document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington DC 20426.

54. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, 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 the docket number), in the docket number field.

55. User assistance is available for eLibrary and the Commission's Web site during normal business hours. For assistance, please contact 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.
Commissioner Norris voting present.

Kimberly D. Bose,

Secretary.

In consideration of the foregoing, the Commission proposes to amend part 35, Chapter J, Title 18, Code of Federal Regulations, as follows:

PART 35—FILING OF RATE SCHEDULES AND TARIFFS.

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

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

2. Subpart J is added to read as follows:

Subpart J—Credit Practices In Organized Wholesale Electric Markets

Sec.
35.45 Applicability.
35.46 Definitions.
35.47 Tariff provisions governing credit practices in organized wholesale electric markets.

Subpart J—Credit Practices In Organized Wholesale Electric Markets

§ 35.45 Applicability.

This part establishes credit practices for organized wholesale electric markets for the purpose of minimizing risk to market participants.

§ 35.46 Definitions.

(a) *Market Participant* means an entity that qualifies as a Market Participant under 18 CFR 35.34.

(b) *Organized Wholesale Electric Market* includes an independent system operator and a regional transmission organization.

(c) *Regional Transmission Organization* means an entity that qualifies as a Regional Transmission Organization under 18 CFR 35.34.

(d) *Independent System Operator* means an entity operating a transmission system and found by the Commission to be an Independent System Operator.

§ 35.47 Tariff provisions regarding credit practices in organized wholesale electric markets.

Each organized wholesale electric market must have tariff provisions that:

(a) Limit the amount of unsecured credit extended to any market participant to no more than $50 million.

(b) Adopt a settlement period of no more than seven days and allow no more than an additional seven days to receive payment.

(c) Eliminate unsecured credit in the financial transmission rights market.

(d) Allow it to offset market obligations owed to market participants against market obligations owed by market participants.

(e) Limit to no more than two days the time period provided to post additional collateral when additional collateral is requested by the organized wholesale electric market.

(f) Provide minimum participation criteria required of market participants to be eligible to receive credit from the organized wholesale electric market.

(g) Specify when a market administrator may invoke the "material adverse change" as a justification for requiring additional collateral.

[FR Doc. 2010–1537 Filed 1–26–10; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Chapter I

[Docket No. RM10–11–000]

Integration of Variable Energy Resources

Issued January 21, 2010.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of Inquiry.

SUMMARY: In this Notice of Inquiry, the Federal Energy Regulatory Commission (Commission) seeks comment on the extent to which barriers may exist that impede the reliable and efficient integration of variable energy resources (VERs) into the electric grid, and whether reforms are needed to eliminate those barriers. In order to meet the challenges posed by the integration of increasing numbers of VERs, ensure that jurisdictional rates are just and reasonable, eliminate impediments to open access transmission service for all resources, facilitate the efficient development of infrastructure, and ensure that the reliability of the grid is maintained, the Commission seeks to explore whether reforms are necessary to ensure that wholesale electricity tariffs are just, reasonable and not unduly discriminatory. This Notice will enable the Commission to determine whether wholesale electricity tariff reforms are necessary.

DATES: Comments are due March 29, 2010.

ADDRESSES: You may submit comments, identified by docket number by any of the following methods:

- *Agency Web site: http://ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Commenters unable to file comments electronically must mail or hand deliver an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

FOR FURTHER INFORMATION CONTACT:
Mk Shean (Technical Information), Office of Energy Policy and Innovations, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6792, *Mk.Shean@ferc.gov.*
Timothy Duggan (Legal Information), Office of General Counsel—Energy Markets, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8326, *Timothy.Duggan@ferc.gov.*

SUPPLEMENTARY INFORMATION:

1. In this Notice of Inquiry, the Federal Energy Regulatory Commission (Commission) seeks comment on the extent to which barriers exist that may impede the reliable and efficient integration of variable energy resources (VERs) [1] into the electric grid and

[1] For purposes of this proceeding, the term variable energy resource (VER) refers to renewable

whether reforms are needed to eliminate those barriers. VERs, such as resources powered by wind and solar energy, continue to make up an increasing percentage of the nation's energy supply portfolio; however, they present unique challenges (such as location constraints and limited dispatchability) that are not typically presented by conventional electricity generating resources. VERs also present benefits, such as low marginal energy costs and reduced greenhouse gas emissions, which have contributed to the accelerated development of these resources. In order to meet these challenges and fully realize these benefits of VERs in a reliable and efficient manner, the Commission seeks to explore whether reforms of existing policies are necessary to ensure that jurisdictional rates are just and reasonable and that the terms of jurisdictional service do not unduly discriminate against these resources.

I. Background

2. While the amount of VERs remains relatively small as a percentage of total generation, it is rapidly increasing, reaching a point where such resources are becoming a significant component of the nation's energy supply portfolio. In 2008, new wind generating capacity, totaling 8,376 MW, made up 42 percent of all newly installed generating capacity.[2] Moreover, in recent years, a number of state renewable portfolio standards and other incentives/mandates have been passed to encourage the development of renewable energy resources, in response to a growing concern about the environmental impacts and sustainability of the Nation's current electricity supply portfolio. As of December 2009, 30 states, including the District of Columbia, had a renewable portfolio standard.[3]

3. While VERs have many desirable characteristics, including low marginal energy costs and reduced greenhouse gas and other pollutant emissions, compared to conventional fossil-fueled generation, they also present unique challenges as public utilities work to integrate VERs in a way that ensures system reliability. For example, because VERs cannot control or store their fuel source, they have limited ability to control their production of electricity, and the weather-related phenomena that drive VER output levels can be difficult to forecast. Also, the output from some VERs can be negatively correlated with demand, such that a resource's greatest energy output often comes at a time of limited energy demand. Changes in the rate of output from VERs may also result in substantial ramps,[4] which can require additional resources to allow System Operators[5] to balance generation and demand while maintaining reliability in real time.

4. In this proceeding, the Commission seeks to explore whether existing rules, regulations, tariffs, or industry practices within the Commission's jurisdiction may hinder the reliable and efficient integration of VERs, resulting in rates that are unjust and unreasonable and/or terms of service that unduly discriminate against certain types of resources. The Commission seeks comment on how best to reform any such rules, regulations, tariffs, or industry practices.

5. Under sections 205 and 206 of the Federal Power Act, the Commission has a responsibility to remedy undue discrimination with respect to transmission of electric energy and sales of electric energy for resale in interstate commerce and to ensure that rates for these services are just and reasonable.[6] As the electric power industry has evolved, the Commission has discharged this responsibility in different ways. In Order No. 888, the Commission exercised its authority to remedy undue discrimination by requiring all public utilities to provide open access transmission service consistent with the terms of a *pro forma* open access transmission tariff (OATT).[7] The *pro forma* OATT addresses the terms of transmission service, including, among other things, the terms for scheduling transmission service, curtailments, and the provision of ancillary services. In Order No. 2003, the Commission acted to remove barriers in the generator interconnection process and adopted standard procedures (the Large Generation Interconnection Procedures or LGIP), and a standard agreement (the Large Generation Interconnection Agreement or LGIA) for the interconnection of generation resources larger than 20 MW.[8] More recently, in a further effort to remedy the potential for undue discrimination, the Commission revised and updated the *pro forma* OATT in Order No. 890.[9]

6. With limited exceptions,[10] these and other Commission efforts to remedy undue discrimination have not expressly accounted for the differences between VERs and more conventional generation resources. In large part this is due to the fact that the electric grid was developed during a time when electricity was almost exclusively generated from centralized, dispatchable resources that were powered by fuel sources that could be stored and used as needed. The Commission's policies and the concomitant implementation of its responsibility under sections 205 and 206 were premised on this underlying physical reality of the electric grid.

7. Where relevant, however, the Commission on several occasions has taken the operational characteristics of

energy resources that are characterized by variability in the fuel source that is beyond the control of the resource operator. This includes wind and solar generation facilities and certain hydroelectric resources.

[2] Div. of Market Oversight, Fed. Energy Regulatory Comm'n, *2008 State of the Markets Report* 19 (2009), *available at http://www.ferc.gov/market-oversight/st-mkt-ovr/2008-som-final.pdf.*

[3] Div. of 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.*

[4] A ramp is the rate, expressed in megawatts per minute, that a generator changes its output.

[5] System Operator refers to the individual at a control center—balancing authority, transmission operator, generator operator (VERs as well as conventional resources), or reliability coordinator—whose responsibility it is to monitor and control the electric system in real time.

[6] 16 U.S.C. 824d, 824e.

[7] *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 (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).

[8] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007). Similarly, the Commission also adopted standard procedures for the interconnection of small generation resources. *Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g,* Order No. 2006–A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification,* Order No. 2006–B, FERC Stats. & Regs. ¶ 31,221 (2006).

[9] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g,* Order No. 890–A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g,* Order No. 890–B, 123 FERC ¶ 61,299 (2008), *order on reh'g,* Order No. 890–C, 126 FERC ¶ 61,228, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[10] *See, e.g., Interconnection for Wind Energy,* Order No. 661, FERC Stats. & Regs. ¶ 31,186, *order on reh'g,* Order No. 661–A, FERC Stats. & Regs. ¶ 31,198 (2005) (adopting reforms to the LGIA and LGIP to establish standard technical requirements for interconnection of wind plants); Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 665 (establishing a standard offer generation imbalance service, but exempting intermittent resources from the highest penalty band).

VERs into consideration in efforts to ensure just and reasonable rates and to remedy undue discrimination. In Order No. 661, the Commission required public utilities to revise their LGIAs and LGIPs to incorporate standard technical requirements for the interconnection of wind resources larger than 20 MW.[11] In Order No. 890, the Commission applied a reduced penalty amount to intermittent resources' imbalances that would otherwise be subject to the highest-tier generation imbalance penalties, recognizing "that intermittent generators cannot always accurately follow their schedules and that high penalties will not lessen the incentive to deviate from their schedules." [12] In addition, in Order No. 890 the Commission created conditional firm point-to-point transmission service, noting that conditional firm service can be particularly beneficial to renewable energy resources.[13] Shortly after the issuance of Order No. 890, the Commission accepted a unique cost allocation mechanism for interconnection facilities connecting renewable energy resources that are location-constrained, recognizing that the difficulties faced by these resources are different from those faced by other generation developers, and therefore support an appropriate variation of the interconnection pricing policy.[14]

8. Such actions are premised on the notion that targeted revisions to Commission policies are sometimes necessary to ensure that jurisdictional rates are just and reasonable and to prevent undue discrimination against any one type of customer or resource as the characteristics of the nation's generation portfolio change.

II. Subject of the Notice of Inquiry

9. In this proceeding, the Commission seeks to take a fresh look at existing policies and practices in light of the changing characteristics of the nation's generation portfolio with the aim of removing unnecessary barriers to transmission service and wholesale markets for VERs (and other technologies that may aid their integration) and promoting greater efficiencies that ultimately will reduce costs to consumers. While the Commission seeks comment on numerous challenges presented by the integration of VERs, this proceeding will not address issues related to transmission planning and cost allocation, as the Commission is considering those issues in another forum.[15]

10. Our goal is not to adopt rules that favor one type of supply source over another. Instead, the Commission's purpose in this proceeding is to investigate market and operational reforms necessary to achieve two goals: first, to ensure that rates for jurisdictional service are just and reasonable, reflecting the implementation of practices that increase the efficiency of providing service; and second, to prevent VERs from facing undue discrimination. These goals are consistent with the requirements of sections 205 and 206 of the FPA.

11. In addition, the Commission must ensure that any reforms are consistent with the need to maintain system reliability in accordance with Reliability Standards proposed by the North American Electric Reliability Corp. (NERC) and approved by the Commission pursuant to section 215 of the FPA.[16] Although the scope of this proceeding is directed to market and operational reforms, in certain instances where commenters believe existing NERC Reliability Standards should be modified or new standards developed in conjunction with the market reforms considered herein, they may indicate as much, if directly related to this proceeding. In responding to the following questions, commenters should indicate how the reforms that they propose ensure the reliable operation of the grid, or would impact the reliable operation of the grid, as required by the reliability standards.[17]

III. Questions for Response

12. To ensure that all generation resources are afforded non-discriminatory access to wholesale markets and the electric power grid and that wholesale market prices and the rates for transmission service are just and reasonable, the Commission seeks comment on the perceived barriers, and suggested solutions to removing those barriers, of integrating VERs into the electric grid in a reliable and efficient manner. The Commission's preliminary view is that one of the most important operational issues affecting the integration costs for VERs involves the reserves necessary to address variability in VER output. Addressing this issue means examining a number of operational practices and processes that affect both the determination of the amount of reserves needed as well as the cost of those reserves. The Commission seeks comment on the impact of integrating an increasing number of VERs in the following subject areas: (1) Data and reporting requirements, including the use of accurate forecasting tools; (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.

13. The Commission does not seek to limit its inquiry and encourages all comments regarding the topics broadly discussed herein. Commenters are invited to share with the Commission their overall thoughts, including technical, commercial, and legal observations, on the challenges posed by the increasing number of VERs, operational and technical barriers faced by VERs, and the extent to which Commission policies can and/or should be revisited in light of the increasing number of VERs. Where commenters believe specific revisions to Commission rules and/or *pro forma* OATT provisions are necessary to implement their proposed reforms, they are encouraged to cite those rules and/or provisions with specificity and suggest revised language as appropriate. In this Notice of Inquiry we seek information with regard to whether changes to rules or practices as applied to VERs will achieve the Commission's goals. However, there may be instances where a change to a rule or practice could also assure just and reasonable rates and address undue discrimination if applied to other resources. Therefore, we ask commenters to address whether any proposed changes to the Commission rules or OATT provisions should apply to all resources. In

[11] Order No. 661, FERC Stats. & Regs. ¶ 31,186 (adopting, among other things, a low voltage ride-through standard, a power factor range, dynamic reactive power capability, and supervisory control and data acquisition (SCADA) capability).

[12] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 664–65.

[13] *Id.* P 912.

[14] *Cal. Indep. Sys. Operator Corp.,* 119 FERC ¶ 61,061, at P 69–70 (2007). *See also Southwest Power Pool, Inc.,* 127 FERC ¶ 61,283, at P 29 (2009) (accepting a proposal to allocate network upgrade costs differently for wind resources being used to serve demand in a different zone than the methodology used for other resources).

[15] *Transmission Planning Processes Under Order No. 890,* Docket No. AD09–8–000 (Oct. 8, 2009) (notice of request for comments).

[16] 16 U.S.C. 824o.

[17] *See id.* at 824o(a)(3). We note that NERC has an ongoing stakeholder process to examine how to accommodate high levels of variable generation. *See* North American Elec. Reliability Corp., *Accommodating High Levels of Variable Generation* (2009).

addition, the Commission seeks responses to the specific questions listed below.

A. Data and Forecasting

14. The scheduling and operational practices of the bulk power system are predicated on the ability to predict, with relative precision, the output of generation resources and the ability of reserve products to accommodate fluctuations in demand and emergency conditions. The rapid increase in the development of VERs has presented the industry with a variety of challenges related to predicting the exact output of VERs at any point in time.

15. These challenges could become more manageable for System Operators through the development and use of state-of-the-art meteorological forecasts, which are supplied with data from multiple diverse locations. Specifically, the implementation of enhanced forecasting tools and procedures could assist in projecting the output of VERs with greater accuracy, thereby promoting the efficient scheduling of all generation resources to meet expected demand, especially during the morning increase and evening decrease in demand. Enhanced forecasting could also allow System Operators in all regions to anticipate system ramping events more effectively and respond to them in an economically efficient manner, thereby ensuring that jurisdictional rates are just and reasonable.

16. To assist in the development of state-of-the-art forecasting tools for VERs, the Commission seeks comment on whether and, if so, how the Commission should modify existing operational data reporting requirements. The Commission also aims to determine what data and what level of data-sharing is necessary, coupled with advanced communication and metering tools, to ensure that VERs are integrated in a reliable and efficient manner, particularly with respect to scheduling, ramping needs, and the procurement of reserve services.

17. To that end, the Commission seeks comment on the following questions:

1. What are the current practices used to forecast generation from VERs? Will current practices in forecasting VERs' electricity production be adequate as the number of VERs increases? If so, why?

2. What is necessary to transition from the existing power generation forecasting systems for wind and solar generation resources to a state-of-the-art forecasting system? What type of data (*e.g.,* meteorological, outage, etc.), sampling frequency, and sampling location requirements are necessary to develop and integrate state-of-the-art forecasts, and what technical or market barriers impede such development?

3. What data, forecasting tools and processes do System Operators need to more effectively address ramping events and other variations in VER output, and to validate enhanced forecasting tools and procedures?

4. What operational, outage and meteorological data should the Commission require VERs to provide to non-VER System Operators? To what size resources, in MWs, should any such data requirements apply, and what revisions to the *pro forma* OATT would be necessary to accommodate these requirements?

5. State-of-the-art forecasts may necessitate the sharing of meteorological data across regions to assure that the movement of weather patterns can be accurately predicted and analyzed. To what extent should meteorological data be made publically available to aid in the development of state-of-the-art forecasts? Should the Commission require public utilities to maintain a meteorological data reporting system? If so, should such a system be akin to or in collaboration with Open Access Same Time Information System (OASIS) postings? In order to retain the confidentiality of commercially sensitive data reported by VERs for the purpose of developing state-of-the-art forecasts, what limits and/or safeguards should be established to protect operational data and generator outage reports?

6. Should the Commission encourage both decentralized and centralized meteorological and VER energy production forecasting? For example, should transmission providers have independent forecasting obligations as part of their reliability commitment processes similar to what is done today for demand forecasting?

7. To what extent is a lack of data regarding the operational status and forecasted output of distributed, or behind-the-meter, VERs leading to a need for additional reserves? To what extent would the provision of such data reduce the need for System Operators to rely on reserves?

B. Scheduling Flexibility and Scheduling Incentives

1. Scheduling Flexibility

18. Existing scheduling practices were designed at a time when virtually all generation on the system could be scheduled with relative precision. With increasing numbers of VERs, System Operators appear to be relying more on expensive reserves, such as regulation reserves, to balance the variation in energy output from VERs. Improvements in scheduling procedures may offer the potential for greater efficiency in dispatching all energy resources if the degree of variability can be reduced, better anticipated, and/or planned for more precisely.

19. In regions outside of those run by regional transmission organizations (RTOs) or independent system operators (ISOs), resources typically schedule transmission service on an hourly basis and are only allowed to adjust their schedules during the hour for emergency situations that threaten reliability.[18] Because transmission schedules for VERs are typically set 20–30 minutes ahead of the hour, the forecast of output may be 90 minutes old by the end of the operating hour. Additionally, by limiting the ability of resources to adjust their schedules during the hour or to submit shorter scheduling timeframes, non-RTO/ISO System Operators may not be utilizing the full operational flexibility of the resources on their systems to change output levels to address the variable output of VERs.

20. In RTOs/ISOs, real-time markets are employed to address imbalance energy needs. Real-time markets utilize intra-hour economic dispatch of internal resources, which affords RTOs/ISOs the ability to respond quickly and economically to fluctuations in VER supply. However, RTOs/ISOs often schedule external resources on an hourly basis, consistent with non-RTO/ISO scheduling practices.

21. The Commission questions whether the retention of existing transmission scheduling practices as additional VERs come on-line is causing rates for reserves (as part of transmission service) to become unjust and unreasonable by inhibiting the ability of VERs to establish operationally-viable schedules and preventing System Operators from utilizing the full flexibility of their systems. Accordingly, the Commission seeks to explore whether greater scheduling flexibility, such as intra-hour scheduling, could provide benefits to the system and facilitate the reliable and efficient use of all resources.

22. To that end, the Commission seeks comment on the following questions:

1. Would shorter scheduling intervals allow System Operators to more

[18] 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. However, section 13.8 of the *pro forma* OATT gives the transmission provider the discretion to accept schedule changes no later than 20 minutes prior to the operating hour.

efficiently manage the ramps of VERs and/or demand? To what extent would the availability of intra-hour scheduling decrease the overall reliance on regulation reserves to manage the variability of VERs?

2. What are the benefits and costs of allowing resources and transactions to schedule on an intra-hour basis, and what tariff and/or technical barriers exist to implementing intra-hour scheduling? Are there best practices that could be implemented to facilitate greater intra-hour scheduling?

3. Are there an optimum number of intervals within the hour for scheduling? What time increments would be necessary and/or desirable in order to achieve optimum flexibility while still meeting the relevant reliability requirements?

4. Identify any reliability issues that may result from changes to the scheduling rules. What changes, if any, to NERC Reliability Standards would be needed to fully implement additional scheduling flexibility while still ensuring reliability?

5. How would intra-hour scheduling affect the operation of other processes such as available transfer capability (ATC), the E-Tag system, issuance of dispatch instructions for generation and/or demand resources, transmission loading relief procedures, and/or dynamic schedules? What costs would be incurred as a result?

6. If intra-hour scheduling is implemented in non-RTO/ISO regions, how would RTO/ISO scheduling practices at interties be affected? Would intra-hour scheduling at interties present problems for RTO/ISO markets? If so, describe the problems and feasible solutions for intra-hour scheduling at interties.

2. Scheduling Incentives

23. Reforms to existing scheduling practices to promote intra-hour scheduling could enable VERs to more accurately meet their schedules, which in turn should help to ensure that rates for reserves are just and reasonable. In order to achieve overall improvements in scheduling accuracy, particularly with respect to VERs, it is also important to ensure that such resources have the appropriate incentives to meet their schedules with real-time output to the extent feasible.

24. In Order No. 890, the Commission adopted *pro forma* OATT imbalance provisions that implemented a graduated bandwidth approach to imbalance penalties that recognized the link between escalating deviations and potential reliability impacts on the system.[19] The Commission exempted intermittent resources from the third tier deviation band, which required imbalances of greater than 7.5 percent of scheduled amounts (or 10 MW) to be settled at 125 percent of the incremental cost or 75 percent of the decremental cost of providing the imbalance energy.[20] Instead, intermittent resources with such imbalances would only be subject to the second tier imbalance penalties, i.e., 110 percent of the incremental or 90 percent of the decremental cost.[21] The Commission is interested in examining the experience with this exemption to determine whether it has resulted in scheduling practices that may result in an overall rate for transmission service that is not just and reasonable.

25. To that end, the Commission seeks comment on the following questions:

1. Has the exemption from third-tier penalty imbalances worked as a targeted exemption that recognizes operational limitations of VERs,[22] or has it encouraged inefficient scheduling behaviors to develop? If the latter, what reforms to this exemption would encourage more accurate scheduling practices?

2. Assuming that efficient forecasting and scheduling practices help minimize deviations between scheduled and actual energy output of VERs, are additional incentives needed to encourage VERs to submit schedules that are informed by state-of-the-art forecasting? What would be the proper incentives?

3. Under an RTO/ISO market design, are there sufficient incentives to encourage VERs to submit accurate schedules? What costs and/or penalties should be assigned to VERs when their real-time output is not accurately scheduled on a forward basis? Should VERs be treated the same as conventional resources with respect to deviations from their production schedules?

C. Day-Ahead Market Participation and Reliability Commitments

1. Day-Ahead Market Participation

26. The presence of a day-ahead market is a key characteristic of most RTOs/ISOs. When resources are scheduled accurately in the day-ahead market, subsequent out-of-market commitments are minimized and market participants can manage their financial exposure more effectively. However, VERs appear to participate in the day-ahead market on a limited basis, choosing instead to self-schedule the majority of their supply in the real-time energy markets (*i.e.,* act as a price taker). Because day-ahead schedules are financially binding, there can be significant financial risk for VERs participating in the day-ahead market and not being able to meet these obligations in the real-time market. This may serve as a disincentive for VERs to participate in the day-ahead market.

27. In light of the increasing number of VERs, the Commission is interested in receiving comments on whether the lack of day-ahead market participation may be resulting in costly out-of-market commitments, thereby rendering rates unjust and unreasonable, as well as whether the financial risk associated with participating in the day-ahead market may unduly discriminate against VERs by inhibiting their ability to participate in such a market. Such comments should enable the Commission to determine whether reforms are necessary to facilitate VERs to participate more in the day ahead market rather than primarily in the real time market.

28. To that end, the Commission seeks comment on the following questions:

1. Does the lack of day-ahead market participation by VERs present operational challenges or reduce market transparency as the number of VERs increases? Will out-of-market commitments increase as the number of VERs increases? If so, why?

2. How can new or existing market design features assure that the day-ahead market will accurately represent real-time system conditions and that day-ahead and real-time energy prices will converge under the scenario of increasing numbers of VERs?

3. Do current RTO/ISO market designs place undue barriers to participation in forward markets by VERs? Could the timing of certain RTO/ISO market design elements, such as the day-ahead market, be modified in a manner that would facilitate VERs to participate more in the day ahead market rather than primarily in the real time market? If so, how?

4. Would the use of more accurate forecasting tools facilitate participation of VERs in the day-ahead market rather than primarily in the real time market? If so, how?

[19] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 663–64.

[20] *Id.* P 664–65.

[21] In RTOs/ISOs, because real-time markets are used to address imbalance energy needs, VERs are typically exempt from some *pro forma* OATT deviation penalties.

[22] For the purposes of this section, the term "VERs" refers to the same resources that the Commission identified as "intermittent" in Order No. 890. Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 666.

5. Should the financial risk of VERs' participating in the day-ahead market be different than the risk imposed on other resources in that market in recognition of their unique characteristics? Are there settlement practices, such as netting deviations, which could be employed to address VERs' participating in the day-ahead market? If so, what are they?

6. Will changes to the financial risk of participating in the day-ahead market encourage VERs to participate in day-ahead markets, and will this participation result in day-ahead market schedules that accurately reflect real-time market activity?

2. Reliability Commitments

29. Following the results of the day-ahead market, RTOs/ISOs conduct a reliability unit commitment process to ensure that sufficient generation will be available in the appropriate places to meet the RTO/ISO's estimate of the next day's forecasted demand. If the cleared resources are insufficient to meet that demand, the RTO/ISO commits additional units. Non-RTOs/ISOs conduct a similar assessment to evaluate the sufficiency of bilaterally scheduled resources.

30. Similar to the inefficiency associated with the lack of intra-hour transmission scheduling, the lack of a more frequent unit commitment process may result in unjust and unreasonable rates by causing System Operators to make inefficient reliability commitment decisions, which may cause unnecessary system uplift costs.

31. To that end, the Commission seeks comment on the following questions:

1. Would the implementation of a formalized and transparent intra-day reliability assessment and commitment process prior to each operating hour reduce the amount of reserves needed and/or reduce system uplift costs? What would be the optimal time (*e.g.,* 4 to 6 hours ahead of the operating hour) for such a process?

2. Would an additional market that coincides with the timing of an intra-day reliability commitment process be beneficial in the forward scheduling of VERs? If such a market is implemented, would an intra-day reliability commitment process be necessary? Should the frequency of scheduling intervals resulting from such a market coincide with intra-hour schedules discussed above?

3. What role should centralized forecasting of VERs' output play in reliability assessment and commitment processes?

D. Balancing Authority Coordination

32. Smaller balancing authorities may be unable to capture the benefits associated with VERs that are spread across a large and/or diverse geographical area. Accordingly, the Commission is interested in determining whether a limited ability of smaller balancing authorities to efficiently integrate VERs may result in rates that are unjust and unreasonable. Therefore, the Commission seeks to explore whether increased coordination among balancing authorities has the potential to enlarge the base of generation and demand available to customers, thereby making variability more manageable and ultimately reducing overall costs. In this proceeding, the Commission seeks comments on ways to increase customer access to energy, capacity, and reserve products through the use of pseudo-ties,[23] dynamic scheduling, and/or other tools and agreements.

33. To that end, the Commission seeks comment on the following questions:

1. Will smaller balancing authorities, when operated individually, have higher VER integration costs than geographically or electrically larger balancing authorities? If so, why?

2. Should the Commission encourage the consolidation of balancing authorities? If so, indicate the potential for and impediments to consolidation among balancing authorities and the means by which the Commission should encourage consolidation.

3. What tools or arrangements (*e.g.,* dynamic schedules, pseudo-ties, and virtual balancing authorities) are available and/or could be enhanced or created to reduce barriers to greater operational coordination among balancing authorities? What role should the Commission play in facilitating inter-balancing authority coordination?

4. What are the costs and benefits, if any, associated with the proliferation of small generation-only balancing authorities? How do NERC Certification and Reliability Standards encourage or discourage the creation of small generation-only balancing authorities?

5. The Commission is interested in receiving comments on whether the integration of VERs with small host balancing authorities may limit the benefits derived from geographical diversity and increase integration costs. Should the Commission encourage and/or facilitate the creation of a VER balancing authority, essentially a large area virtual balancing authority primarily designed to accommodate VERs across a broad geographic region? What would be the benefits and costs of creating such a large area entity?

6. Would a large area VER balancing authority be capable of capturing the reduced variability of VERs located across a broad and geographically diverse region? What tariff or technical limitations would prevent and/or inhibit the development of a large area VER balancing authority?

7. What reliability impacts may be associated with the creation of a large area VER balancing authority?

8. Should a large area VER balancing authority be limited only to VERs? Why or why not?

9. Should the Commission consider establishing specific policies that support the creation of a large area VER balancing authority? If so, why?

E. Reserve Products and Ancillary Services

34. During normal operations, System Operators maintain reserve products to ensure that demand and generation are kept in balance.[24] Reserve products are generally defined by the timeframes in which they are available. In the moments-to-seconds timeframe, Frequency Response services provide an immediate arresting of the frequency decline or increase due to any system imbalance. In the seconds-to-minutes timeframe, regulation services provide maneuverable capacity (typically through automatic generation control), and in the minutes-to-hours time frame, following services [25] allow for the rapid deployment of resources to maintain and/or restore system balance.

35. The Commission seeks to explore whether the variability associated with increased VER deployment may result in an over-reliance on expensive reserves, such as regulation reserves. The Commission seeks to ensure that reserves are being used efficiently such that the resulting rates are just, reasonable, and not unduly discriminatory. The Commission is also interested in ensuring that requirements for VERs to contribute to system reliability are not unduly discriminatory. Finally, the Commission seeks to ensure that changes to the rules or requirements do not hinder the

[23] Pseudo-ties are defined as telemetered readings or values that are used as "virtual" tie line flows between balancing authorities where no physical tie line exists.

[24] Contingency Reserves are used to recover from variations caused by a system disturbance but not for balancing normal variations.

[25] In RTO/ISO markets, following services are generally provided through real-time energy markets.

reliable operation of the grid under the reliability standards.[26]

36. To that end, the Commission seeks comment on the following questions:

1. To what extent do existing reserve products provide System Operators with the most cost-effective means of maintaining reliability during VER ramping events? To what extent would the other reforms discussed herein, if implemented, mitigate the need for additional reforms to existing reserve products without adversely impacting system reliability?

2. How could System Operators, managing the variability of VER resources, more fully utilize forecasting information and knowledge about existing system conditions to optimize reserve requirement levels?

3. Would a following or similar reserve product facilitate the reduction of costs associated with ensuring that sufficient reserve capacity is available to address the uncertainty and variability associated with VERs? If so, what are the ideal characteristics of such a product?

4. Existing contingency reserve products were designed to be utilized by System Operators to respond to disturbances (*i.e.,* contingency events) due to a loss of supply and to assure system reliability.[27] Does or should the definition of a contingency event include extreme VER ramping events? If so, would an additional level of contingency reserves be needed to achieve the same level of system reliability? In responding to this question, please include a proposed definition of "extreme ramping event."

5. Should a new category of reserves, that would be similar to contingency reserves, be developed to maintain reliability during VER ramping events in a cost effective manner? If so, what benefit would such reserves provide to System Operators and customers?

6. Could the expanded use of reserve-sharing programs between balancing authorities contribute to lowering the costs associated with integrating VERs? If so, how?

7. Should the ancillary services provisions of the *pro forma* OATT be revised or new provisions added to expressly address the added reserve capacity necessitated by increased number of VERs? If so, how?

8. Are there new sources and/or providers for reserve products (such as inter-balancing authority pooling arrangements, demand response aggregators and/or storage devices) that can be used to maintain reliability and lower reserve costs during VER ramping events? Based on experience, are there characteristics of these new sources of reserves that would positively or negatively impact their ability to match the reserve product needs presented by the variability of VERs?

9. To what extent are VERs capable of providing reserve services? Should VERs be expected to provide reserve services? What are the tariff and technical barriers that may impede VERs from providing these reserve products?

10. To what extent should all resources, and VERs in particular, be required to provide Frequency Response? How would such a requirement be implemented?

11. Should the Commission revisit the reactive power requirements set forth in Order No. 661? [28] What other requirements, if any, should apply to VERs to ensure that all resources contribute to grid reliability in a manner that is not unduly discriminatory?

F. Capacity Markets

37. The procurement of capacity services, either through resource adequacy bilateral programs or centralized capacity markets, is commonplace in RTO/ISO markets.[29] Typically, VERs are eligible to receive compensation for capacity services in most RTOs/ISOs. However, due to their operating characteristics and the capacity rating rules, which vary among RTOs/ISOs, VERs are eligible to offer only a portion of their nameplate capacity. The price paid for capacity services depends in part on the amount of available capacity. Additionally, resources that participate in capacity markets typically are required to offer capacity in the day-ahead market, which, as discussed above, VERs often do not do.

38. The Commission questions whether existing rules governing capacity markets may result in rates for capacity services that are not just and reasonable. Moreover, to the extent existing rules limit the ability of VERs to provide capacity services that they are capable of providing, the Commission seeks to explore whether such rules may be unduly discriminatory.

39. To that end, the Commission seeks comment on the following questions:

1. Should the Commission examine whether capacity rating rules as applied to VERs are unduly discriminatory and investigate whether standard rules may be appropriate?

2. Do obligations for capacity resources to offer into the day-ahead market unfairly discriminate against VERs? If so, how?

3. As more VERs choose to become capacity resources, will existing processes for compensating capacity services adequately compensate all generating resources that may be needed for reliability services? If not, what reforms may be necessary? For instance, should the Commission examine formation of forward ancillary services capacity markets?

4. Should capacity markets incorporate a goal of ensuring sufficient generation flexibility to accommodate ramping events in addition to the goal of ensuring sufficient generation to meet peak demand?

G. Real-Time Adjustments

40. Redispatch and curtailment protocols vary depending on the region of the country and scenario. The Commission is interested in receiving comments on whether VERs may be curtailed too frequently in response to transmission congestion, minimum generation events,[30] and ramping events, because of a lack of clarity in curtailment protocols. Accordingly, the Commission seeks to explore whether redispatch and curtailment practices and protocols, especially as they relate to VERs, are transparent, non-discriminatory and efficient. The Commission also seeks to determine whether redispatch and curtailment protocols may result in unnecessary costs, thereby rendering rates unjust and unreasonable.

41. To that end, the Commission seeks comment on the following questions:

1. How have redispatch and curtailment practices changed with increased numbers of VERs? Are there any shortcomings of current redispatch and curtailment practices?

2. Do existing redispatch and curtailment processes unduly discriminate against VERs? If so, how should they be modified?

3. Some RTOs/ISOs will redispatch VERs based on required economic bids. Should all RTOs/ISOs implement similar practices? Why or why not?

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[26] *See* 16 U.S.C. 824o(a)(3).

[27] *Disturbance Control Performance,* Standard No. BAL–002–0 (Apr. 1, 2005).

[28] Order No. 661, FERC Stats. & Regs. ¶ 31,186 at P 50–51.

[29] Centralized capacity markets exist in ISO New England, Inc., New York Independent System Operator, Inc., and PJM Interconnection LLC. California Independent System Operator Corp. and Midwest Independent Transmission System Operator, Inc. rely primarily on bilateral resource adequacy programs to procure capacity services.

[30] During a minimum generation event, system demand is at its lowest and generation resources tend to operate at the minimum feasible output level.

4. Should transmission loading relief protocols be altered to allow reliability coordinators in non-RTO/ISO regions to consider economic merit when considering curtailing VERs? If so, how? Similarly, should redispatch and curtailment protocols in non-RTOs/ISOs be revised to consider economic merit for all resources? If so, how?

5. Is the increasing number of VERs affecting operational issues that arise during minimum generation events? Are there ways to minimize curtailments during a minimum generation event? Should conventional base-load resources be offered incentives to lower their minimum operating levels or even shut down during minimum generation events to reflect an economically efficient dispatch of resources? If so, what would be the benefits and costs of doing so?

6. To what extent do VERs have the capability to respond to specific dispatch instructions? Are there any advanced technologies that could be adopted by VERs to control output to match system needs more effectively? Should incentives be put into place for VERs that can respond to dispatch instructions? If so, what types of incentives would be appropriate?

IV. Comment Procedures

42. The Commission invites interested persons to submit comments, and other information on the matters, issues and specific questions identified in this notice.

43. Comments are due March 29, 2010. 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.

44. 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.

45. Commenters that are not able to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE., Washington, DC 20426.

46. 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.

V. Document Availability

47. 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.

48. 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.

49. 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.*

By direction of the Commission. Commissioner Norris voting present.

Kimberly D. Bose,

Secretary.

[FR Doc. 2010–1536 Filed 1–26–10; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF LABOR

Occupational Safety and Health Administration

29 CFR Part 1910

[Docket No. OSHA–2007–0007]

RIN 1218–AC39

Additional Quantitative Fit-testing Protocols for the Respiratory Protection Standard

AGENCY: Occupational Safety and Health Administration (OSHA), Labor.

ACTION: Proposed rule; withdrawal.

SUMMARY: After thoroughly reviewing the comments and other information available in the record for the proposed rulemaking, OSHA concludes that the revised PortaCount® quantitative fit-testing protocols are not sufficiently accurate or reliable to include among the quantitative fit tests listed in Part II of Appendix A of its Respiratory Protection Standard. Therefore, OSHA is withdrawing the proposed rule without prejudice, and is inviting resubmission of the revised protocols after developers of the protocols address the issues described in this notice.

DATES: The proposed rulemaking is withdrawn as of January 27, 2010.

FOR FURTHER INFORMATION CONTACT: *General information and press inquiries:* Contact Ms. Jennifer Ashley, Office of Communications, Room N–3647, OSHA, U.S. Department of Labor, 200 Constitution Avenue, NW., Washington, DC 20210; telephone (202) 693–1999.

Technical inquiries: Contact Mr. John E. Steelnack, Directorate of Standards and Guidance, Room N–3718, OSHA, U.S. Department of Labor, 200 Constitution Avenue, NW., Washington, DC 20210; telephone: (202) 693–2289; facsimile: (202) 693–1678.

Copies of this notice: Electronic copies of this **Federal Register** notice, as well as news releases and other relevant documents, are available at OSHA's Web page at *http://www.osha.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

Appendix A of OSHA's Respiratory Protection Standard at 29 CFR 1010.134 currently includes three quantitative fit-testing protocols using the following challenge agents: a non-hazardous generated aerosol such as corn oil, polyethylene glycol 400, di-2-ethyl hexyl sebacate, or sodium chloride; ambient aerosol; and controlled negative pressure. Appendix A of the Respiratory Protection Standard also specifies the procedure for adding new fit-testing protocols to the standard. The criteria for determining whether OSHA must publish a fit-testing protocol for notice-and-comment rulemaking under Section 6(b)(7) of the Occupational Safety and Health Act of 1970 (29 U.S.C. 655) include: (1) A test report prepared by an independent government research laboratory (*e.g.,* Lawrence Livermore National Laboratory, Los Alamos National Laboratory, the National Institute for Standards and Technology) stating that the laboratory tested the protocol and found it to be accurate and reliable; or (2) an article published in a peer-reviewed industrial-hygiene journal describing the protocol and explaining how the test data support the protocol's accuracy and reliability. Using this procedure, OSHA added one fit-testing protocol *(i.e.,* the controlled negative pressure REDON quantitative fit- testing protocol) to Appendix A of