DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM10–11–000]

Integration of Variable Energy Resources

November 18, 2010.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: In this Notice of Proposed Rulemaking, the Federal Energy Regulatory Commission proposes to reform the *pro forma* Open Access Transmission Tariff to remove unduly discriminatory practices and to ensure just and reasonable rates for Commission-jurisdictional services. Accordingly, the Proposed Rule would: require public utility transmission providers to offer intra-hourly transmission scheduling; incorporate provisions into the *pro forma* Large Generator Interconnection Agreement requiring interconnection customers whose generating facilities are variable energy resources to provide meteorological and operational data to public utility transmission providers for the purpose of power production forecasting; and add a generic ancillary service rate schedule through which public utility transmission providers will offer regulation service to transmission customers delivering energy from a generator located within the transmission provider's balancing authority area. The proposed reforms will remove barriers to the integration of variable energy resources.

DATES: Comments are due January 31, 2011.

ADDRESSES: You may submit comments, identified by docket number and in accordance with the requirements posted on the Commission's Web site, *http://www.ferc.gov.* Comments may be submitted by any of the following methods:

- *Agency Web site:* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format, and not in a scanned format, at *http://www.ferc.gov/docs-filing/efiling.asp.*
- *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver an original copy of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

These requirements can be found on the Commission's Web site, *see, e.g.,* the "Quick Reference Guide for Paper Submissions," available at *http://www.ferc.gov/docs-filing/efiling.asp,* or via phone from FERC Online Support at 202–502–6652 or toll-free at 1–866–208–3676.

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I. Introduction

1. In this Notice of Proposed Rulemaking (Proposed Rule), the Federal Energy Regulatory Commission (Commission) proposes reforms to the *pro forma* Open Access Transmission Tariff (OATT) that derive from the Integration of Variable Energy Resources Notice of Inquiry.[1] The Commission initiated that inquiry to obtain information on barriers to the integration of variable energy resources (VER)[2] and on the current state of VER integration in various regions of the country. Not unexpectedly, commenters indicate that VER presence is not uniform throughout the country. Commenters also describe their experiences integrating VERs and the on-going industry efforts designed to address issues posed by increasing numbers of VERs. Many of these industry efforts are significant in scope and have the potential to address issues confronting regions where large

[1] *Integration of Variable Energy Resources,* 130 FERC ¶ 61,053 (2010) (Integrating VERs NOI).

[2] For the purpose of this proceeding, the term variable energy resource (VER) refers to an electric generating facility 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.

concentrations of VERs are located.[3] Accordingly, in the Proposed Rule, the Commission has decided to propose a limited set of reforms to existing operational procedures that we preliminarily find to be unduly discriminatory and leading to unjust and unreasonable rates for transmission service. Specifically, the Proposed Rule addresses transmission scheduling practices, VER power production forecasts, and the recovery of capacity charges associated with generator imbalance service (*i.e.,* generator regulation service).

2. In Order No. 890, the Commission made several reforms to the *pro forma* OATT, recognizing that the mix of generation resources on the system was changing and that not all generation resources were similarly situated.[4] The Commission 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.[5] Similarly, the Commission preliminarily finds 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.

3. In this Proposed Rule, the Commission proposes the following three reforms: (1) Amend the *pro forma* OATT to require intra-hourly transmission scheduling; (2) amend the *pro forma* Large Generator Interconnection Agreement 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. The Commission recognizes that as the number of VERs increases, public utility transmission providers and their customers will need processes and tools to manage the changing nature of generation resources on the transmission grid. As such, the Commission believes the reforms proposed herein will address some of the barriers to the integration of VERs by remedying operational and other challenges that may be causing undue discrimination and increased costs ultimately borne by consumers.

4. Specifically, the Commission preliminarily finds that requiring transmission customers to adhere to hourly schedules may be unduly discriminatory and result in the inefficient use of transmission and generation resources to the detriment of consumers. The Commission also preliminarily finds that a lack of VER power production forecasts may unnecessarily increase the volume of regulation reserves deployed by a public utility transmission provider, resulting in rates that are unjust and unreasonable, and that a public utility transmission provider currently lacks the means by which to require VERs to provide it with basic information on meteorological and operational conditions which can be used to develop VER power production forecasts. Finally, although the Commission contemplated a case-by-case approach to generator regulation service in Order No. 890,[6] the increased interest as evidenced by commenters and the number of Commission filings related to this service has led us to consider a generic approach to the provision of generator regulation service, such as the one proposed here.

5. Taken together, these proposed reforms mean: VERs and other resources will be able to adjust schedules within the operating hour, allowing public utility transmission providers to commit fewer generation and non-generation resources to provide reserves; public utility transmission providers will have better meteorological and operational information from interconnection customers whose generating facilities are VERs and will be able to use this information to develop power production forecasts for use in operating their systems, thus mitigating the volume of regulation reserves they deploy; and public utility transmission providers will have a generic schedule from which to recover the costs of providing generator regulation service, and customers and other market participants will know the cost of such service. These proposed reforms are intended to ensure that the requirements set forth in the *pro forma* OATT result in the provision of Commission-jurisdictional services at rates that are just and reasonable, and not unduly discriminatory or preferential, consistent with the Commission's responsibilities under sections 205 and 206 of the Federal Power Act (FPA).[7]

II. 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 that which they provide to themselves.[8] 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

[3] *See, e.g.,* Joint Initiative at 1–12 (describing collaborative efforts in the Western Interconnection for high-value and cost-effective regional products involving increased coordination among different transmission providers), SMUD at 8–12 (describing SMUD's participation in regional efforts in California and the Northwest), ISO/RTO Council at 12–18 (discussing ISO/RTO efforts to develop and incorporate VER forecasting into their system operations).

[4] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 5, *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, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[5] 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).

[6] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690.

[7] 16 U.S.C. 824d, 824e.

[8] *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).

that there was a pressing need for a single set of procedures and a single, uniformly applicable interconnection agreement for large generator interconnections.[9] Accordingly, the Commission adopted standard procedures (the Large Generator Interconnection Procedures or LGIP) and a standard agreement (the Large Generator Interconnection Agreement or LGIA) for the interconnection of generation resources greater than 20 MW.[10] These reforms were designed to minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable.[11]

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.[12] The Commission therefore 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.[13] Subsequently, in Orders Nos. 661 and 661–A, the Commission adopted a package of interconnection standards applicable to large wind generators for inclusion in Appendix G of the LGIA.[14]

9. More recently, in recognition of the evolving energy industry and in a further effort to remedy the potential for undue discrimination, the Commission revised and updated the *pro forma* OATT in Order No. 890.[15] Among other things, the Commission adopted a set of transmission planning principles,[16] created a new *pro forma* ancillary service schedule designed to address energy imbalances caused by generators,[17] and instituted a new conditional firm transmission product.[18]

10. As these and other reforms illustrate, the Commission routinely evaluates the effectiveness of its regulations and policies in light of changing industry conditions. Consistent with this practice, the Commission issued the Integrating VERs NOI on January 21, 2010 to better 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.[19] The Commission explained that the changing characteristics of the nation's generation portfolio compelled a fresh look at existing policies and practices.[20] Therefore, in the Integrating VERs NOI, the Commission sought comments on the following 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.[21]

11. The response from commenters was significant, with more than 135 entities submitting comments that responded to some or all of the questions posed by the Commission.[22] A number of commenters, especially from the VER industry, argue that there is a clear need for the Commission to undertake basic reforms, and they urge the Commission to do so.[23] At the same time, a common theme expressed by a number of commenters is that different parts of the country face different challenges associated with the integration of VERs.[24] For example, commenters in the Northwest tend to focus on the difficulties posed by the deployment of wind resources,[25] whereas commenters in the Southwest tend to focus on the difficulties posed by the deployment of solar resources.[26] Further still, commenters in the South explain that in many areas the geography and regional conditions are less suitable to the development of significant wind and solar resources.[27] Commenters therefore express a need for flexibility in responding to these challenges and urge the Commission to take this need into account in crafting any proposed rules.[28]

III. The Need for Reform

12. The Commission preliminarily finds that the package of reforms proposed herein is needed to protect against unjust and unreasonable rates, terms, and conditions and undue discrimination in the provision of Commission-jurisdictional services. Specifically, the Commission is proposing to reform the *pro forma* OATT to ensure that the services provided are not structured in an unduly discriminatory manner, that public utility transmission providers have access to needed information to facilitate the integration of VERs, and that transmission customers have a clear understanding of the determination of and obligations for the provision of ancillary services.[29] The Commission believes that this set of proposed reforms represents a reasonable foundation upon which public utility transmission providers will be well positioned to manage system variability associated with increased numbers of

[9] *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 (DC Cir. 2007).

[10] *Id.*

[11] *Id.*

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

[13] *Id.*

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

[15] Order No. 890, FERC Stats. & Regs. ¶ 31,241, order on reh'g, Order No. 890–A, FERC Stats. & Regs. ¶ 31,261, *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299, *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126.

[16] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 435–43.

[17] *Id.* P 663–72.

[18] *Id.* P 911–15.

[19] Integrating VERs NOI, 130 FERC ¶ 61,053 at P 9.

[20] *Id.*

[21] *Id.* P 12.

[22] *See* Appendix A.

[23] AWEA at 2; Iberdrola at 8–10; NextEra 2–8.

[24] Southern at 3; EEI at 2; ISO/RTO Council at 2.

[25] *See, e.g.,* NorthWestern at 4–6; Idaho Power at 2–4; Puget at 2.

[26] *See, e.g.,* NV Energy at 2, 6; Southern California Edison at 7.

[27] *See, e.g.,* Southern at 19.

[28] Southern at 4–10; EEI at 2; ColumbiaGrid at 4–5.

[29] As part of this Proposed Rule, the Commission is also proposing a minor revision to 18 CFR 35.28. To date, when amending its regulations concerning 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 (as indicated by, e.g., proposed regulatory text included in another recently issued Notice of Proposed Rulemaking: *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* 131 FERC ¶ 61,253 (2010)). This process is increasingly cumbersome. Thus as part of this Proposed Rule, the Commission proposes 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 includes 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.

VERs. The Commission anticipates that the proposed operational and pricing reforms will result in a more efficient utilization of all generation, non-generation,[30] and transmission resources and lay the basis for continued development, including the possibility of innovative solutions, such as efforts by the Joint Initiative in the West.

13. As noted in the Integrating VERs NOI, the composition of the electric generation portfolio is changing. VERs are making up an increasing percentage of new generating capacity being brought on line—in 2009, new wind generating capacity rose to 9,994 MW, or 39 percent of all newly installed generating capacity, bringing total wind generating capacity to more than 35,000 MW.[31] In addition to this existing capacity, another 85 GW of wind generating capacity has been proposed to be on line by the end of 2012.[32] The amount of new solar generating capacity also has increased in recent years, adding 351 MW in 2008 and 481 MW in 2009, bringing the total solar generating capacity to more than 2,000 MW.[33]

14. The Commission expects the number of VERs, both in real numbers and as a percentage of total generation capacity, to continue to grow. Indicators of this anticipated growth are suggested by the significant number of public policies, both at the state and federal levels, encouraging the development of VERs. In the Integrating VERs NOI, the Commission noted that as of December 2009, 30 states and the District of Columbia had a renewable portfolio standard.[34] Moreover, federal tax policies that provide incentives to the development of renewable generation facilities have been in place for a number of years. For example, 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.[35] In February 2009, the American Recovery and Reinvestment Act (ARRA) not only extended the production tax credit for a period of three additional years,[36] 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.[37] Other federal policies that provide incentives to renewable generation facilities include accelerated depreciation of certain renewable generation facilities and loan guarantee programs.

15. The Commission has recognized this policy development, not only in this proceeding, but also in the Transmission Planning and Cost Allocation Proposed Rule, observing that "state policies to promote increased reliance on renewable energy resources, such as the renewable portfolio standard measures discussed above, accentuate the need for transmission to deliver electricity from location-constrained renewable energy resources to load centers."[38] The same observation is true for the operational reforms proposed here. Public policies that promote renewable resources accentuate the need for reforms to operational protocols that unduly discriminate against VERs and/or have the effect of maintaining rate structures that are no longer just and reasonable.

16. As the number of VERs has increased, the Commission has received a variety of proposals that seek variations from the *pro forma* OATT and/or LGIA in order to address system needs resulting from the integration of VERs. In recent years, a number of public utility transmission providers have proposed to assess various forms of ancillary services charges to wind generating resources, while others have proposed revised interconnection standards addressing reporting requirements and additional ancillary service obligations.[39] Consistent with many of the comments received in response to the Integrating VERs NOI, such filings suggest that the *pro forma* OATT and LGIA may need adjustments to address operational issues arising in response to the increased integration of VERs in individual balancing authority areas.

17. In light of these filings, comments, and the increasing deployment of VERs on the nation's transmission system, the Commission has identified reforms that it preliminarily finds would eliminate operational procedures that have the *de facto* effect of imposing an undue burden on VERs. 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 these reforms, the Commission seeks to ensure that VERs are integrated into the transmission system in a coherent and cost-effective manner, consistent with open access principles.

18. The Commission is aware that, in many instances, issues associated with VER integration are highly technical in nature and can vary significantly from one region to the next. The Commission is also cognizant of and supports ongoing industry initiatives dedicated to crafting regional solutions to the challenges associated with VER integration. Such regional efforts include the work being conducted by the North American Electric Reliability Corporation (NERC) through the Integration of Variable Generation Task Force[40] and the work of the Joint Initiative.[41] As such, the reforms proposed here do not purport to resolve all of the challenges associated with VER integration, nor are they intended to undermine progress being made in various regions regarding VER integration. The Commission's goal in this proceeding is simply to identify those basic reforms that can and should be implemented in the near term. The Commission believes that the reforms

[30] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 888 (modifying Schedules 2, 3, 4, 5, 6, and 9 of the *pro forma* OATT to indicate that the ancillary services provided in those rate schedules may be provided by generating units as well as other non-generation resources such as demand response where appropriate).

[31] Ryan Wiser & Mark Bolinger, Lawrence Berkeley National Laboratory, *2009 Wind Technologies Market Report* 3–5 (2010), *available at http://www1.eere.energy.gov/windandhydro/pdfs/2009_wind_technologies_market_report.pdf.*

[32] Div. of Energy Market Oversight, Fed. Energy Regulatory Comm'n, *2009 State of the Markets Report* (2010), available at *http://www.ferc.gov/market-oversight/st-mkt-ovr/som-rpt-2009.pdf.*

[33] Solar Energy Industries Ass'n, *US Solar Industry Year in Review* 2009, at 2, *available at http://seia.org/galleries/default-file/2009%20Solar%20Industry%20Year%20in%20Review.pdf.*

[34] *See* Integrating VERs NOI, 130 FERC ¶ 61,053 at P 2 (citing Div. of Energy Market Oversight, Fed. Energy Regulatory Comm'n, *Renewable Power and Energy Efficiency Market: Renewable Portfolio Standards 1 (2009), available at http://www.ferc.gov/market-oversight/othr-mkts/renew/othr-rnw-rps.pdf*).

[35] 26 U.S.C. 45.

[36] American Recovery and Reinvestment Tax Act of 2009, Pub. L. 111–5, sec. 1101, 123 Stat. 115, 319 (2009).

[37] *Id.* sec. 1102, 123 Stat. 115, 319–20.

[38] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* 131 FERC ¶ 61,253, at P 36 (2010) (Transmission Planning and Cost Allocation Proposed Rule).

[39] *See, e.g., NorthWestern Corp.,* 129 FERC ¶ 61,116 (2009) (*NorthWestern*), *order on reh'g,* 131 FERC ¶ 61,202 (2010); *Westar Energy Inc.,* 130 FERC ¶ 61,215 (2010) (*Westar*); *Cal. Indep. Sys. Operator Corp.,* 131 FERC ¶ 61,087 (2010); *Puget Sound Energy, Inc.,* 132 FERC ¶ 61,128 (2010) (*Puget Sound*).

[40] *See* North American Elec. Reliability Corp., *Accommodating High Levels of Variable Generation* (2009), *available at http://www.nerc.com/files/IVGTF_Report_041609.pdf.*

[41] *See* Joint Initiative at 3–11 (describing projects currently being developed by members of Columbia Grid, Northern Tier Transmission Group and WestConnect such as an Intra-Hour Transaction Accelerator Platform and a Dynamic Scheduling System).

proposed herein can and should be implemented in a way that complements ongoing stakeholder proceedings.

IV. Summary of Proposed Reforms

19. The Commission is proposing three reforms that, taken together, are 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. First, the Commission proposes to provide the transmission customer with the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals, so that they may adjust their transmission schedules to reflect, in advance of real-time, more accurate power production forecasts, load profiles, and other changing system conditions. At the same time, this proposed reform will enable public utility transmission providers and other entities to manage the system's variability more effectively and, over time, rely less on ancillary services and more on the flexibility of generation and non-generation resources.

20. Second, the Commission proposes to require public utility transmission providers to amend their *pro forma* LGIAs to incorporate provisions requiring interconnection customers whose generating facilities are VERs to provide certain meteorological and operational data to public utility transmission providers to facilitate public utility transmission providers' development and deployment of VER power production forecasting tools. Under the LGIA provisions proposed here, the interconnection customer whose generating facility is a VER would only be required to provide such data in the instance where the interconnecting public utility transmission provider is developing and/or deploying VER power production forecasting tools.

21. Third, the Commission proposes to add a generic ancillary service rate schedule to the *pro forma* OATT through which 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 transmission provider's balancing authority area. Under this proposed rate schedule, a public utility transmission provider will have the opportunity to recover reserve service costs associated with management of supply-side variability. In Order No. 890, the Commission took a case-by-case approach to filings by public utility transmission providers seeking to recover the costs of additional regulation reserves associated with providing generator imbalance service.[42] This existing policy, however, has led to uncertainty and allows the potential for undue discrimination. To prevent this uncertainty and potential undue discrimination, we believe it is appropriate now to propose a generic generator regulation reserve rate schedule that will delineate the rights and obligations of public utility transmission providers and customers with respect to the provision of this service.

22. Additionally, the Commission is proposing guidelines under which public utility transmission providers may assess generator regulation reserve charges to transmission customers. Such charges must be established based on traditional cost causation principles. To the extent 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, such differing volumes must be shown to be commensurate with the variability that VERs exhibit on the transmission provider's system. Furthermore, the public utility transmission provider must show that it has adopted measures to mitigate the total amount of regulation reserve necessary to manage the variability through the implementation of VER power production forecasting and intra-hourly scheduling. This mitigation requirement will help to ensure that the rates for this service are just and reasonable.

23. Through these three proposals, the Commission seeks to reform operational protocols that present barriers to the integration of VERs and to ensure the cost of integrating new resources, such as VERs, are not unnecessarily inflated by inappropriate systems and processes. While the proposed reforms focus on discrete operational protocols, they are integrally related and should be understood as complementary parts of a package. The Commission believes this set of reforms will help to level the playing field for all types of resources, provide much-needed clarification as to the roles and responsibilities of public utility transmission providers and transmission customers, and bring greater transparency and efficiency to existing system operations. As described in more detail below, the Commission believes that these proposed rules are necessary to remedy undue discrimination in existing transmission system operations and to ensure that rates for Commission-jurisdictional services are just and reasonable.

24. As should be clear from the scope of this Proposed Rule, the Commission is not proposing to address the additional issues identified in the Integrating VERs NOI at this time. Upon review of the comments, the Commission believes that further study of many issues identified in the Integrating VERs NOI is required. In addition, a number of parties are actively developing solutions to address issues raised in the Integrating VERs NOI.[43] Therefore, in keeping with the suggestion of a number of commenters to allow individual regions to continue to develop solutions to the challenges unique to their characteristics and resources, and in recognition of commenters who seek Commission engagement on these issues, the Commission proposes to instruct its staff to monitor and conduct outreach with industry stakeholders to keep abreast of developments.

V. Proposed Reforms

A. Intra-Hourly Scheduling

25. Outside of regions that have an RTO or ISO, resources typically

[42] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 689 n.401, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 313. More recently, the Commission clarified transmission providers' obligation to offer generator regulation service by rejecting a transmission provider's proposal to require VERs exporting out of the transmission provider's balancing authority area to provide or arrange for their own generator regulation capacity. *See NorthWestern,* 129 FERC ¶ 61,116 at P 24 (finding that the proposal to disclaim the obligation to provide the capacity reserves necessary to providing generator imbalance service would be inconsistent with the transmission provider's obligation to offer generator imbalance service set forth in the *pro forma* OATT).

[43] *See, e.g.,* Joint Initiative at 7–12 (explaining ongoing efforts in the West to develop a dynamic scheduling system and intra-hour transaction accelerator platform to facilitate transactions among balancing authorities); ISO/RTO Council at 44 (indicating that ISOs and RTOs have begun to integrate centralized forecasting into reliability commitment processes); NERC, *Integration of Variable Generation Task Force, 2009–2011 Work Plan (2009), available at http://www.nerc.com/docs/pc/ivgtf/IVGTF_Work_%20Plan_111309.pdf* (detailing on-going efforts to establish mechanisms to calculate the capacity associated with VERs). *See also* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 1626–27 (requiring transmission providers to use an OASIS template that will be developed by the North American Energy Standards Board to post information concerning curtailments, including the circumstances and events leading to a firm service curtailment, specific customers and services curtailed, and the duration of the curtailment).

schedule transmission service on an hourly basis, and adjustments to such schedules are permitted during the hour only for emergency situations that threaten reliability.[44] In the Integrating VERs NOI, the Commission noted that existing scheduling practices were designed at a time when virtually all generation on the system could be scheduled with relative precision.[45] The Commission also acknowledged that, with increasing numbers of VERs, system operators appear to be relying more on reserves, such as regulation reserves, to balance the variation in energy output from VERs.[46]

26. The Commission further explained that because transmission schedules are typically set 20–30 minutes ahead of the hour, the forecast of a VER's output (upon which its schedule is based) may be 90 minutes old by the end of the operating hour.[47] As a result, because of a resource's limited ability to adjust its schedules during the hour, the operational flexibility of all resources on the transmission provider's system may not be utilized.[48]

27. Therefore, the Commission sought to explore whether the retention of existing transmission scheduling practices had caused the rates for reserves to become unjust and unreasonable by inhibiting the ability of VERs to establish operationally-viable schedules and preventing public utility transmission providers from utilizing the flexibility of their systems. More specifically, the Commission sought to explore whether greater transmission scheduling flexibility, such as intra-hour scheduling or other improvements in the scheduling procedures, might offer the potential for greater efficiency in dispatching all resources. For instance, the Commission noted the potential for more efficient dispatch if the magnitude of schedule deviations could be reduced, better anticipated, and/or planned for more precisely.[49]

1. Comments

28. Most commenters recognize the benefits and support the implementation of some form of intra-hour transmission scheduling. AWEA states that shorter scheduling intervals will allow generators to provide inexpensively much of the flexibility that is currently being provided by expensive regulation reserves.[50] AWEA points out that the Avista Wind Integration Study similarly found wind integration costs would be reduced by 40–60 percent by moving from hourly to intra-hourly dispatch intervals.[51] Additionally, AWEA asserts that Bonneville has publicly stated that wind integration costs on its system would be reduced by 80 percent by moving from hourly schedules to intra-hourly schedules.[52] Bonneville states that intra-hour scheduling has the potential to help better manage the costs and operational impacts of VER generator imbalances.[53]

29. WECC explains that shorter scheduling intervals allow system operators to manage the integration of VERs more efficiently, because they permit the use of forecasts that are closer to the operating time frame, and are therefore more accurate.[54] EEI states that for regions with significant amounts of VERs, it appears that shorter intervals would allow system operators to manage VER ramp events [55] and variability, provide more accurate scheduling, reduce the reliance on regulating reserves and make it easier to meet NERC CPS–2.[56] NERC claims that while additional system flexibility can come from many sources, such as the availability of flexible conventional resources and non-conventional resources such as storage and demand response programs, an additional contributor to greater system flexibility includes shorter scheduling intervals, for both within a balancing authority area and between balancing authority areas.[57] Joint Initiative states that allowing transmission customers to schedule transactions within an operating hour increases operating flexibility for VERs and the rest of the system.[58] NERC claims that the ideal scheduling increments to achieve optimum flexibility while still meeting relevant reliability requirements may be between five and fifteen minutes; however, this depends on system characteristics, the type of VERs present on the system, and the level of VER penetration.[59]

30. AWEA argues that hourly scheduling practices have a much greater negative impact on VERs than on traditional dispatchable resources and that it is within the Commission's statutory duty to address these issues of discrimination.[60] AWEA notes that shorter scheduling intervals will yield significant benefits even on transmission systems without wind energy, as there is significant intra-hour variability in load, as well as in the output of non-VER resources when they experience forced outages or otherwise fail to provide their scheduled output.[61] AWEA also contends that moving to shorter dispatch intervals will actually improve power system reliability by freeing up additional system flexibility that is currently underutilized.[62] Iberdrola argues that the Commission should modify its *pro forma* OATT to require, at a minimum, intra-hourly scheduling of generation, explaining that intra-hour scheduling will improve VER scheduling accuracy and reduce VER integration costs.[63] Southern California Edison argues that the Commission should ensure that new scheduling tools, such as half-hour scheduling intervals, are available, as these could help reduce forecast errors, and in turn, result in optimal transmission utilization, market efficiency, and system reliability.[64] Southern California Edison also explains that, because it does not expect reliability issues to arise from scheduling rule changes, NERC Reliability Standards will require minimal or no changes.[65]

31. Many commenters, however, seek the flexibility to develop regional solutions without a Commission mandate that they be required to do so. The common reason given for this view is that each region has a unique mix of conventional generation resources and VERs, and each region should be

[44] Section 13.8 of the *pro forma* OATT requires transmission customers to schedule use of firm point-to-point transmission service by 10:00 a.m. the day prior to operation. That section also gives the transmission provider the discretion to accept schedule changes no later than 20 minutes prior to the operating hour.

[45] Integrating VERs NOI, 130 FERC ¶ 61,053 at P 18.

[46] *Id.*

[47] *Id.* P 19.

[48] *Id.*

[49] *Id.* P 18–21.

[50] AWEA at 38 (citing M. Milligan & B. Kirby, *Impact of Balancing Area Size, Obligation Sharing, and Ramping Capability on Wind Integration,* 27–29 (2007), *available at http://www.nrel.gov/wind/systemsintegration/pdfs/2007/milligan_wind_integration_impacts.pdf*).

[51] AWEA at 20 (citing Avista Corp., *Wind Integration Study* (2007), *available at http://www.uwig.org/AvistaWindIntegrationStudy.pdf*).

[52] AWEA at 20 (citing Presentation by Bart McManus, Bonneville. *Large Wind Integration Challenges and Solutions for Operations/System Reliability* at slide 26 (Oct. 2008), *available at http://www.uwig.org/Denver/McManus.pdf*) (stating 10 minute schedule changes would solve approximately 80% of the issues Bonneville is anticipating).

[53] Bonneville at 6.

[54] WECC at P 6.

[55] Ramp events are instances where the generating facility experiences a significant change in electrical output.

[56] EEI at 9.

[57] NERC at 16.

[58] Joint Initiative at 3.

[59] NERC at 17–18.

[60] AWEA at 16.

[61] *Id.* at 38.

[62] *Id.* at 40.

[63] Iberdrola at 10.

[64] Southern California Edison at 10–11.

[65] Southern California Edison at 12.

allowed to explore and coordinate its own scheduling practices to suit its unique system needs through stakeholder processes. For example, EEI states that in light of the variation in market structures and rules throughout the country, it is unlikely that any single scheduling practice will suit all regions.[66] EEI argues that the Commission should allow each region to explore its own flexible scheduling options and provide policy guidance that encourages flexible scheduling practices to the maximum extent possible.[67] Bonneville argues that mandating intra-hour scheduling or standardizing national practices is premature.[68] The ISO/RTO Council supports moving toward intra-hour scheduling across the inter-ties for purposes of VER integration where warranted by system needs.[69]

32. Additionally, several of the commenters that oppose a Commission mandate to implement intra-hour scheduling cite reform efforts that are already underway. For example, the Joint Initiative describes its development of model intra-hour transmission purchase and scheduling business practices in the Western Interconnection.[70] The Joint Initiative also explains that a number of utilities in the Northwest have begun to implement these practices to one degree or another.[71] SMUD points out that the Western Systems Power Pool currently seeks to develop two new service schedules that will accommodate VERs through the provision of reserve services and intra-hour supplemental energy. For this reason, SMUD argues that the Commission should avoid taking actions where industry efforts are in progress to cost-effectively achieve similar goals, particularly when those efforts are further taking into account regional characteristics.[72]

33. Commenters generally recognize that the implementation process is not without some costs. AWEA states that the cost of transitioning to intra-hourly dispatch is quite modest and the bulk of these costs are up-front expenditures while the benefits of making the transition will be realized in perpetuity.[73] AWEA explains that the costs associated with the transition to an intra-hourly dispatch include: (1) Modifications of dispatch/energy management and NERC e-Tag systems in order to accommodate intra-hour schedules/settlements, (2) OATT revisions necessary to accommodate transmission reservations for periods of less than a full clock hour, and (3) possible staffing increases to handle the greater number of transactions.[74]

34. Entergy states that it moved from hourly scheduling to twenty-minute anytime-scheduling several years ago.[75] According to Entergy, no changes to the OATT, e-Tag or NERC rules were required.[76] Entergy states that its scheduling systems were significantly modified to implement this additional flexibility, but such changes have proven to be manageable to date. Entergy cautions that if intra-hour scheduling is mandated, the burden on the system operators may increase, such as when there are reliability issues on the system.[77] Entergy explains that at these times, system operators would have to handle intra-hour schedules and reliability issues simultaneously.[78] Therefore, Entergy asks the Commission to proceed carefully and consider differences among balancing authority areas, in terms of software, manpower, and scheduling work load, before mandating intra-hour scheduling.[79] Similarly, Northwestern argues that system automation will be necessary to allow much greater number of schedules and transmission service requests to be processed without impacting reliability.[80] National Rural Electric Cooperative Association (NRECA) claims that a number of NERC standards would need to be reviewed to determine the impacts of a move towards flexible scheduling.[81]

35. Smaller public utility transmission providers highlight challenges with respect to their size and explain that the implementation of intra-hour scheduling may be infeasible for certain entities. NRECA indicates that for smaller systems, implementation of intra-hour scheduling would be a significant additional burden and could require substantial costs in software modification.[82] NRECA explains that while changes to infrastructure required for trading may be absorbed by large entities, smaller cooperatives would be affected disproportionately because of their inability to spread the costs over the large volume of trade.[83] NRECA claims that in any cost-benefit analysis, it is less likely that smaller entities will benefit, even over time, especially where they lack a large customer base, which is the case for many rural electric cooperatives.[84] Consequently, NRECA contends that intra-hour scheduling is simply infeasible for some of its members at this time.[85]

36. Finally, some commenters oppose the implementation of intra-hour scheduling for their regions regardless of cost or whether the Commission allows for regional differences. Generally, these commenters base their objections on two grounds. First, commenters under the impression that the intra-hour scheduling would be available only to transmission customers using VERs argue that it would be unfair to afford scheduling opportunities to one class of transmission customers and not others, such as those utilizing conventional resources. Southern argues that there should not be any unique or special scheduling protocols applicable to only certain types of generation.[86] Second, commenters argue that the responsibility for scheduling efficiency should fall on VERs. These commenters generally argue that VERs should be required to maintain the accuracy of their schedules and should not expect public utility transmission providers to change scheduling practices that have worked in the past. Altresco states that maintaining scheduling practices is essential to the reliability of the grid, and that VERs should take responsibility for the reliability impact of the variability of their resource.[87] Southern states that all generators (including VERs) should be responsible for providing accurate schedules and that the risk and responsibility for forecasting availability should always be the generator's responsibility and should not be shifted to the public utility transmission provider or system operator.[88]

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[66] EEI at 8.

[67] *Id.* at 9.

[68] Bonneville at 44.

[69] ISO/RTO Council at 36.

[70] Joint Initiative at 4.

[71] *Id.* at 5–6 (citing sub-hourly scheduling initiatives by the following: NV Energy, PacifiCorp, Bonneville, Puget, Portland General Electric, Avista Corp., Seattle City Light, Chelan County PUD, Grant County PUD, and Tacoma Power).

[72] SMUD at 20.

[73] AWEA at 39.

[74] *Id.*

[75] Entergy at 2.

[76] *Id.*

[77] *Id.*

[78] *Id.*

[79] *Id.*

[80] NorthWestern at 14.

[81] NRECA at 30 (citing BAL (Resource and Demand Balancing), INT (Interchange Scheduling and Coordination), IRO (Interconnection Reliability Operations and Coordination), and MOD (Modeling, Data, and Analysis) Standards).

[82] NRECA at 28.

[83] *Id.* at 29.

[84] *Id.*

[85] *Id.*

[86] Southern at 11.

[87] Altresco at 5–6.

[88] Southern at 11.

2. Commission Discussion

37. The Commission preliminarily finds 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, we preliminarily find 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 proposes 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.[89] The Commission notes that the proposed 15-minute interval is consistent with the ideal time increments (*i.e.,* 5 to 15 minutes) recommended by NERC to achieve greater flexibility while still meeting relevant reliability requirements.[90] Additionally, the Commission notes that many commenters claim that shorter scheduling intervals may enhance system reliability.[91] As such, we do not believe, as NRECA suggests, that an independent review of NERC standards is necessary to making this proposed reform. However, the Commission seeks comment on the issue to ensure that there is no inconsistency among relevant NERC standards and the proposed intra-hour scheduling tariff reform.

38. As explained above, hourly transmission scheduling protocols were developed at a time when virtually all generation on the system could be scheduled with relative precision.[92] The resulting net system variability, i.e., the net variation between the load and generator imbalance, was such that hourly scheduling protocols were sufficient to maintain system balance. As higher amounts of VERs interconnect with the grid, these hourly scheduling protocols make it increasingly difficult for public utility transmission providers and balancing authorities to maintain system balance.[93] In order to accommodate any increased intra-hour supply-side variability caused by increasing numbers of VERs, public utility transmission providers in areas without organized real-time energy markets rely on reserve services, which are provided under a number of existing ancillary service rate schedules.[94]

39. The Commission believes that it is unduly discriminatory to perpetuate the practice for resources to match hourly transmission schedules, especially when the output of a resource (such as a VER) fluctuates beyond its reasonable control. Moreover, the Commission believes that requiring public utility transmission providers to procure ancillary services to manage generating resources' deviations across an operating hour is an inefficient and burdensome operating protocol with the potential to result in unjust and unreasonable rates. Therefore, in order to prevent excessive costs attributable to reserve services, an over-reliance on these reserve services in maintaining overall system balance, and undue discrimination against VERs, the Commission proposes to reform existing transmission scheduling practices. Under this proposed reform, all transmission customers will have the opportunity to take advantage of the shorter scheduling intervals and submit accurate intra-hour schedules, thereby mitigating the amount of regulation reserves or other ancillary services public utility transmission providers will need to procure.

40. The Commission expects this proposed reform to benefit many types of entities. For example, with shorter scheduling intervals, public utility transmission providers should have greater assurance that the schedules submitted by transmission customers using VERs are accurate. Therefore, these public utility transmission providers will be in a better position to anticipate and respond to fluctuations in VER energy production. In this way, the public utility transmission provider will be able to rely more on planned scheduling and dispatch procedures in maintaining overall system balance and rely less on reserves. At the same time, transmission customers delivering energy from VERs will be in a reasonable position to match their scheduled output with actual output, thereby managing their exposure to generator imbalance charges. Likewise, transmission customers delivering energy from energy constrained resources, such as flow-limited hydro generators, emission-limited thermal generators, demand response resources and energy storage resources will be better able to schedule transmission to reflect constraints in their operations. In addition, increased scheduling flexibility should help balancing authorities to more closely match scheduled production with actual output, which will enhance their ability to meet NERC Reliability Standards.

41. Accordingly, the Commission proposes to require public utility transmission providers to offer all transmission customers the option to submit changes to schedules in an interval of 15 minutes and allow all transmission customers the option of submitting intra-hour schedules up to 15 minutes before the scheduling interval. While the Commission proposes to establish a 15-minute scheduling interval, this proposed reform is not intended to deter public utility transmission providers from providing transmission scheduling intervals that are less than the proposed 15-minute period. To the extent public utility transmission providers incur costs as a result of implementing this proposed scheduling reform, the Commission proposes to allow such costs to be recovered pursuant to Schedule 1 of the transmission providers' OATTs.

42. The Commission acknowledges that a number of public utility transmission providers already have begun implementing intra-hour scheduling practices, primarily through reforms to their business practices.[95] While these individual reforms are important steps toward the efficient integration of VERs, the Commission believes that it is important to establish 15-minute scheduling periods as the default scheduling process among transmission providers. Because VERs tend to be located far from load centers, energy produced from VERs in one region is often sold to load serving entities in another region, requiring transmission service spanning one or more systems. The Commission believes that the proposed 15-minute scheduling protocols will benefit transmission customers delivering energy across multiple systems by allowing them to schedule energy on more than one system at similar intra-hour scheduling intervals that are in no event less than four times within the hour. In this way,

[89] The Commission's proposed reform allows for intra-hour scheduling adjustments; it does not propose changes to the hourly transmission service reservations provided in the OATT.

[90] NERC at 17–18.

[91] NERC at 20, AWEA at 40, EEI at 29, Southern California Edison at 11–12, CalWEA at 7, Pacific Gas and Electric at 6, NaturEner at 11, and Wärtsilä at 7.

[92] *See* Integrating VERs NOI, 130 FERC ¶ 61,053 at P 18.

[93] Bonneville at 45.

[94] Order No. 888, FERC Stats. & Regs. at 31,703–704.

[95] See Joint Initiative at 5–6 (citing sub-hourly scheduling initiatives by the following: NV Energy, PacifiCorp, Bonneville, Puget, Portland General Electric, Avista Corp., Seattle City Light, Chelan County PUD, Grant County PUD, and Tacoma Power).

the proposed 15-minute scheduling protocols will afford transmission customers using multiple systems the same flexibility as those using only one transmission system. Such intra-hour scheduling intervals also could lay the groundwork for the development of flexible energy and/or capacity products, thereby reducing the need for public utility transmission providers to rely on ancillary services to manage the variability of VERs.

43. At the same time, the Commission acknowledges 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 this regard, the Commission seeks comment on the best approach for implementing the intra-hour scheduling reforms proposed here. The Commission recognizes 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, commenters should consider any impacts on transmission customers scheduling across multiple systems and whether these impacts diminish the benefits of implementing intra-hour scheduling.

44. Finally, several commenters point out that hardware, software, and personnel modifications may be required in order to implement intra-hour transmission scheduling. To more fully understand the modifications that this proposed reform may require, the Commission seeks more detailed comment on the specific hardware, software, and personnel changes that are necessary to implement intra-hour scheduling, any additional impacts on relatively small public utility transmission providers, and how to best facilitate this reform for small public utility transmission providers.

B. Power Production Forecasting and Data Reporting

45. Research has shown that VERs power production forecasts are essential in managing the variability of VERs and, equally importantly, the use of these forecasting methodologies enhances economic efficiency and allows transmission providers to manage the operational effects of VERs on their transmission system.[96] Detailed and timely power production forecasts are critical to reducing uncertainty regarding the expected level of VER power output at various points in time.[97] By reducing uncertainty, power production forecasts give transmission providers an improved situational awareness of their transmission systems. These power production forecasting tools also provide transmission providers with the advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than managing the variability through the deployment of reserve services, such as regulation reserves. With situational awareness of forecasted variability, the transmission provider and/or balancing authority can commit or de-commit resources providing regulation reserves, to the extent and when they will be needed to maintain system reliability.[98] NREL's *Western Wind and Solar Integration Study* found that, while state-of-the-art power production forecasting for VERs may be imperfect, it is still beneficial to incorporate such forecasts into the existing scheduling and unit commitment processes. Additional research indicates that the accuracy of wind power forecasts is directly connected to the amount of balancing energy needed and hence the cost of wind power integration.[99] In WECC alone, NREL estimates that the use of VER power production forecasts has the potential to reduce operating costs by up to 14 percent or $5 billion per year.[100]

46. In SPP [101] and ERCOT,[102] studies have been commissioned that recommend the use of VER power production forecasting in unit commitment and reliability assessment analyses and the procurement of ancillary services. In Minnesota, research conducted in 2006 suggested that the failure to consider probable wind generation in the day-ahead market could result in incorrect price signals and market inefficiencies.[103]

47. Some public utility transmission providers have already instituted forecasting programs that are designed to address the variability associated with VERs. In 2004, the Commission accepted the CAISO's Participating Intermittent Resources Program (PIRP) and acknowledged the importance of centralized power production forecasting in reducing the barriers to VERs participation in the CAISO energy market.[104] To effectuate this program, CAISO is provided with the real-time operational and meteorological data necessary to forecast VER power production over a variety of time periods. VERs that participate in the PIRP are required to submit a power production schedule, through their scheduling coordinator, consistent with the CAISO's forecast of energy generation. PIRP participants are assessed a fee to defray CAISO's cost of providing this forecasting service.

48. In 2008, the Commission approved NYISO tariff revisions that implemented similar VER power production forecasting capabilities.[105] The Commission found NYISO's proposal to implement a centralized wind forecasting mechanism would allow it to predict the availability of wind resources more accurately and indicated that such a capability should reduce overall system operating costs. Similarly, both PJM and MISO have recognized the value of VER power production forecasting and have included in their respective business practice manuals centralized VER power production forecasting programs and responsibilities. Xcel states that it forecasts wind generation in its service territory in partnership with the National Center for Atmospheric Research (NCAR) using enhanced, state-of-the-art wind output prediction tools.[106] Xcel explains that while these tools require large amounts of meteorological information and turbine-level real-time operational data, migrating to this methodology has proven to be beneficial in terms of economics and reliability.[107]

49. In light of these and other acknowledgements of the benefits

[96] NERC, Integration of Variable Generation Task Force, *Task 2.1 Report: Variable Generation Power Forecasting for Operations* 5 (2010), *available at http://www.nerc.com-/docs/pc/ivgtf/Task2-1(5.20).pdf.*

[97] *Id.* at 54. *See also* National Renewable Energy Laboratory, Eastern Wind *Integration Study* 29 (2010), *available at http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf.*

[98] NERC at 6.

[99] Bernhard Ernst *et al.,* Predicting the Wind, IEEE Power & Energy Mag., Nov.–Dec. 2007, at 78, 79, *available at http://www.awea.org/utility/pdf/04383126predicting.pdf.*

[100] National Renewable Energy Laboratory, *Western Wind and Solar Integration Study* ES–18 (2010), *available at http://www.nrel.gov/wind/systemsintegration/wwsis.html.*

[101] Charles River Assoc., *SPP WITF Wind Integration Study* 6–19 (2010), *available at http://www.crai.com/consultingexpertise/listingdetails.aspx?id=12091&tID=828&subtID=0&tertID=0&fID=34&SectionTitle=Energy+%26+Environment.*

[102] GE Energy, *Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements* 9–7 (2008), *available at http://www.uwig.org/AttchB ERCOT_A-S_Study_Final_Report.pdf.*

[103] Enernex Corporation, *2006 Minnesota Wind Integration Study* 73–74 (2006), *available at http://www.uwig.org/windrpt_vol%201.pdf.*

[104] *Cal. Indep. Sys. Operator Corp.,* 98 FERC ¶ 61,327, *order on compliance,* 99 FERC ¶ 61,309 (2002).

[105] *New York Indep. Sys. Operator, Inc.,* 123 FERC ¶ 61,267, at P 13–14 (2008).

[106] Xcel at 3.

[107] *Id.*

associated with the increased use of VER power production forecasting in transmission system operations, the Commission sought comments in the Integrating VERs NOI on the state of VER power production forecasting in order to determine what additional tools and/or data may be necessary to incorporate increasing levels of VERs on the interstate transmission system.[108] The Commission sought information in three general areas: (1) Current VER power production forecasting efforts; (2) the data needed to create state-of-the-art power production forecasts; and (3) regulatory changes, if any, needed to incorporate power production forecasts into system operations.

1. Comments

50. In response to the Integrating VERs NOI, commenters filed detailed accounts of the current state of VER power production forecasting, and the necessary steps to incorporate state-of-the-art forecasting into system operations. Argonne National Lab's research indicates that increased levels of VERs will necessitate the incorporation of power production forecasting in unit commitment analyses to maintain system reliability.[109] NREL adds that ignoring VER power production forecasting during the unit commitment process may result in the commitment of too much or too little generating capacity and potentially generate economic losses over time.[110] NERC states that VER power production forecasts must be integrated into day-to-day reliability analyses and operations to ensure that system operators and market participants can create operating plans and procure necessary resources to keep supply and demand in balance on a real-time basis.[111] NERC explains that the goal of power production forecasting should be to identify high-risk periods where procurement of additional flexibility or reserves is justified to maintain system balance and reduce the commitment of expensive reserves when there is little risk of them being needed for reliability.[112] Commenters note that, while the goal of VER power production forecasts is to use forecasts to make better unit commitment and reliability assessment decisions, significant work is needed to develop better power production forecasts and determine how best to incorporate those forecasts into system operational decisions.[113]

51. One important clarification made by commenters is the differentiation between the underlying Numerical Weather Prediction (NWP) models and the power production forecasts used to estimate wind and solar plant power output. While government agencies like the National Oceanic and Atmospheric Administration (NOAA) are responsible for the development of the NWP models, the private sector focuses on using these models, in combination with data obtained from VERs, to develop power production forecasts tailored to the needs of individual clients (such as VERs, transmission providers and balancing authorities).[114]

52. The Commission received a number of responses to questions in the Integrating VERs NOI addressing the manner in which public utility transmission providers and balancing authorities could be provided with the data necessary to support centralized VER power production forecasts. Bonneville indicates that the Commission could aid in the creation of more advanced VER power production forecasts through a requirement in the LGIA or SGIA that the VER disclose operational or meteorological data to the public utility transmission provider for reliability and operational reasons. Another option mentioned by Bonneville and other parties is to modify the NERC Reliability Standards to require VERs to provide the data necessary to forecast VER power production.[115]

53. NERC[116] and others[117] provided detailed lists of the types of operational and meteorological data that may be necessary to develop VER power production forecasting tools for both generators and public utility transmission providers. Additionally, the CAISO explains that it requires members of the PIRP to install meteorological equipment at their facilities to obtain wind speed, direction, barometric pressure, and ambient temperature. CAISO also requires real-time energy output and outage and de-rate information, among other data, from participating intermittent resources.[118] CAISO explains that it is currently engaged in a stakeholder process to develop power production forecasting tools for solar resources with a special emphasis on the data necessary to forecast solar ramp events.[119] SEIA, however, notes that solar power production forecasting is still in its infancy, and states that overly prescriptive reporting and forecasting requirements for solar resources would be premature because the forecasting needs for solar facilities are only currently being identified.[120]

54. The Integrating VERs NOI also sought comments on whether public utilities should be required to maintain a meteorological reporting system and/or make meteorological data publically available to aid in the development of state-of-the-art forecasting tools. APS states that public utility transmission providers should not be required to post meteorological data on OASIS because the information typically comes from proprietary sources.[121] Others, like AWEA, claim that it should be possible to share meteorological data publicly without compromising sensitive market data. AWEA warns, however, that protections should be in place to assure commercially sensitive data cannot be inferred from publicly available data.[122] Bonneville notes that inclusion of data reporting requirements in the LGIA and SGIA would be appropriate because those agreements already include confidentiality measures.[123] SEIA contends that the value of meteorological data does not come from its public disclosure, but rather, through the provision of such data to system operators and forecast service providers that incorporate the data into centralized and decentralized power production forecast. SEIA adds that operational data and information regarding generating unit outages should not be made publicly available.[124]

2. Commission Discussion

55. In accord with the general consensus articulated by commenters, the Commission preliminarily finds that power production forecasting can play a significant role in removing barriers to the integration of VERs into the transmission system. The Commission believes 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

[108] Integrating VERs NOI, 130 FERC ¶ 61,053 at P 14–17.

[109] Argonne National Lab at 1.

[110] NREL at 9.

[111] NERC at 3.

[112] *Id.* at 20.

[113] AWEA at 23, Iberdrola at 19, NERC at 7.

[114] ISO/RTO Council at 17.

[115] Bonneville at 40, G&T Cooperative at 12, NaturEner at 6.

[116] NERC at 5.

[117] CAISO at 22, Iberdrola at 17, ISO–NE at 13, Xcel at 6–7.

[118] CAISO at 13.

[119] *Id.* at 12.

[120] SEIA at 20.

[121] APS at 6.

[122] AWEA at 35.

[123] Bonneville at 40.

[124] SEIA at 20.

unit commitment and dispatch processes, and, ultimately, lead to a reduction in the amount of reserve products needed to maintain system reliability. At the same time, the Commission recognizes that in areas of the country with very limited production from VERs, the implementation of power production forecasting for VERs could be of less use.[125]

56. Therefore, the Commission does not propose, to require all public utility transmission providers to implement power production forecasting at this time. Instead, the Commission proposes to require VER power production forecasting only by those public utility transmission providers seeking to require a subset of transmission customers to purchase, or otherwise account for, different volumes of generator regulation reserve service under proposed Schedule 10 (addressed below). This proposed reform is intentionally structured in a way that recognizes that VER power production forecasting may not be presently needed in all parts of the country (*e.g.,* those with very limited production from VERs). Because there may be little need for power production forecasting on transmission systems where VERs are not present in significant numbers, the Commission proposes to refrain from imposing a one-size-fits-all requirement to use VER power production forecasting tools on all public utility transmission providers.

57. The Commission is not proposing to require all public utility transmission providers to implement power production forecasting in this Proposed Rule. Nor is the Commission proposing a single appropriate method of cost recovery for the development and implementation of power production forecasts. Instead, the Commission seeks comments on how public utility transmission providers may recover the costs incurred to develop and deploy power production forecasting tools.

58. The Commission's proposal to adopt this requirement is founded on its review of the comments [126] and other technical analysis [127] indicating that the failure to consider VER power production forecasts in the hour-ahead, intra-day, day-ahead, and monthly time frames may result in an over-procurement of reserves, leading in turn to rates that may be unjust, unreasonable, and unduly discriminatory to VERs. Moreover, the Commission believes that the current ISO/RTO use of day-ahead, hour-ahead, and even intra-hour VER power production forecasts in unit commitment and reliability assessment analyses and dispatch procedures [128] demonstrates the benefits to be gained from incorporating these tools into system operations.

59. As indicated above, the Commission believes that power production forecasting on systems where VERs are present can lead to greater situational awareness as well as greater efficiency within the unit commitment, dispatch and reliability assessment processes. In the long-term, seasonal power production forecasts can identify months when the variability of VERs may need to be evaluated in light of planned outages for other generation. In the day-ahead and intra-day time frames, power production forecasts can be incorporated into reliability unit commitments, and in the hour ahead and shorter time frame, power production forecasts can be factored into dispatch instructions. Power production forecasts enable public utility transmission providers and balancing authorities to use their system resources in the most efficient manner. As mentioned by several parties,[129] power production forecasts that predict the timing of potential ramp events are critical to situational awareness for a balancing authority.

60. With respect to data necessary to develop and use a VER power production forecasting model, the Commission notes the NERC Reliability Standards [130] may provide transmission providers with authority to request some operational data from generators. However, to facilitate the development and deployment of power production forecasting, the Commission proposes to revise the *pro forma* LGIA to require interconnection customers whose generating facilities are VERs to provide certain meteorological and operational data to the public utility transmission providers with whom they are interconnected. Such data are necessary to enable a public utility transmission provider to develop and deploy state-of-the-art power production forecasting tools. This proposal builds upon existing Commission data sharing requirements by outlining specific meteorological and operational data necessary to develop power production forecasts. The Commission also preliminarily finds that the *pro forma* LGIA includes adequate confidentiality protections for sensitive data obtained from the VERs.[131]

61. The Commission proposes revisions to the LGIA that will result in different types of meteorological information being provided by interconnection customers based on the type of VER they own and/or operate. In order to enable the most accurate power production forecasts, the proposed revision to the LGIA would require that such data be transmitted from the interconnection customer to the public utility transmission provider at or near real-time. The Commission proposes to revise the *pro forma* LGIA to require interconnection customers with 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 proposes to revise the *pro forma* LGIA to require interconnection customers with 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 recognizes that different forecasts may require meteorological instruments to be located at hub height, up-wind of resources, or at ground level. However, the Commission will refrain from proposing specific requirements in this respect, and instead proposes to allow the public utility transmission provider and interconnection customer to negotiate these details taking into account the size and configuration of the VER facility, its characteristics, location, and its importance in maintaining generation resource adequacy and transmission system reliability in its area. The resource-specific data requirements contained in individual LGIAs must be negotiated on a not unduly discriminatory basis.

62. With respect to operational data, the Commission proposes to revise the *pro forma* LGIA to require

[125] *See* NERC, *Accommodating High Levels of Variable Generation 54 (2009), available at http://www.nerc.com/files/IVGTF_Report_041609.pdf.* ("[I]n many areas where wind power has not reached high penetration levels, uncertainty associated with the wind power has normally been less than that of demand uncertainty * * *. Consequently, power system operators have been able to accommodate current levels of wind plant integration and the associated uncertainty with little or no effort.").

[126] Bonneville at 5, Calpine at 13, M–S–R Public Power Agency at 4, NEPOOL at 7.

[127] *See supra* P 45–46.

[128] ISO/RTO Council at 16.

[129] Iberdrola at 14–18, NERC at 3 & 7, and NREL at 3.

[130] TOP–001, R7.1 (generator outage); TOP–002–2, R14, 15 (changes in output capability and seven day production forecasts); TOP–003–1 R1–3 (outage information); TOP–006–2 (monitoring system conditions); and IRO–004, R4 (generation, operating reserve projections).

[131] *See Pro Forma* LGIA Article 22 (setting forth the confidentiality provisions applicable to data exchanged through the interconnection process).

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. This proposal is similar to a recent CAISO proposal accepted by the Commission on April 30, 2010.[132] As indicated in that case, the requirement to report outages down to a 1 MW threshold will improve power production forecasting accuracy.[133] Provision of VER outage data to this level of granularity will allow a public utility transmission provider to ascertain the extent to which VER current power production is a result of unit availability as opposed to changing weather conditions.[134] If a VER is composed of a number of individual generating units, it is important for the public utility transmission provider to know how many individual generating units are capable of producing energy at any given time. Having such information will eliminate a significant source of forecasting error 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. For example, a 50 MW wind generating facility composed of fifty 1 MW turbines will have a maximum output of 50 MW when all of the individual turbines are operating. However, if one of those turbines experiences a forced outage, then the maximum output of the facility is 49 MW. To the extent that a public utility transmission provider is not aware that one turbine is unable to produce energy, the power production forecast for that wind generating facility, during the time the turbine is out of service, will experience an additional uncertainty.[135]

63. The Commission seeks comment on the extent to which the lists of basic meteorological and operational data articulated above may be inadequate or incomplete to achieve the power production forecasting goals discussed herein. Further, the Commission seeks comments 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.

64. In order to effectuate the above proposed changes, the Commission proposes to amend the *pro forma* LGIA to add a new definition of Variable Energy Resource to Article 1, add a new section Article 8.4, Provision of Data from a Variable Energy Resource and amend the table of contents. The Commission proposes to define 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. The Commission believes this definition is consistent with NERC's characterization of variable generation.[136] The Commission seeks comment on this proposed definition. Consistent with our approach in Order Nos. 2003 and 661,[137] the Commission proposes not to require retroactive changes to large generator interconnection agreements that are already in effect. However, the Commission seeks comment as to whether this approach would prevent public utility transmission providers from effectively implementing power production forecasting.

65. Because the Commission proposes that this reform would apply only to interconnection customers whose generating facilities are VERs greater than 20 MW, we are proposing revisions only to the *pro forma* LGIA and not the *pro forma* Small Generator Interconnection Agreement (SGIA). By definition, the VER generating facility of an interconnection customer that would interconnect with a public utility transmission provider pursuant to an SGIA is less than or equal to 20 MW in size. The Commission seeks comment on whether this proposed reform should also apply to interconnection customers whose generating facilities are VERs of 20 MW or less and therefore require revisions to the *pro forma* SGIA.

C. Generator Regulation Service-Capacity

66. In Order No. 888, the Commission identified six ancillary services necessary to provide basic transmission service and required public utility transmission providers to offer and/or provide them to transmission customers.[138] Among the ancillary services that the Commission required public utility transmission providers to offer were Regulation and Frequency Response Service (Regulation Service) and Energy Imbalance Service.[139]

67. 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).[140] 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 [141] to serve load in that area.[142] However, the Commission did not require public utility transmission providers to offer Regulation Service for transmission service out of or through the transmission provider's balancing authority area to serve load in another balancing authority area.[143]

68. 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.[144] In Order No. 888, the Commission required public utility transmission providers to offer Energy Imbalance Service for transmission service within and into the transmission provider's balancing authority area to serve load in that area.[145] 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.

69. As described above, Regulation Service and Energy Imbalance Service, while different in function, are complementary services through which public utility transmission providers

[132] *Cal. Indep. Sys. Operator Corp.,* 131 FERC ¶ 61,087 (2010).

[133] *Id.* P 42.

[134] *Id.* P 45.

[135] *Id.* P 19 (noting that while poor outage data make immediate forecasts less accurate, they also affect future forecasts because the past data serves as an input in the forecast algorithm for future time periods).

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

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

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

[139] *Id.*

[140] *Id.* at 31,707–708 (referencing *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,514, at 33,086 (1995)).

[141] The term control area, used in the *pro forma* OATT, has been superseded in the NERC Reliability Standards and industry usage by the term balancing authority area.

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

[143] *Id.*

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

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

maintain their systems' balance and recover both the capacity (Regulation) and energy (Energy Imbalance) 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 only provide standardized ancillary service schedules for transmission used to service load because load (rather than generation) exhibited the greatest amount of variability.[146] 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.

70. In Order No. 890, the Commission noted that the existing energy imbalance charges were the subject of significant concern and confusion in the industry.[147] 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.[148] 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.[149] The Commission found that formalizing generator imbalance provisions in the *pro forma* OATT would standardize the 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.[150]

71. 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.[151] 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.[152] Accordingly, the Commission provided a mechanism by which public utility transmission providers could recover these costs, explaining that "[t]o the extent a transmission provider wishes to recover costs of additional regulation reserves associated with providing imbalance service,[153] 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." [154] 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.[155] Since the issuance of Order No. 890, on a case-by-case basis, the Commission has accepted proposals to recover such generator regulation charges pursuant to this mechanism.[156]

72. More recently, the Commission has addressed a number of filings for the provision of generator regulation service to wind energy resources. Public utility transmission providers have proposed different methods of allocating the costs of or assigning the responsibility for generator regulation service needed to manage the variability of VERs.[157] These proposals have originated from public utility transmission providers that have a substantial amount of existing and projected wind resource generation on their systems, and the proposals have taken different approaches to managing and charging for the variability of wind resources. In *NorthWestern,* the transmission provider proposed to require wind energy resources using transmission service to export energy to another balancing authority area to provide for their own generator regulation service (either through becoming their own balancing authority areas, dynamically scheduling their energy out of NorthWestern's balancing authority area, or by self-supplying the required generator regulation reserves).[158] The Commission denied NorthWestern's proposal, finding that a requirement for intermittent renewable generators to supply or otherwise account for their own generator regulation (*i.e.,* capacity) service would undermine NorthWestern's obligation to offer generator imbalance (*i.e.,* energy) service under Schedule 9 of its OATT.[159]

73. Unlike *NorthWestern,* in *Westar,* the transmission provider proposed to offer and charge for generator regulation service to all generation resources that use transmission service to export energy from Westar's balancing authority area.[160] However, rather than proposing a standardized generator regulation service charge, Westar proposed to apportion the total charge between dispatchable generation resources and intermittent generation resources, commensurate with the respective generator regulation service burden each of these resources placed on Westar's system.[161] The Commission accepted Westar's proposal as an interim measure to be in effect only until the implementation of an ancillary services market, and the balancing authority area consolidation in Southwest Power Pool, Inc. (SPP).[162]

74. Most recently, in *Puget Sound,* the Commission evaluated a proposed "following service" for wind resources, which Puget described as a capacity service designed to follow and balance the within-hour variations in output from wind generators in Puget's balancing authority area.[163] Because Puget Sound's proposed rate was based on the capacity cost of a proxy unit that it may never construct, the Commission found that Puget Sound had not shown its rate to be a reasonably accurate

[146] 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. *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). As mentioned above, wind capacity has developed at a significant pace, now totaling more than 35,000 MW of capacity. *See supra* note 17.

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

[148] *Id.*

[149] *Id.* P 663.

[150] *Id.* P 667.

[151] *See 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.").

[152] *Id.* P 690.

[153] Refers to costs associated with capacity used to provide generator imbalance reserve service that otherwise are not recovered through Schedule 3.

[154] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at n. 401.

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

[156] *See, e.g., Entergy Services Inc.,* 120 FERC ¶ 61,042, at P 62–66 (2007); *Sierra Pac. Res. Operating Cos.,* 125 FERC ¶ 61,026 (2008).

[157] *See, e.g., NorthWestern,* 129 FERC ¶ 61,116, *order on reh'g,* 131 FERC ¶ 61,202; *Westar,* 130 FERC ¶ 61,215; *Puget Sound,* 132 FERC ¶ 61,128; Bonneville Power Admin., June 29, 2009 Filing, Docket No. EF09–2011–000.

[158] *NorthWestern,* 129 FERC ¶ 61,116, *order on reh'g,* 131 FERC ¶ 61,202.

[159] *NorthWestern,* 129 FERC ¶ 61,116 at P 24.

[160] *Westar,* 130 FERC ¶ 61,215 at P 1.

[161] *Id.* P 35–36.

[162] *Id.* P 35.

[163] *Puget Sound,* 132 FERC ¶ 61,128 at P 4.

representation of the costs incurred in providing a following service to wind resources.[164]

75. In the Integrating VERs NOI, the Commission sought to explore whether the variability associated with the increased number of VERs may result in an over-reliance on procuring additional reserves.[165] The Commission sought comment on the appropriate use of reserve products to ensure that reserves are being deployed efficiently such that the resulting rates are just, reasonable, and not unduly discriminatory.[166] Particularly relevant to the proposed reform discussed below, the Commission also sought comment on whether the "*pro forma* OATT [should] be revised or new provisions added to expressly address the added reserve capacity necessitated by increased number of VERs." [167]

1. Comments

76. The Commission received a number of comments on this issue, and different sectors of the industry hold widely divergent views on whether and in what manner public utility transmission providers should be allowed to charge VERs to account for the variability exhibited by those resources. The VER industry strongly opposes what it characterizes as "integration charges," such as the above-described proposals from Westar and Puget Sound. AWEA views any proposal to assess a VER integration charge (*i.e.,* any type of ancillary service) that is not justified by the variability of the actual resources as discriminatory on its face.[168] AWEA further contends that any added costs that result from VER integration are the result of the fact that current power system operating procedures were not designed to accommodate VERs.[169] Accordingly, AWEA argues that before any integration charge is assessed to VERs, public utility transmission providers should first be required to implement operational reforms to update their systems, including the following: 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.[170] NextEra agrees, adding that procurement of ancillary services is based on numerous factors within a balancing authority area and that the costs of these services should not be allocated to individual facilities on an incremental basis.[171]

77. NERC also contends that enhancements to existing operating criteria, practices, and procedures to account for large increases in the number of VERs should be developed through the stakeholder processes of reliability bodies, such as NERC, Regional Entities and RTOs, noting that it is critical that practices such as reserve procurement for VERs are reviewed to assist system operators in managing increased uncertainty from VERs.[172]

78. Public utility transmission providers, however, generally hold a different view, seeking the flexibility to develop rate schedules that address the particular circumstances and resource mix present within their balancing authority areas. For example, Xcel recommends that the Commission encourage specific VER integration rates for public utility transmission providers outside of the regional markets. Xcel suggests that these integration rates could be based on increased regulation, load-following and cycling operations and maintenance impacts on the remainder of the balancing fleet providing the integration service, with VERs paying the costs of this service in place of conventional load-based billing.[173] Westar states that "[t]he ancillary services provisions of the *pro forma* OATT should be revised or new provisions added to expressly address the added reserve capacity necessitated by increased number of VERs." [174]

79. Bonneville asserts that existing reserve products are not the most cost-effective means of supplying reserves of VERs and that balancing authorities should be permitted to establish new reserve services to address the uncertainty associated with VERs.[175] Bonneville cautions that if reliability or cost recovery issues arise in regions where VERs are concentrated, it will become increasingly difficult to build new projects in those regions.[176] Bonneville also notes that the current generator imbalance service under Schedule 9 is for energy only and does not account for the capacity required to accommodate the full range of deviations within any scheduling period, hourly or intra-hourly. To better account for this capacity, Bonneville states that it is necessary to charge for the regulation, following, and generator imbalance capacity components that are required to manage the variability of VERs.[177]

80. Bonneville also emphasizes the challenges faced by balancing authority areas in which a large number of VERs are located, and where much of the energy generated by these resources is exported to serve load in other balancing authority areas. Bonneville stresses that current policies are leading to duplicative and inefficient carrying of reserves by source and sink balancing authorities, as well as creating cost and reliability risks for balancing authority areas from which VERs are exported.[178] Accordingly, Bonneville believes that rather than serving as default suppliers, source balancing authorities should strive to facilitate options (*e.g.,* self-supply and dynamic transfers) for VER exporters to acquire balancing services from alternative sources.[179] Bonneville argues that clear delineation between being a default supplier versus a fully compensated party to a defined transaction is essential to the sustainable growth of VERs.[180]

81. Some commenters urge the Commission to eliminate any obligation on the part of a public utility transmission provider to ensure that sufficient capacity is available to manage the moment-to-moment variability of VERs located within their balancing authority area, and instead place that obligation on the VER and/or the entity using the VER to serve load.[181] NorthWestern contends that "because not all transmission providers will have the resources available to provide the service, there should be no obligation on the transmission provider

[164] *Id.* P 35.

[165] Integrating VERs NOI, 130 FERC ¶ 62,053 at P 35.

[166] *Id.*

[167] *Id.* P 36.

[168] AWEA at 15–16.

[169] *Id.* at 67.

[170] *Id. See also* Iberdrola at 37.

[171] NextEra at 25 (explaining that while contingency reserve requirements are set by the single largest contingency within a balancing authority area, the entity that owns that contingency is not charged an incremental rate for those reserves).

[172] NERC at 22–23.

[173] Xcel at 38.

[174] *See* Westar at 27–28. Westar contends that its OATT Schedule 3A approved by the Commission in *Westar,* 130 FERC ¶ 61,125 provides a model that can be followed.

[175] Bonneville at 84.

[176] *Id.* at 2.

[177] *Id.* at 94.

[178] *Id.* at 3.

[179] *Id.* at 22.

[180] *Id.* at 4.

[181] Bonneville at 22 (arguing that the VER owner and the entity that is using the VER for its own load service should have the fundamental planning, operational, and financial responsibility for ensuring that there is sufficient capacity available to manage the full range of variability of the VER—including regulation, load following, generator imbalance, and extreme tail events (large up and down ramp events)).

to do so." [182] Instead, NorthWestern argues that a new ancillary services schedule could define the amount of service necessary to maintain system reliability and the options the transmission customer has to acquire and/or self-supply the service.[183] Some commenters urge the Commission to require VERs to submit "balancing plans" to host balancing authorities during the interconnection process, including such things as third-party balancing arrangements, comparisons of a VER's balancing needs with products offered by the host balancing authority, and requests to the host balancing authority to develop new balancing products and/or dynamically scheduling tools.[184]

82. Several entities suggest that it is premature for the Commission to require new or different reserve products. For example, EEI argues that the Commission should first allow industry-based studies addressing the reliability-related reserve issues to proceed. EEI believes that after the reliability issues are addressed, the Commission should examine the ancillary services mandated in the *pro forma* OATT to determine whether they provide the proper market-based incentives for supply and demand resources to mitigate the costs of variability associated with VERs.[185] EEI stresses, however, that the Commission should not mandate a particular outcome, such as a required reserve product, and instead should allow regional solutions to be developed.[186]

83. Other entities, such as NREL and NaturEner, indicate that different reserve products should be used to respond to different types of events. NREL indicates that where VER ramp events frequently exceed the ramp capabilities of existing resources, a ramp service may be justified; however, where such VER ramp events happen infrequently (what NREL refers to as "tail" events) a service more like supplemental or non-spinning reserves may be desirable.[187] NaturEner argues that it is not financially feasible to use regulation reserves for rare VER ramp events, and that public utility transmission providers should be able to use contingency reserves [188] for such events.[189] Lastly, the Commission notes that commenters express various opinions, as well as confusion, regarding a public utility transmission provider's ability to use contingency reserves to manage extreme VER ramp events.[190]

2. Commission Discussion

84. As the Commission explained in *NorthWestern,* 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.[191] The Commission also stated in *NorthWestern* that eliminating this obligation or placing conditions on the ability of transmission customers using VERs to receive this capacity service would undermine the public utility transmission provider's ability to offer generator imbalance service.[192] In this way, the Commission in *NorthWestern* recognized public utility transmission providers' obligation to provide this generator regulation service to customers using transmission service to deliver energy from generators located within their balancing authority area.

85. In the Proposed Rule, the Commission seeks to bring consistency to the manner in which public utility transmission providers carry out this obligation by incorporating Schedule 10—Generator Regulation and Frequency Response Service into the *pro forma* OATT. In doing so, the Commission seeks to bring clarity and transparency to the rates, terms and conditions that apply to the provision of this service, as well as the mechanism through which public utility transmission providers can recover the associated costs. At the same time, we recognize that on many transmission systems, especially those that do not have a significant number of transmission customers that export energy, public utility transmission providers already recover the costs of providing regulation service to transmission customers serving load on their systems through Schedule 3 of the *pro forma* OATT. The proposed reform would require public utility transmission providers to file Schedule 10, setting forth the transmission provider's obligation to offer generator regulation service and the rate at which the service would be provided. However, the proposed reform refrains from requiring a volumetric reserve requirement until the public utility transmission provider chooses to make a subsequent filing proposing an appropriate volumetric reserve requirement.

86. We recognize that the Commission adopted, in Order No. 890, a case-by-case approach to filings by public utility transmission providers seeking to recover the costs of additional regulation reserves associated with providing generator imbalance service.[193] However, in light of the increasing number and diversity of proposals filed with the Commission, it is appropriate to revisit the case-by-case approach and bring a measure of consistency to the manner in which generation regulator reserve service is provided.

87. Therefore, the Commission proposes 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. 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 reform recognizes this *de facto* obligation and establishes 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 finds 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.

88. Proposed 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 will 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

[182] *See* NorthWestern at 30.

[183] *Id.*

[184] PUD No. 2 Grant County at 4, Bonneville at 25–26.

[185] EEI at 20–21.

[186] *Id.* at 21–22.

[187] NREL at 15.

[188] Contingency reserves are reserves held and deployed in the event of an unexpected failure or outage of a generation, non-generation or transmission resource.

[189] NaturEner at 21.

[190] Westar at 27, Puget at 13, Exelon 15–16, Xcel at 36–37, Grant PUD at 25–26.

[191] *NorthWestern,* 129 FERC ¶ 61,116 at P 27.

[192] *See id.* P 24.

[193] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 689 n.401, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 313.

serving load within the transmission provider's balancing authority area and when they are exporting to load in other balancing authority areas.

89. Under proposed 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 transmission provider's balancing authority area. A transmission customer subject to Schedule 10 must either take service pursuant to this proposed rate schedule or demonstrate that it has satisfied its regulation service obligation through dynamically scheduling its generation to another balancing authority area [194] or by self-supplying regulation reserve capacity from generation or non-generation resources.[195] Furthermore, consistent with Order No. 890, public utility transmission providers may not charge transmission customers for regulation reserves under both Schedule 3 and proposed Schedule 10 for the same transaction.[196]

90. As with generator imbalance service, it may be appropriate for a public utility transmission provider to allow a generator located within its balancing authority area, which is not otherwise a transmission customer, to execute a service agreement for generator regulation service.[197] In the instance where multiple transmission customers are delivering energy from a single generator, the public utility transmission provider would need to apportion among those multiple transmission customers the generator regulation service charge for such generator. The apportionment process could be difficult and administratively burdensome for the public utility transmission provider. Accordingly, by establishing a contractual arrangement between the public utility transmission provider and such generator through the execution of a service agreement, the public utility transmission provider can charge the generator directly for generator regulation service, and any transmission customer delivering energy from such generator will be deemed to have satisfied its obligation to purchase generator regulation service under section 3 and Schedule 10.

91. The Commission proposes that this service should apply to transmission customers delivering energy from all generators (as opposed to VERs only) located within a public utility transmission provider's balancing authority area. The Commission reiterates that in establishing proposed Schedule 10, we are not changing the nature of the services that a public utility transmission provider must offer its transmission customers. Nothing in this 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 proposal here is simply 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.

92. As with Schedule 3, the proposed Schedule 10 charge will be the product of two components: A per-unit rate for regulation reserve capacity and a volumetric component for regulation reserve capacity. The regulation reserve capacity requirement is the cost and volume of unloaded generation or other non-generation resources held in reserve to manage the variability of load (under Schedule 3) and generation (under proposed Schedule 10) in a reliable manner.

93. Schedule 3 and the proposed Schedule 10 both are 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 proposes 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 proposed Schedule 10. 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. Moreover, the Commission notes 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 proposed generator regulation rate that the Commission accepted in *Westar.*

94. Whereas the Commission finds that the per-unit rate for service under proposed Schedule 10 should be the same as the rate for service under existing Schedule 3, the Commission recognizes that generators and load may exhibit different amounts of overall variability. Moreover, the Commission recognizes that variability may be different among different types of resources. A number of commenters indicate that VERs may impose a disproportionate impact on overall system variability, thereby requiring public utility transmission providers to hold a greater per MW amount of regulation reserves for VERs than for load and/or other generation resources.[198] As a general matter, the Commission agrees that regulation reserve costs should be allocated to transmission customers consistent with cost causation principles. Further, the Commission does not propose to mandate a particular method for apportioning the volume of regulation reserves of proposed Schedule 10. Instead, we preliminarily find that each public utility transmission provider should propose a method of apportioning such volumes of regulation reserves, based on the facts and circumstances of its individual system. For example, the Commission recognizes 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. This may be the case to the extent that the impact of VERs on its 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.

95. Alternatively, where a subset of transmission customers causes a public utility transmission provider to procure a different per unit volume of regulation

[194] See Joint Initiative at 7 (describing the development of the Dynamic Scheduling System in order to simplify, enhance and reduce the cost of dynamically scheduling resources between Balancing Authority Areas across the western interconnection).

[195] *See* Order No. 888, FERC Stats. & Regs. at 31,717 (establishing the same options to dynamically schedule or self-supply for customers subject to Schedule 3 of the *pro forma* OATT). The self-supply option would allow VERs to acquire regulating reserves to meet their schedules or to self-curtail according to specified criteria in order to reduce the amount of reserves they are obligated to supply or purchase. *See also* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 888 (modifying Schedules 2, 3, 4, 5, 6, and 9 of the pro forma OATT to indicate that the services provided under those rate schedules may be provided by generating units as well as other non-generation resources such as demand response).

[196] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690 (requiring transmission providers to demonstrate that any proposals to recover capacity costs associated with Generator Imbalance Service do not lead to double recovery). *See also Entergy,* 120 FERC ¶ 61,042 at P 62–66*; Sierra Pac. Res. Operating Cos.,* 125 FERC ¶ 61,026; *Westar,* 130 FERC ¶ 61,215 at P 4.

[197] *See* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 at P 288.

[198] Westar at 7, NorthWestern 5–6.

reserves than for other transmission customers, public utility transmission providers may require that subset of transmission customers to purchase, or otherwise account for, a different volume of generator regulation reserves, commensurate with its relative impacts on the system. The Commission accepted such a proposal (on an interim basis) in *Westar,* where a public utility transmission provider demonstrated the disproportionate impact of VERs on overall system variability, and the Commission found that it was consistent with cost causation principles for the public utility transmission provider to allocate a different regulation reserve capacity requirement to those resources.[199] Accordingly, under proposed Schedule 10, a public utility transmission provider may require a transmission customer delivering energy from VERs to purchase, or otherwise account for, a different volume of generator regulation reserve to the extent that the different regulation reserve volumes are supported by data showing that, on the public utility transmission provider's system, VERs impose a different per unit impact on overall system variability than conventional generating units.

96. At the same time, the Commission acknowledges commenters who argue that public utility transmission providers should be required to adopt operational reforms to mitigate the volume of regulation reserves that may be required to manage the variability of VERs. As discussed above, AWEA contends that before imposing any specific generator regulation reserve costs to VERs, public utility transmission providers should first implement the following: 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.[200] We agree that public utility transmission providers should implement certain operational reforms before requiring transmission customers delivering energy from VERs to purchase, or otherwise account for, different volumes of generator regulation service than those transmission customers delivering energy from other generators.

97. Accordingly, a public utility transmission provider may not require different volumes of generator regulation service from transmission customers delivering energy from VERs as opposed to conventional generators without implementing intra-hourly scheduling and power production forecasting as discussed in this Proposed Rule. Subsequently, a public utility transmission provider may require the subset of transmission customers who deliver energy from VERs to purchase, or otherwise account for, different volumes of generator regulation service, provided that it demonstrates that the different regulation reserve volume is necessitated by that subset of transmission customers.

98. However, the Commission will not require public utility transmission providers to implement the other reforms suggested by AWEA at this time. While the Commission believes that it is appropriate to require public utility transmission providers to implement those reforms that are within their individual control (as is the case with intra-hourly scheduling and power production forecasting) some of AWEA's proposals would require measures that go beyond an individual public utility transmission providers' reasonable control (such as the development of ancillary services markets or a regional ACE diversity interchange) and are coordinated reforms that require the cooperation of other transmission providers. As discussed above, industry stakeholder groups are currently addressing a number of these issues, and our intention here is to propose those reforms that can be adopted in the near-term by individual public utility transmission providers.

99. In addition to the generator regulation reform proposed herein, commenters in response to the Integrating VERs NOI address a number of issues related to ancillary services reforms that do not appear ripe for Commission action in this proceeding. For example, commenters suggest the possibility of reforming rules associated with the provision of contingency reserves to allow the use of these reserves to cover infrequent but significant VER ramp events, described as "tail" events.[201] Still other commenters suggest that the Commission revisit the rules applicable to VERs regarding their obligations to provide reactive power capabilities.[202] The Commission proposes to make no additional reforms to the ancillary services sections of the OATT beyond those proposed at this time. We believe these suggested reforms require further study and will benefit from continued stakeholder discussions, such as through NERC's Integration of Variable Generation Task Force. Accordingly, the Commission will continue to monitor these and other potential ancillary services reforms, but will not address them in this proceeding.

100. Finally, the Commission seeks comments from NERC and industry stakeholders on the steps needed to resolve the confusion regarding the use of contingency reserves to manage extreme ramp events of VERs.[203] The Commission seeks 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 re-mailning consistent with NERC Reliability Standards.

VI. Compliance Filings

101. The Commission proposes that each public utility transmission provider must comply with the requirements of this Proposed Rule. The Commission proposes to require each public utility transmission provider to submit a compliance filing within six months of the effective date of the final rule in this proceeding revising its OATT, LGIA, or other document(s) subject to the Commission's jurisdiction as necessary to demonstrate that it meets the proposed requirements set forth in this Proposed Rule.[204] Accordingly, in the compliance filing required by the Proposed Rule, 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

[199] *Westar,* 130 FERC ¶ 61,215 at P 35–36. In *Westar*, the proposal was an interim measure that would be in place only until the implementation of Southwest Power Pool's balancing area consolidation and ancillary services market. *Id.*

[200] AWEA at 67. *See also* Iberdrola at 37.

[201] *See, e.g.,* NREL at 16–17.

[202] *See, e.g.,* Bonneville at 100, Xcel at 41, Nevada Power at 7–8.

[203] 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."

[204] *See* Appendix B and C for the proposed *pro forma* OATT and LGIA provisions consistent with this Proposed Rule.

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.

102. In some cases, 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. 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.

103. The Commission will assess whether each compliance filing satisfies the proposed requirements and principles stated above and issue additional orders as necessary to ensure that each public utility transmission provider meets the requirements of this Proposed Rule.

104. The Commission proposes that transmission providers that are not public utilities will have to adopt the requirements of this Proposed Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[205]

105. Subsequent to the acceptance of its compliance filing, a public utility transmission provider will have the opportunity to justify, in a section 205 filing, 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.[206] Where a public utility transmission provider proposes the same volume of generator regulation reserves for all generators, it must demonstrate that the volume of regulation reserves required of transmission customers delivering energy from generators located within its balancing authority area is commensurate with their proportionate effect on net system variability and taking account of diversity benefits.[207] 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.

106. 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, it must 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 variability and taking account of diversity benefits. 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 and must also show the public utility transmission provider has developed and deployed power production forecasting for VERs. The Commission seeks comment on the manner by which a public utility transmission provider should be required to show they have developed and deployed power production forecasts.

107. The Commission proposes that any such subsequent filing including different volumetric requirements for different subsets of transmission customers should be supported with actual data collected over a one year period subsequent to the implementation of intra-hourly scheduling and power production forecasting for VERs. The Commission acknowledges that this proposal may delay a public utility's ability to recover the cost associated with providing generator regulation service. We further acknowledge that there may be alternative methods for developing the data necessary to support different volumetric requirements for different subsets of transmission customers. The Commission seeks 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.

VII. Information Collection Statement

108. The following collections of information contained in this Proposed Rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[208] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[209] The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

109. Additionally, the Commission encourages comments regarding the time burden expected to be required to comply with the proposed rule regarding intra-hourly transmission scheduling requirements and the requirement to coordinate and provide meteorological and operational data where relevant. Specifically, the Commission seeks comment on: (1) The additional burden and cost (human, hardware and software) associated with implementation, operation and maintenance of intra-hour transmission scheduling in 15-minute increments; and (2) the additional time burden and cost (human, hardware and software) involved in implementation, operation and maintenance for an interconnection customer to coordinate and provide meteorological and operational data to the public utility transmission provider where relevant.

Burden Estimate: The additional estimated public reporting burdens for the proposed reporting requirements in this rule are as follows:

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

[206] The Commission expects that in any subsequent filing to establish a volumetric requirement in Schedule 10, public utility transmission providers will address how Schedule 10 and Schedule 3 will work together to allow for the recovery of total regulation reserve costs.

[207] 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. 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 the Commission finds that sharing of these benefits among the customers is reasonable. *Westar,* 130 FERC ¶ 61,215 at P 37–38.

[208] 44 U.S.C. 3507(d) (2006).

[209] 5 CFR 1320.11 (2010).

Data collection FERC 516	Number of respondents [1]	Number of responses [2]	Hours per response [3]	Total annual hours [1 × 2 × 3]
Conforming tariff changes to require intra-hourly scheduling or deviation request (18 CFR 35.28(c)(1)(vi)).	134	1	3	402.
Implementation of intra-hourly scheduling (15-minute intervals)	134	1	6 initial set up, 2 maintenance and operation.	804 initial year, 268 subsequent years.
Addition of ancillary service rate schedule, Schedule 10 or deviation request (18 CFR 35.28(c)(1)(vi)).	134	1	5	670.
Conforming changes to LGIA (for meteorological and operational data provided by Interconnection Customers with VERs) or deviation request (18 CFR 35.28(f)(1)(v)).	134	1	7	938.
Provision of meteorological and operational data by Interconnection Customers with VERs to public utility transmission providers.	270*	1	4 initial set up, 2 maintenance and operation.	1,080 initial year, 540 subsequent years.
Totals				3,894 initial year, 2,818 subsequent years.

* The Commission estimates that there are approximately 270 VERs under construction, permitted, with an application pending, or proposed to come online 2010–2011 potentially subject to this requirement.

Cost To Comply: The Commission has projected the cost of compliance to be $443,916 in the initial year and $321,252 in subsequent years.

Total Annual Hours for Collection in initial year (3,894 hours) @ $114 an hour [average cost of attorney ($200 per hour), consultant ($150), technical ($80), and administrative support ($25)] = $443,916

Total Annual Hours for Collection in subsequent years (2,818 hours) @ $114 an hour = $321,252.

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

Action: Proposed Collection.

OMB Control No. 1902–0096.

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

Frequency of Information: As indicated in the table.

Necessity of Information: The Federal Energy Regulatory Commission is proposing changes to the *pro forma* OATT in order to remedy operational challenges related to the increased integration of VERs to the bulk electric system. The purpose of this Proposed 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 Proposed Rule seeks to achieve this goal by amending the *pro forma* OATT and LGIA to incorporate provisions that require intra-hourly transmission scheduling, 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 and create a generic ancillary service schedule.

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.

110. 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], *e-mail: DataClearance@ferc.gov, Phone:* (202) 502–8663, *fax:* (202) 273–0873.

111. Comments on the collections of information and the associated burden estimates in the proposed rule should be sent to the Commission in this docket and may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW., Washington, DC 20503 [*Attention:* Desk Officer for the Federal Energy Regulatory Commission], at the following e-mail address: *oira_submission@omb.eop.gov.* Please reference OMB Control No. 1902–0096 and the docket number of this proposed rulemaking in your submission.

VIII. Environmental Analysis

112. 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.[210] The Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for this Proposed 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.[211]

IX. Regulatory Flexibility Act Analysis

113. The Regulatory Flexibility Act of 1980 (RFA) [212] generally requires a description and analysis of final rules that will have a significant economic impact on a substantial number of small entities. This Proposed Rule applies to public utilities that own, control or operate interstate transmission facilities other than those that have received waiver of the obligation to comply with Order Nos. 888, 889, and 890. The total estimated number of public utility transmission providers that, absent waiver, would have to modify their current OATTs by filing the revised *pro forma* OATT is 134. Of these public utility transmission providers, an estimated 10 filers, or 7.5 percent, have

[210] *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).

[211] 18 CFR 380.4(a)(15) (2010).

[212] 5 U.S.C. 601–612 (2006).

output of four million MWh or less per year.[213] The Commission does not consider this a substantial number and, in any event, each of these entities may seek waiver of these requirements. 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.

114. As the Commission has previously explained, in determining whether a regulatory flexibility analysis is required, the Commission is required to examine only direct compliance costs that a rulemaking imposes on small business.[214] It is not required to examine indirect economic consequences, nor is it required to consider costs that an entity incurs voluntarily. As discussed above, only public utility transmission providers are required to make filings in compliance with the Proposed Rule. However, to the extent that interconnection customers whose generating facilities are VERs are also impacted by the Proposed Rule, such impacts only apply to those interconnection customers subject to standard generator interconnection agreements for VERs larger than 20 MW,[215] which exceeds the threshold of the small business size standard of the Small Business Administration. Accordingly, the Commission certifies that the proposed rule will not have a significant economic impact on a substantial number of small entities.

X. Comment Procedures

115. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due January 31, 2011. Comments must refer to Docket No. RM10–11–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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

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

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

XI. Document Availability

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

120. 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.

121. 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 e-mail at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659. E-mail the Public Reference Room at *public.referenceroom@ferc.gov.*

List of Subjects in 18 CFR Part 35

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

By direction of the Commission.

Kimberly D. Bose,

Secretary.

In consideration of the foregoing, the Commission proposes to amend 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 is revised.

b. Paragraphs (c)(1)(i), (ii), (iii), (c)(1)(v) and (c)(1)(vi) are revised.

c. Paragraphs (c)(3) introductory text and (c)(3)(ii) are revised.

d. Paragraphs (c)(4) is revised.

e. Paragraph (d) is revised.

f. Paragraphs (e)(1)introductory text, (e)(1)(ii) and (e)(2) are revised.

h. Paragraphs (f)(1) introductory text and (f)(1)(i) are revised.

i. Paragraphs (f)(1)(ii) through (f)(1)(iv) are removed and (f)(1)(ii) is reserved.

j. Paragraph (f)(3) is revised.

k. Paragraph (f)(4) is removed.

§ 35.28 Non-discriminatory open access transmission tariff.

* * * * *

(c) * * *

(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.

(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.

[213] 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. Based on the filers of the annual FERC Form 1 and Form 1–F, as well as the number of companies that have obtained waivers, we estimate that 7.5 percent of the filers are "small."

[214] *Credit Reforms in Organized Wholesale Electric Markets,* 133 FERC ¶ 61,060, at P 184 (2010).

[215] Standard generator interconnection agreements and procedures are segmented into large generators which are greater than 20 MW and small generators which are 20 MW or less. This proposed rule applies only to generators in the LGIA category of more than 20 MWs.

(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) * * *

(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) * * *

(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.

(ii) [Reserved]

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

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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 Inquiry on Integration of Variable Energy Resources—Docket No. RM10–11–000, January 2010

Short name or acronym	Commenter
A123	A123 Systems, Inc.
AEP	American Electric Power Service Corporation.
Altresco	Altresco Integrated LLC.
American Gas	American Gas Association.
APPA	American Public Power Association.
Argonne National Lab	Argonne National Laboratory.
APS	Arizona Public Service Company.
Avista	Avista Corporation.
AWEA	American Wind Energy Association.
Beacon Power	Beacon Power Corporation.
Ben Carver	Ben Carver.
Bernard Lee	Bernard S. Lee.
Bonneville	Bonneville Power Administration.
BP Energy	BP Energy Company.
BrightSource	BrightSource Energy, Inc.
Brookfield	Brookfield Renewable Power Inc.
California ISO	California Independent System Operator Corporation.
CMUA	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.
California PUC	California Public Utilities Commission.
California State Water Project	California Department of Water Resources State Water Project.
CalWEA	California Wind Energy Association.
Calpine	Calpine Corporation.
Cazalet Group	Edward G. Cazalet.
Chelan County PUD	Public Utility District No. 1 of Chelan County, Washington.
Clean Line	Clean Line Energy Partners, LLC.
Clean Urban Energy	Clean Urban Energy, Inc.
CAREBS	Coalition to Advance Renewable Energy through Bulk Storage.
ColumbiaGrid	ColumbiaGrid.
Constellation	Constellation Energy Commodities Group, Inc. and Constellation New Energy, Inc.
Covanta	Covanta Energy Corporation.
Detroit Edison	Detroit Edison Corporation.
Dominion	Dominion Resources Services, Inc.
Duke	Duke Energy Corporation.
EEI	Edison Electric Institute.
ELCON	Electricity Consumers Resource Council.
Entergy	Entergy Services, Inc.
E.ON	E.ON U.S. LLC.
E.ON Climate & Renewables North America.	E.ON Climate & Renewables North America.
EPSA	Electric Power Supply Association.
Exelon	Exelon Corporation.
Federal Trade Commission	Federal Trade Commission.
FirstEnergy	FirstEnergy Affiliates.
FIT Coalition	FIT Coalition.
G&T Cooperative	Associated Electric Cooperative, Inc.; Basin Electric Power Cooperative; Tri-State Gas & Transmission Association, Inc.
Glenn Schleede	Glenn R. Schleede.
Grant PUD	Public Utility District No. 2 of Grant County, Washington.
HDR Engineering	HDR Engineering, Inc of the Carolinas.
Iberdrola	Iberdrola Renewables, Inc.
Idaho Power	Idaho Power Company.
Imperial Irrigation District	Imperial Irrigation District (CA).

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.
Indicated New York Transmission Owners.	Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; Long Island Power authority; New York Power Authority; New York State Electric & Gas Corporation; Orange and Rockland Utility, Inc.; and Rochester Gas and Electric Corporation.
Invenergy Wind	Invenergy Wind Development LLC.
ISO New England	ISO New England Inc.
ISO/RTO Council	California Independent System Operator; Electric Reliability Council of Texas; ISO New England, Inc.; Midwest Independent Transmission System Operator, Inc.; New York Independent System Operator; 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 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); IID Energy; JEA (Jacksonville, FL); Long Island Power Authority; 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.
LAWP	Department of Water and Power of the City of Los Angeles.
Manitoba Hydro	Manitoba Hydro.
Mark Strauch	Mark Strauch.
MidAmerican	MidAmerican Energy Holdings Company.
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
Midwest ISO Transmission Owners	Ameren Services Company (as agent for Union Electric Company; Central Illinois Public Service Company; Central Illinois Light Co., and Illinois Power Company); City of Columbia Water and Light Department (Columbia, MO); City Water, Light & Power (Springfield, IL); Great River Energy; Hoosier Energy Rural Electric Cooperative, Inc.; Indiana Municipal Power Agency; Indianapolis Power & Light Company; (Minnesota Power (and its subsidiary Superior Water, L&P); Montana-Dakota Utilities Co.; Northern Indiana Public Service Company; Northern States Power Company (Minnesota and Wisconsin corporations); Northwestern Wisconsin Electric Company; Otter Tail Power Company; Southern Illinois Power Cooperative; Southern Indiana Gas & Electric Company; Southern Minnesota Municipal Power Agency; Wabash Valley Power Association, Inc.; and Wolverine Power Supply Cooperative, Inc.
Modesto Irrigation District	Modesto Irrigation District.
Morgan Stanley	Morgan Stanley Capital Group Inc.
M-S-R Public Power Agency	Modesto Irrigation District; City of Santa Clara, California; and City of Redding, California.
NARUC	National Association of Regulatory Utility Commissioners.
NEMA	National Electrical Manufacturers Association and NEMA Energy Storage Council.
National Grid	National Grid USA.
National Hydropower	National Hydropower Association.
NRECA	National Rural Electric Cooperative Association.
Natural Gas	Natural Gas Supply Association.
NaturEner	NaturEner USA, LLC.
Nebraska Power	Nebraska Power Association.
NEPOOL Participants	New England Power Pool Participants Committee.
NV Energy	Nevada Power Company and Sierra Pacific Power Company.
New England States' Committee on Electricity.	New England States' Committee on Electricity.
New York ISO	New York Independent System Operator, Inc.
New York PSC	New York State Public Service Commission.
NextEra	NextEra Energy Resources, LLC.
NERC	North American Electric Reliability Corporation.
NOAA	National Oceanic and Atmospheric Administration.
NorthWestern	NorthWestern Corporation.
Northeast Utilities	Northeast Utilities Service Company.
NREL	National Renewable Energy Research Laboratory's Transmission and Grid Integration Group.
NRG	NRG Energy, Inc.
Opatrny Consulting	Opatrny Consulting, Inc.
Organization of SE Utilities	Georgia Transmission Corporation; Jacksonville Electric Authority; Municipal Electric Authority of Georgia; Orlando Utilities Commission; Progress Energy, Inc.; South Carolina Electric & Gas Corporation; South Carolina Public Service Authority; and Southern Company Services, Inc.
Pacific Gas and Electric	Pacific Gas and Electric Company.
PNNL	Pacific Northwest National Laboratory.
PJM	PJM Interconnection, LLC.
Portland General Electric	Portland General Electric Company.
Powerex	Powerex Corporation.
PSEG Companies	Public Service Electric and Gas Company; PSEG Power LLC; PSEG Energy Resources & Trade LLC.
Public Interest Organizations	Center for Energy Efficiency & Renewable Technologies; Environmental Defense Fund; Fresh Energy; Natural Resources Defense Council; Northwest Energy Coalition; Office of the Ohio Consumers' Counsel; Project for Sustainable FERC Energy Policy; and Western Grid Group.
Public Power Council	Franklin County Public Utility District; PNGC Power; Northwest Requirements Utilities; and Western Montana Gas & Electric Cooperative
Public Service of New Mexico	Public Service Company of New Mexico.

Short name or acronym	Commenter
Puget	Puget Sound Energy, Inc.
SMUD	Sacramento Municipal Utility District.
Salt River Project	Salt River Project Agricultural Improvement and Power District.
San Diego Gas & Electric	San Diego Gas & Electric Company.
Sempra	Sempra Generation.
Six Cities	Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California.
Snohomish County PUD	Public Utility District No. 1 of Snohomish County, Washington.
SEIA	Solar Energy Industries Association.
Southern California Edison	Southern California Edison Company.
Southern	Southern Company Services, Inc.
SWTC & AEP	Southwest Transmission Cooperative, Inc. and Arizona Electric Power Cooperative, Inc.
Summit Wind	Summit Wind LLC.
Sunflower and Mid-Kansas	Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC.
Symbiotics	Symbiotics, LLC.
Tacoma Power	City of Tacoma, Department of Public Utilities, Light Division (Washington).
Transmission Access Policy Study Group.	Transmission Access Policy Study Group.
Transmission Agency of Northern California.	Transmission Agency of Northern California.
Turlock Irrigation	Turlock Irrigation District.
University of Delaware	University of Delaware Center for Carbon-Free Power Integration.
US Bureau of Reclamation	United States Bureau of Reclamation.
Utility Economic Engineers	Utility Economic Engineers.
Viridity Energy	Viridity Energy, Inc.
Wärtsilä	Wärtsilä North America.
WECC	Western Electricity Coordinating Council.
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; 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.
Westar	Westar Energy, Inc. and Kansas Gas and Electric Company.
Western Farmers	Western Farmers Electric Cooperative.
Western Grid	Western Grid Group.
Western Power Trading Forum	Western Power Trading Forum.
William Short	William P. Short III & Lisa Linowes.
Wyoming Power Producers	Wyoming Power Producers Coalition.
Xcel	Xcel Energy Services Inc.

Appendix B: Proposed inserts to the Pro Forma Open Access Transmission Tariff

The Commission proposes to amend and/or add the following sections of the pro forma OATT:

a. Table of Contents (Add Section 3.8, Generator Regulation and Frequency Response Service, and Schedule 10, Generator Regulation and Frequency Response Service)

b. Section 3

c. Section 3.8

d. Section 13.8

e. Section 14.6

f. Schedule 10

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide (or offer to arrange with the local Control Area operator as discussed below), and the Transmission Customer is required to purchase, the following Ancillary Services (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation or Other Sources.

The Transmission Provider is required to offer to provide (or offer to arrange with the local Control Area operator as discussed below) the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area (i) Regulation and Frequency Response, (ii) Energy Imbalance, (iii) Operating Reserve—Spinning, and (iv) Operating Reserve—Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is required to provide (or offer to arrange with the local Control Area Operator as discussed below), to the extent it is physically feasible to do so from its resources or from resources available to it, Generator Regulation and Frequency Response Service and Generator Imbalance Service when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer using Transmission Service to deliver energy from a generator located within the Transmission Provider's Control Area is required to acquire Generator Regulation and Frequency Response Service and Generator Imbalance Service, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider. A Transmission Customer that exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or an Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved is required to pay for all of the Ancillary Services identified in this section that were provided by the Transmission Provider associated with the unreserved service. The Transmission Customer or Eligible Customer will pay for Ancillary Services based on the amount of transmission service it used but did not reserve.

If the Transmission Provider is a public utility providing transmission service but is not a Control Area operator, it may be unable to provide some or all of the Ancillary Services. In this case, the Transmission Provider can fulfill its obligation to provide Ancillary Services by acting as the Transmission Customer's agent to secure these Ancillary Services from the Control Area operator. The Transmission Customer may elect to: (i) Have the Transmission Provider act as its agent, (ii) secure the Ancillary Services directly from the Control Area operator, or (iii) secure the Ancillary

Services (discussed in Schedules 3, 4, 5, 6, 9 and 10) from a third party or by self-supply when technically feasible.

The Transmission Provider shall specify the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (1) Any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.8 below list the eight Ancillary Services.

3.8 Generator Regulation and Frequency Response Service

Where applicable the rates and/or methodology are described in Schedule 10.

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 fifteen (15) minutes 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 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 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 up to fifteen (15) minutes 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.

SCHEDULE 10

Generator Regulation and Frequency Response Service

Generator Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Generator Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and/or by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in generation output. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the Balancing Authority that performs this function for the Transmission Provider). The Transmission Provider (or the Balancing Authority that performs this function for the Transmission Provider) must offer this service when Transmission Service is used to deliver energy from a generator physically or electrically located within its Balancing Authority Area. The Transmission Customer or generator must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources or processes capable of providing this service, to satisfy its Generator Regulation and Frequency Response Service obligation. The amount of and charges for Generator Regulation and Frequency Response Service are set forth below. To the extent the Balancing Authority performs this service for the Transmission Provider, charges to the Transmission Customer or generator are to reflect only a pass-through of the costs charged to the Transmission Provider by that Balancing Authority.

Appendix C: Proposed Inserts to the Pro Forma Large Generator Interconnection Agreement

The Commission proposes to amend and/or add 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 other operational data to the Transmission Provider to the extent necessary for the Transmission Provider's development and deployment of power production forecasts for 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 temperature, atmospheric pressure, and cloud cover. Additional meteorological data requirements for any Interconnection Customer whose Generating Facility is a Variable Energy Resource will require a showing by the Transmission Provider that such data is needed to develop and deploy a power production forecast for that Variable Energy Resource, or is mutually agreed to by the Interconnection Customer and the Transmission Provider. The exact specifications of the data to be provided by the Interconnection Customer to the Transmission Provider 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.

The Interconnection Customer whose Generating Facility is a Variable Energy Resource shall submit operational data to the Transmission Provider regarding all unanticipated outages that reduce the generating capability of the Variable Energy Resource by 1 MW or more for 15 minutes or more.

[FR Doc. 2010–29574 Filed 12–1–10; 8:45 am]

BILLING CODE 6717–01–P