of the *pro forma* LGIA defines Confidential Information to include, among other things, all information relating to a Party's technology, research and development, business affairs, and pricing. Each party to an LGIA must hold in confidence and may not disclose to any person Confidential Information during the term of an LGIA and for a period of three years after the expiration or termination of an LGIA.

[222] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 64.

[223] *Id.* (citing NERC, *Accommodating High Levels of Variable Generation* 13–14 (2009), *available at http://www.nerc.com/files/IVGTF_Report_041609.pdf*).

[224] *E.g.,* AWEA; BrightSource; NaturEner; NextEra; RenewElec; SEIA.

203. Several of these commenters question the applicability of the proposed definition to resources that use energy storage to control output. NaturEner provides a hypothetical example of a plant coupled with storage and asks that the Commission provide clarification regarding the impact of such pairing on capacity reserve obligations. BrightSource asks the Commission to modify the definition to address how much storage results in a plant not being considered a VER for purposes of the Proposed Rule and any future rules. AWEA and NextEra request clarification that the proposed definition would not prevent VERs from electing to maintain VER status even if they use energy storage, other firming technologies, or otherwise have the ability to adjust output. RenewElec and SEIA argue that, regardless of the Commission's determination on the storage issue for VERs, such resources should not be exempt from reporting meteorological data to their public utility transmission provider. BrightSource and SEIA state that the applicability of the proposed definition is sufficiently important that the Commission should consider a technical conference on the issue.

204. Some commenters focus on the applicability of the proposed definition to particular types of resources, such as tidal, run-of-river hydro, conduit hydro, co-generation, or biomass.[225] Snohomish County PUD argues that, although such facilities would appear to satisfy the proposed definition, they should not be required to report the proposed data to public utility transmission providers because the data reporting would provide minimal benefit to grid operators while imposing a significant burden on these resources. Focusing on run-of-river hydro, Snohomish County PUD contends that whether such a facility is available at any given moment has no impact on the extent to which a sudden wind ramp might change production on the grid. NorthWestern and Pacific Gas & Electric agree, arguing that run-of-river hydro is much more predictable than wind or solar generation on a short-term basis and, as a result, there would be little benefit to collecting the meteorological data from such resources. In contrast, Entergy argues that the proposed definition and associated reporting requirements should be imposed on Qualifying Facilities to avoid gaps in forecasting and to allow public utility transmission providers to accommodate the variability that exists with both Qualifying Facilities and VERs.

205. Other commenters question the application of the proposed definition to solar resources.[226] California ISO explains that while solar thermal resources store solar thermal heat, they do not store solar irradiance itself, which is the energy source for the solar thermal facility. California ISO asks the Commission to clarify that a solar thermal facility would fall under the proposed definition. BrightSource contends that the storage and variability elements of the proposed definition appear to overlap functionally for a solar thermal plant, given that variability during the operating day could be controlled in many ways by the facility. BrightSource requests clarification regarding whether a VER would have to meet both or just one of these elements to fall within the definition.

206. ISO New England and NorthWestern offer opposing views on application of the proposed definition and associated reporting requirements on behind-the-meter generation. ISO New England recommends that all distributed or behind-the-meter generation should be required to provide to the balancing and transmission entities in its area, at a minimum, specification of the technology and precise location of the installed resource so that a forecast of output can be developed on an aggregate scale to include in the balancing area forecast.

207. California State Water Project argues that its wholesale participating load resource also meets the definition of a VER. California State Water Project explains that participating load's primary purpose is not the provision of services to the grid, but rather water management, and that the load is subject to variability for reasons beyond California State Water Projects' control, such as competing environmental and water management requirements. Accordingly, California State Water Project requests that consideration be given to expanding the VERs definition to include large wholesale demand response resources that bid into markets not through a baseline mechanism, but rather on a basis comparable to generation.

208. ISO New England requests that the Commission afford flexibility for entities to use existing, superior definitions of VERs. The ISO New England Tariff already uses the term ''Intermittent Power Resources'' for wind, solar, run-of-river hydro and other renewable resources that do not have control over their net power output. As such, ISO New England requests that the Commission allow entities to use existing, superior approaches to the extent these are consistent with the objectives of the proposed reforms. ISO New England states that adding another term to its tariff could potentially lead to confusion, and therefore, argues that the region should be afforded the opportunity to consider the existing terminology in the ISO New England Tariff, and determine whether any changes are warranted.

209. Bonneville Power states that, in light of its position that the *pro forma* LGIA provides transmission providers with the authority to update operational requirements for VERs, the Commission's proposed definition is unnecessary. However, Bonneville Power nonetheless states that it supports the inclusion of the proposed definition in all new VER interconnection agreements.

c. Commission Determination

210. The Commission adopts the Proposed Rule's definition of VER and, accordingly, amends Article 1 of the *pro forma* LGIA to include the following definition:

> Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

The Commission finds it necessary to define VERs in the *pro forma* LGIA in order to identify those resources that are required to provide to their public utility transmission provider meteorological and forced outage data necessary to enable the public utility transmission provider to develop and deploy power production forecasting. The Commission therefore declines to define VERs by their operating characteristics as suggested by BrightSource and MidAmerican or by reference to their lack of ability to store output, self-curtail production, or otherwise firm deliveries as suggested by BrightSource, NextEra and others. The Commission also declines to define VERs by their fuel type as suggested by California ISO, because fuel type is an unduly restrictive subset of energy type.[227]

211. As noted elsewhere in this Final Rule, power production forecasting

[225] *E.g.,* Grays Harbor PUD; NorthWestern; Pacific Gas & Electric; Snohomish County PUD.

[226] *E.g.,* BrightSource; California ISO.

[227] ''Fuel'' is defined as a material used to produce heat or power by burning. *See Merriam Webster, http://www.Merriam-Webster.com,* 2011. (November 4, 2011).

allows the public utility transmission provider to understand the characteristics of the input energy source for particular resources, to use those characteristics to predict how the resources will operate, and in turn to determine whether and to what degree the public utility transmission provider will need to reserve capacity to manage variability in generation output. Therefore, it is the variability of the energy source, not the operating characteristics of the plant or nature of output, that are critical to identifying the set of resources that must be subject to the meteorological and forced outage data requirements adopted above. Defining VERs by reference to operating characteristics or level of storage could limit the reporting of data in ways that undermines that ability of public utility transmission providers to engage in power production forecasting.

212. The Commission declines to establish an exemption to the data reporting requirements in this Final Rule for VERs utilizing energy storage or other firming technologies. Not only would this exemption inhibit the public utility transmission provider's capacity to predict how the VER resources will operate, but there is also insufficient evidence in this record to identify an objective threshold for exemption. The Commission clarifies that the purpose of this definition is to identify the resources that are required by this Final Rule to provide to their public utility transmission provider meteorological and forced outage data; the purpose is not, as suggested by NaturEner, to assign capacity reserve obligations or other charges. Nor does this definition supersede those created by other entities for purposes outside this rule, such as tax benefit purposes or renewable energy credits.

213. For similar reasons, the Commission declines to limit the VER definition in the *pro forma* LGIA to solar and wind resources so as to exclude run-of-river hydro, tidal, or other new and emerging VER technologies. Although the Commission anticipates that public utility transmission providers initially will engage in power production forecasting predominantly for wind and solar VERs, we leave to the public utility transmission providers to determine whether their individual systems necessitate power production forecasting for other types of VERs. Categorically excluding other types of resources would undermine the flexibility being provided in this Final Rule. At the same time, we decline to establish minimum reporting requirements for non-wind and non-solar VERs and leave to the public utility transmission providers and VERs to negotiate what data are necessary for developing and deploying power production forecasting for these resources, taking into account the size and configuration of the VER, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area.[228] Because such requirements will vary system by system, it is not necessary to hold a technical conference to explore generic application of the VER definition as suggested by BrightSource and SEIA.

214. In response to California State Water Project, the Commission clarifies that VERs are not defined herein to include demand response resources. A demand response resource is not a device for the production of electricity and, therefore, would not fall within the VER definition adopted in the *pro forma* LGIA.[229] In response to ISO New England and NorthWestern, the definition potentially could apply to behind-the-meter generation, although such resources would only be subject to data reporting requirements adopted in this Final Rule to the extent they enter into a new LGIA or materially modify an existing LGIA after the effective date of this Final Rule.

215. ISO New England inquires as to the impact of the VER definition on other definitions in a public utility transmission provider's existing tariff. As noted above, public utility transmission providers that are RTOs or ISOs may seek to demonstrate in their compliance filing how existing tariffs, business practices or market rules are adequate to satisfy the requirements of this Final Rule using the independent entity variation standard set forth in Order No. 2003, if relevant, or by demonstrating variations from the *pro forma* OATT are consistent with or superior to the requirements of this Final Rule.

216. With regard to Entergy's request that the Commission apply the proposed outage reporting requirement to Qualifying Facilities, we clarify that the data-reporting requirements under this rule apply to interconnection customers whose generating facilities are VERs as defined herein. Specifically, when an electric utility purchases an interconnected Qualifying Facility's total output, the relevant state authority exercises authority over the interconnection and the allocation of interconnection costs. But when an electric utility interconnecting with a Qualifying Facility does not purchase all of the Qualifying Facility's output and instead transmits the Qualifying Facility power in interstate commerce to another purchaser, the Commission exercises jurisdiction over the rates, terms, and conditions affecting or related to such service, such as interconnections.[230] Thus, for a Qualifying Facility that is a VER, when the interconnected Qualifying Facility is selling its total output to an electric utility, the meteorological and forced outage reporting requirements of this Final Rule do not apply. However, when an electric utility interconnecting with a Qualifying Facility does not purchase all of the Qualifying Facility's output and instead transmits the Qualifying Facility power in interstate commerce to another purchaser, the meteorological and forced outage reporting requirements of this Final Rule are applicable.

3. Data Sharing

a. Commission Proposal

217. In the Proposed Rule, the Commission sought comment on whether public utility transmission providers should be allowed or required to share VER-related data received from interconnection customers with other entities, like the source or sink balancing authority area for a transaction, or a government agency, such as NOAA, assuming confidentiality is protected.[231]

b. Comments

218. Clean Line and RenewElec state that operational and meteorological data should be made public to the maximum extent possible. RenewElec argues that there is a significant lack of operational data available to researchers in the area of VERs integration, and asks that the Commission require that: (1) VER data be made public within six months of the date on which such data is submitted by the interconnection customer, and (2)

[228] If parties are unable to reach an agreement the public utility transmission provider may submit a filing requesting the data and demonstrating how it will be used for power production forecasting pursuant to section 205 of the FPA.

[229] A demand response resource may use behind-the-meter generation, potentially including VERs, to facilitate the provision of demand response. Such use, however, does not mean that such behind-the-meter generation is itself a demand response resource.

[230] Order No. 2003, FERC Stats. & Regs. ¶ 61,103 at P 813. The Commission regulations governing the exemptions enjoyed by Qualifying Facilities are codified at 18 CFR Part 292, Subpart F (18 CFR 292.601–292.602 (2011)). Limited exemptions from sections 205 and 206 of the FPA apply to certain sales of energy and capacity made by Qualifying Facilities. *See also Terra-Gen Dixie Valley, LLC,* 132 FERC ¶ 61,215, at PP 45–46 (2010).

[231] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 63.

operational data, including VER data, used by transmission providers to develop VER power production forecasting be made available to interested parties.

219. While generally stating support for the sharing of data, some commenters raise confidentiality concerns and point out the commercially-sensitive nature of data subject to the reporting requirements contemplated in the Proposed Rule.[232] For example, Southern California Edison supports sharing VER-related data for the purposes of increasing forecasting accuracy, as long as the data are not proprietary data that the public utility transmission provider is prohibited from disclosing to other parties. Bonneville Power and a few others contend that while sharing data from individual VERs poses confidentially issues, sharing aggregate VER data does not pose the same problems.[233] Sunflower and Mid-Kansas state that, within RTOs, the stakeholders should decide which entities should be provided VER data. Western Farmers request that the Commission confirm that, where the transmission provider is not the balancing authority, the data should also be provided to the relevant balancing authority. NextEra and AWEA only support sharing data with other balancing authorities when the resource is being dynamically scheduled or dispatched into that balancing authority. Bonneville Power suggests that, at a minimum, the Commission should allow public utility transmission providers and balancing authorities to share aggregate forecasts for VER output with all parties to an e-tag.

220. Several commenters support sharing VER-related meteorological data with NOAA, including having the data incorporated into foundational models run by NOAA.[234] Commenters, including NOAA, request that the Commission require VERs to submit meteorological data to NOAA for the purpose of improving atmospheric characterization and forecast accuracy.[235] In response to confidentiality concerns, NOAA states that private sector proprietary data can be protected from distribution and anonymized in the analysis and generation of forecasts, which would then allow improved predictions to be available for the private sector to incorporate into power production forecasts.

c. Commission Determination

221. The Commission declines to expand the Proposed Rule to require public utility transmission providers to share VER related data with other entities such as a balancing authority area or NOAA. However, the Commission strongly encourages the voluntary sharing of data where appropriate. Many commenters assert that significant benefits might flow from VERs sharing data with entities such as a balancing authority area or NOAA. The Commission finds that VERs are in the best position to negotiate what data are needed and to weigh the benefits that may be expected as a result of providing such data. In addition, negotiating directly with other entities will allow VERs to ensure that adequate confidentiality protections are in place for information that they may consider to be commercially sensitive or otherwise confidential. If helpful to industry participants, the Commission will consider making staff available to work through issues and, if appropriate, take additional steps to facilitate the voluntary sharing of information.

4. Cost Recovery

a. Commission Proposal

222. In the Proposed Rule, the Commission refrained from proposing a single method of cost recovery for the development and implementation of power production forecasts. Instead, the Commission sought comments on how public utility transmission providers may recover costs incurred to develop and deploy power production forecasting tools.[236]

b. Comments

223. Among those seeking flexibility, AWEA states that the Commission is correct to not propose a single uniform method for allocating these costs, and instead should defer to public utility transmission providers and others to determine how these costs should be allocated. Several commenters request that the Final Rule provide flexibility to public utility transmission providers and/or regions to propose cost recovery approaches.[237] For example, EEI contends that generally no interconnected resource should be exempt from the responsibility for costs that it causes to be incurred, but asks that the Commission not mandate how costs should be allocated at this time, allowing regions to develop appropriate cost-recovery solutions.

224. Some commenters recommend that the cost of forecasting be spread among all transmission customers.[238] Independent Power Producers Coalition-West argues that forecasting tools will ultimately reduce costs to utilities and generators, and will ultimately be a small cost of doing business in a world where forecasting can and should be a constant element of the power scheduling process. Public Interest Organizations state that the costs of centralized forecasting infrastructure should be spread across all those who benefit from the improved accuracy and decreased costs, provided those costs are demonstrated to be just and reasonable. Joined by NextEra, Public Interest Organizations argue that the broad benefits of forecasting justify the sharing of related costs across the transmission system(s) that benefit.

225. Iberdrola contends that there is no difference in the costs incurred to develop and deploy power production forecasting tools and the costs of developing and implementing other market design features. Iberdrola states that these types of costs typically are not directly assigned to one set of market participants, but are spread to all users of the transmission system because they benefit all users of the system. Iberdrola states that the costs incurred to develop and deploy power production forecasting tools should similarly be spread to all system users.

226. Exelon recommends recovering the cost of forecasting within administrative charges, the approach taken by PJM and ERCOT. Exelon provides an example of ERCOT's handling of the costs: the cost of developing the ramp probability tool was a one-time investment that was recovered by the transmission provider in uplift to the market. The ongoing cost of using the tool is also spread across the market. Exelon states that this approach avoids the problem of free-ridership by future market participants that would occur if these costs were recovered solely from existing market participants.

227. Other commenters argue either that the VERs, or the beneficiaries of VERs, should be financially responsible for the costs of forecasting.[239] These

[232] *E.g.,* CGC; California PUC; EEI; NextEra; PJM; SMUD; ISO New England.

[233] *E.g.,* Bonneville Power; California ISO; Exelon; SEIA.

[234] *E.g.,* AWEA; Bonneville Power; CGC; Iberdrola; ISO New England; MidAmerican; NaturEner; NOAA.

[235] *E.g.,* Bonneville Power; Iberdrola; NOAA.

[236] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 57.

[237] *E.g.,* AWEA; California PUC; Duke; ISO New England; MidAmerican; Pacific Gas & Electric.

[238] *E.g.,* Iberdrola; Independent Power Producers Coalition-West; NextEra; Public Interest Organizations; Exelon.

[239] *E.g.,* Bonneville Power; ELCON; Large Public Power Counci; MidAmerican; Midwest ISO Transmission Owners; Montana PSC; NorthWestern; NRECA; Oregon & New Mexico PUC;

commenters generally contend that public utility transmission providers should be able to recover the costs incurred to develop and deploy power production forecasting by imposing a fee or rate upon the VERs causing the costs to be incurred. For example, NRECA argues that non-VER transmission customers are neither causing nor benefiting from the enhancements to power production forecasting and, therefore, should not be forced to subsidize its costs, citing *Northern States Power Company.*[240] Montana PSC suggests that all VERs of 1 MW or greater should be responsible for power production forecasting costs. Pacific Gas & Electric notes the approach taken in the California ISO's Participating Intermittent Resources Program, in which the California ISO charges a fee to VERs to recover costs to develop and deploy power production forecasts.

228. ELCON and Tacoma Power argue that any resource, whether or not it is a VER, should be held fully accountable for the costs it causes the transmission provider to incur on its behalf. ELCON argues that meteorological forecasting is simply a cost of doing business for wind energy, just as a nuclear power plant must pay for storage of spent fuel. ELCON argues that these costs should not be recovered in uplift charges in regions served by ISOs or RTOs, or allocated to non-customers of VER transactions.

229. SEIA recommends that the Commission examine whether there may be market entities that would consider contributing to the costs of the forecast service providers in the non-organized market regions, *e.g.,* power traders may be willing to pay for the aggregate day-ahead and hour-ahead forecasts across such regions. SEIA states that these revenues could be used to develop aggregated forecasts for more geographical areas within a region that could further reduce integration costs.

230. Duke argues that the Commission should allow public utility transmission providers to update any costs associated with the Proposed Rule's reporting and power production forecasting requirements without triggering a general rate case. Duke suggests that one possible option would be through a formula rate that is updated periodically for changes in costs related to forecasting and data reporting.

231. Finally, some commenters request that the Commission recognize that the costs of centralized forecasting go beyond the expense of forecasting tools.[241] These additional costs include gathering data, installing and operating onsite telemetry, equipment to record meteorological data, and data management. Southern California Edison points out that data and telemetry are only as good as the personnel assessing the information.

c. Commission Determination

232. The Commission finds that it is not necessary to prescribe a single method of cost recovery for developing and implementing power production forecasting, as it is likely that not all public utility transmission providers will develop power production forecasting, given regional differences in the types and penetration of VERs. Moreover, the record in this proceeding demonstrates that the circumstances under which a public utility transmission provider may decide to develop and deploy power production forecasting may vary by system. In some instances, public utility transmission providers might develop and employ power production forecasting in order to manage more effectively the commitment of reserves associated with the provision of generator regulation service, as discussed in other sections of this Final Rule. In other circumstances, public utility transmission providers might develop and employ power production forecasting to manage reserve costs recovered under other ancillary services. In addition, public utility transmission providers may seek to recover costs associated with power production forecasting in different ways, as cost recovery may be sought via a general rate case, formula rate, or other mechanism. Given the myriad of factors that may be relevant to the allocation and recovery of such costs, the Commission finds it appropriate to evaluate requests for the recovery of costs incurred to develop and deploy power production forecasts on a case-by-case basis consistent with FPA section 205 and Commission precedent.

C. Generator Regulation Service-Capacity

233. In the Proposed Rule, the Commission preliminarily found that clarifying the manner by which public utility transmission providers may recover the costs associated with fulfilling their obligation to offer generator regulation service would remove barriers to the integration of VERs by eliminating public utility transmission providers' uncertainty regarding cost recovery.[242] As discussed below, the Commission concludes that adoption of this reform could inhibit the flexibility to design capacity services that align with the operational practices or needs of a particular public utility transmission provider. The Commission therefore declines to adopt a generic Schedule 10 for generation regulation service this reform and instead provides guidance to assist public utility transmission providers and their customers in the development and evaluation of proposals related to recovering the costs of regulation reserves associated with VER integration.

1. Schedule 10—Generator Regulation and Frequency Response Service

234. In the Proposed Rule, the Commission proposed incorporating into the *pro forma* OATT a new ancillary service schedule for Generator Regulation and Frequency Response Service. The Commission introduced this proposal with a review of the adoption in Order Nos. 888[243] and 890[244] of ancillary services schedules for Regulation and Frequency Response Service (regulation service), energy imbalance service, and generator imbalance service.[245] The Commission repeats that introduction here for background.

235. Regulation service, offered under Schedule 3 of the *pro forma* OATT, provides the capacity reserve necessary for the continuous balancing of resources (generation and interchange) with load to maintain a scheduled interconnection frequency of 60 cycles per second (60 Hz).[246] In Order No. 888, the Commission required public utility transmission providers to offer regulation service for transmission service within or into the public utility transmission provider's balancing authority area to serve load in that area.[247] However, the Commission did not require public utility transmission providers to offer regulation service for transmission service out of or through the public utility transmission provider's balancing authority area to

PNW Parties; SMUD; Southern California Edison; Tacoma Power.

[240] NRECA (citing *N. States Power Co.,* 64 FERC ¶ 61,324, at P 63,379 (1993)).

[241] *E.g.,* Pacific Gas & Electric; Southern California Edison; NorthWestern.

[242] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 87.

[243] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,703–04.

[244] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 627.

[245] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at PP 66–71.

[246] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,707–08.

[247] *Id.* at 31,717.

serve load in another balancing authority area.[248]

236. Energy imbalance service, offered under Schedule 4 of the *pro forma* OATT, accounts for hourly energy deviations between a transmission customer's scheduled delivery of energy and the actual energy used to serve load.[249] In Order No. 888, the Commission required public utility transmission providers to offer energy imbalance service for transmission service within and into the public utility transmission provider's balancing authority area to serve load in that area.[250] Like regulation service, the Commission did not require public utility transmission providers to offer energy imbalance service for transmission service being used to serve load in another balancing authority area.

237. Regulation service and energy imbalance service, while different in function, are complementary services through which public utility transmission providers maintain their systems' balance and recover both the capacity (regulation service) and energy (energy imbalance service) costs of doing so from transmission customers serving load on their systems. At the time of Order No. 888, the Commission believed that it was reasonable to provide only standardized ancillary service schedules for transmission used to service load because load (rather than generation) exhibited the greatest amount of variability.[251] The Commission noted that generators should be able to deliver scheduled hourly energy with precision and that the requirements for generators to meet their schedules should be contained in interconnection agreements.

238. In Order No. 890, the Commission noted that the existing energy imbalance charges were the subject of significant concern and confusion in the industry.[252] The Commission expressed concern about the variety of different methodologies used for determining imbalance charges and whether the level of the charges provided the proper incentive to keep schedules accurate without being excessive.[253] Such concerns led the Commission to revise existing *pro forma* energy imbalance service provisions and require public utility transmission providers to offer a new service, generator imbalance service, to account for hourly energy deviations between a transmission customer's scheduled delivery of energy from a generator and the amount of energy actually generated.[254] The Commission found that formalizing generator imbalance provisions in the *pro forma* OATT would standardize future treatment of such imbalances, thereby lessening the potential for undue discrimination, increasing transparency, and reducing confusion in the industry that resulted from the then current plethora of different approaches.

239. While the *pro forma* generator imbalance service provides a mechanism for public utility transmission providers to recover the cost of providing the energy needed to manage hourly generator imbalances, it does not provide a mechanism for public utility transmission providers to recover the costs of holding reserve capacity associated with providing generator imbalance energy.[255] Although the Commission in Order No. 890 did not create a new rate schedule to expressly account for these capacity costs, it acknowledged the likelihood that such costs would be incurred in connection with the provision of generator imbalance service.[256] Accordingly, the Commission provided a mechanism by which public utility transmission providers could recover these costs, explaining that ''[t]o the extent a [public utility] transmission provider wishes to recover costs of additional regulation reserves associated with providing imbalance service, it must do so via a separate FPA section 205 filing demonstrating that these costs were incurred correcting or accommodating a particular entity's imbalances.'' [257] In Order No. 890–A, the Commission clarified that public utility transmission providers may propose to assess regulation charges to generators selling in the balancing authority area, as well as generators selling outside the balancing authority area, and that the Commission will consider such proposals on a case-by-case basis.[258]

a. Commission Proposal

240. In the Proposed Rule, the Commission sought to add a new rate schedule to the *pro forma* OATT that complements the generator imbalance service provided under Schedule 9 of the *pro forma* OATT. The Commission noted that, in order to meet their obligations to offer generator imbalance service under Schedule 9, public utility transmission providers must hold unloaded resources in reserve to respond to moment-to-moment variations attributable to generation. The Proposed Rule recognized this *de facto* obligation and proposed to establish a generic rate schedule (Schedule 10—Generator Regulation and Frequency Response Service) through which public utility transmission providers may recover the costs of providing this service. The Commission preliminarily found that clarifying the manner by which public utility transmission providers may recover the costs associated with fulfilling their obligation to offer this service will remove barriers to the integration of VERs by eliminating public utility transmission providers' uncertainty regarding cost recovery.[259]

241. In the Proposed Rule, the Commission stated that Schedule 10 is modeled on Schedule 3—Regulation and Frequency Response Service of the *pro forma* OATT. Where Schedule 3 allows public utility transmission providers to recover the costs of regulation reserves associated with variability of load within its balancing authority area, proposed Schedule 10 would provide a mechanism through which public utility transmission providers can recover the costs of providing regulation reserves associated with the variability of generation resources both when they are serving load within the public utility transmission provider's balancing authority area and when they are exporting to load in other balancing authority areas.[260]

242. The Commission proposed that, consistent with Order No. 890, public utility transmission providers would not be permitted to charge transmission customers for regulation reserves under both Schedule 3 and Schedule 10 for the same transaction.[261] The Commission

[248] *Id.*

[249] *Id.* at 31,708.

[250] *Id.* at 31,717.

[251] In 1996, when Order No. 888 was developed and issued, wind generation was not a significant energy source, with a total capacity of approximately 1,698 MW. *See Imbalance Provisions for Intermittent Resources; Assessing the State of Wind Energy in Wholesale Electricity Markets,* Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,581, at P 7 (2005).

[252] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 634.

[253] *Id.*

[254] *Id.* P 663.

[255] *Id.* P 689 (''The Commission concludes that excluding additional regulation costs as a general matter is appropriate because much of those costs would be demand costs.'').

[256] *Id.* P 690.

[257] *Id.* at P 689 & n.401 (referring to costs associated with capacity used to provide generator imbalance service that otherwise are not recovered through Schedule 3).

[258] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 313.

[259] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 87.

[260] *Id.* P 88.

[261] *Id.* P 89 (citing Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690 (requiring transmission

emphasized that in establishing Schedule 10, it was not changing the nature of the services that a public utility transmission provider must offer its transmission customers. The Commission stated that nothing in the Proposed Rule would affect the manner in which balancing authorities are required to maintain balanced systems that are operated in a safe and reliable fashion, consistent with NERC Reliability Standards. The Commission explained that it simply proposed to establish a generic cost recovery mechanism for a service that public utility transmission providers already are obligated to offer customers taking transmission service within their balancing authority area.[262]

243. In the Proposed Rule, the Commission explained that public utility transmission providers are not permitted to disclaim the obligation to offer to provide transmission customers with the capacity reserves associated with the provision of generator imbalance service.[263] Therefore, the Commission proposed that, under Schedule 10, a public utility transmission provider must offer generator regulation service to the extent it is physically feasible to do so from its resources or from resources available to it, to transmission customers using transmission service to deliver energy from a generator located within the public utility transmission provider's balancing authority area.[264]

b. Comments

i. Proposed Schedule 10

244. Although several commenters support the Commission's proposal to establish a schedule for the recovery of capacity costs for regulation reserves, much of that support is tempered by concern about the scope and design of proposed Schedule 10, as well as the flexibility afforded public utility transmission providers to design services relevant to recover all costs associated with the integration of VERs under proposed Schedule 10.[265] For example, while EEI indicates that it supports the establishment of a cost recovery mechanism for regulation reserves from transmission customers as promoting rate certainty and transparency, it also cautions the Commission that the proposal may unduly condition cost recovery and may not encompass all cost incurred by the transmission provider. While Independent Power Producers Coalition—West supports the concept of a generic generator imbalance tariff to bring certainty to disparate tariffs that must now be negotiated in WECC, it contends that the Commission should require utilities to revise operating agreements, business practices or other procedures such that independently owned generator resources are available to balancing authorities in the WECC to reduce generator imbalance costs for VERs. Large Public Power Council supports the new Schedule 10 provided it is implemented in a way that allows transmission providers to receive full compensation for providing the service.

245. NRECA indicates that it also supports the cost recovery proposal embodied in proposed Schedule 10; however, it expresses concern that Schedule 10 should not be limited to just the recovery of regulation costs, and should instead be expanded to allow public utility transmission providers the opportunity to demonstrate that additional VER integration costs should be recovered through individual Schedule 10s. According to NRECA, such costs may include the following: (1) Intra-hour schedule implementation costs; (2) power production forecasting implementation costs; or (3) other various costs such as load-following service, ramping costs, out-of-merit dispatch costs, and additional spinning and supplemental reserves, among other things.

246. Public Power Council and Puget express similar concerns that the proposed Schedule 10 would not allow for full recovery of all costs of balancing and integrating VERs. According to Public Power Council, Schedule 3 recovers the costs of balancing reserves deployed for frequency and regulation control, which in turn leads Schedule 10 to only recover the costs of regulation (capacity following near instantaneous changes in generation) but not the costs arising from either load following capacity (capacity used minute-to-minute over approximately a 10-minute period) or capacity needed to make up a variable generator's schedule error for the scheduling period. Public Power Council also argues that Schedule 10 charges should include the costs of power production forecasting systems as these would not be needed but for the integration of variable generation. The PNW Parties agree and suggest that Schedule 10 should be expanded further to allow for the recovery of all costs incurred by the public utility transmission provider in providing regulating reserves that are not recoverable through the generation imbalance rate, including but not limited to, extra energy costs and operation and maintenance costs.

247. Southern states that the capacity required to provide generator imbalance service or otherwise respond to operational challenges presented by substantial swings in output from generators (particularly VERs) may mostly be conceptualized as providing a ''regulation'' service, but it should be understood that some public utility transmission providers may also incur additional costs that may implicate other ancillary services, such as reactive power and load following, if not contingency response. Southern asserts that the Commission should not categorically foreclose or limit in advance the right of public utility transmission providers under section 205 to file tariffs or tariff amendments on a case-by-case basis to recover any and all additional reasonable costs specific to VER-related regulation reserve requirements. Southern requests that the Commission confirm that the invitation in Order No. 890 for public utility transmission providers to file rate schedules and amendments to address costs of generator imbalances on a case-by-case basis remains open.

248. Public Interest Organizations contend that it may be unjust and unreasonable to charge VERs regulation rates for capacity requirements that can be addressed by less expensive ancillary services. Public Interest Organizations state that the Commission could address this problem either by reforming Schedule 10 into a slower service akin to load-following or non-spinning reserves, or by clarifying that Schedule 10 is designed to compensate only for the moment-to-moment balancing associated with generation variability, and not for VER variability that affects the system beyond the balancing timeframe.

249. AWEA suggests that the Commission focus on such longer-term variability, requesting that the Commission reformulate proposed Schedule 10 as a system non-spinning service to accommodate the aggregate system variability that is not accommodated through other ancillary services. AWEA states that this type of service would benefit all users of the system by providing inexpensive reserves to accommodate all types of gradual variability on the power system, including changes driven by inaccurate

providers to demonstrate that any proposals to recover capacity costs associated with Generator Imbalance Service do not lead to double recovery); *Entergy Serv., Inc.,* 120 FERC ¶ 61,042, at PP 62–66 (2007); *Sierra Pac. Res. Operating Cos.,* 125 FERC ¶ 61,026 (2008); *Westar Energy Inc.,* 130 FERC ¶ 61,215, at P 4 (2010)).

[262] *Id.* P 91.

[263] *Id.* P 84 (citing *NorthWestern, Corp.,* 129 FERC ¶ 61,116, at P 27 (2009)).

[264] *Id.* P 89.

[265] CMUA at 10–11; EEI at 25–33; Midwest ISO at 14; NRECA at 23–24; Organization of Midwest ISO States at 8–9.

load forecasts, changes in demand driven by large electricity users, as well as aggregate changes of many small users. AWEA notes that wind and solar exhibit little variability over the regulation time period while variability over the course of an hour can be more significant. AWEA argues that a system non-spinning service would be well-suited for accommodating the incremental increase in system variability caused by the addition of such resources.

250. Similarly, Iberdrola recommends the Commission structure Schedule 10 as a following reserves service rather than regulation reserve, arguing that the rate of change associated with wind ramps is not instantaneous but rather occurs over longer time periods within the hour and often for multiple hours. To the extent that the Commission does not reformulate Schedule 10 in this way, Iberdrola requests that the Commission convene a technical conference that focuses on the ancillary services needed to support VERs. NextEra agrees that the Commission should convene a technical conference to address what kind of ancillary services should be developed to complement the growth of VERs, among other things.

251. Duke suggests that the Commission should unbundle regulation and frequency response service into separate ancillary service schedules. In support, Duke points to such industry activities as NERC developing a revision to Frequency Response Reliability Standard BAL–003–0, which will prescribe specific amounts of frequency response that each balancing authority must procure; the Commission report prepared by the Lawrence Berkeley National Laboratory, which discusses operational characteristics and distinctions of primary and secondary frequency control reserves (Docket No. AD11–8–000); and the Commission's Notice of Proposed Rulemaking in Docket Nos. RM11–7–000 and AD10–11–000, which also distinguishes frequency response from regulation.

252. American Clean Skies argues that the Proposed Rule should require RTOs to offer additional ancillary services, such as load following (on a minute-to-minute basis), reactive power and other comparable backup capabilities. Coalition for Green Capital similarly asks the Commission to encourage the development of power and ancillary services products that match the technical and commercial capabilities of VERs to allow VERs to integrate into the bulk power grid at rates and on terms and conditions that are just and reasonable and not unduly discriminatory or preferential. Independent Energy Producers assert that, while it is critical that ancillary service products be identified and developed to permit VERs to be integrated, it is equally critical that the necessary compensation measures be developed to ensure that dispatchable generation is available when and where it is needed to support the ancillary services products, particularly within the California ISO market.

253. With regard to charging transmission customers under both Schedule 3 and the proposed Schedule 10, Bonneville Power agrees with the Commission's decision in Order No. 890 regarding the potential for double recovery if energy settlement charges (under Schedules 4 and 9 of the OATT) are imposed on both the generator and load when they reside in the same balancing authority, but argues that there are significant differences between energy settlement charges and capacity charges recovered under Schedule 3 and Proposed Schedule 10. Bonneville Power states that the public utility transmission provider must maintain balancing reserve capacity for movement of both the load and the generators located in its balancing authority area because the deviations from schedule for the load and generation move independently from one another, and that the transmission provider should be allowed to recover costs for capacity it is providing to both generation and load.

254. Duke similarly argues that the Commission should allow the public utility transmission provider to recover both Schedule 3 and 10 costs if both services are utilized by the transmission customer. Duke contends that it is appropriate in some circumstances to charge a load for Schedule 3, and a generator for Schedule 10, even if they are owned by the same party. According to Duke, unless the generator is coupled to the load by an energy management system (i.e., the generator is controlling to the load), or the generator is dynamically serving a load (i.e., where its output can be controlled to match the load it serves), a public utility transmission provider should be permitted to charge for both Schedule 3 and Schedule 10 as they are two different services which can be provided at the same time (e.g., where a load serving entity owns load within a control area, as well as a generator).

255. Finally, several commenters contend that Schedule 10 is not necessary in organized markets.[266] PJM interprets Schedule 10 as optional and seeks clarification that this interpretation is correct. Sunflower and Mid-Kansas submit that the SPP market rules already are consistent with or superior to the *pro forma* OATT as the Commission proposed to amend it in the Proposed Rule and believes it is highly likely that all of the other RTOs' rules are also superior to what has been proposed. Clean Line contends that the potential of double recovery exists for generators receiving compensated through organized market mechanisms. AWEA contends that the Commission should clarify that the creation of Schedule 10 service should apply only in areas of the country that do not have functioning ancillary services markets. Likewise, Iberdrola explains that a Schedule 10-type product is not necessary in organized markets, as most organized markets balance the system's energy and reserve requirements through use of simultaneously co-optimized Security Constrained Unit Commitment and Security Constrained Economic Dispatch algorithms that clear and dispatch energy and reserves.

ii. Obligation To Offer Generator Regulation Service

256. Several commenters seek clarification regarding the extent to which the public utility transmission provider must provide generator regulation service. NaturEner states that public utility transmission providers should not be able to avoid providing regulating reserves based upon claims that they themselves do not own generation in sufficient amounts to supply the service. Xtreme Power asks that the Commission make clear that, in the event that a public utility transmission provider's existing resources are not adequate to meet the obligation to provide generator regulation service and new resources are needed to accommodate additional variability, the public utility transmission provider is obligated to procure a sufficient quantity of the appropriate resources.

257. Grant PUD asks whether a public utility transmission provider must procure additional regulation resources if the demand for these services exceeds the contractual and owned resources available to the public utility transmission provider that can provide regulation service at the time of the request for service. NorthWestern requests that the Commission clarify

[266] *E.g.,* AWEA; California ISO; Iberdrola; ISO New England, New York ISO; Sunflower and Mid-Kansas.

that the phrase ''or from resources available to it'' refers to acquisition of generator regulation service from third parties and is not intended to mean that, if the utility does not have access to its own resource or resources from the market, the utility must build generation for Schedule 10 service. Independent Power Producers Coalition—West states that transmission providers should not be permitted to charge VERs for generator imbalance services unless they provide VERs with the capability to obtain those services from third parties on a non-discriminatory basis. If a public utility transmission provider does not have access to its own resources or resources from the market and chooses to build new generation to offer Schedule 10 service, EEI asks the Commission to clarify that these costs can be recovered from the resources that trigger the need to build. EEI also states that the language ''or from resources available to it'' could be read to require the public utility transmission provider to violate reliability standards by using resources set aside for contingency reserves to support generation regulation service.[267] EEI requests that the Commission clarify the statement as follows: ''a public utility transmission provider must offer generator regulation service; to the extent it is physically feasible to do so from its existing resources or from resources currently available to it, without violating applicable reliability standards.'' [268]

258. Puget asks that the Commission clarify that public utility transmission providers are only required to provide Schedule 10 service within a defined confidence interval commensurate with the public utility transmission provider's level of regulation capacity set aside for cost recovery under the Schedule 10. If those resources' capabilities are exceeded or if system conditions otherwise warrant, Puget suggests that the public utility transmission provider should retain the right to curtail generation production or export schedules to preserve reliability. Public Power Council and Bonneville Power also question whether the obligation to provide generator regulation service is unlimited, suggesting that such service could require firming of every generation delivery, which would be extremely expensive. Bonneville Power contends that the source balancing authority should have the ability to offer a base level quantity of balancing reserve capacity and should have the right to use operational tools to limit the deployment of reserves to that quantity. In support, Bonneville Power explains that it has developed Dispatcher Standing Order 216 (DSO 216) to require reductions in wind generation or changes to wind generators' transmission schedules when the schedule error of the wind fleet exhausts the total amount of balancing reserve capacity that Bonneville Power has made available for wind and load.

259. Bonneville Power states that it is currently providing enough balancing reserve capacity to meet the needs of the wind fleet in its balancing authority during 99.5 percent of the forecast VER variability events. Bonneville Power describes the remaining 0.5 percent as representing the most extreme variability in VER generation (i.e., ''tail events''). Because of the substantial wind generation exports from Bonneville Power's balancing authority area, Bonneville Power explains that it needs a mechanism to ''clip the tails'' of wind ramps when they exhaust the total amount of balancing reserve capacity that Bonneville Power makes available for wind and load. Bonneville Power states that DSO 216 allows it to establish the amount of balancing reserve capacity that will be deployed and, because there is a set limit, it is able to quantify its obligation and risks for rate setting, system planning, and reliability purposes. Bonneville Power contends that a requirement to maintain balancing reserve capacity at all times to manage tail events would be significantly expensive.

260. Bonneville Power also asks the Commission to clarify that the public utility transmission provider is required to offer to provide Schedule 10 service only to the extent it can do so without harming system reliability or risking non-compliance with state and Federal law and other non-power requirements that affect system operations. Snohomish County PUD and Grays Harbor PUD similarly ask the Commission to clarify that Bonneville Power should not be required to offer capacity from the Federal System to meet demand for services under Schedule 10 where that capacity is not available due to statutory and regulatory obligations that limit the availability of the Federal System's capacity. Grays Harbor PUD adds that the Commission should make clear that, during periods when Bonneville Power's system is limited by statutory and regulatory constrains, it is not ''physically feasible'' for Bonneville Power to use that capacity to support integration of VERs and, therefore, during those periods is exempt from requirements to do so. Bonneville Power further requests that the Commission clarify that the public utility transmission provider is obligated to provide generator regulation service pursuant to Schedule 10 and generator imbalance service pursuant to Schedule 9 only to the extent that balancing reserve capacity is made available pursuant to Schedule 10. In addition, Bonneville Power suggests that the Commission should address the pricing policy articulated in the *Avista* line of cases, which restricts public utility transmission providers that are not in organized markets to recovering cost-based rates for ancillary services, to ensure public utility transmission providers have the ability to obtain the necessary balancing reserve capacity.[269] Tres Amigas concurs with Bonneville Power and suggests that the Commission alter its approach so that these services can be bought and sold competitively outside of organized RTO markets as they are in most RTOs.

iii. Self-Supply of Generator Regulation Service

261. First Wind asks the Commission to clarify that Schedule 10 charges would be imposed on VERs only to the degree they take transmission service or otherwise elect to take Schedule 10 service. AEP contends that the Proposed Rule contains a loophole in that purchasers of VER energy outside of the resource's native balancing authority's footprint would be able to avoid any ancillary service charges caused by their purchase and transport of energy. Other commenters discuss how the balancing authority into which generation is dynamically scheduled would be compensated for providing regulation service.[270] These commenters contend that because the sink balancing authority is providing the regulation service for that generator in these situations, it should be clear in Schedule 10 that the sink balancing authority will be paid for providing that service.

262. Commenters address the option for transmission customers to self-supply generator regulation service. Bonneville Power states that it recognizes that VERs may find it economical to self-supply balancing reserve capacity to provide balancing service and asks the Commission to clarify in Schedule 10 that a customer electing to self-supply is subject to the public utility transmission provider's requirements for Schedule 10 service

[267] EEI at 32.

[268] *Id.*

[269] Bonneville Power (referencing *Avista Corp.*, 87 FERC ¶ 61,223 (1999); *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities,* Order No. 697, 119 FERC ¶ 61,295 (2007) (Order No. 697)).

[270] *E.g.,* Duke; EEI; Exelon.

and the transmission provider's reliability and operational protocols, including any transmission curtailments and generation limitations in the event the self-supplying VER fails to meet the transmission provider's standards. Powerex agrees that the public utility transmission provider should have discretion to decide whether a method of self-supply is acceptable but argues that the public utility transmission provider should be required to describe what it considers to be acceptable comparable arrangements in posted business practices.

263. Xtreme Power similarly contends that, in order for self-supply or third-party procurement of generator regulation service to be a viable option, the public utility transmission provider must specify how a customer's generator regulation service requirements are determined and how the requirements may be satisfied through self-supply or third-party procurement. NaturEner contends that the self-supply provision should be administered on a flexible basis and this could include use of self-curtailment, carrying of a portion of the regulating reserve capacity on a dynamic basis, and carrying of a varying level of regulating reserves because a constant level is not necessary. Independent Power Producers Coalition—West argues that public utility transmission providers should only be permitted to charge VERs for generator imbalance services if they provide VERs with the capability to obtain those services from third parties on a non-discriminatory basis.

264. Beacon Power indicates that entities subject to Schedule 10 should be allowed to work with public utility transmission providers in non-RTO/ISO markets to determine different volumes of self-supplied regulation reserve capacity required based on the ramp-rate capability of its regulation resource(s). CESA agrees that, if a transmission customer subject to the Schedule 10 chooses to self-supply its regulation reserve capacity, the amount of capacity self-supplied should account for the fact that a MW of reserve capacity from a fast-ramping resource provides more regulation value to the grid per MW than a slow-ramping resource. NEMA indicates that some resources that provide generator regulation service, such as batteries and flywheels, can dampen variations much more quickly than can traditional generators. Therefore, NEMA contends that the generator regulation service requirements should be based on the amount of generator regulation service actually *provided,* rather than solely the *capacity* of regulation service. A123 recommends that the Commission clarify the phrase ''alternative comparable arrangements'' to include resources that may differ in MW capacity but supply equivalent or superior regulation performance when compared to the public utility transmission provider's default service.

265. Powerex asks that the Commission confirm that self-supply includes the ability of the transmission customer to self-supply by purchasing regulation reserve capacity from third parties.[271] Powerex states that it could be helpful for the Commission to provide guidance on what should qualify as an ''alternative comparable arrangement.'' SEIA supports providing transmission customers with the opportunity to avoid regulation service costs through dynamic scheduling or self-supply arrangements, but ask the Commission to clarify how self-supply would allow solar plants to avoid regulation reserve requirements, which SEIA believes would assign a constantly varying share of the Schedule 10 requirement to a solar plant capable of providing regulation service. The Federal Trade Commission asserts that the self-supply option under Schedule 10 is vague and should recognize that VERs could address their regulation requirements by matching their generation variability to demand variability.

266. Other commenters request that additional requirements be included in Schedule 10 with regard to self-supply. CGC states that the Proposed Rule fails to require public utility transmission providers to provide dynamic transfer capability out of their balancing authority area or provide an ancillary services market through which a generator could self-supply generator regulation service. CGC asks the Commission to require all public utility transmission providers, either by themselves or in association with other public utility transmission providers, to provide access to a fully functioning competitive ancillary services market and/or dynamic transfer capabilities. ELCON asserts that the Commission should specify that public utility transmission providers must consider using dispatchable demand response resources to provide Schedule 10 service. CESA recommends that FERC allow Schedule 10 self-supply requirements to vary based on the ramp-rate of the resources providing the service, offering that faster-acting resources provide more ACE correction than slower resources.

[271] Powerex at 22.

c. Commission Determination

267. The Commission declines to amend the *pro forma* OATT to include a standardized ancillary services schedule for generator regulation services as proposed in the Proposed Rule. As indicated above, the Commission intended for proposed Schedule 10 to be a clearly defined mechanism for public utility transmission providers to recover the costs of capacity held in reserve to provide generator imbalance service under Schedule 9 of the *pro forma* OATT, while also providing customers with certainty as to the rates they will be required to pay when taking this service. The Commission also sought to confirm the right of public utility transmission providers to recover the reasonably incurred costs of providing this capacity service and to distinguish, where appropriate, among classes of customers who cause such costs to be incurred.

268. In response to the Proposed Rule, the Commission received numerous comments urging flexibility in the design of capacity services needed to integrate VERs into transmission systems, suggesting that the proposed *pro forma* generator regulation service may not be the most efficient and economical service with which to integrate VERs. For example, Southern notes that the recovery of capacity costs incurred to provide Schedule 9 generator imbalance service could implicate a range of services, from regulation to load following, depending on how the public utility transmission provider conceptualizes the service provided. Iberdrola suggests that VER integration has more significant implications for within hour spinning and non-spinning capacity than moment-to-moment regulation capacity. In light of these comments, the Commission concludes that the adoption of a standardized *pro forma* Schedule 10 could inhibit the flexibility commenters seek to design capacity services that align with the operational needs of a particular public utility transmission provider. Accordingly, the Commission declines to adopt the proposed Schedule 10 component of the Proposed Rule and will continue to evaluate proposals to recover capacity costs incurred to provide Schedule 9 generator imbalance service on a case-by-case basis. In this way, public utility transmission providers will remain free to propose capacity services that best respond to the needs of their customers and will not have to expend resources adopting the one-size-fits-all generator regulation service discussed in the

Proposed Rule, even in situations where some other service or rate design may be more appropriate.

269. To be clear, the Commission emphasizes that our decision not to implement a generic rate schedule for generator regulation service should not be interpreted as an unwillingness to consider individual proposals brought by public utility transmission providers. The Commission recognizes that a public utility transmission provider may incur capacity costs associated with fulfilling obligations to provide Schedule 9 generator imbalance service and that existing rate mechanisms may be inadequate for some public utility transmission providers to properly allocate and recover those costs. For many years, the Commission has evaluated proposals to recover such capacity costs on a case-by-case basis in light of the specific facts and circumstances in each case.[272] The Commission concludes that continuation of this case-by-case approach is more appropriate to tailor the particular capacity services needed by a public utility transmission provider to its operations. At the same time, the Commission is sensitive to commenter requests to provide guidance regarding the proper design of a generator regulation service charge should a public utility transmission provider desire to propose one. In the section that follows, the Commission provides a framework that can be used for those public utility transmission providers seeking to develop a proposal to recover capacity costs incurred to provide Schedule 9 generator imbalance service.[273]

270. Before turning to the mechanics of a generator regulation service charge, the Commission clarifies in response to comments that our decision not to adopt a generic Schedule 10 does not relieve public utility transmission providers of obligations under the *pro forma* OATT to provide Schedule 9 generator imbalance service. This in turn requires the public utility transmission provider to maintain sufficient capacity to provide that service.[274] However, as the Commission explained in Order No. 890–A, if it is not physically feasible for a transmission provider to offer generator imbalance service using its own resources, either because they do not exist or they are fully subscribed, the public utility transmission provider must attempt to procure alternatives to provide the service, taking appropriate steps to offer an option that customers can use to satisfy their obligation to acquire generator imbalance service as a condition of taking transmission service.[275] The Commission explained that each transmission provider can state on its OASIS the maximum amount of generator imbalance service it is able to offer from its resources, based on an analysis of the physical characteristics of its system. Alternatively, a public utility transmission provider may consider requests for generator imbalance service on a case-by-case basis, performing, as necessary, a system impact study to determine the precise amount of additional generation it can accommodate and still reliably respond to the imbalances that could occur.[276]

271. Because a proposal for generator regulation service would be associated with generator imbalance service, it follows that the public utility transmission provider would use a similar analysis to identify any limitations on its ability to offer either service.[277] Just as it can for generator imbalance service, the public utility transmission provider could explain on its OASIS the maximum amount of generator regulation service it is able to offer after having attempted to procure alternative resources to provide the service. Alternatively, the public utility transmission provider could perform a system impact study to determine the precise amount of generator regulation service it can provide. In response to NorthWestern, this Final Rule does not place any obligation on the public utility transmission provider to build generation.

272. With regard to comments regarding self-supply of ancillary services, the Commission acknowledges that self-supply may come from many sources, including purchased capacity and the use of non-generation resources, as suggested by ELCON. The option to self-supply certain ancillary services has been in place since Order No. 888, and the Commission declines here to specify any particular requirements for self-supply arrangements for generator regulation service proposals. To do so could restrict flexibility to develop competitively priced options tailored to particular customer needs. As suggested by some commenters, such options could include the use of faster ramping resources to provide the service.

273. In response to Powerex, the Federal Trade Commission and others, the Commission does not believe that the self-supply option is vague or that additional guidance is necessary on what should qualify as an ''alternative comparable arrangement.'' The Commission notes that public utility transmission providers already are obligated to post on their public Web sites all rules, standards, and practices, to the extent they exist, that relate to transmission service.[278] The provision of ancillary services is necessary to accomplish transmission service and, therefore, we conclude this posting obligation applies equally to ancillary services.[279] Public utility transmission providers must post any rules, standards, and practices regarding self-supply requirements pursuant to their obligation to allow self-supply of ancillary services.[280] The Commission declines to adopt further requirements at this time regarding the self-supply of ancillary services.[281]

274. In response to the Federal Trade Commission, the Commission encourages transmission providers, generators, and transmission customers to work together to explore options to find the least cost methods of balancing the system as a whole and to provide maximum flexibility for products and services that meet the needs of the customers and the transmission

[272] *See Florida Power Corp.,* 89 FERC ¶ 61,263, at 61,765 (1999) (*Florida Power*) (''The Commission concludes that a generator imbalance capacity obligation is imposed on the transmission provider for export transactions, and therefore the Commission accepts Florida Power Corp's Generator Regulation Service as a reasonable proposal in those circumstances where the service is not already covered in an interconnection agreement or a separate generator tariff.''); *Entergy,* 120 FERC ¶ 61,042 at PP 62–66 (accepting a generator regulation service rate schedule for independent power producers selling out of the control area that retained charges that had been previously negotiated between Entergy and the relevant independent power producers); *Sierra Pac. Res. Operating Cos.,* 125 FERC ¶ 61,026, at P 10 (2008) (accepting a generator regulation service rate schedule to provide the capacity necessary to follow the moment-to-moment changes caused by generators selling outside of the transmission provider's control area).

[273] *See infra* § IV.C.2 (Mechanics of a Generator Regulation Charge). While this section is framed primarily in terms of a generator regulation service, the principles discussed would also apply more broadly to other capacity services designed to recover capacity costs incurred to provide Schedule 9 generator imbalance service.

[274] *NorthWestern Corp.,* 129 FERC ¶ 61,116, at P 24 (2009), *order denying reh'g,* 131 FERC ¶ 61,202, at PP 17–18 (2010).

[275] Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at PP 289–90.

[276] *Id.* P 289.

[277] In the unlikely event that there are no additional resources available to enable the public utility transmission provider to meet its obligation to offer generator regulation service, the public utility transmission provider must accept the use of dynamic scheduling with a neighboring control area. *See id.* P 290.

[278] Order No. 890, FERC Stats.& Regs. ¶ 31,241 at P 1652.

[279] The Commission notes that this obligation is subject to audit as are all other OATT requirements.

[280] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,705.

[281] *Id.*

providers alike. This includes, for example, evaluating the extent to which regulation service obligations can be addressed by matching generation variability to demand variability, as suggested by the Federal Trade Commission. Indeed, in Order No. 888, the Commission stated that the pricing of ancillary services should include the amount of each ancillary service that the transmission customer must purchase, self-supply, or otherwise procure and must be readily determinable from the transmission provider's tariff and comparable to obligations to which the transmission provider itself is subject.[282] The Commission also specified that the transmission provider is required to identify the regulating margin requirements for transmission customers serving loads in its balancing authority area and to develop procedures by which customers can avoid or reduce such requirements.[283]

275. For reasons explained elsewhere in this Final Rule, the Commission declines to adopt CGC's suggestion to require transmission providers to provide dynamic transfer capability out of their balancing authority area or mandate the creation of an ancillary services market through which a generator could self-supply generator regulation service.[284]

2. Mechanics of a Generator Regulation Charge

276. The Proposed Rule stated that, as with Schedule 3, the proposed Schedule 10 charge would be the product of two components: a per-unit rate for regulation reserve capacity, and a volumetric component for regulation reserve capacity.[285] The Commission proposed to require each public utility transmission provider to submit a compliance filing that includes the addition of a Generator Regulation and Frequency Response rate schedule to the OATT that includes the same per unit rate from their currently effective Regulation and Frequency Response rate schedule and a blank or unfilled volumetric component.[286]

277. The Commission preliminarily found that the per-unit rate for service under proposed Schedule 10 should be the same as the rate for service under existing Schedule 3.[287] The Commission explained that Schedule 3 and the proposed Schedule 10 are both designed to recover the costs of holding regulation reserve capacity to meet system variability. Because the service provided under both schedules is functionally equivalent, the Commission proposed to find that it is just and reasonable to use the same rate currently established in a public utility transmission provider's Schedule 3 when charging transmission customers under Schedule 10. The Commission stated that, for a public utility transmission provider to apply a different rate under the proposed Schedule 10, the public utility transmission provider would have to demonstrate that the per-unit cost of regulation reserve capacity is somehow different when such capacity is utilized to address system variability associated with generator resources. The Commission also noted that the use of a common rate is consistent with Commission policy utilizing the same rate structure for energy and generator imbalance service, as well as the generator regulation rate that the Commission accepted in *Westar Energy Inc.*[288]

278. With regard to the volumetric component of the Schedule 10 rate, the Commission proposed to provide each public utility transmission provider with the opportunity to justify a proposal: (1) To require all transmission customers who are delivering energy from generators to purchase, or otherwise account for, the same volume of generator regulation reserves; or (2) to require transmission customers who are delivering energy from VERs to purchase, or otherwise account for, a different volume of generator regulation reserves than it proposes to charge transmission customers delivering energy from other generating resources.[289] The transmission provider's proposal would be made in a section 205 filing after the acceptance of its compliance filing.

279. Where a public utility transmission provider proposes the same volume of generator regulation reserves for all generators, the Commission proposed that it demonstrate that the volume of regulation reserves required of transmission customers delivering energy from generators located within its balancing authority area be commensurate with their proportionate effect on net system variability, taking account of diversity benefits.[290] The Commission stated that such a filing must show that the public utility transmission provider has fully implemented (or been granted waiver from) the intra-hourly scheduling requirement set forth in the Proposed Rule.[291] The Commission recognized that a public utility transmission provider with few VERs located in its balancing authority area may choose to apply only one volumetric regulation requirement for all generating resources in its balancing authority area. The Commission noted that this also may be the case to the extent the impact of VERs on a public utility transmission provider's system is minimal and the public utility transmission provider, in its judgment, deems the administrative burden of justifying two separate volumetric regulation requirements is uneconomic.[292]

280. The Commission proposed that where a public utility transmission provider proposes to require transmission customers who are delivering energy from VERs to purchase, or otherwise account for, a different volume of generator regulation reserves than it proposes to charge transmission customers delivering energy from other generating resources, the Commission proposed that it demonstrate that the volumes of regulation reserves required of those subsets of transmission customers delivering energy from generators located within its balancing authority area are commensurate with their proportionate effect on net system

[282] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,721.

[283] *Id.* at 31,717. Order No. 890 did not alter the requirements of Order No. 888 in this regard, but did clarify that regulation and frequency response, as well as imbalance energy, may be provided by public utility transmission providers or through self-supply using generating units as well as other non-generation resources such as demand resources where appropriate. Order No. 890, FERC Stats. & Regs. ¶ 21,241 at P 888.

[284] *See supra* IV.A.1 (Intra-Hour Scheduling Requirement).

[285] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 92. The Commission is exploring potential reforms to ancilliary services pricing in other proceedings. *See Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Notice of Proposed Rulemaking, 139 FERC ¶ 61,245 (2012) (NOPR).

[286] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 101.

[287] *Id.* P 94.

[288] *Id.* P 93 (citing *Westar Energy Inc.,* 130 FERC ¶ 61,215 (2010) (*Westar*)).

[289] The Commission noted its expectation that, in any subsequent filing to establish a volumetric component in Schedule 10, public utility transmission providers would address how Schedule 10 and Schedule 3 work together to allow for the recovery of total regulation reserve costs. *Id.* P 105 & n.206.

[290] The Commission explained that diversity benefits result from the aggregation of the variations of all resources such that one resource's negative deviation can offset some or all of another resource's positive deviation. The Commission stated that, when the transactions of two customers result in diversity benefits, it is incorrect to say that one customer is benefitting the other but not vice versa. Instead, the Commission preliminarily found that diversity benefits would result from both transactions and that sharing of these benefits among the customers would be reasonable. *Westar,*130 FERC ¶ 61,215 at P 37.

[291] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 105.

[292] *Id.* P 94.

variability and taking account of diversity benefits.[293] That is, any proposal for different volumes of generator regulation reserves based on the generating resource would need to be supported by data showing that, on the public utility transmission provider's system, VERs have a different per unit impact on overall system variability than conventional generating units.[294] The Commission proposed that such a filing must also show that the public utility transmission provider has fully implemented (or been granted waiver from) the intra-hourly scheduling requirement set forth in the Proposed Rule and has developed and deployed power production forecasting for VERs.[295]

281. Specifically, the Commission proposed that any filing by public utility transmission providers including different volumetric requirements for different subsets of transmission customers must be supported with actual data collected over a one-year period subsequent to the deployment of power production forecasting for VERs and the implementation of intra-hourly scheduling at 15-minute intervals. The Commission acknowledged that this proposal could delay a public utility's ability to recover the cost associated with providing generator regulation service. The Commission further acknowledged that there may be alternative methods for developing the data necessary to support different volumetric requirements for different subsets of transmission customers. The Commission sought comment as to such methods of demonstration, how they could support a Commission finding that the Schedule 10 filing is just and reasonable, and ways in which these methods of demonstration may be preferable to this aspect of the Commission's proposal.[296]

282. In the Proposed Rule, the Commission stated that the increased use of power production forecasts in transmission systems where VERs are located can provide transmission providers with improved situational awareness, enable transmission providers to utilize existing system flexibility through the unit commitment and dispatch processes, and, ultimately, lead to a reduction in the amount of reserve products needed to maintain system reliability. The Commission also recognized that, in areas of the country with very limited production from VERs, the implementation of power production forecasting for VERs could be less useful.[297] The Commission sought comment in the Proposed Rule on the manner by which a public utility transmission provider should be required to show it has developed and deployed power production forecasts to support a proposal to require a differentiated volumetric component of rates for generator regulation reserves under proposed Schedule 10.[298]

a. Comments

i. General

283. Invenergy Wind requests that the Commission clarify that, in requiring initial Schedule 10 charges to adopt the utility's then-effective Schedule 3 charges, the application of the rate will be consistent. Invenergy Wind states that Schedule 3 charges are typically applied on the basis of a percentage of the customer's schedule. Beacon Power questions the reliance on existing regulation service charges, stating that a transmission provider in non-RTO/ISO markets could optimize the performance of its existing fleet to potentially lower costs to customers under Schedule 3 or 10. Beacon Power requests that the Commission encourage such transmission providers to evaluate the technologies and benefits they provide. Xtreme Power agrees, asking the Commission to require public utility transmission providers to make a showing that the rates proposed for Schedule 10 are based on an appropriate type and quantity of resources needed, considering the technologies available in the market today rather than using dated rates from Schedule 3. CESA suggests that the reforms proposed for Schedule 3 in the Commission's Frequency Regulation Notice of Proposed Rulemaking be included in Schedule 10 for RTO and ISO markets.[299]

284. Some commenters suggest that public utility transmission providers be permitted to recover opportunity costs associated with providing generator regulation service.[300] For example, the Large Public Power Council states that, consistent with the decision in *Puget,* generator regulation service rates should be fully compensatory, and may legitimately reflect a utility's full opportunity cost.[301] According to Puget, there may also be lost opportunity costs associated with reserving unloaded generation capacity during peak market conditions. NRECA argues the integration of a significant amount of VERs will cause the Schedule 3 rate to rise as Schedule 10 demand increases particularly in regions with a lot of hydropower, where the additional VERs cause the need for more thermal reserves, which are more expensive than the existing reserve rate base.

ii. Quantity of Reserves

285. Some commenters request further direction from the Commission regarding the calculation of the volumetric component of Schedule 10, i.e., the quantity of reserves transmission customers are required to purchase or otherwise account for.[302] For example, the California PUC asserts that the Commission should recommend or require that a public utility transmission provider consider the system's resource mix and the amount of operational flexibility of the transmission system's generation fleet to develop the volumetric component of Schedule 10. LADWP indicates that measures of alleged diversity benefits may lead to unintended results if significant diversity occurs in one part of a year and forms the basis for a smaller volumetric component than is necessary for another part of the year.

286. Some commenters question whether the Commission should allow public utility transmission providers the opportunity to file for differentiated volumetric rates under Schedule 10. AWEA contends that it would be unjust and unreasonable and break with Commission precedent to allocate to generators the costs of Schedule 10, whether kept as a regulation reserve or reformulated to a system non-spin service, while allocating other ancillary services costs broadly to load. AWEA states that all users of the grid add variability and uncertainty and that all benefit when the grid is better able to accommodate variability and uncertainty. AWEA also argues that the capacity used to provide Schedule 10 service would be available to provide a number of other ancillary services, not to mention to the public utility transmission provider to meet peak demand.

287. Western Grid states that the integration costs of other types of generation are largely ignored and the

---

[293] *Id.* P 106.

[294] *Id.* P 95.

[295] *Id.* P 106.

[296] *Id.* P 107.

[297] *Id.* P 55 n.125.

[298] *Id.* P 106.

[299] CESA; *See also Notice of Proposed Rulemaking on Frequency Regulation Compensation in the Organized Wholesale Electric Markets,* 134 FERC ¶ 61,124 (2010) (Frequency Regulation NOPR); *Frequency Regulation Compensation in the Organized Wholesale Power Markets,* Order No. 755, 76 FR 67260 (Oct. 31, 2011), FERC Stats. & Regs. ¶ 31,324 (2011), *reh'g denied,* Order No. 755–A,138 FERC ¶ 61,123 (2012).

[300] *E.g.,* SMUD; WUTC; EEI; Large Public Power Council; Puget.

[301] *E.g.,* Large Public Power Council (citing *Puget Sound Energy,* 132 FERC ¶ 61,128 (2010)).

[302] *E.g.,* CPUC; LADWP; SEIA.

regulation and frequency costs imposed by large loads are broadly socialized. Western Grid therefore contends that grid integration costs related to VERs should be recovered in a manner comparable to the way grid integration costs imposed by large conventional generators are recovered. Argonne National Lab argues that calculating the net impact of VERs on regulation service needs is likely to be difficult and contentious and that to ensure just and reasonable treatment of all resources, the Commission should be careful in imposing specific requirements on VERs without considering the specific impacts on system reliability and operating reserve costs from other generating resources as well. Similarly, the Federal Trade Commission recommends that the Commission consider whether the costs of imbalance services provided to other types of generators can readily be identified and charged to the responsible parties.

288. Some commenters support the proposal to condition the implementation of differentiated volumetric rates on whether that transmission provider has implemented power production forecasting and intra-hour scheduling reforms.[303] AWEA states that Schedule 10 should not be charged at all until a transmission provider has fully implemented the Efficient Dispatch Toolkit and the Commission's proposed sub-hourly scheduling and variable energy forecasting operating reforms. Clean Line states that implementation of forecasting should be required before any special charges are assigned to renewable generators. Clean Line argues that, before transmission providers can charge a just and reasonable rate to recover ancillary service costs, they must use reasonable means to minimize those costs—such as forecasting.

289. Some commenters suggest that differentiated volumetric rates should be conditioned on implementation of additional reforms beyond those set forth in the Proposed Rule.[304] For example, Environmental Defense Fund maintains that a public utility transmission provider should not be permitted to establish different volumetric reserve requirements for VERs unless it has demonstrated to the Commission that the balancing authority area is optimally sized or cooperating with other balancing authority areas. Oregon & New Mexico PUC similarly state that Schedule 10 charges for VERs should be conditioned on a demonstration by the public utility transmission provider regarding the measures it has considered to increase cooperation with other balancing authorities to lower the cost of integrating wind and solar. First Wind argues that public utility transmission providers should only be permitted to charge for generator regulation service once they have implemented procedures for dynamic transfers in addition to intra-hour scheduling. CESA contends that, before imposing any generator regulation costs on VERs, public utility transmission providers should first implement fast intra-hour markets and intra-hourly scheduling; a robust ancillary services market; the option for third-party or self supply of ancillary services; dynamic transfer capability out of the balancing authority area; and Area Control Error (ACE) diversity interchange or an energy imbalance service market.

290. In contrast, ELCON asserts that Schedule 10 as proposed is a mechanism for the socialization of costs that should be directly assigned to VERs or their customers. Grant PUD argues that variable loads and variable resources should be charged differently for regulation service according to the nature of the different costs placed on the public utility transmission provider. A number of other commenters agree, objecting to any delay in cost recovery associated with providing generator regulation service.[305] For example, Pacific Gas & Electric and Idaho Power argue that public utility transmission providers incur costs to provide generator regulation service regardless of whether they are employing intra-hourly scheduling and, thus, preventing recovery of generator regulation service costs shifts those costs to other customers in violation of cost causation principles.

291. EEI opposes requiring a public utility transmission provider to commit specific actions before seeking rate recovery under section 205, particularly when such actions violate cost causation principles. EEI states that as articulated by the Commission in *Northern States Power Company,* ''[t]he *fundamental* theory of Commission ratemaking is that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the cost to be incurred.'' [306] According to EEI, the D.C. Circuit echoed this sentiment in *KN Energy, Inc.* v. *FERC,* ''[s]imply put, it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.'' [307] EEI and others state that, to the extent the Commission conditions generator regulation service cost recovery on implementing the Proposed Rule's reforms, the Commission should explain how such a limitation does not effectively force public utility transmission providers to waive their sections 205 and 206 rights under the FPA in contravention of *Atlantic City Electric Company.*[308]

292. Southern opposes conditioning public utility transmission providers' rights to recover rates under section 205 of the FPA for generator regulation and frequency response service on the implementation of such reforms. Southern argues that utilities have a statutory right to establish just and reasonable rates under sections 205 and 206 of the FPA. If the Commission pursues these limitations, Southern asks the Commission to explain how such a limitation does not effectively force public utility transmission providers to waive their section 205 and 206 rights.

293. LADWP argues that the proposed requirements would place public utility transmission providers in a defensive role. LADWP states that presuming a public utility transmission provider makes a sufficient showing that it implemented intra-hour scheduling and deployed power production forecasting for VERs, a transmission provider is further compelled to demonstrate the basis for any difference in regulating reserves between VER transmission customers and non-VER transmission customers. LADWP argues that this could put the public utility transmission providers in a defensive role of justifying the findings and conclusions within a system impact study report, in

[303] *E.g.,* AWEA; BP Energy; Iberdrola; Independent Power Coalition West; NextEra; Oregon & New Mexico PUC; Public Interest Organizations; Vestas.

[304] *E.g.,* Iberdrola; First Wind; Oregon & New Mexico PUC; Environmental Defense Fund.

[305] *E.g.,* Tacoma Power; Montana PSC; Pacific Gas & Electric; PNW Parties; NV Energy; Public Power Council; Natural Gas; WUTC.

[306] EEI at 29 (citing *N. States Power Co.,* 64 FERC ¶ 61,324, at P 13 (1993) (emphasis supplied) (citations omitted)).

[307] EEI at 29 (citing *KN Energy, Inc.* v. *FERC,* 968 F.2d 1295, 1300 (D.C. Cir. 1992); *Alcoa Inc.* v. *FERC,* 564 F.3d 1342, 1346 (D.C. Cir. 2009); *Illinois Commerce Commission* v. *FERC,* 576 F.3d 470, 476 (7th Cir. 2009); *Pub. Serv. Comm. of Wisc.* v. *FERC,* 545 F.3d 1058, 1067 (D.C. Cir. 2008); *Pac. Gas & Electric Co.* v. *FERC,* 373 F.3d 1315, 1320 (D.C. Cir. 2004)).

[308] EEI at 27–28 (citing *Atlantic City Elec. Co.,* 295 F.3d 1, 10 (2002) (finding that the Commission lacks the authority to require public utility transmission providers to cede their rights under section 205 of the FPA); MidAmerican at 26; Puget at 17 (questioning whether whether requiring one-year of data reporting interferes with a public utility transmission provider's rights under section 205 of the FPA); WUCT at 7 (questioning whether requiring 15-minute scheduling and one-year of data reporting interfere with a public utility transmission provider's rights under section 205 of the FPA)).

the event performed by the public utility transmission provider.

iii. Power Production Forecasting

294. Some commenters state specific opposition to linking power production forecasting to the implementation of differentiated volumetric rates under Schedule 10.[309] Southern argues the Commission would exceed its statutory authority if it required implementation of power production forecasting. Southern states courts have recognized that the Commission ''is a 'creature of statute,' having no constitutional or common law existence or authority, but only those authorities conferred upon it by Congress.'' [310] Southern contends that, because the FPA never mentions meteorological forecasting, it is beyond the scope of the Commission's authority. Southern explains that public utilities have long engaged in meteorological forecasting for load forecasting and dispatch purposes; however, there never has been an indication that such practices were within the scope of the Commission's jurisdiction, and the advent of VER generation has not added such forecasting to the scope of the Commission's authority.

295. While Bonneville Power acknowledges that centralized power production forecasts will facilitate system-wide benefits, Bonneville Power disagrees that such forecasts should be a prerequisite to the cost recovery of balancing reserve capacity used to provide generator regulation reserve-type services. Bonneville Power believes that such a requirement would shift costs to other users of the transmission system that would not be otherwise incurred but for the VER generation. Puget believes that requiring transmission providers to implement power production forecasting as a precondition to Schedule 10 cost recovery inappropriately shifts the costs of integrating VERs from the VER to the balancing authority. Southern argues that meteorological forecasting issues are business decisions that are best left to the transmission providers and the market. EEI states that it is not convinced that the power production forecasting requirements are necessary to support requiring a higher volumetric amount of Schedule 10 regulation service. According to EEI, the data necessary to substantiate a higher volumetric charge can be derived by analyzing the deviation between a VER's scheduled versus actual production. EEI, therefore, claims that requiring a public utility transmission provider to implement power production forecasting prior to establishing a higher volumetric rate creates a barrier to cost recovery.

296. Montana PSC notes that the Proposed Rule's data reporting requirements to support power production forecasting would only apply to generators that are 20 MW or larger. Montana PSC argues that conditioning differentiation of volumetric rates on the implementation of power production forecasting could unduly restrict application of Schedule 10 generation regulation charges to smaller resources. Montana PSC argues that all VERs one MW or greater should be responsible for Schedule 10 services that they cause.

297. Other commenters ask the Commission to mandate use of power production forecasting by all public utility transmission providers with significant amounts of VERs instead of relying on the public utility transmission owner's decision to charge differentiated Schedule 10 rates.[311] The ISO/RTO Council argues that, while transmission providers in areas with low to moderate levels of VER interconnection may be able to manage variability on their systems without using power production forecasting, areas with larger levels of VERs should be required to adopt power production forecasting tools to ensure that conditions affecting generation output can be anticipated and managed appropriately. SEIA suggests that each transmission provider that provides interconnection to or has interconnections with more than 50 MW of VERs should be required to develop a power production methodology to accommodate integration of VERs. First Wind contends that power production forecasting should be mandatory for public utility transmission providers with five percent of VER resources on their system. CPUC asks that the Commission clarify that any public utility transmission provider may require power production forecasting if VERs are currently or anticipated to become significant.

298. Some commenters support the Commission's recognition that certain regions may not have a need for VER power production forecasting because of a low likelihood of VERs development.[312] For example, Bonneville Power states that the requirement to implement centralized forecasting should not apply if the penetration of VERs is less than 10 percent of load served. Puget argues that it should not be required to use power production forecasting because it only serves one exporting VER in its region.

299. Several commenters provide detailed discussions of the various activities that public utility providers should be required to undertake in order to show power production forecasting is in use. Public Interest Organizations suggest that the Commission require public utility transmission providers to demonstrate that VER power production forecasts are incorporated into unit commitment, scheduling, and dispatch efforts. Oregon & New Mexico PUC state that at a minimum, a public utility transmission provider needs to demonstrate that it has requested meteorological and operational data from wind and solar generators and has integrated forecast information into control room operations.

300. Some commenters contend that the public utility transmission provider should demonstrate that it is using the VER forecast to efficiently and reliably commit and dispatch resources. These parties offer various criteria regarding costs, accepted industry practices, and performance metrics that should be required of public utility transmission providers in order to be deemed compliant with the Final Rule.[313] The California PUC states that, while it does not recommend that the Commission set specific minimum quality standards or cost maximums for VERs forecasts at this time, the Commission should monitor results of public utility transmission providers' assessments. If the quality of forecasts varies significantly among public utility transmission providers, the Commission may determine that minimum quality standards or maximum cost limits for VERs forecasts are necessary to prevent unjust, unreasonable, or unduly discriminatory rates.

301. Other commenters argue that the Commission should ensure that the risks associated with inaccurate schedules or resource specific forecasts remain with the VER.[314] Montana PSC states that the forecasting requirement should be the responsibility of VER instead of the public utility transmission provider. NorthWestern states that it is inappropriate to make

[309] *E.g.,* Bonneville Power; Montana PSC; Natural Gas; Public Power Council; Puget Sound Energy; NV Energy.

[310] Southern (citing *Cal. Indep. Sys. Operator Co.* v. *FERC,* 372 F.3d 395, 398 (D.C. Cir. 2004) (citing *Atlantic City Elec. Co.* v. *FERC,* 295 F.3d at 8)).

[311] *E.g.,* CPUC; ISO RTO Council; Midwest ISO; SEIA.

[312] *E.g.,* Bonneville Power; NextEra; PNW Parties.

[313] *E.g.,* AWEA; California PUC; Iberdrola; NaturEner.

[314] *E.g.,* AEP; Large Public Power Council; Midwest ISO Transmission Owners; Montana PSC; NorthWestern.

the public utility transmission provider responsible for forecasting the VER power output when it is the responsibility of the VER to provide its schedule. NorthWestern points out that, if the public utility transmission provider provides a forecast of the VER power production, as proposed by the Proposed Rule, and the VER submits a different schedule, Control Performance Standard 2 violations may occur that would not have occurred if an accurate power production forecast had been submitted by the VER. NorthWestern argues that the forecasting requirement would place the balancing authority in an unacceptable position if the forecast or power production data is inaccurate. Midwest ISO Transmission Owners state that regardless of whether the public utility transmission provider requires VERs to provide meteorological data or employs other tools in order to increase the effectiveness of scheduling and dispatching activities, all generation resources must retain the ultimate responsibility for determining their unit's deliverability; accordingly, variations from scheduled deliveries must remain the responsibility of the generating resource, including VERs.

302. Bonneville Power argues that, if the Commission requires centralized power production forecasts for public utility transmission providers with significant amounts of VERs on their systems that intend to differentiate their Schedule 10 pricing, it is preferable that the Commission also require all VERs to schedule according to the centralized forecast component for each plant. Puget explains that, if the public utility transmission provider's forecast sets the schedule, then there could be a perverse incentive for public utility transmission providers to generate inaccurate forecasts and collect larger generator imbalance charges under Schedule 9; however, if the VER is permitted to set its own schedule that differs from the public utility transmission provider's forecast, it remains unclear how the public utility transmission provider is supposed to manage and deploy its resources—according to its own forecast or to the VER's schedule. Puget requests that these questions be clarified before the Commission implements a power production forecasting requirement for public utility transmission providers, whether as a stand-alone mandate or as a precondition to Schedule 10 cost recovery.

303. Invenergy argues that the Final Rule should hold public utility transmission providers: (1) Accountable for the accuracy of the forecasts that they use to determine regulation capacity requirements; and (2) to performance levels that current technology supports. Invenergy states that ISOs and RTOs that have implemented centralized wind forecasting are generally realizing accuracy rates of 89 percent or greater. Invenergy argues that the Final Rule should require the public utility transmission provider to provide customers with forecasting performance metrics on a periodic basis and, if forecasts do not prove to be reliable, require the public utility transmission provider to take immediate steps (including improving its forecasting systems and equipment or relinquishing responsibilities to an independent third party) to ensure that future forecasts are accurate.

304. Commenters state that in RTO regions, the RTO would be the more appropriate entity to conduct power production forecasting. National Grid asks the Commission to clarify who the ''transmission providers'' are that will undertake the energy forecasting responsibility. National Grid states that the role of developing and implementing energy forecasting tools is well suited to a centralized entity with existing capabilities in data collection, region wide system forecasting and centralized dispatch responsibilities such as RTOs and ISOs. National Grid requests that the Commission clarify that for the purposes of its data forecasting Final Rule the term ''transmission provider'' means the ISOs or RTOs in those regions, as this avoids confusion where the term ''transmission provider'' can refer to either the ISO or its members.

305. Some commenters point out that many regions are currently undertaking their own forecasting and data gathering initiatives or programs to integrate VERs, and request that the Commission allow for regional flexibility.[315] Pacific Gas & Electric requests that individual public utility transmission providers be given flexibility on how to implement that requirement. Pacific Gas & Electric requests that in its Final Rule the Commission provide latitude for the California ISO and other similarly situated transmission providers to continue their existing programs to gather the relevant meteorological and operational data, and to propose incremental refinements to them, so long as the programs maintained by these transmission providers can accomplish the purposes set forth in the Proposed Rule for gathering this information.

[315] *E.g.,* Massachusetts DPU; Pacific Gas & Electric; Midwest ISO.

iv. One Year Data Requirement

306. Some commenters contend that the proposal to require public utility transmission providers to collect power production forecasting data for one year prior to instituting a differentiated regulation requirement for VERs violates cost causation principles and imposes costs of balancing reserve capacity needed for VERs on other customers.[316] Such commenters maintain that the one-year data collection requirement unreasonably delays public utility transmission providers from demonstrating that they are entitled to recover different volumetric amounts associated with providing generator regulation service from different types of generators.[317] Bonneville Power argues that there may be sound economic and operational bases for providing or procuring differential quantities of incremental and decremental balancing reserve capacity. Western Farmers suggest that the Commission allow public utility transmission providers to propose the volumetric component of the Schedule 10 charge along with the proposed rates in their initial Schedule 10 compliance filing. Natural Gas and Puget similarly argue that public utility transmission providers should have an opportunity to allocate ancillary service costs as soon as they are justifiably able to do so. MidAmerican contends that the one-year data collection requirement is inconsistent with the *Westar* precedent.

307. Some commenters suggest that public utility transmission providers should be permitted to establish rates using historical data, subject to adjustment as necessary over time.[318] For example, Bonneville Power states that rates can be updated as public utility transmission providers gain experience with reductions in the need for balancing reserve capacity requirements associated with intra-hourly scheduling, centralized forecasting and any other initiatives. Similarly, Puget suggests that reductions in the VERs volumetric component could be incorporated into a subsequent rate filing after implementation of 15-minute scheduling and power production forecasting by the utility. NorthWestern suggests that, just as the Commission routinely allows a proposed rate to take effect on an interim basis subject to refund until final approval is received, the Commission likewise should consider

[316] *E.g.,* Bonneville Power; Puget; MidAmerican; Southern California Edison; Natural Gas.

[317] *E.g.,* EEI; MidAmerican; Puget; WUTC.

[318] *E.g.,* Bonneville Power; Southern California Edison; California PUC; EEI; NorthWestern.

applying a similar principle in allowing interim regulating service cost recovery. Pacific Gas & Electric proposes that until one year's worth of data are available, public utility transmission providers should be able to use simulated data to estimate the relative contribution of load, imports, VERs and other generation for the overall need for generator regulation reserves.

308. In contrast, Vestas argues that public utility transmission providers should be required to implement the two operational changes immediately and then collect data over at least the next 12 months regarding the levels of schedule deviations on their systems for all types of generation. According to Vestas, the Commission should require the submission of that data to the Commission and take comments from interested market participants on the appropriate rate mechanism to permit the recovery of any costs incurred to address remaining variations between generator schedules and generator output.

309. Organization of Midwest ISO States asks the Commission to require public utility transmission providers with significant VER capacity, such as three percent or more of total capacity, to submit statistical data on the variability of generation across the different types of generation resources and load. If there is a significant difference between types of resources, Organization of Midwest ISO States contends that the public utility transmission provider should be required to allocate the costs of increased regulation and other ancillary services developed in the future to the generation resources causing those costs.

v. Other

310. Some commenters express concern about the static nature of the rates and volumes in Schedule 10.[319] SEIA argues that public utility transmission providers who have selected a methodology and begun to apply different Schedule 10 rates for different categories of customers should be required to revisit their forecasting methodologies and rates on a regular basis. RenewElec notes that data collected over a one-year period that may feature anomalies (e.g., wind droughts). RenewElec suggests that the Commission require transmission providers to retain data provided under the new *pro forma* LGIA Article 8.4 for at least 10 years and commit to performing annual follow-up studies over a period of not less than five years that update power production forecasts with new data received. RenewElec suggests that the Commission include a biannual re-opener provision for VER-specific Schedule 10 charges, or through other review and implementation combinations.

311. NaturEner asserts that an annual re-evaluation of the integration charge needs to be undertaken to take into account the impact of increased diversity, improved operations, market innovations and other changed circumstances, as well as to correct any inaccuracy in the original (or immediately prior) assessment. NaturEner also requests clarification regarding whether a VER transmission customer could be required to pay a VER integration charge in arrears if a public utility transmission provider is subsequently permitted to levy the charge.

312. Some commenters oppose the Commission's proposal to group resources together for the purpose of allocating Schedule 10 volumes.[320] For example, BrightSource states that assigning all VERs the same regulation requirement could distort the incentives created by the cost allocation if they are evaluated as a single, undifferentiated class. First Wind asserts that the rate should be designed to recognize the actual variability of output of the resource paying the rate because two wind generation projects of the same installed capacity and energy production might have different levels of variability due to factors such as local differences in the variability of the "wind resource" (the relative wind generating value of the location); the number, size, and manufacturer of the wind turbines; and differences in distances between wind turbines. RenewElec offers that high capacity wind generation units have a disproportionally smaller impact on variability than lower capacity units. According to AWEA, the variability of resources within a category cancels each other out to the benefit of those resources in that category, imposing a disadvantage on customers that are grouped in smaller categories.

313. Snohomish County PUD questions whether it is appropriate to apportion any volume of generator regulation reserves to behind-the-meter generation. Snohomish County PUD contends that variations in output from the behind-the-meter generator are, from the perspective of the public utility transmission provider, indistinguishable from variations in the distribution utility's load. Accordingly, Snohomish County PUD asks the Commission to clarify that behind-the-meter generators—those that are interconnected directly to and consumed by the load of the local distribution utility rather than a transmission utility—will not be required to purchase generator balancing capacity from the public utility transmission provider in the absence of a voluntary agreement between the public utility transmission provider and the generator to install appropriate metering that measures the variability of the generator and to pay the Schedule 10 charges justified by that variation.

314. Several commenters suggest that the Commission convene a technical conference or require other processes to determine the appropriate per-unit and volumetric rates under the proposed Schedule 10.[321] AWEA states that a technical conference would be appropriate to establish consistent principles for determining the methodology that should be used for calculating and allocating Schedule 10 costs. Some commenters request that the Commission require stakeholder involvement in connection with the development of Schedule 10 volumes.[322] For example, First Wind requests that the Commission require RTOs to conduct a robust and transparent stakeholder process which attempts to reach consensus prior to them making an allocation filing, and that non-RTO public utility transmission providers conduct public workshops prior to any allocation filing.

b. Commission Determination

315. For the reasons discussed above, the Commission is not implementing a generic Schedule 10 to the *pro forma* OATT for generator regulation service. Instead, the Commission takes this opportunity to respond to the individual commenter concerns regarding the proper design of a generator regulation service charge in order to provide guidance in the development of proposals for such services.

316. In response to the Large Public Power Council and Puget, those public utility transmission providers that choose to propose a rate schedule for generator regulation service may include opportunity costs for generator regulation service in certain circumstances. Such resources are often dispatched in the middle of their operating range to allow the generator to provide regulation-up as well as

[319] *E.g.,* SEIA, RenewElec, NaturEner.

[320] *E.g.,* BrightSource; FirstWind; RenewElec; AWEA.

[321] *E.g.,* AWEA; BrightSource; EPSA; SEIA.

[322] *E.g.,* California PUC; First Wind; SEIA.

regulation-down and as a result forego other opportunities. Not to allow compensation would create a barrier to the provision of services by frustrating the recovery of legitimate costs.

317. A number of commenters question the appropriate design of the volumetric component of Schedule 10 rates, i.e., the component in the Proposed Rule that allowed public utility transmission providers to require different transmission customers (or generator classes) to purchase or otherwise account for different quantities of regulation reserves based on cost causation principles. The Commission agrees that calculating the relative impact of individual customers or customer classes on a public utility transmission provider's overall generation regulating reserve needs and allocating those costs accordingly can be a difficult and complex determination. However, the Commission believes that the complexity of these proceedings can be mitigated where entities take note of, and incorporate, the following principles.

318. First, public utility transmission providers seeking to distinguish customers into classes for the purpose of requiring them to purchase or otherwise account for different quantities of generation regulating reserves should do so only to the extent such classes and distinctions among classes are reasonably related to operational similarities and differences among those resources.[323]

319. Second, to the extent a public utility transmission provider proposes to break customers into specific groups based on operational characteristics, we expect public utility transmission providers to provide detailed explanations as to why such classifications are appropriate if and when they propose to allocate different generating regulation reserve obligations to different customer classes. The Commission has required that overall generator regulation requirements be established by taking diversity benefits into account. Diversity benefits result from aggregating the variations of all resources so that one resource's negative deviation can offset some or all of another resource's positive deviation. When the transactions of two customers result in diversity benefits, it is incorrect to say that one customer is benefitting the other but not vice versa. Instead, the diversity benefits result from both transactions and sharing of these benefits among the customers is reasonable. In *Westar,* the Commission found that this portfolio-wide approach to assessing generator regulation charges appropriately shares diversity benefits among generators and load.[324] Ultimately, this concept will need to be reconciled with any customer classifications proposed by the public utility transmission provider in a way that prevents any over-recovery of these capacity costs.

320. Third, to the extent a public utility transmission provider proposes to differentiate among customers (or customer classes) in determining their relative regulating reserve responsibilities, the public utility transmission provider must demonstrate that the overall quantity of regulating reserve it requires of its transmission customers accounts for diversity benefits among all resources and loads, and the allocations to individual customers (or customer classes) of their proportionate share is based on the operational characteristics of such customers (or customer classes).

321. Fourth, weather events such as droughts may affect the required quantity of generator regulating reserves that the public utility transmission provider must have in reserve more or less during one portion of the year versus another portion of the year. In such cases, these diversity events, though perhaps characterized as anomalies, should be included in the data set so that the quantity and costs of such reserves are more reflective of actual system operations.

322. Fifth, there is a relationship between the use of intra-hour scheduling by transmission customers and the quantity of reserves needed to provide Schedule 9 generator imbalance service. In other sections of this Final Rule, the Commission requires all public utility transmission providers to offer transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals, noting that over time public utility transmission providers will be able to rely more on planned scheduling and dispatch procedures and less on reserves to maintain overall system balance. In the Proposed Rule, the Commission sought comment on whether to condition the ability of public utility transmission providers to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves on the implementation of intra-hour scheduling reforms. Given that such reforms are mandated in this Final Rule, the Commission concludes that condition to be satisfied.[325] In designing any proposals for generator regulation service charges, a public utility transmission provider should consider the extent to which transmission customers are using intra-hour scheduling in evaluating whether to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves.

323. Sixth, there also is a relationship between the use of power production forecasting and the allocation of generator regulation reserve quantities to a particular class of customers. The record in this proceeding demonstrates that the quantity of reserves used to provide generator regulation service can be most efficiently managed with the implementation of power production forecasting (as well as intra-hour scheduling) by public utility transmission providers. While commenters disagree on the extent to which power production forecasting may affect reserve commitments, the Commission finds that power production forecasts can provide public utility transmission providers with advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than through the deployment of reserve services, such as regulation reserve. Without the increased situational awareness of projected variability provided by power production forecasts, the public utility transmission provider's ability to commit or de-commit resources providing regulation reserves efficiently can be constrained. This lack of situational awareness potentially can result in rates for generator regulation service that are unjust and unreasonable or unduly discriminatory.

324. We recognize that conditioning the allocation of different quantities of regulation reserves to different transmission customers on the public utility transmission provider developing and deploying power production forecasting is contentious. On one hand certain public utility transmission providers believe that they should either be able to use historical data or make other approximations to establish the quantity of regulation reserves to be required of a given transmission customer or class of customers. On the other hand, transmission customers that are VERs contend that the Commission has not gone far enough and that additional reforms are necessary to

[323] *See Westar,* 137 FERC ¶ 61,142 at PP 27–28.

[324] *See Westar,* 130 FERC ¶ 61,215 at PP 37–38.

[325] *See supra* IV.A.1 (Intra-Hour Scheduling Requirement).

ensure that VERs do not disproportionately bear the burden of the cost of regulating reserves. The Commission believes that public utility transmission providers need an effective opportunity to file for cost recovery, while VERs need assurance that they are not unduly assigned costs.

325. Accordingly, while the Commission reserves judgment as to the appropriate power production forecasting requirements for a particular public utility transmission provider, we expect that the implementation of power production forecasting will be addressed in any proposal to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves. For example, a public utility transmission provider could demonstrate that it is utilizing power production forecasts (or other comparable technique) to manage system operating costs and/or to improve reliability by enabling the more efficient commitment and dispatch of resources. The Commission agrees with the California PUC that, as part of such a demonstration, the public utility transmission provider should explain how the data required from VERs are incorporated into the power production forecast and how the resulting forecast is used to support the management of operating costs and/or reserves or otherwise ensure that capacity costs incurred to provide Schedule 9 service are prudently incurred.

326. The Commission declines to require the additional forecasting-related showings suggested by NaturEner and others. The technologies and techniques for power production forecasting are still being refined and may differ from region to region. While the recommendations made by AWEA, Iberdrola, and NaturEner may be appropriate benchmarks for power production forecasts utilizing today's technology, the Commission believes that pre-defining these additional criteria would not provide the flexibility needed for public utility transmission providers to adopt new forecasting techniques or technologies as they are developed. The Commission also declines to adopt the further recommendations of the California PUC and others to include monitoring and reporting requirements for public utility transmission providers that engage in power production forecasting. The Commission finds adopting these requirements to be unnecessary at this time.

327. However, the Commission agrees with Iberdrola and others that the public utility transmission provider should make the results of any centralized forecast used by the public utility transmission provider available through a secure information exchange to VER generators providing related data. The Commission believes that the VERs should be able to access the results of the public utility transmission provider's forecast in order to ensure that the forecasting service is producing accurate results. Thus, public utility transmission providers proposing to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves should explain in their proposals how forecasting results will be shared.

328. In response to comments regarding forecasting risk, the Commission clarifies that the transmission customer is responsible for the accuracy of transmission schedules and the public utility transmission provider is responsible for the reliability of its system. Therefore, the public utility transmission provider would utilize the power production forecast to identify the necessary amount of reserves and to use those reserves to maintain reliability of the transmission system. The obligation of the transmission customer is to submit schedules for deliveries. Power production forecasting is intended to inform the transmission provider regarding aggregate system variability that results from having VERs on its system, not to replace transmission schedules from transmission customers delivering from VERs. Public utility transmission providers using power production forecasts should do so to manage uncertainty in the same manner they use other forecasts of uncertainty for the transmission system. For example, despite service agreements to serve load, public utility transmission providers develop and use load forecasts to assure load can be met reliably and efficiently. Similarly, despite transmission schedules to deliver from a VER, public utility transmission providers should use power production forecasts to assure energy can be provided to load in a reliable and efficient manner.

329. Therefore, the Commission agrees with NorthWestern and others that the transmission customer maintains responsibility for the accuracy of its transmission schedule. However, we disagree with NorthWestern's interpretation concerning NERC Control Performance Standard 2 violations. A public utility transmission provider is not responsible for submitting a transmission schedule on behalf of a VER. As explained above, power production forecasting would be utilized to identify and acquire the appropriate amount of reserves needed to integrate VERs reliably. Nothing in this Final Rule alleviates the public utility transmission provider's obligations under NERC Reliability Standards.

330. The Commission declines to require transmission customers delivering from a VER to submit transmission schedules according to the public utility transmission provider's forecast, as suggested by Bonneville Power. While the public utility transmission provider is able to forecast the *aggregate* variability of the system with greater accuracy through centralized power production forecasting, the individual VER may be better able to produce the most accurate schedule for its particular facility. Requiring a transmission customer to submit transmission schedules for VER deliveries according to a centralized forecast would cloud the delineation between the obligations of the VER and the obligations of the public utility transmission provider with respect to the provision of transmission service.

331. The Commission disagrees with Puget's example, and clarifies that the public utility transmission provider's obligation should be to deploy its resources according to its own forecast in order to maintain the reliability of the system. The public utility transmission provider retains the risk and responsibility for inaccurate procurement of reserve requirements while the transmission customer retains the financial risk and responsibility for inaccurate schedules. The Commission finds that the incentive to avoid Schedule 9 generator imbalance penalties and any relevant charges for generator regulation service provides sufficient incentive for VERs to submit an accurate schedule.

332. The Commission agrees with National Grid and others that, as the entity providing transmission service under an OATT, the ISO or RTO would engage in power production forecasting within its region. In response to Pacific Gas & Electric and others requesting flexibility to implement power production forecasting, the Commission finds that the guidance provided affords sufficient flexibility to allow public utility transmission providers to tailor their forecasting programs to meet their needs, whether for the purpose of developing proposals for generator regulation charges or otherwise.

333. The Commission emphasizes that the foregoing discussion is intended to provide a framework to assist public utility transmission providers in

developing proposals for generator regulation service should they desire to do so. The Commission does not intend this guidance to preclude a public utility transmission provider from making an alternative proposal under section 205 of the FPA. However, it does provide guidance to public utility transmission providers regarding the facts and circumstances that the Commission may find relevant in evaluating such proposals.

334. A number of commenters challenged the Commission's proposal to condition proposals that require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves on performance of the activities discussed above. These arguments have largely been rendered moot by the Commission's decision not to adopt the Proposed Rule in that regard. Even as applied to the guidance provided above, the Commission disagrees that a future decision by the Commission to condition proposals that require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves on the performance of certain actions would violate cost causation principles or otherwise would preclude public utility transmission providers from recovering prudently incurred costs. In reviewing any future proposal to allocate a greater quantity of capacity costs to a particular set of transmission customers, it would be reasonable for the Commission to consider whether the public utility transmission provider has taken steps to mitigate such costs. This does not mean, as some commenters imply, that the public utility transmission provider has no other means to recover its costs. The public utility transmission provider could continue to rely on existing rate mechanisms to recover reserve costs or may propose to require a uniform quantity of generation regulating reserves from all transmission customers that is commensurate with transmission customers' proportionate effect on net system variability and taking diversity benefits into account.

335. The Commission agrees with commenters that implementing other reforms, such as consolidating balancing authority areas or implementing an ancillary services market, may be beneficial to the reliable and efficient integration of VERs. However, the Commission is not persuaded that these additional reforms are a necessary precondition to proposals that require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves. As noted in the Proposed Rule, many of these additional reforms are being discussed in other forums. The Commission will continue to monitor these proposals as they develop and modify our approach to this issue as appropriate as conditions develop.

3. Use of Contingency Reserves

a. Commission Proposal

336. In the Proposed Rule, the Commission sought comments from NERC and industry stakeholders on the steps needed to resolve confusion regarding the use of contingency reserves to manage extreme ramp events of VERs.[326] The Commission also sought comments from NERC and industry stakeholders on the extent to which some additional type of contingency reserve service (beyond the services provided under Schedule 5 and 6 of the *pro forma* OATT) would ensure that VERs are integrated into the interstate transmission system in a non-discriminatory manner while remaining consistent with NERC Reliability Standards.[327]

b. Comments

337. NERC indicates that large wind ramping events are similar to conventional generator contingency events in that they are large and relatively infrequent, yet they differ in that wind ramps are much slower than instantaneous contingency events and may be possible to forecast. NERC states that the use of contingency reserves to address wind ramps is similar to what is used to address large, relatively infrequent wind ramps because contingency reserves are seldom deployed, yet long ramp durations can make it difficult to include wind ramps as actual contingencies. NERC explains that Resource and Demand Balancing (BAL) Reliability Standard BAL–002 (Disturbance Control Performance) requires ACE to be restored 15 minutes following the disturbance (R4) and the contingency reserves to be restored within 105 minutes (90 minutes after the 15 minute disturbance recovery period—R6). NERC states that both of these requirements can be problematic for wind ramps because they can be longer than the disturbance recovery period as well as the reserve restoration period.

338. Still, NERC indicates that it may be appropriate to use contingency reserves in response to a portion of a wind ramp. NERC states that shared contingency reserves could be used to initiate the response, allowing time for alternate supply (or load reduction) to be implemented. NERC suggests that the industry consider developing rules governing reserve deployment and restoration, similar to those that currently address conventional contingencies.

339. Other commenters express openness to using contingency reserves for wind events.[328] Commenters indicate that there are discussions in the Northwest Power Pool (NWPP) about the use of contingency reserves for wind events.[329] AWEA contends that contingency reserves should be used for the initial period of an extreme wind ramp because both contingency events and extreme wind ramp events are very infrequent, and therefore, the use of contingency reserves for extreme wind ramp events would be highly unlikely to coincide with a need to use those reserves for a conventional generator's contingency event. NextEra urges the Commission to convene a technical conference to address how to deploy contingency reserves to address ramp events in a manner that will promote reliability.

340. Xcel indicates that there is confusion regarding the use of contingency reserves to manage extreme ramping events. Xcel states that the confusion arises as entities attempt to define the allowable triggering events for the activation of contingency reserves. Xcel recommends that the standard for contingency reserve activation include disturbances related to less-than-anticipated VER (e.g., wind) production, sudden drop-off of VER production, or associated ramp limitations on balancing resources due to forecast errors. Xcel contends that ramp events related to VERs are not necessarily caused by the sudden failure of generation, but instead may be due to an incorrect wind forecast or limited dispatchable generation response. For these reasons, Xcel recommends: (1) Expanding the definition of disturbances to include ramp events which may occur over a half-hour time frame; (2) including a measurement technique related to a ramp event in BAL–002; (3) identifying a specific

[326] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 100 (citing Schedule 5 (Operating Reserve—Spinning Reserve Service) and Schedule 6 (Operating Reserve—Supplemental Reserve Service) respond to contingency events. Spinning Reserve Service is used to serve load ''immediately in the event of a system contingency'' whereas Supplemental Reserve Service ''is not available immediately to serve load but rather within a short period of time.'').

[327] *Id.* P 100.

[328] *E.g.,* Powerex; NaturEner; California PUC; MidAmerican.

[329] *E.g.,* Powerex; Tacoma Power.

restoration period in BAL–002 (e.g., 45 minutes) related to contingency reserves that were deployed for ramping events; and (4) identifying compliance metrics and other issues related to deployment of contingency reserves for ramp-limited events. Xcel recommends that the Commission request that NERC begin a standards drafting process to consider revisions to the existing BAL–002 standard to address the issues discussed by Xcel.

341. Other commenters express reservations with using contingency reserves in response to wind events is an improper use of contingency reserves.[330] Duke indicates to the extent that there is a need for a new service to address VER ramp rates, a new rate schedule should be developed for such a service. Pacific Gas & Electric states that there may be a need for new integration services to incorporate VERs into the reliable operation of the grid. Pacific Gas & Electric submits that various industry activities are already underway to consider these issues, and the Final Rule should endorse their continued efforts.

c. Commission Determination

342. Based on comments received, the Commission concludes that the issues related to the appropriate use of contingency reserves under NERC Reliability Standards need further study and vetting before any action is considered. Indeed, comments range from expressing confusion over what would constitute an extreme VER event to asking the Commission to define ''ramp'' with some specificity. Rather than opining on any of the comments and risk providing guidance without the benefit of more information, the Commission finds that the better course of action is to allow industry to continue its work and direct our staff to monitor those efforts and engage industry as appropriate.

V. Other Issues

1. Regulatory Text

a. Commission Proposal

343. As part of the Proposed Rule, the Commission sought comment on a minor revision to 18 CFR 35.28. To date, when amending its regulations concerning the open access requirements of the *pro forma* OATT, the Commission has listed by name Commission rulemaking proceedings promulgating and amending the *pro forma* OATT when explaining the details of a public utility transmission provider's obligation to have an OATT on file with the Commission. The Commission proposed to no longer explicitly reference, by name, prior Commission rulemaking proceedings promulgating and amending the *pro forma* OATT in its regulations. Likewise, the Proposed Rule included a similar change with respect to a public utility transmission provider's obligation to have standard generator interconnection procedures and agreements and standard small generator interconnection procedures and agreements on file with the Commission.[331]

b. Comments

344. No comments were received on this aspect of the Proposed Rule.

c. Commission Determination

345. The Commission adopts its proposed minor revision to 18 CFR 35.28. We find that the existing process for amending regulations concerning the *pro forma* OATT, which necessitates listing by name Commission rulemaking proceedings promulgating and amending the *pro forma* OATT when explaining the details of a public utility transmission provider's obligation to have an OATT on file with the Commission, is increasingly cumbersome and provides little, if any, benefit. Thus, the Commission will no longer explicitly reference, by name, prior Commission rulemaking proceedings promulgating and amending the *pro forma* OATT in its regulations. Likewise, the Final Rule adopts a similar change with respect to a public utility transmission provider's obligation to have standard generator interconnection procedures and agreements and standard small generator interconnection procedures and agreements on file with the Commission.

2. Market Mechanisms

a. Comments

346. Several commenters ask the Commission to revise specific RTO and ISO market rules not at issue in the Proposed Rule, while other commenters seek to have the Commission address additional market mechanisms for the non-RTO and ISO areas. For example, Environmental Defense Fund states that the Proposed Rule does not reform the day-ahead market to increase VER participation and decrease the amount of costly out-of-market commitments, leading to unjust and unreasonable rates, and undue discrimination against VERs. In addition, ACSF asserts that scheduling in the day-ahead market and in the unit commitment process should be reformed. ACSF states that the technology that makes 15-minute schedules feasible in the spot market also makes reforms possible in these other areas. According to ACSF, it is important to prevent the least clean and efficient generation from dominating dispatch at all hours, especially in the unit commitment process.

347. Environmental Defense Fund further states that because VERs are only permitted to bid a portion of their capacity into the market, they generally receive a lower price. According to Environmental Defense Fund, many capacity markets require bidders to also participate in the day-ahead market, which most VERs do not do because of the financial risk associated with failing to meet day-ahead obligations. Thus, Environmental Defense Fund argues that the Commission must consider the available options to facilitate VER participation in capacity markets.

348. With regard to non-RTO regions, EPSA states that the Proposed Rule does not sufficiently address the lack of market mechanisms available in non-RTO regions to conventional generation resources, which have the ability to contribute to VERs integration. EPSA suggests that possible market mechanisms and other competitive options for integrating VERs in the non-RTO regions should be considered as part of the technical conference that EPSA has requested. Similarly, Independent Power Producers Coalition—West states that without an organized ISO or RTO market, public utilities must face regulatory pressure to advance their integration of VERs and sharing of data, otherwise the utilities have little incentive to move toward better integration between transmission providers and balancing authorities. Independent Power Producers Coalition—West contends that the lack of a competitive ancillary services market that would allow independent power producers the opportunity to provide generator imbalance services in WECC results in unjust and unreasonable rates.

349. Tres Amigas contends that Order Nos. 888 and 890 have left little room for a market to develop balancing services outside of an ISO/RTO, because the primary provider of these services, the balancing authority, has to acquire the capability to provide the ancillary services on behalf of all its transmission customers and then sell the services at cost-based rates. Tres Amigas states that the Commission should have a two-fold objective: (1) Determining how market

[330] *E.g.,* Tacoma Power; ENBALA; Grant PUD; California ISO; Duke; Pacific Gas & Electric.

[331] Proposed Rule, FERC Stats. & Regs. ¶ 32,664 at P 12 & n.29.

forces can identify and competitively price the resources that will be used by balancing authorities for balancing; and (2) establishing appropriate mechanisms for allocating the costs incurred by balancing authorities to acquire these resources in the marketplace. Further, Tres Amigas asserts that the Commission should grant market-based rates to new entrants in order to promote formation of a vibrant market for balancing services that includes participation by new technologies. Tres Amigas states that the balancing authorities should then file proposals to allocate the costs incurred to balance the system among load and generation (including generation within the control area that is scheduled to another control area). According to Tres Amigas, these cost allocation proposals should take into account the extent to which different market participants contribute to the costs of acquiring balancing services and benefit from such services.

350. Recycled Energy urges the Commission to consider implementing various payments designed to compensate efficient gas generators and combined heat and power facilities for the flexibility they provide to utilities. In addition, Recycled Energy asserts that the Commission could improve the grid's reliability and efficiency by encouraging the placement of distributed generators in ways that reduce line losses and obtain ancillary benefits. Similarly, Business Council asserts that the OATT should be revised to ensure that flexible resources (such as natural gas and pumped storage facilities) are better able to provide their services to system operators who integrate VERs, and that these services are properly valued. Business Council explains that flexible generation resources should be given more opportunities to sell their balancing services to transmission providers and should be paid a just and reasonable rate for these services. Business Council argues that if the Commission adopts a universal requirement for 15-minute scheduling, it should make clear that generators should be able to supply balancing services on the same 15-minute (or less) basis.

b. Commission Determination

351. The *pro forma* OATT terms and conditions of service create the platform by which the public utility transmission provider makes available non-discriminatory open, access transmission service. Since the issuance of Order No. 888, the Commission has taken numerous actions to ensure that the principles enunciated in that rule continue to remain true, allowing all types of resources—existing and new—access to the grid for the benefit of developing competitive markets. In response to commenters like Independent Power Producers-West, EPSA and Tres Amigas who assert that the Commission should take various steps to establish a competitive ancillary services market or other market mechanisms, we believe that the reforms in this Final Rule continue to facilitate the development of competitive markets without imposing any particular type of structure for doing so. The Commission allows third party sellers to make sales of ancillary services at market-based rates, requires all public utility transmission providers to offer open access transmission service and undertake open and transparent transmission planning, and allows transmission customers to self-supply their own ancillary services. The Commission has long-standing precedent on cost allocation and has long supported reserve sharing and power pooling arrangements. Nothing in this rule is intended to prevent or create a barrier to the further development of competitive markets. Indeed, we think that the reforms adopted herein should help to facilitate the further development of competitive markets by allowing transmission customers to tailor their transmission schedules and, in turn, better manage generator imbalance and ancillary services costs. As the liquidity of intra-hour energy products stabilizes, market participants also may begin to commit or otherwise acquire fewer reserves in advance, with the knowledge that they can purchase additional reserves on an as-needed basis from third parties. Requiring public utility transmission providers to offer intra-hour scheduling is a necessary predicate to facilitate these market opportunities.

352. For similar reasons we decline the request from Recycled Energy and Business Council to expand the scope of this rulemaking proceeding to include additional payments to flexible generation. Both commenters urge the Commission to adopt mechanisms that would increase payments to flexible generation resources, such as high-efficiency natural gas facilities, so as to properly value the flexibility they provide to transmission providers. The Commission has already addressed, in the context of the organized markets, compensation for resources providing frequency regulation and is currently exploring a similar issue in bilateral markets outside of RTOs and ISOs.[332] In this proceeding, the Commission is primarily concerned with providing reforms that will provide public utility transmission providers with greater awareness of the variability experienced on their systems, as well as providing transmission customers with a tool to manage imbalances from schedules by providing for 15-minute adjustments to schedules. How these public utility transmission providers choose to provide this service is beyond the scope of this inquiry.

353. With regard to commenters that request additional changes to the RTO and ISO day-ahead and capacity markets to facilitate VER integration, we fail to see the direct connection between the specific reforms of the Commission's Proposed Rule and the reforms requested. Commenters did not establish that connection and failed to demonstrate that the Commission's proposed reforms are unjust and unreasonable without the additional requested reforms. Instead, these commenters merely asked that the Commission extend the scope of the rule. As such, we find that commenters' requests that we require additional reforms to RTO/ISO day-ahead, residual unit commitment, and capacity market rules are beyond the scope of this proceeding.

354. Finally, we cannot allow sales of energy or capacity at unchecked rates, even by new entrants, as suggested by Tres Amigas.[333] As noted above, the Commission allows for sales at market-based rates upon a showing of lack of market power and is in the process of considering ways to streamline the market-based rate showing for certain ancillary services.[334]

c. Pipeline Transportation Nomination Procedures

i. Comments

355. Some commenters assert that if the Commission requires transmission providers to allow intra-hour transmission scheduling to accommodate VERs, the Commission must also consider the impact of such requirements on the operation of natural-gas-fired electric generation

[332] *See Frequency Regulation Compensation in the Organized Wholesale Power Markets,* Order No. 755, 76 FR 67260 (Oct. 31, 2011), FERC Stats. & Regs. ¶ 31,324 (2011); *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies,* 139 FERC ¶ 61,245 (NOPR).

[333] *See Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities,* Order No. 697, 72 FR 39904 (July 20, 2007), FERC Stats. & Regs. ¶ 61,295, at P 320 (2007).

[334] *See Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, 139 FERC ¶ 61,245 (NOPR).

units, and the concomitant need to modify pipeline transportation service nomination procedures to calibrate gas transportation and usage more closely with the operation of natural gas-fired electric generation units to support VERs.[335] Specifically, APPA contends that despite access to real-time electronic metering and flow control and technological advances that enable the electronic submission of gas nominations, the current time period used to process pipeline transportation service nominations and to schedule natural gas is the same time period (up to 4 hours) that was adopted over a decade and a half ago. APPA notes that this already substantial disconnect between the nomination and scheduling procedures used in the natural gas and electric power industries will only become more severe if intra-hour scheduling is adopted. Similarly, Joint Parties request that the Commission open a companion docket to examine barriers that may exist in the natural gas industry that inhibit the timely access to natural gas that is needed to ensure the seamless integration of VERs.[336]

356. American Gas and INGAA state that gas transmission systems have developed innovative services to accommodate the needs of gas-fired generators to access gas supplies quickly in response to electric system dispatch orders. American Gas and INGAA explain that these offerings demonstrate that individual, tailored solutions may better address gas-electric coordination concerns than a modification of the gas nomination schedule. For this reason, American Gas encourages the Commission to continue to be open to creative market solutions to meet the needs of gas-fired generators in ways that do not unnecessarily affect existing shippers in adverse ways. American Gas also encourages the Commission to hold a technical conference or other non-NAESB forum to discuss ways in which the natural gas and electric industries can work together.

357. American Gas further contends that the Commission's consideration of gas-electric coordination issues should not focus narrowly on the gas nomination and scheduling cycle as a primary solution to the reliability issues which both industries face. While American Gas believes that a single, nationwide gas nomination schedule is essential to the efficient functioning of the natural gas system, a modification to that schedule alone is not the most effective means to address gas-electric coordination issues.

358. AEP adds that while the proposed scheduling option appears on the surface to be feasible within the power industry, the increased quantity of VERs and subsequent increased ramping capability requirements will further exacerbate the operational difficulties associated with the varied scheduling timelines existing between the gas and power industries. AEP concludes that such discrepancies place the gas-fired generation operators, whose typically superior ramping capabilities will become increasingly beneficial, in a position of speculating on fuel supply needs because they are unsure whether the increase in variable generation will mean an increased need for the faster ramping capabilities of gas.

359. AEP notes that these differences have existed for many years, and managing them has become more challenging with the introduction of RTO-administered markets, as unit commitment is generally made by the RTO, and not the individual asset owner. AEP argues that any proposed scheduling practices related to incremental VER penetration must account for such inter-market dependencies.

360. Spectra Entities notes that the interface issues between the gas and electric industries go beyond revisiting coordinating and the gas/electric scheduling timelines. Spectra Entities argues that there are regulatory policy and market barriers discouraging the electric industry in some markets from contracting for adequate firm gas supply and firm transportation arrangements to serve those generators which must run in order to maintain the reliability of the electric grid. For example, the Commission's ''no-bump'' policy and the need to coordinate scheduling of interruptible services are irrelevant during peak or high load days in natural gas markets, because interruptible capacity is rarely available on the pipeline grid under those conditions. Spectra Entities argue that unless these barrier issues are addressed, any changes to coordination and scheduling or the offering of innovative transportation solutions will not be sufficient to achieve the Commission's goals.

ii. Commission Determination

361. While comments asking the Commission to undertake reforms to natural gas pipeline rules and procedures in order to facilitate greater cross-market coordination are beyond the scope of this proceeding, we agree that the interdependence of these two industries merits careful attention. The Commission has recently addressed proposed changes to the gas pipeline nomination procedures. In the past, the Commission has urged the industry, working through NAESB, to consider changes to its nomination procedures to provide better coordination between gas and electric scheduling.[337] More recently, in Order No. 587–U, the Commission acknowledged that NAESB lacked consensus to implement any such changes and did not find a nationwide scheduling solution in response to concerns over gas pipeline nomination procedures (including the ''no-bump'' rule).[338] While eschewing nationwide changes, Order No. 587–U emphasized that ''individual pipelines may be able to offer special services or increased nomination opportunities that better fit the profile of gas-fired generation.'')[339] In fact, some pipelines have begun to offer special services to facilitate the flexibility needs of gas-fired generation.[340]

362. On March 30, 2012, a number of entities submitted further comments on gas-electric coordination issues in response to a notice issued in Docket No. AD12–12–000 that requested comments in response to a set of questions and other text concerning gas-electric interdependence issued by Commissioner Moeller on February 3, 2012. The Commission is currently evaluating these comments to determine what, if any, additional steps would be appropriate to take to facilitate coordination between the gas and electric industries.

3. Power Factor Design

a. Comments

363. Midwest ISO Transmission Owners state that Order No. 661 exempted wind generators from having to maintain power factor design criteria absent a specific finding in the relevant system impact study that the generator needs to maintain a specific power factor in order to ensure safety and reliability. Midwest ISO Transmission Owners submit that the Commission should convene a technical conference to examine this issue, or allow

[335] *E.g.,* Joint Parties; TVA; Midwest Energy; APPA.

[336] TVA contends that the Commission should reevaluate its policy of not allowing a firm gas transportation holder to take precedence over (i.e., bump) a non-firm customer, because gas-fired generators paying for firm gas transportation service must be able to support electric needs in general and in integrating VERs specifically.

[337] *See Standards for Business Practices for Interstate Natural Gas Pipelines: Standards for Business Practices for Public Utilities,* Order No. 698, FERC Stats, & Regs ¶ 31,251, at P 69 (2007).

[338] Order No. 587–U, FERC Stats. & Regs. ¶ 31,307 at P 27.

[339] *Id.*

[340] *See Texas Gas Transmission LLC,* 138 FERC ¶ 61,176 (2012).

individual transmission providers to file to eliminate this exemption from their *pro forma* LGIAs or generator interconnection agreements. Midwest ISO Transmission Owners explain that wind and other VERs have obtained significant penetration levels in many areas of the country, such that wind is no longer a new technology that needs protection. Midwest ISO Transmission Owners contend that eliminating this exemption will ensure that wind does not receive an unfair competitive basis.

b. Commission Determination

364. Since issuance of the Proposed Rule in this proceeding, the Commission has directed staff to convene a technical conference in Docket No. AD12–10–000 to examine whether the Commission should reconsider or modify the reactive power provisions of Order No. 661–A and examine what evidence could be developed under Order No. 661 to support a request to apply reactive power requirements more broadly than to individual wind generators during the interconnection study process.[341] The Commission concludes that potential issues regarding the exemption provided under Order No. 661–A are better addressed in that proceeding.

VI. Compliance

A. Commission Proposal

365. In the Proposed Rule, the Commission indicated that each public utility transmission provider must submit a compliance filing within six months of the effective date of the Final Rule revising its OATT and LGIA to demonstrate compliance with the Final Rule. The Commission indicated that to demonstrate compliance, a public utility transmission provider must file: (1) Revisions to its OATT to implement 15-minute scheduling; (2) revisions to its LGIA to include a requirement for interconnection customers whose generating facility is a VER to provide data to the public utility transmission provider when the public utility transmission provider is developing and deploying power production forecasting for VERs; and (3) the addition of Schedule 10 to the OATT, which includes the same per unit rate from their currently effective Schedule 3, and a blank or unfilled volumetric component, among other things.

366. The Commission acknowledged that public utility transmission providers may have provisions in their existing OATTs and LGIAs that the Commission has deemed to be consistent with or superior to the *pro forma* OATT and LGIA. The Commission indicated that where these provisions are being modified by the Final Rule, public utility transmission providers must either comply with the Final Rule or demonstrate that these previously-approved variations continue to be consistent with or superior to the *pro forma* OATT and LGIA as modified by the Final Rule.

367. The Commission also proposed that transmission providers that are not public utilities would have to adopt the requirements of the Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[342]

B. Comments

368. Commenters addressing the six month timeframe generally argue that the proposed compliance deadline does not provide enough time for the industry to implement intra-hour scheduling effectively.[343] Specifically, commenters assert that additional time is needed to allow transmission providers time to: (1) Develop necessary revisions to inter-regional agreements and procedures, and finish ongoing pilot programs; and (2) evaluate all potential impacts to operations and address issues regarding reliability via NERC, and perhaps business standards via NAESB.

369. Southern California Edison argues that regional differences and the need to implement intra-hour scheduling efficiently require careful consideration of each region's scheduling rules. Specifically, Southern California Edison suggests that the Commission provide three years to implement 30-minute scheduling followed by an 18–24 month evaluation period before deciding if 15-minute intra-hour scheduling is necessary. Pacific Gas & Electric recommends that the Commission lengthen the implementation timeline for intra-hour scheduling, so that regional technical conferences on intra-hour scheduling can be convened for affected transmission providers, and so that ongoing pilot studies on intra-hour scheduling may be completed.

370. NorthWestern comments that six months is insufficient time for a compliance filing implementing the intra-hour scheduling requirements of the Proposed Rule. NorthWestern argues that compliance will include, but not be limited to, implementation of software and hardware upgrades, adoption of common regional scheduling practices in the region with jurisdictional and non-jurisdictional balancing authorities, and hiring and properly training of additional staff. NorthWestern encourages the Commission to be flexible and allow balancing authorities the ability to define implementation timeframes, perhaps up to one year before the compliance filing is due.

371. Commenters also point more generally to areas of the Proposed Rule that may require additional time for compliance. Midwest ISO Transmission Owners state, for example, that additional time may be needed to make changes that are highly technical or require an extensive stakeholder process to implement.[344] Midwest ISO suggests that at least 18 months should be allotted for transmission providers to submit compliance filings revising their OATT, LGIA, or other documents.[345] MidAmerican recommends that sufficient time be allocated so that transmission providers may (1) evaluate and address all potential impacts to operations and reliability and (2) be afforded the necessary time to procure resources, develop and adopt administrative processes, conduct training, and perform testing and validation critical to successfully effectuate the proposed reforms.

372. EEI suggests that the Commission not require the changes set forth in the Proposed Rule until the regional planning and cost allocation Final Rules have gone through any rehearing and legal challenges that may develop. On the other hand, Iberdrola supports the Commission's proposal to require a compliance filing within six months; however, if the Commission extends the deadline, Iberdrola recommends that implementation of Schedule 10 occur coincidentally with the implementation of the other two proposed operational changes.

C. Commission Determination

373. The Commission extends the deadline for compliance filings by 6 months so that public utility transmission providers will have 12 months from the effective date of this Final Rule to submit their compliance filings. The Commission also provides the *pro forma* tariff language that public utility transmission providers must include in their OATTs and LGIAs, with modifications to the language based

[341] *Reactive Power Resources,* Notice of Technical Conference, Docket No. AD12–10–000 (issued Feb. 17, 2012).

[342] Order No. 888, FERC Stats. & Regs. at 31,760–763.

[343] *E.g.,* MidAmerican; EEI; FriiPwr; NRECA; Southern California Edison; Pacific Gas & Electric; Grant PUD; NextEra; PNW Parties; Powerex; NV Energy; New York ISO; ISO/RTO Council.

[344] Midwest ISO Transmission Owners at 16.

[345] Midwest ISO at 15.

upon the comments received, as discussed within the body of this Final Rule.[346]

374. Consistent with the discussion in the intra-hourly scheduling section, the Commission requires public utility transmission providers to revise their OATTs to provide an opportunity for transmission customers to submit transmission schedules at 15-minute intervals within 12 months of the effective date of this Final Rule.[347] Public utility transmission providers with provisions in their existing OATTs that the Commission has deemed to be consistent with or superior to the *pro forma* OATT being modified by the Final Rule can seek to demonstrate in their compliance filings that those previously-approved variations continue to be consistent with or superior to the *pro forma* OATT as modified by the Final Rule. In addition, public utility transmission providers may submit alternative proposals that are consistent with or superior to the intra-hour scheduling requirements of this Final Rule and are otherwise just and reasonable and not unduly discriminatory or preferential.[348]

375. Consistent with the discussion in the data reporting section, the Final Rule modifies the compliance obligation set forth in the Proposed Rule and requires public utility transmission providers to modify their *pro forma* LGIAs to effectuate the data reporting requirement within 12 months of the effective date of this Final Rule rather than the six months initially proposed.[349] The Commission adopts proposed Article 8.4 of the *pro forma* LGIA, as modified per the discussion in the data reporting section. The Commission also adopts the proposed definition of VER. The Commission appreciates that public utility transmission providers in some regions, including RTOs and ISOs, have already implemented meteorological or forced outage reporting under relevant tariffs, business practices and/or markets rules. Such public utility transmission providers may seek to demonstrate in their compliance filings how continued use of these existing tariffs, business practices and/or market rules is adequate to satisfy the requirements of this Final Rule using the independent entity variation standard set forth in Order No. 2003, if relevant, or by demonstrating variations from the *pro forma* OATT are consistent with or superior to the requirements of this Final Rule.[350]

376. The Commission concludes that 12 months is a reasonable amount of time to implement the requirements of this Final Rule. Many public utility transmission providers have already implemented some form of sub-hourly scheduling, resolving many of the issues that must be addressed in order to accept transmission schedules on a 15-minute interval. Twelve months also is an adequate amount of time for public utility transmission providers to determine the extent to which meteorological and forced outage data are necessary to support power production forecasting. Although we are extending the compliance deadline to 12 months from the compliance schedule in the Proposed Rule, we do not believe that more than 12 months will be necessary. Therefore, we will not extend the compliance deadline beyond 12 months, nor will we adopt commenters' other proposed recommendations.

377. Finally, the Commission also adopts the proposal that transmission providers that are not public utilities must adopt the requirements of the Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[351]

VII. Information Collection Statement

378. The Office of Management and Budget (OMB) regulations require approval of certain information collection and data retention requirements imposed by agency rules.[352] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

379. The Commission is submitting the proposed modifications to its information collections to OMB for review and approval in accordance with section 3507(d) of the Paperwork Reduction Act of 1995.[353] In the Proposed Rule, the Commission solicited comments on the need for this information, whether the information will have practical utility, the accuracy of provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing the respondent's burden, including the use of automated information techniques. The Commission also included a table that listed the estimated public reporting burdens for the proposed reporting requirements, as well as a projection of the costs of compliance for the reporting requirements.

380. The Commission did not receive any comments specifically addressing the burden estimates provided in the Proposed Rule. However, commenters did respond to questions in the NOPR regarding the specific hardware, software, and personnel changes that are necessary to implement intra-hour scheduling. As noted in Section IV above, some parties argue that the cost to implement intra-hour scheduling will be modest, while other commenters state that implementation costs may be significant. In addition to the Commission's responses to the comments previously provided, the Commission believes that the revised burden estimates below are representative of the average burden on respondents.

381. In the Final Rule, the Commission adds two burden categories that were not included in the Proposed Rule burden estimates. First, the Commission includes a burden estimate for transmission providers who choose to share power production forecast results with VERs. Second, the Commission includes a burden estimate for transmission providers who choose to voluntarily share VER-provided meteorological and forced outage data with third parties. Neither of these additional categories is required under the Final Rule. However, the Commission assumes that all Transmission Providers will implement these changes for the purposes of calculating a burden estimate. The Commission also notes that certain VERs will have increased burden due to submission of intra-hour schedules to transmission providers. However, the Commission assumes that only VERs who choose to participate in intra-hour scheduling are those who will receive at

[346] *See* Appendix A and B for the adopted *pro forma* OATT and LGIA provisions consistent with this Final Rule.

[347] *See* Appendix A for the revised section 13.8 and 14.6 of the *pro forma* OATT provisions consistent with this Final Rule. As *noted supra* § IV.A.1 (Intra-Hour Scheduling Requirement), the implementation of 15-minute scheduling will only apply to intertie transactions in organized wholesale energy markets.

[348] *See supra* § IV.A.1 (Intra-Hour Scheduling Requirement).

[349] *See* Appendix B for the revisions to the *pro forma* LGIA consistent with this Final Rule. Specifically, a new Article 8.4 and a new definition in Article 1 have been added to the *pro forma* LGIA and conforming revisions have been made to the table of contents.

[350] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 910.

[351] Order No. 888, FERC Stats. & Regs. at 31,760–63.

[352] 5 CFR 1320.11(b).

[353] 44 U.S.C. 3507(d).

least as much benefit as the cost that must be expended. For this reason, the Commission is not including a burden estimate for this category in the table below.

Burden Estimate and Information Collection Costs: The estimated Public Reporting burden and cost for the requirements contained in this Final Rule follow.

Data collection FERC 516 (as contained in Final Rule in RM10–11)	Number and type of respondents (1)	Number of responses per respondent (2)	Hours per response (3)	Total annual hours (1 × 2 × 3)
Conforming tariff changes to require intra-hourly scheduling, waiver, or deviation request; and rate treatment terms for Ancillary Service.	142 Transmission Providers.[354]	1	8 first year only	1,136 first year only.
Implementation of intra-hourly scheduling	142 Transmission Providers.	1	30 reoccurring	4,260 reoccurring.
Conforming changes to LGIA.[355]	142 Transmission Providers.	1	20 first year only	2,840 first year only.
Sharing of power production forecasting results with VER.	142 Transmission Providers.	1	30 reoccurring	4,260 reoccurring.
Sharing of VER provided meteorological and forced outage data with third party entities (e.g. NOAA, balancing authority area).	142 Transmission Providers.	1	30 reoccurring	4,260 reoccurring.
Provision of meteorological and forced outage data to public utility transmission providers for use in power production forecasting.[356]	160 Interconnection Customers with VERs per year.[357]	1	60 reoccurring	9,600 reoccurring.
Totals				26,356 first year + reoccurring.[358]
				22,380 subsequent years.[359]

Cost to Comply: The Commission has projected the total cost of compliance to be $3,004,584 in the first year, and $2,551,330 each year after.

Total Annual Hours in the first year (26,356 hours) @ $114 an hour [average cost of attorney ($200 per hour), consultant ($150), technical ($80), and administrative support ($25)] = $3,004,584.

Total Annual Hours in subsequent years (22,380 hours) @ $114 an hour = $2,551,320.

Title: FERC–516, Electric Rate Schedules and Tariff Filings

Action: Proposed Collection.

OMB Control No. 1902–0096.

Respondents for this Rulemaking: Transmission Providers (an RTO or ISO also may file some materials on behalf of its members) and Variable Energy Resources.

Frequency of Information: As indicated in the table.

Necessity of Information: The Federal Energy Regulatory Commission is adopting these amendments to the *pro forma* OATT to remedy operational challenges related to the increased integration of VERs to the bulk electric system. The purpose of this Final Rule is to strengthen the *pro forma* OATT, so VERs can be reliably and efficiently integrated into the electric grid and to ensure that Commission-jurisdictional services are provided at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential. This Final Rule seeks to achieve this goal by amending the *pro forma* OATT and LGIA to incorporate provisions that require intra-hourly transmission scheduling and require interconnection customers whose generating facilities are VERs to provide meteorological and operational data to public utility transmission providers for the purpose of power production forecasting. The Commission also provides guidance regarding the development of proposals for generator regulation service.

Internal Review: The Commission has reviewed the proposed changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

382. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], email: *DataClearance@ferc.gov,* Phone: (202) 502–8663, fax: (202) 273–0873. Comments concerning the collection of information and the associated burden estimate(s), may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–4638, fax (202) 395–7285]. Due to security concerns, comments should be sent electronically to the following email address:

[354] The Commission estimated in the NOPR that 134 transmission providers would have additional burdens due to the Proposed Rule. Since then, the Commission has identified eight additional transmission providers who are non-public utilities that file reciprocity open access transmission tariffs that are also expected to voluntarily comply with this rule.

[355] Consistent with the approach taken in Order No. 2003, public utility transmission providers with power production forecasting systems in place via tariff provisions and/or other mechanisms will be required to demonstrate that deviations from the *pro forma* LGIA are consistent with or superior to the *pro forma* LGIA.

[356] Once a data exchange is implemented, the Commission expects that this process will be automated and require little to no day to day burden.

[357] The Commission estimates that there will be approximately 160 VERs that will sign an LGIA each year during the period from July 2012–July 2015 potentially subject to this requirement. This update from the NOPR represents more recent data.

[358] First year hours total 26,356, the sum of first year and reoccurring hours.

[359] Annual hours total 22,380, the sum of all reoccurring hours.

oira_submission@omb.eop.gov. Comments submitted to OMB should include OMB Control No. 1902–0096 and Docket No. RM10–11–000.

VIII. Environmental Analysis

383. 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.[360] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Rule under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[361]

IX. Regulatory Flexibility Act Analysis

384. The Regulatory Flexibility Act of 1980 (RFA) [362] generally requires a description and analysis of Final Rules that will have a significant economic impact on a substantial number of small entities. This Final Rule applies to public utilities that own, control or operate interstate transmission facilities [363] and to variable energy resources. The total estimated number of small public utility transmission providers [364] impacted by this Final Rule is estimated to be ten. The Commission assumes that the Final Rule will impact all the applicable small transmission providers equally at an average cost of $13,500 per year. The Commission does not consider this to be a significant economic impact. In any event, each of these entities may seek waiver of these requirements.[365] The Commission estimates that all of the applicable VERs (160 per year) are small. Of these 160 entities, approximately 100 that are greater than 20 MW will be required to comply with the Final Rule and approximately 60 that are 20 MW or less will have the option to comply with the rule. The Commission estimates that each VER will have an average cost of $6,800 per year because of the Final Rule. The Commission does not consider this to be a significant economic impact on these small entities. The costs incurred by VERs due to this rule are offset by an expected reduction in energy imbalance penalties that will be assessed to VERs in the future due to improved forecasting and reduced uncertainty across 15-minute scheduling periods compared to hour-long scheduling periods. Accordingly, the Commission certifies that this Final Rule will not have a significant economic impact on a substantial number of small entities.

X. Document Availability

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

386. From FERC'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.

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

XI. Effective Date and Congressional Notification

388. These regulations are effective September 11, 2012. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. The Commission will submit this Final Rule to both houses of Congress and the Government Accountability Office.

List of Subjects in 18 CFR Part 35

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

By the Commission. Commissioner LaFleur is dissenting in part with a separate statement attached. Commissioner Clark voting present.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

In consideration of the foregoing, the Commission amends Part 35, Chapter I, Title 18, Code of Federal Regulations, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS

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

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 71–7352.

■ 2. Amend § 35.28 as follows:
■ a. Paragraphs (c)(1) introductory text and (c)(1)(i) through (c)(1)(iii) are revised.
■ b. Paragraphs (c)(1)(v) and (c)(1)(vi) are revised.
■ c. Paragraphs (c)(3) introductory text and (c)(3)(ii) are revised.
■ d. Paragraph (c)(4) is revised.
■ e. Paragraph (d) is revised.
■ f. Paragraphs (e)(1) introductory text, (e)(1)(ii), and (e)(2) are revised.
■ g. Paragraphs (f)(1) introductory text and (f)(1)(i) are revised.
■ h. Paragraphs (f)(1)(ii) through (f)(1)(iv) are removed and reserved.
■ i. Paragraph (f)(3) is revised.
■ j. Paragraph (f)(4) is removed.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c) *Non-discriminatory open access transmission tariffs.*

(1) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the *pro forma* tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

[360] *Regulations Implementing the National Environmental Policy Act of 1969,* Order No. 486, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987).

[361] 18 CFR 380.4(a)(15) (2010).

[362] 5 U.S.C. 601–612 (2006).

[363] Other than those that have received waiver of the obligation to comply with Order Nos. 888, 889, and 890.

[364] A ''small entity'' as referenced in the RFA refers to the definition provided in section 3 of the Small Business Act where a firm is ''small'' if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

[365] The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889, and 890.

(i) Subject to the exceptions in paragraphs (c)(1)(ii), (c)(1)(iii), (c)(1)(iv), and (c)(1)(v) of this section, the open access transmission tariff, which tariff must be the *pro forma* tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff, and accompanying rates must be filed no later than 60 days prior to the date on which a public utility would engage in a sale of electric energy at wholesale in interstate commerce or in the transmission of electric energy in interstate commerce.

(ii) If a public utility owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, it must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff, pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(iii) If a public utility owns, controls, or operates transmission facilities used for the transmission of electric energy in interstate commerce, such facilities are jointly owned with a non-public utility, and the joint ownership contract prohibits transmission service over the facilities to third parties, the public utility with respect to access over the public utility's share of the jointly owned facilities must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(v) If a public utility obtains a waiver of the tariff requirement pursuant to paragraph (d) of this section, it does not need to file the open access transmission tariff required by this section.

(vi) Any public utility that seeks a deviation from the *pro forma* tariff promulgated by the Commission, as amended from time to time, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(3) Every public utility that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce, and that is a member of a power pool, public utility holding company, or other multi-lateral trading arrangement or agreement that contains transmission rates, terms or conditions, must have on file a joint pool-wide or system-wide open access transmission tariff, which tariff must be the *pro forma* tariff promulgated by the Commission, as amended from time to time, or such other open access transmission tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(ii) For any power pool, public utility holding company or other multi-lateral arrangement or agreement that contains transmission rates, terms or conditions and that is executed on or before May 14, 2007, a public utility member of such power pool, public utility holding company or other multi-lateral arrangement or agreement that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce must file the revisions to its joint pool-wide or system-wide open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(4) Consistent with paragraph (c)(1) of this section, every Commission-approved ISO or RTO must have on file with the Commission an open access transmission tariff of general applicability for transmission services, including ancillary services, over such facilities. Such tariff must be the *pro forma* tariff promulgated by the Commission, as amended from time to time, or such other tariff as may be approved by the Commission consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(i) Subject to paragraph (c)(4)(ii) of this section, a Commission-approved ISO or RTO must file the revisions to its open access transmission tariff required by Commission rulemaking proceedings promulgating and amending the *pro forma* tariff pursuant to section 206 of the FPA and accompanying rates pursuant to section 205 of the FPA in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(ii) If a Commission-approved ISO or RTO can demonstrate that its existing open access transmission tariff is consistent with or superior to the *pro forma* tariff promulgated by the Commission, as amended from time to time, the Commission-approved ISO or RTO may instead set forth such demonstration in its filing pursuant to section 206 in accordance with the procedures set forth in Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

(d) *Waivers.* A public utility subject to the requirements of this section and Order No. 889, FERC Stats. & Regs. ¶ 31,037 (Final Rule on Open Access Same-Time Information System and Standards of Conduct) may file a request for waiver of all or part of the requirements of this section, or Part 37 (Open Access Same-Time Information System and Standards of Conduct for Public Utilities), for good cause shown. Except as provided in paragraph (f) of this section, an application for waiver must be filed no later than 60 days prior to the time the public utility would have to comply with the requirement.

(e) *Non-public utility procedures for tariff reciprocity compliance.*

(1) A non-public utility may submit an open access transmission tariff and a request for declaratory order that its voluntary transmission tariff meets the requirements of Commission rulemaking proceedings promulgating and amending the *pro forma* tariff.

* * * * *

(ii) If the submittal is found to be an acceptable open access transmission tariff, an applicant in a Federal Power Act (FPA) section 211 or 211A proceeding against the non-public utility shall have the burden of proof to show why service under the open access transmission tariff is not sufficient and why a section 211 or 211A order should be granted.

(2) A non-public utility may file a request for waiver of all or part of the reciprocity conditions contained in a public utility open access transmission tariff, for good cause shown. An application for waiver may be filed at any time.

(f) *Standard generator interconnection procedures and agreements.*

(1) Every public utility that is required to have on file a non-discriminatory open access transmission tariff under this section must amend such tariff by adding the standard interconnection procedures and

agreement and the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, or such other interconnection procedures and agreements as may be required by Commission rulemaking proceedings promulgating and amending the standard interconnection procedures and agreement and the standard small generator interconnection procedures and agreement.

(i) Any public utility that seeks a deviation from the standard interconnection procedures and agreement or the standard small generator interconnection procedures and agreement required by Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements, must demonstrate that the deviation is consistent with the principles set forth in Commission rulemaking proceedings promulgating and amending such interconnection procedures and agreements.

* * * * *

(3) A public utility subject to the requirements of this paragraph (f) may file a request for waiver of all or part of the requirements of this paragraph (f), for good cause shown.

* * * * *

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

Appendix A: List of Short Names of Commenters on the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking on Integration of Variable Energy Resources—Docket No. RM10–11–000, November 2010

Short name or acronym	Commenter
A123	A123 Systems, Inc.
AEP	American Electric Power Service Corporation
ALLETE	ALLETE Inc.
ACSF	American Clean Skies Foundation
Alstom	Alstom Grid, Inc.
American Gas	American Gas Association
APPA	American Public Power Association
Argonne National Lab	Argonne National Laboratory
Arizona Corporation Commission	Arizona Corporation Commission
Avista	Avista Corporation
AWEA	American Wind Energy Association
Beacon Power	Beacon Power Corporation
Bonneville Power	Bonneville Power Administration
BP Companies	BP Energy Company and BP Wind Energy North America, Inc.
BrightSource	BrightSource Energy, Inc.
Business Council	Business Council for Sustainable Energy
CESA	California Energy Storage Alliance
California State Water Project	California Department of Water Resources State Water Project
California ISO	California Independent System Operator Corporation
California PUC	California Public Utilities Commission
CEERT	Center for Energy Efficiency and Renewable Technologies
Center for Rural Affairs	Center for Rural Affairs
CMUA	California Municipal Utilities Association; Cities of Alameda, Anaheim, Azusa, Banning, Burbank, Cerritos, Colton, Corona, Glendale, Gridley, Healdsburg, Hercules, Lodi, Lompoc, Moreno Valley, Needles, Palo Alto, Pasadena, Pittsburg, Rancho Cucamonga, Redding, Riverside, Roseville, Santa Clara, Shasta Lake, Ukiah, and Vernon; the Imperial, Merced, Modesto, and Turlock Irrigation Districts; the Northern California Power Agency; Southern California Public Power Authority; Transmission Agency of Northern California; Lassen Municipal Utility District; Power and Water Resources Pooling Authority; Sacramento Municipal Utility District; the Trinity and Truckee Donner Public Utility Districts; the Metropolitan Water District of Southern California; and the City and County of San Francisco, Hetch-Hetchy
Clean Line	Clean Line Energy Partners, LLC
CGC	Coalition for Green Capital
Defenders of Wildlife	Wilderness Society and Defenders of Wildlife
Detroit Edison	Detroit Edison Company
Dominion	Dominion Resources Services, Inc.
Duke	Duke Energy Corporation
EEI	Edison Electric Institute
ELCON	Electricity Consumers Resource Council
EPSA	Electric Power Supply Association
ENBALA	ENBALA Power Networks
Entergy	Entergy Services, Inc.
Environmental Defense Fund	Environmental Defense Fund
E.ON C&R	E.ON Climate & Renewables North America
Exelon	Exelon Corporation
Federal Trade Commission	Federal Trade Commission
FirstEnergy	FirstEnergy Service Company
First Wind	First Wind Energy, LLC
FriiPwr	FriiPwr USA Ltd
Grant PUD	Public Utility District No. 2 of Grant County, Washington
Grays Harbor PUD	Public Utility District No. 1 of Grays Harbor County, Washington
Iberdrola	Iberdrola Renewables, Inc.
Idaho Power	Idaho Power Company
Independent Energy Producers	Independent Energy Producers Association

Short name or acronym	Commenter
Independent Power Producers Coalition-West	Arizona Competitive Power Alliance; Colorado Independent Energy Association; Independent Energy Producers Association (California); New Mexico Independent Power Producers Coalition; and the Northwest & Intermountain Power Producers Coalition.
INGAA	Interstate Natural Gas Association of America
Invenergy Wind	Invenergy Wind Development LLC
ISO New England	ISO New England Inc. and the New England Power Pool
ISO/RTO Council	Alberta Electricity System Operator; California Independent System Operator; Electric Reliability Council of Texas; Independent Electricity System Operator of Ontario; ISO New England, Inc.; Midwest Independent Transmission System Operator, Inc.; New Brunswick System Operator; New York Independent System Operator, Inc.; PJM Interconnection, L.L.C.; and Southwest Power Pool, Inc.
ITC Companies	ITC*Transmission;* Michigan Electric Transmission Company, LLC; ITC Midwest LLC; and ITC Great Plains, LLC
Joint Parties	Arizona Public Service Company; The Boeing Company, El Paso Electric; New York Independent System Operator; Old Dominion Electric Cooperative; PJM Interconnection, L.L.C.; Salt River Project Agriculture Improvement and Power District; Southwest Power Pool; Tennessee Valley Authority; Tucson Electric Power Company; UNS Gas, Inc.; and the Vermont Department of Public Service
Joint Initiative	Joint Initiative Facilitators
Large Public Power Council	Austin Energy; Chelan County Public Utility District No. 1; Clark Public Utilities, Colorado Springs Utilities; CPS Energy (San Antonio); ElectriCities of North Carolina; Grant County Public Utility District; IID Energy (Imperial Irrigation District); JEA (Jacksonville, FL); Long Island Power Authority; Los Angeles Department of Water and Power; Lower Colorado River Authority; MEAG Power; Nebraska Public Power District; New York Power Authority; Omaha Public Power District; Orlando Utilities Commission; Platte River Power Authority; Puerto Rico Electric Power Authority; Sacramento Municipal Utility District; Salt River Project; Santee Cooper; Seattle City Light; Snohomish County Public Utility District No. 1; and Tacoma Public Utilities
LADWP	Department of Water and Power of the City of Los Angeles
Massachusetts DPU	Massachusetts Department of Public Utilities
MidAmerican	MidAmerican Energy Holdings Company
Midwest Energy	Midwest Energy, Inc.
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
Midwest ISO Transmission Owners	Ameren Services Company, as agent for Union Electric Company d/b/a Ameren Missouri; Ameren Illinois Company d/b/a Ameren Illinois and Ameren Transmission Company of Illinois; American Transmission Company LLC; Big Rivers Electric Corporation; City Water, Light & Power (Springfield, IL); Dairyland Power Cooperative; Duke Energy Corporation for Duke Energy Ohio, Inc., Duke Energy Indiana, Inc., and Duke Energy Kentucky, Inc.; Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc. (“Hoosier”); Indiana Municipal Power Agency; Indianapolis Power & Light Company (“IPL”); Michigan Public Power Agency; MidAmerican Energy Company; Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, subsidiaries of Xcel Energy Inc. (“Xcel Energy”); NorthWestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company (d/b/a Vectren Energy Delivery of Indiana); Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.
M–S–R Public Power Agency	Modesto Irrigation District; City of Santa Clara, California; and City of Redding, California
Montana PSC	Montana Public Service Commission
NEMA	National Electrical Manufacturers Association
National Grid	National Grid USA
NRECA	National Rural Electric Cooperative Association
Natural Gas	Natural Gas Supply Association
NaturEner	NaturEner USA, LLC
NE Conference of PUCs	New England Conference of Public Utilities Commissioners
NESCOE	New England States Committee on Electricity
NV Energy	Nevada Power Company and Sierra Pacific Power Company
New York ISO	New York Independent System Operator, Inc.
NextEra	NextEra Energy, Inc.
NERC	North American Electric Reliability Corporation
NAESB	North American Energy Standards Board
NOAA	National Oceanic and Atmospheric Administration
NorthWestern	NorthWestern Corporation
Organization of Midwest ISO States	Organization of Midwest ISO States
Oregon & New Mexico PUC	Public Utility Commissioners of Oregon and New Mexico and Paul Newman, Arizona Commissioner
Pacific Gas & Electric	Pacific Gas and Electric Company
PNW Parties	Avista Corporation; the Bonneville Power Administration; Idaho Power Company; NorthWestern Corporation, dba NorthWestern Energy; PacifiCorp; Portland General Electric Company; the Public Generating Pool (Tacoma Power, Eugene Water and Electric Board, and Public Utility Districts for Chelan, Clark, Cowlitz, Douglas, Grant, Klickitat, Pend Oreille, and Snohomish counties); the Public Power Council; Puget Sound Energy, Inc.; and Seattle City Light

Short name or acronym	Commenter
PJM	PJM Interconnection, L.L.C.
Powerex	Powerex Corporation
Public Interest Organizations	Alliance for Clean Energy New York; Center for Rural Affairs; Citizens Utility Board of Wisconsin; Climate and Energy Project; Conservation Law Foundation; Defenders of Wildlife; Energy Conservation Council of Pennsylvania; Energy Future Coalition; Environment Northeast; Environmental Defense Fund; Environmental Law & Policy Center; Fresh Energy; Great Plains Institute; Natural Resources Defense Council; Office of the Ohio Consumers' Counsel; Pace Energy and Climate Center; Project for Sustainable FERC Energy Policy; Sierra Club; The Wilderness Society; Union of Concerned Scientists; Western Grid Group; Western Resource Advocates; and Wind on the Wires
Public Power Council	Public Power Council
Puget	Puget Sound Energy, Inc.
Recycled Energy	Recycled Energy Development
RENEW	Renewable Energy New England, Inc.
RenewElec	The RenewElec Project
SMUD	Sacramento Municipal Utility District
San Diego Gas & Electric	San Diego Gas & Electric Company
Snohomish County PUD	Public Utility District No. 1 of Snohomish County, Washington
SEIA	Solar Energy Industries Association and the Large-Scale Solar Association
Southern California Edison	Southern California Edison Company
Southern	Southern Company Services, Inc.
Southern MN Municipal	Southern Minnesota Municipal Power Agency
SWEA	Southwest Energy Alliance
Southwestern	Southwestern Power Administration
Spectra Entities	Spectra Energy Transmission, LLC and Spectra Energy Partners, LP
Sunflower and Mid-Kansas	Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC
TA Miller	T.A. Miller
Tacoma Power	City of Tacoma, Department of Public Utilities, Light Division (Washington)
Tres Amigas	Tres Amigas LLC
TVA	Tennessee Valley Authority
US Bureau of Reclamation	United States Bureau of Reclamation
Utility Economic Engineers	Utility Economic Engineers
Vestas	Vestas-American Wind Technology, Inc.
Viridity Energy	Viridity Energy, Inc.
Vote Solar	Vote Solar Initiative
WUTC	Washington Utilities and Transportation Commission
WestConnect	Arizona Public Service Company; El Paso Electric Company, Imperial Irrigation District; NV Energy, Public Service Company of Colorado; Public Service Company of New Mexico; Sacramento Municipal Utility District; Salt River Project; Southwest Transmission Cooperative, Inc.; Transmission Agency of Northern California; Tri-State Generation and Transmission Association, Inc.; Tucson Electric Power Company and Western Area Power Administration
Western Farmers	Western Farmers Electric Cooperative
Western Grid	Western Grid Group
Xcel	Xcel Energy Services Inc.
Xtreme Power	Xtreme Power Inc.

Appendix B: *Pro Forma* Open Access Transmission Tariff

The Commission amends the following sections of the *pro forma* OATT:

a. Section 13.8
b. Section 14.6

13.8 Scheduling of Firm Point-To-Point Transmission Service: Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next scheduling interval provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service: Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next scheduling interval, provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

Appendix C: *Pro Forma* Large Generator Interconnection Agreement

The Commission amends and/or adds the following sections of the *pro forma* LGIA:

a. Table of Contents (Add Article 8.4, Provision of Data from a Variable Energy Resource)

b. Article 1 (Add definition of Variable Energy Resource)

c. Article 8.4

Article 1 Definition

Variable Energy Resource shall mean a device for the production of electricity that is characterized by an energy source that: (1) Is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

Article 8.4 Provision of Data From a Variable Energy Resource

The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall provide meteorological and forced outage data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The Interconnection Customer with a Variable Energy Resource having wind as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, wind speed, wind direction, and atmospheric pressure. The Interconnection Customer with a Variable Energy Resource having solar as the energy source, at a minimum, will be required to provide the Transmission Provider with site-specific meteorological data including: temperature, atmospheric pressure, and irradiance. The Transmission Provider and Interconnection Customer whose Generating Facility is a Variable Energy Resource shall mutually agree to any additional meteorological data that are required for the development and deployment of a power production forecast. The Interconnection Customer whose Generating Facility is a Variable Energy Resource also shall submit data to the Transmission Provider regarding all forced outages to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for that class of Variable Energy Resources. The exact specifications of the meteorological and forced outage data to be provided by the Interconnection Customer to the Transmission Provider, including the frequency and timing of data submittals, shall be made taking into account the size and configuration of the Variable Energy Resource, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. All requirements for meteorological and forced outage data must be commensurate with the power production forecasting employed by the Transmission Provider. Such requirements for meteorological and forced outage data are set forth in Appendix C, Interconnection Details, of this LGIA, as they may change from time to time.

LaFLEUR, Commissioner, *dissenting in part:*

I am dissenting in part on this Final Rule.

I strongly support renewable energy, and I have stated many times that I believe one of the most important jobs of this Commission is to support the development of rules to address new power supply choices being made at the state and federal level. For that reason, I support the requirements in the rule for intra-hour scheduling and power production forecasting, as well as the guidance we provide on generator regulation service charges.

I am dissenting on the narrow point of the compliance requirements in the Final Rule. As noted in the rule, we heard from many parties about ongoing efforts to establish intra-hour scheduling and other market improvements in various regions. However, the rule as issued would only allow parties to demonstrate compliance through incremental reforms beyond those already underway, without any explanation of why the ongoing efforts are insufficient. I would give regions more flexibility to demonstrate on compliance that these ongoing efforts meet the objectives of the rule.

Accordingly, I respectfully dissent in part.

Cheryl A. LaFleur,
Commissioner.

[FR Doc. 2012–15762 Filed 7–12–12; 8:45 am]

BILLING CODE 6717–01–P