DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EL16–39–000]

Tri-State Generation and Transmission Association, Inc.; Notice of Petition for Declaratory Order

Take notice that on February 17, 2016, pursuant to Rule 207 of the Commission's Rules of Practice and Procedure of the Federal Energy Regulatory Commission's (Commission), 18 CFR 385.207(2015), Tri-State Generation and Transmission Association, Inc. (Tri-State) filed a petition for declaratory order finding that Tri-State's fixed cost recovery proposal contained in revised Board Policy 101 is consistent with the Public Utility Regulatory Policies Act of 1978 and the Commission's implementing regulaltions, as more fully explained in the petition.

Any person desiring to intervene or to protest in this proceeding must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214) on or before 5:00 p.m. Eastern time on the specified comment date. Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Petitioner.

The Commission encourages electronic submission of protests and interventions in lieu of paper, using the FERC Online links at *http://www.ferc.gov.* To facilitate electronic service, persons with Internet access who will eFile a document and/or be listed as a contact for an intervenor must create and validate an eRegistration account using the eRegistration link. Select the eFiling link to log on and submit the intervention or protests.

Persons unable to file electronically should submit an original and 5 copies of the intervention or protest to the Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426.

The filings in the above proceeding are accessible in the Commission's eLibrary system by clicking on the appropriate link in the above list. They are also available for review in the Commission's Public Reference Room in Washington, DC. There is an eSubscription link on the Web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email *FERCOnlineSupport@ferc.gov.or* call (866) 208–3676 (toll free). For TTY, call (202) 502–8659.

Comment Date: 5:00 p.m. Eastern time on March 18, 2016.

Dated: February 18, 2016.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2016–03835 Filed 2–23–16; 8:45 am]

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RM16–6–000]

Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response

AGENCY: Federal Energy Regulatory Commission, Energy.

ACTION: Notice of Inquiry.

SUMMARY: In this Notice of Inquiry, the Federal Energy Regulatory Commission (Commission) seeks comment on the need for reforms to its rules and regulations regarding the provision and compensation of primary frequency response.

DATES: Comments are due April 25, 2016.

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: Those unable to file electronically must mail or hand deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

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

FOR FURTHER INFORMATION CONTACT:

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Mark Bennett (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426, (202) 502–8524, *Mark.Bennett@ferc.gov.*

SUPPLEMENTARY INFORMATION:

1. In this Notice of Inquiry (NOI), the Commission seeks comment on the need for reforms to its rules and regulations regarding the provision and compensation of primary frequency response. In recent years, the nation's electric supply portfolio has transformed to a point where fewer resources may now be providing primary frequency response than when the Commission considered this issue in other relevant proceedings. As discussed below, in light of the changing resource mix and other factors, it is reasonable to expect this trend to continue. Considering the significance of primary frequency response to the reliable operation of the Bulk-Power System,[1] the Commission seeks input on whether and what action is needed to address the provision and compensation of primary frequency response.

2. Specifically, the Commission seeks comment on whether amendments to the *pro forma* Large Generator Interconnection Agreement (LGIA) and Small Generator Interconnection Agreement (SGIA) are warranted to require all new generation resources to have frequency response capabilities as a precondition of interconnection. The Commission also seeks comment on the performance of existing resources and whether primary frequency response requirements for these resources are warranted. Further, the Commission seeks comment on the requirement to provide and compensate for primary frequency response.

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[1] Section 215(a)(1) of the Federal Power Act (FPA), 16 U.S.C. 824o(a)(1) (2012) defines ''Bulk-Power System'' as those ''facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) [and] electric energy from generating facilities needed to maintain transmission system reliability.'' The term does not include facilities used in the local distribution of electric energy. *See also Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 76, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

I. Background

A. Technical Overview: The Nature and Operation of Frequency Response

3. Reliably operating an Interconnection [2] requires maintaining balance between generation and load so that frequency remains within predetermined boundaries around a scheduled value (60 Hz in the United States). Interconnections occasionally experience system contingencies (*e.g.,* the loss of a large generator) that disrupt the balance between generation and load. These contingencies result in frequency deviations that can potentially cause under frequency load shedding (UFLS), additional generation tripping, or cascading outages.[3] Consequently, some generators within an Interconnection automatically deploy frequency control actions, including inertial response and primary frequency response, during disturbances to arrest and stabilize frequency deviations. The reliability of the Bulk-Power System depends in part on the operating characteristics of generating resources that balancing authorities [4] commit to serve load. However, not all generating resources provide frequency support services, which are essential to maintaining the reliability and stability of the Bulk-Power System.[5]

4. Frequency response is a measure of an Interconnection's ability to arrest and stabilize frequency deviations within pre-determined limits following the sudden loss of generation or load. Frequency response is affected by the collective responses of generation and load resources throughout the entire Interconnection. Inertial response, primary frequency response, and secondary frequency response all contribute to stabilizing the Bulk-Power System by correcting frequency deviations.

5. Inertial response, or system inertia, involves the release or absorption of kinetic energy by the rotating masses of online generation and load within an Interconnection, and is the result of the coupling between the rotating masses of synchronous generation and load and the electric system.[6] An Interconnection's inertial response influences how fast frequency drops after the loss of generation and how fast it rises after a reduction of load. The less system inertia there is, the faster the rate of change of frequency [7] during disturbances. An adequate amount of system inertia is important since following the sudden loss of generation, inertia serves to reduce the rate of change of frequency, allowing time for primary frequency response actions to arrest the frequency deviation and stabilize the power system.

6. Primary frequency response, net of changes in generation real power (MW) output and power consumed by load in response to a frequency deviation, is the first stage of overall frequency control, begins within seconds after the frequency changes, and is critical to the reliable operation of the Bulk-Power System.[8] Primary frequency response is mostly provided by the automatic and autonomous actions (*i.e.,* outside of system operator control) of turbine-governors, while some response is provided by frequency responsive loads due to changes in system frequency. Primary frequency response actions are intended to arrest the frequency deviation until it reaches the minimum frequency, or nadir.[9] An important goal for system planners and operators is for the frequency nadir, during large disturbances, to remain above the first stage of firm UFLS set points within an Interconnection. The time-frame to arrest frequency deviations typically ranges from five to 15 seconds, depending on the Interconnection.

7. Secondary frequency response involves changes to the MW output of resources on automatic generation control (*e.g.,* regulation resources) that respond to dispatch instructions.[10] Secondary frequency response actions usually begin after 30 seconds or more following a contingency, and can take 5 minutes or more to restore system frequency to its scheduled value.

B. Evolving Generation Resource Mix

8. The nation's generation resource mix is undergoing a transformation that includes the retirement of baseload, synchronous units, with large rotational inertia. The changing resource mix also includes the integration of more distributed generation, demand response, and natural gas resources, and the rapid expansion of variable energy resources (VERs) [11] such as wind and solar.[12] Several factors, such as existing and proposed federal and state environmental regulations, renewable portfolio standards, tax incentives, and low natural gas prices, have driven these developments.

9. During 2015, natural gas-fired generation surpassed coal as the predominant fuel source for electric generation, and is now the leading fuel type for capacity additions.[13] In addition, NERC recently determined that there has been almost 50 GW of baseload (*e.g.,* coal, nuclear, petroleum, and natural gas) retirements since 2011.[14]

10. In addition, between 2014 and 2015, all three U.S. Interconnections have experienced growth in the installed nameplate capacity of wind and solar generation. For example, as illustrated by the figure below, NERC

[2] An Interconnection is a geographic area in which the operation of Bulk-Power System components is synchronized. In the continental United States, there are three Interconnections, namely the Eastern, Electric Reliability Council of Texas (ERCOT), and Western Interconnections.

[3] UFLS is designed for use in extreme conditions to stabilize the balance between generation and load. Under frequency protection schemes are drastic measures employed if system frequency falls below a specified value. *Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards,* Notice of Proposed Rulemaking, 137 FERC ¶ 61,067 (2011).

[4] The North American Electric Reliability Corporation's (NERC) Glossary of Terms defines a balancing authority as ''(t)he responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports Interconnection frequency in real time.''

[5] As discussed below, NERC Reliability Standard BAL–003–1 has requirements related to frequency response, but it is applicable to balancing authorities and not individual generating resources.

[6] *See, e.g., Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation,* Ernest Orlando Lawrence Berkeley National Laboratory, at 13–14 (December 2010), *available at: http://energy.lbl.gov/ea/certs/pdf/lbnl-4142e.pdf* (LBNL Frequency Response Metrics Report).

[7] Rate of change of frequency is mainly a function of the magnitude of the loss of generation (or load) and system inertia and is measured in Hz/second.

[8] *See, e.g.,* LBNL Frequency Response Metrics Report at 15–16.

[9] The point at which the frequency decline is arrested (following the sudden loss of generation) is called the frequency nadir, and represents the point in which the net primary frequency response (MW) output from all generating units and the decrease in power consumed by the load within an Interconnection matches the net initial MW loss of generation.

[10] *See e.g.,* LBNL Frequency Response Metrics Report at 9–11.

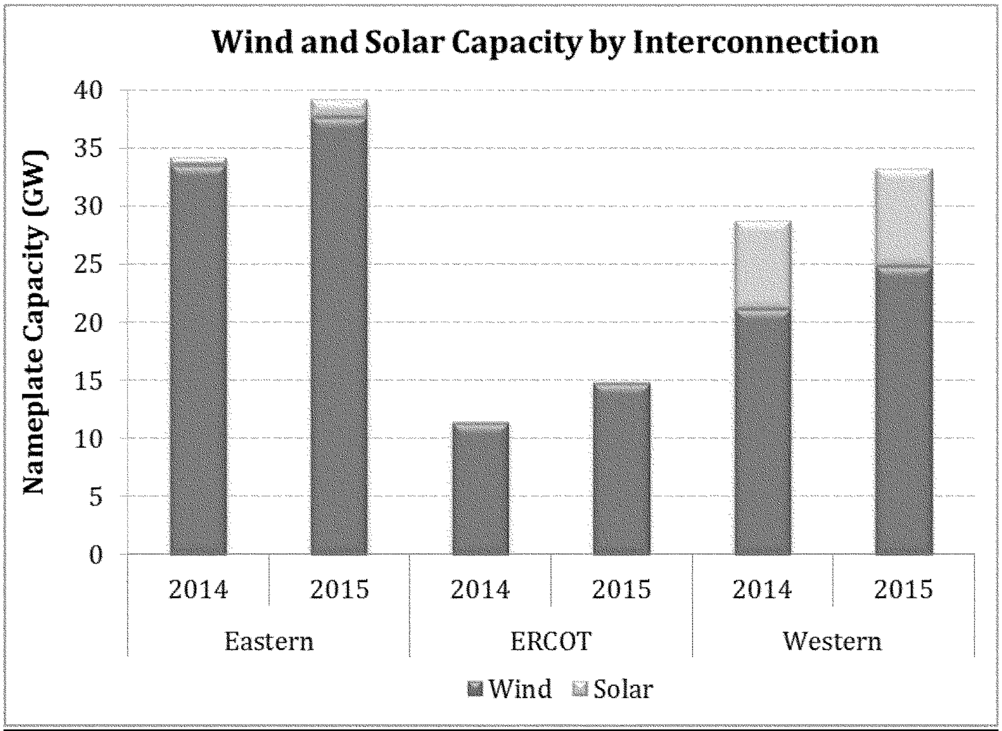
[11] For the purposes of this proceeding, the term Variable Energy Resource refers to a device for the production of electricity that is characterized by an energy source that: (1) Is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities. *See Integration of Variable Energy Resources,* Order No. 764, FERC Stats. & Regs. ¶ 31,331 at n. 1 (2012), *order on reh'g and clarification,* Order No. 764–A, 141 FERC ¶ 61,232 (2012), *order on clarification and reh'g,* Order No. 764–B, 144 FERC ¶ 61,222 (2013).

[12] The Solar Energy Industries Association (SEIA) recently reported that more than 50 percent of newly installed electric generating capacity in the U.S. came from solar generation in the first quarter of 2015. *See* SEIA Solar Market Insight Report 2015 Q1 (2015), *http://www.seia.org/research-resources/solar-market-insight-report-2015-q1.*

[13] *See* NERC 2015 Long Term Reliability Assessment at 1 (December 2015), *http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf.*

[14] *See* NERC 2015 Summer Reliability Assessment at 5 (May 2015), *http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015_Summer_Reliability_Assessment.pdf.*

has observed that the three Interconnections collectively added approximately 11.1 GW of wind and 1.73 GW of solar generation between 2014 and 2015.[15] More specifically, in 2015: (1) The Eastern Interconnection had 37.6 GW of wind and 1.6 GW of solar capacity, representing a growth rate of 12 percent and 116 percent over the respective 2014 levels of 33.5 GW and 0.73 GW;[16] (2) ERCOT had 14.7 GW of wind and 0.18 GW of solar, representing a growth rate of 29 percent and 50 percent over the respective 2014 levels of 11.4 GW and 0.12 GW;[17] and (3) Western Interconnection had 24.8 GW of wind and 8.4 GW of solar, representing a growth rate of 17 percent and 11 percent over the respective 2014 levels of 21.1 GW and 7.6 GW.[18]



11. The changing generation resource mix has the potential to reduce the inertial response within some Interconnections, as VERs do not contribute to inertia unless they are specifically designed to do so. For example, solar photovoltaic resources have no rotating mass and thus no rotational inertia. Similarly, while wind turbines have a rotating mass, power converters that interconnect modern wind turbines decouple the rotation of their turbines from the grid. As such, modern wind turbines do not contribute to the system's inertia unless specifically configured to do so.[19] Therefore, increased numbers of VERs, in conjunction with significant retirements of large conventional resources with large rotational inertia, have the potential to reduce system inertia.

12. In addition, VERs do not provide primary frequency response unless specifically configured to do so. Furthermore, since VERs typically have low marginal costs of production, they would likely not be dispatched in a manner necessary to provide primary frequency response, since the provision of primary frequency response involves the reservation of capacity (or ''headroom'') in order for a resource to automatically increase its MW output in response to drops in system frequency. Therefore, there is a significant risk that, as conventional synchronous resources retire or are displaced by increased numbers of VERs that do not typically have primary frequency response capabilities, the net amount of frequency responsive generation online will be reduced.[20]

13. The combined impacts of lower system inertia and lower frequency responsive capability online may adversely affect reliability during disturbances because lower system inertia results in more rapid frequency deviations during disturbances. This, in turn, may result in lower frequency nadirs, particularly if the primary frequency capability online is not sufficiently fast. This is a potential reliability concern because, as the frequency nadir lowers, it approaches the Interconnection's UFLS trip setting, which could result in the loss of load and additional generation across the Interconnection.

14. These developments and their potential impacts could challenge system operators in maintaining reliability. The Commission believes that a substantial body of evidence has emerged warranting consideration of possible actions to ensure that resources capable of providing primary frequency

[15] NERC 2015 Summer Reliability Assessment, Table 3 at page 7.

[16] *Id.*

[17] *Id.*

[18] *Id.*

[19] *See, e.g.,* General Electric WindINERTIA Control Fact Sheet (2009), *http://site.ge-energy.com/prod_serv/products/renewable_energy/en/downloads/GEA17210.pdf.*

[20] Non-synchronous generators such as VERs (*e.g.,* wind and solar resources) produce electricity that is not synchronized to the electric grid (*i.e.,* direct current (DC) power or alternating current (AC) power at a frequency other than 60 hertz). Inverters convert non-synchronized AC or DC power into synchronized AC power that can be transmitted on the transmission system. These resources do not operate in the same way as conventional generators and respond differently to network disturbances.

response are adequately maintained as the nation's resource mix continues to evolve.

15. *In 2014, NERC initiated the Essential Reliability Services Task Force (Task* Force) to analyze and better understand the impacts of the changing resource mix and develop technical assessments of essential reliability services.[21] The Task Force focused on three essential reliability services: frequency support, ramping capability, and voltage support.[22]

16. The Task Force considered the seven ancillary services [23] adopted by the Commission in Order Nos. 888 [24] and 890 [25] as a subset of the essential reliability services that may need to be augmented by additional services as the Bulk-Power System characteristics change. However, the Task Force did not intend to recommend new reliability standards or propose actions to alter the existing suite of ancillary services.[26] Instead, its focus was on educating and informing industry and other stakeholders about essential reliability services, developing measures and industry best practices for tracking essential reliability services, and developing recommendations to ensure that essential reliability services continue to be provided as the nation's generation resource mix evolves.[27]

17. The reliability of the Bulk-Power System will be increasingly dependent upon the operational characteristics of natural gas and renewable generating units, as these types of resources are expected to comprise an increasing percentage of the future generation resource mix. The Task Force stated that ''the reliability of the electric grid depends on the operating characteristics of the replacement resources.'' [28] NERC observed that ''wind, solar, and other variable energy resources that are an increasingly greater share of the Bulk-Power System provide a significantly lower level of essential reliability services than conventional generation.'' [29] The Task Force concluded that it is prudent and necessary to ensure that primary frequency capabilities are present in the future generation resource mix, and recommends that all new generators support the capability to manage frequency.[30]

18. Contributing to the concerns associated with the nature and operational characteristics of the evolving resource mix is the uncertainty whether a resource configured to provide primary frequency response is willing and able to offer such a service when called upon to do so. While almost all existing synchronous resources and some non-synchronous resources have governors or equivalent control equipment capable of providing primary frequency response, generator owners and operators can independently decide whether units provide primary frequency response.[31]

19. For example, at present, it is possible for a generator owner/operator to block or disable the governor or to set a wide dead band setting. A wide dead band setting can result in a unit not providing primary frequency response for most frequency deviations. As discussed more fully below, in February 2015, NERC issued an Industry Advisory which determined that a significant portion of generators within the Eastern Interconnection utilize dead bands or governor control settings that either inhibit or prevent the provision of primary frequency response.[32] In response to this issue and other concerns, NERC's Operating Committee recently approved a Primary Frequency Control Guideline that contains recommended settings for generator governors and other plant control systems, and encourages generators within the three U.S. Interconnections to provide sustained and effective primary frequency response.[33]

20. NERC's State of Reliability Report for 2015 explained that the three U.S. Interconnections currently exhibit stable frequency response performance above their Interconnection Frequency Response Obligations.[34] However, NERC has pointed out a historic decline in frequency response performance in both the Western and Eastern Interconnections.[35] NERC identified several key reasons for the decline, mainly tied to the primary frequency response performance of generators.[36]

C. Prior Commission and Industry Actions

21. In this proceeding, the Commission seeks comment on the need

[21] Essential reliability services are referred to as elemental reliability building blocks from resources (generation and load) that are necessary to maintain the reliability of the Bulk-Power System. *See* Essential Reliability Services Task Force Scope Document at 1 (April 2014), *http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Scope_ERSTF_Final.pdf.*

[22] Essential Reliability Services Task Force Measures Report at 22 (December 2015), *http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.*

[23] The seven ancillary services are: (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve—Spinning Reserve Service; (6) Operating Reserve—Supplemental Reserve Service; and (7) Generator Imbalance Service.

[24] *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).

[25] *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).

[26] NERC Essential Reliability Services Task Force Scope Document at 2.

[27] *Id.*

[28] Essential Reliability Services Task Force Measures Report at iv.

[29] *See* NERC State of Reliability 2015 Report at 16 (May 2015), *http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015%20State%20of%20Reliability.pdf.*

[30] Essential Reliability Services Task Force Measures Report at vi.

[31] A governor is an electronic or mechanical device that implements primary frequency response on a generator via a droop parameter. Droop refers to the variation in MW output due to variations in system frequency. A governor also has a dead band which establishes a minimum frequency deviation (from nominal) that must be exceeded in order for the governor to act. Example droop and dead band settings are 5 percent and ±0.036 Hz, respectively.

[32] NERC Generator Governor Frequency Response Industry Advisory (February 2015), *http://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/2015%20Alerts/NERC%20Alert%20A-2015-02-05-01%20Generator%20Governor%20Frequency%20Response.pdf.*

[33] *See* NERC Primary Frequency Control Guideline Final Draft (December 2015), *http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Primary_Frequency_Control_final.pdf. See also* NERC Operating Committee Meeting Minutes (January 2016), *http://www.nerc.com/comm/OC/Agendas HighlightsMinutes/Operating%20Committee%20Minutes%20-%20Dec%2015-16%202015-Final.pdf.*

[34] NERC State of Reliability Report 2015 at 9 (May 2015). *See http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015%20State%20of%20Reliability.pdf.* Reliability Standard BAL–003–1 establishes Interconnection Frequency Response Obligations that are designed to require sufficient frequency response for each Interconnection to arrest frequency declines even for severe, but possible, contingencies.

[35] *See* NERC *Frequency Response Initiative Industry Advisory—Generator Governor Frequency Response* at slide 10 (April 2015), *http://www.nerc.com/pa/rrm/Webinars%20DL/Generator_Governor_Frequency_Response_Webinar_April_2015.pdf. See also Review of the Recent Frequency Performance of the Eastern, Western and ERCOT Interconnections,* Ernest Orlando Lawrence Berkeley National Laboratory, at pp xiv–xv (December 2010), *http://energy.lbl.gov/ea/certs/pdf/lbnl-4144e.pdf.*

[36] *See* NERC *Frequency Response Initiative Report: The Reliability Role of Frequency Response* (October 2012), *http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf* (Frequency Response Initiative Report).

for reforms to its rules and regulations regarding the provision of primary frequency response. This section offers an overview of Commission and industry action to date related to frequency response to provide the context for the consideration of what, if any, actions the Commission should take to ensure that adequate frequency response is available to maintain grid reliability.

22. In April 1996, the Commission issued Order No. 888, to address undue discrimination in transmission service by requiring all public utilities to provide open access transmission service consistent with the terms of a *pro forma* Open Access Transmission Tariff (OATT).[37] The *pro forma* OATT sets forth the terms of transmission service including, among other things, the provision of ancillary services. Additionally, the Commission adopted six ancillary services stating they are ''needed to accomplish transmission service while maintaining reliability within and among control areas affected by the transmission service.'' [38] The ancillary service involved in this proceeding is Regulation and Frequency Response Service, found in Schedule 3 of the *pro forma* OATT.

23. In July 2003, the Commission issued Order No. 2003, which revised the *pro forma* OATT to include a *pro forma* LGIA, which applies to interconnection requests of large generators (*i.e.,* generators larger than 20 MW).[39] While the *pro forma* LGIA adopted standard procedures and a standard agreement for the interconnection of large generating facilities, it was ''designed around the needs of large synchronous generators.'' [40] The Commission also added a blank Appendix G (Requirements of Generators Relying on Newer Technologies) to the LGIA to serve as a means by which to apply interconnection requirements specific for generators relying on newer technologies, such as wind generators.[41]

24. In May 2005, the Commission issued Order No. 2006, which required all public utilities to adopt standard terms and conditions for new interconnecting small generators (*i.e.,* those no larger than 20 MW) under a *pro forma* SGIA.[42]

25. The Commission recently issued a notice of proposed rulemaking to revise the *pro forma* LGIA and SGIA to eliminate the exemption for wind generators and other non-synchronous generators regarding reactive power requirements.[43] The proposed rule proposes to require all newly interconnecting generators, both synchronous and non-synchronous, to provide reactive power.

26. Although the Commission has previously included technical requirements for generators in the LGIA and Large Generator Interconnection Procedures (LGIP),[44] both the *pro forma* LGIA and SGIA are silent with respect to primary frequency response requirements.

27. In a final rule issued on January 16, 2014, the Commission approved Reliability Standard BAL–003–1, which establishes frequency response requirements for balancing authorities.[45] Reliability Standard BAL–003–1 established Interconnection Frequency Response Obligations that prescribe the minimum frequency response that must be maintained by an Interconnection. The purpose of the Interconnection Frequency Response Obligation is to maintain the minimum frequency (nadir) above UFLS set points following the largest contingency of the Interconnection as defined by the resource contingency criteria in BAL–003–1. Each balancing authority is assigned a Frequency Response Obligation [46] that is a proportionate share of the Interconnection Frequency Response Obligation, and is based on its annual generation and load.[47] Requirement R1 of BAL–003–1 requires each balancing authority to achieve an annual Frequency Response Measure that equals or exceeds its Frequency Response Obligation. The Frequency Response Measure is the median value of a balancing authority's frequency response performance during selected events over the course of a year.[48] Requirement R1 of BAL–003–1 becomes effective on April 1, 2016, and compliance begins on December 1, 2016.

28. Although Reliability Standard BAL–003–1 requires sufficient frequency response from balancing authorities, on average, to maintain Interconnection frequency, it does not require generators to provide primary frequency response. In the rulemaking in which the Commission approved Reliability Standard BAL–003–1, some commenters expressed concern that the standard does not address the availability of generator resources to provide primary frequency response or the premature withdrawal [49] of primary frequency response. In Order No. 794, the Commission directed NERC to submit a report by July 2018 analyzing the availability of resources for each balancing authority and Frequency Response Sharing Group [50] to meet their Frequency Response Obligation.[51] Furthermore, the Commission stated that, if NERC learns that balancing authorities are experiencing difficulty in procuring sufficient resources to satisfy their Frequency Response Obligations,

[37] Order No. 888, FERC Stats. & Regs. ¶ 31,036.

[38] *Id.* at 31,705.

[39] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, app. 6 (LGIP), app. C (LGIA) (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g,* Order No. 2003–B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003–C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs* v. *FERC,* 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied,* 552 U.S. 1230 (2008).

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

[41] *Id.*

[42] *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).

[43] *Reactive Power Requirements for Non-Synchronous Generation,* 153 FERC ¶ 61,175 (2015).

[44] For example, in Order Nos. 661 and 661–A, the Commission adopted standard procedures and technical requirements related to low voltage ride thru and power factor design criteria for the interconnection of large wind plants, and required all public utilities that own, control, or operate facilities for transmitting electric energy in interstate commerce to append Appendix G to their LGIPs and LGIAs in their OATTs to include these requirements. *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).

[45] *Frequency Response and Frequency Bias Setting Reliability Standard,* Order No. 794, 146 FERC ¶ 61,024 (2014). Reliability Standards proposed by NERC are submitted to the Commission for approval pursuant to section 215(d) of the FPA; 16 U.S.C. 824o(d).

[46] NERC's Glossary of Terms defines Frequency Response Obligation as ''[t]he balancing authority's share of the required Frequency Response needed for the reliable operation of an Interconnection.''

[47] The Interconnection Frequency Response Obligation and Frequency Response Obligation are expressed in MW per 0.1 Hertz (MW/0.1 Hz).

[48] Attachment A of BAL–003–1. NERC will identify between 20 to 35 events annually in each Interconnection for calculating the Frequency Response Measure. *See also* Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard, (November 30, 2012), *http://www.nerc.com/pa/Stand/Project%20200712%20Frequency%20Response%20DL/Procedure_Clean_20121130.pdf.*

[49] NERC has stated that ''[w]ithdrawal of primary frequency response is an undesirable characteristic associated most often with digital turbine-generator control systems using setpoint output targets for generator output. These are typically outer-loop control systems that defeat the primary frequency response of the governors after a short time to return the unit to operating at a requested MW output.'' *See* Order No. 794, 146 FERC ¶ 61,024 at P 65 (citing NERC's Frequency Response Initiative Report).

[50] NERC's Glossary of Terms defines a Frequency Response Sharing Group as a ''group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.''

[51] Order No. 794, 146 FERC ¶ 61,024 at P 60.

NERC should immediately report it to the Commission with appropriate recommendations for mitigation.[52]

29. Additionally, in Order No. 794, the Commission stated that the nature and extent of the problems that could result from the premature withdrawal of primary frequency response, and how best to address them, will be better understood after NERC and balancing authorities have more experience with Reliability Standard BAL–003–1.[53] The Commission also stated that the need to take action regarding the premature withdrawal of primary frequency response, including requiring load controllers to include a frequency bias term to sustain frequency response or otherwise modifying Reliability Standard BAL–003–1, should be decided after we have actual experience with the Reliability Standard.[54]

30. In light of the ongoing evolution of the nation's generation resource mix, and other factors, such as NERC's Generator Governor Industry Advisory released in February 2015, the Commission believes that it is prudent to take a proactive approach to better understand the issues related to primary frequency response performance and determine what additional actions beyond Reliability Standard BAL–003–1 may be appropriate. Thus, the Commission is proceeding with a Notice of Inquiry at this time rather than waiting until NERC submits a report in 2018.

31. In the absence of national primary frequency response requirements applicable to individual generating resources, some areas, including ERCOT, ISO New England Inc. (ISO–NE), and PJM Interconnection, L.L.C. (PJM), have implemented regional requirements for individual generating resources within their regions in order to maintain reliability.

32. For example, the Commission accepted Texas Reliability Entity Inc.'s Regional Reliability Standard BAL–001–TRE–01 (Primary Frequency Response in the ERCOT Region) as mandatory and enforceable, which places requirements on generator owners and operators with respect to the provision of primary frequency response within the ERCOT region.[55] In particular, BAL–001–TRE–01 requires generator owners to operate each generating unit/generating facility that is connected to the interconnected transmission system with the governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, and to promptly notify the balancing authority of any change in governor status.[56] Additionally, BAL–001–TRE–01 requires generator owners to set specified governor dead band and droop parameters.[57] Moreover, BAL–001–TRE–01 requires generator owners to provide minimum initial and sustained primary frequency response performance.[58] NERC recently noted that ERCOT experienced a significant improvement in its frequency response performance as generators within its region adjusted their governor settings for compliance with BAL–001–TRE–01.[59]

33. ISO–NE requires each generator within its region with a capability of ten MW or more, including renewable resources, to operate with a functioning governor with specified dead band and droop settings, and to also ensure that the provision of primary frequency response is not inhibited by the effects of outer-loop controls.[60]

34. PJM has *pro forma* interconnection agreements that obligate interconnection customers within its region to abide by all PJM rules and procedures pertaining to generation and transmission, including rules and procedures set forth in the PJM Manuals.[61] PJM requires large, conventional generators to operate on unrestricted governor control to assist in maintaining Interconnection frequency, and recently established specified governor dead band and droop requirements for all generating resources (excluding nuclear units) with a gross plant/facility aggregate nameplate rating greater than 75 MVA.[62] In addition, PJM recently added new interconnection requirements for interconnection customers entering its queue after May 2015 and seeking to interconnect non-synchronous generators, including wind generators, to use ''enhanced inverters'' with the capability to, among other things, provide primary frequency response.[63] PJM stated that the installed capacity of VERs in its region is expected to increase to approximately 15 GW by the 2016–17 delivery year, and that it has an additional 25 GW of VERs in its interconnection queue.[64] PJM expressed a need for VERs to install the capability to automatically reduce or increase their real power output in order to respond to a variety of system conditions, including high or low frequencies. PJM also stated that this capability will provide flexibility in responding to transmission system events using all available resources which, according to PJM, will be increasingly important as VERs displace synchronous generators that have these capabilities.[65]

D. Compensation for Primary Frequency Response Service

35. This section offers an overview of Commission and industry action to date related to compensation for primary frequency response. At present, there are few, if any, entities receiving compensation for selling primary frequency response as a stand-alone product, and there are no current rates applicable to sales of primary frequency response alone. However, several options for transactions involving primary frequency response have been developed. Transmission providers may sell primary frequency response service in combination with regulation service under the bundled *pro forma* OATT Schedule 3 product, Regulation and Frequency Response Service.[66]

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[52] *Id.* P 63.

[53] *Id.* P 75.

[54] *Id.* P 76.

[55] *North American Electric Reliability Corporation,* 146 FERC ¶ 61,025 (2014). The requirements of BAL–001–TRE–01 help to ensure that generation and load remain balanced—or are quickly restored to balance—in the ERCOT Interconnection so that system frequency is restored to stability and near normal frequency even after a significant event occurs on the system. In Order No. 693, the Commission approved a regional difference for the ERCOT Interconnection from Reliability Standard BAL–001–0, allowing ERCOT to be exempt from Requirement R2, and found that ERCOT's approach to frequency response under its own market protocols appeared to be more stringent than Requirement R2. Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 313–315.

[56] Reliability Standard BAL–001–TRE–01, at Requirements R7 and R8.

[57] Reliability Standard BAL–001–TRE–01, at Requirement R6.

[58] Reliability Standard BAL–001–TRE–01, at Requirements R9 and R10.

[59] NERC 2014 Frequency Response Annual Analysis Report at 6 (February 2015), *http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/Final_Info_Filing_Freq_Resp_Annual_Report_03202015.pdf. See also* Table 3 at 6.

[60] Section I of ISO–NE's Operating Procedure No. 14—Technical Requirements for Generators, Demand Resources, Asset Related Demands and Alternative Technology Regulation Resources, *http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.*

[61] PJM Tariff, Attachment O § 8.0.

[62] PJM Manual 14D.

[63] *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097, at n.58 (2015).

[64] PJM Interconnection, L.L.C., Transmittal Letter, Docket No. ER15–1193–000, at 2 (filed Mar. 6, 2015).

[65] *Id.* at 11.

[66] Regulation service is different than primary frequency response because regulation resources respond to automatic generation control signals, which responds to Area Control Error. Regulation is centrally coordinated by the balancing authority. Primary frequency response, in contrast, is autonomous and is not centrally coordinated. Schedule 3 lumps these different services together, despite their differences. The Commission in Order No. 888 found that ''while the services provided by Regulation Service and Frequency Response Service

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Schedule 3 in the *pro forma* OATT in Order Nos. 888 [67] and 890 [68] permits jurisdictional transmission providers to outline their rates for this regulation and frequency response service through a filing under FPA section 205. Schedule 3 charges are cost-based rates paid by transmission customers to the transmission provider. Additionally, Order No. 784 made it possible for third-party sellers to offer Schedule 3 service to the transmission provider at a rate up to the published Schedule 3 rate, or at rates that result from an appropriate competitive solicitation.[69] Such third-party sales could involve any combination of regulation and primary frequency response services, including unbundled primary frequency response service by itself.

36. Finally, in Order No. 819, the Commission revised its regulations to foster competition in the sale of primary frequency response service.[70] In the final rule, the Commission approved the sale of primary frequency response service at market-based rates by entities that qualify for market-based rate authority for sales of energy and capacity to any willing buyer. Order No. 819 focused on how jurisdictional entities can qualify for market-based rates for primary frequency response service in the context of voluntary bilateral sales, and did not place any limits on the types of transactions available to procure primary frequency response service; they may be cost-based or market-based, bundled with other services or unbundled, and inside or outside of organized markets.[71] Order No. 819 did not require any entity to purchase primary frequency response from third parties or develop an organized market for primary frequency response.[72]

are different, they are complementary services that are made available using the same equipment. For this reason, we believe that Frequency Response Service and Regulation Service should not be offered separately, but should be offered as part of one service.'' Order No. 888, FERC Stats. & Regs. ¶ 31,036, at PP 212–213 (1996).

[67] Order No. 888, FERC Stats. & Regs. ¶ 31,036.

[68] Order No. 890, FERC Stats. & Regs. ¶ 31,241.

[69] *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies,* Order No. 784, FERC Stats. & Regs. ¶ 31,349, at PP 6–7 (2013), *order on clarification,* Order No. 784–A, 146 FERC ¶ 61,114 (2014).

[70] *Third-Party Provision of Primary Frequency Response Service,* Order No. 819, 153 FERC ¶ 61,220 (2015).

[71] *Id.* P 13.

[72] *Id.* P 37. The Commission denied Calpine Corporation's request for Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) to be given a deadline to develop tariff changes that would enable them to implement primary frequency response compensation mechanisms.

II. Request for Comments

37. The Commission seeks comment on the need for reforms to its rules and regulations regarding the provision and compensation of primary frequency response. Specifically, the Commission seeks comment on possible actions to ensure that the provision of primary frequency response continues to remain at levels adequate to maintain the reliability of the Bulk-Power System in light of the ongoing transformation of the nation's generation resource mix. The Commission understands that this transformation in the nation's generation portfolio could eventually result in a reduction of system inertia and fewer generation resources with primary frequency response capabilities. In addition, as discussed above, NERC has indicated that a significant number of generators within the Eastern Interconnection utilize dead bands or governor control settings that either inhibit or prevent the provision of primary frequency response. Together, these factors could result in potential downward shifts of the frequency nadir during disturbances, closer to UFLS set points that would trigger significant widespread outages.

38. Presently, there are no *pro forma* agreements for primary frequency response transactions. Voluntary sales of primary frequency response, would most likely involve negotiated, bilateral contracts between buyers and sellers. In this regard, considering their compliance obligations under Reliability Standard BAL–003–1, balancing authorities will be the most likely source of demand for voluntary purchases of primary frequency response service from third-party sellers, including those who have not provided the service in the past. Accordingly, as discussed further below, the Commission seeks comment on whether and to what extent balancing authority demand for voluntary purchases of frequency response would be reduced if all or all newly interconnecting resources were required to provide frequency response service. Further, we also seek comment on the impact this would have on the Commission's efforts under Order No. 819 to foster the development of a bilateral market for market-based rate sales of primary frequency response service as a means of cost-effectively meeting such demand.

39. Within RTO/ISO markets, no current stand-alone primary frequency response product exists. Any RTO/ISO that desires to explicitly procure and compensate primary frequency response would need new tariff provisions because no RTO/ISO currently defines or procures such a product. As discussed below, the Commission seeks comment on the need for and the nature of frequency response compensation within the context of current RTO/ISO market optimization processes.

40. Accordingly, the Commission seeks comment on the following possible actions, discussed in more detail below: (1) Modifications to the *pro forma* LGIA and SGIA mandating primary frequency response requirements for new resources, among other changes; (2) new primary frequency response requirements for existing resources; and (3) the requirement to provide and compensate for primary frequency response.

A. Modifications to the pro forma LGIA and SGIA

41. Reliability Standard BAL–003–1 and the *pro forma* LGIA and SGIA do not specifically address generators' provision of primary frequency response. Article 9.6.2.1 of the *pro forma* LGIA (Governors and Regulators) requires that if speed governors are installed, they should be operated in automatic mode.[73] Reliability Standard BAL–003–1 and the *pro forma* LGIA and SGIA do not explicitly: (1) Require generators to install the necessary capability to provide primary frequency response; (2) prescribe specific governor settings that would support the provision of primary frequency response; [74] or (3) establish generator primary frequency response performance requirements during disturbances (*e.g.,* require the response to be sustained, and not prematurely withdrawn prior to the initiation of secondary frequency response actions to return system frequency back to its nominal value and back within a generator's dead band setting).[75]

42. The Commission's *pro forma* generator interconnection agreements and procedures were developed at a time when traditional generating resources with standard governor controls and large rotational inertia were the predominant sources of electricity generation. However, circumstances are evolving, with NERC and others predicting significant

[73] Order No. 2003, FERC Stats. & Regs. ¶ 31,146, app. C (LGIA).

[74] Generator governors can be enabled or disabled which determines whether or not primary frequency response is provided at all by the generator. In addition, even if a governor is enabled, its control settings can limit the conditions under which the generator provides primary frequency response.

[75] Primary frequency response would not be expected to be provided if no capacity (or ''headroom'') is reserved on a unit.

retirements of conventional synchronous resources, all of which contribute to system inertia, and some of which provide primary frequency response. In addition, VERs are projected to comprise an increasing portion of the installed capacity in many regions of the country, but they do not typically provide inertial response or primary frequency response unless specifically configured to do so.

43. Regarding VERs, the Commission understands that in previous years, many non-synchronous resources were not consistently designed with primary frequency response capabilities. However, NERC and others have stated that VER manufacturers have made significant advancements in recent years to develop the necessary controls that would enable VERs to provide frequency response.[76] NERC recommends that the industry analyze how wind and solar photovoltaic resources can contribute to frequency response and to work toward interconnection requirements that ensure system operators will continue to maintain essential reliability services.[77] Also relevant are PJM's recent additions of new interconnection requirements for VERs entering its queue after May 2015.[78] PJM has stated that the necessary capabilities for non-synchronous resources to provide primary frequency response, among other services, are now ''baked in'' as enhancements to inverter capabilities.[79]

44. In light of the ongoing changes in the nation's resource mix as well as NERC's concerns regarding the primary frequency response performance of existing resources, the Commission seeks comment on whether and how to modify the *pro forma* LGIA and SGIA to require primary frequency response capability and performance of new generating resources.

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

1. Should the *pro forma* LGIA and SGIA be revised to include requirements for all newly interconnecting generating resources, including non-synchronous resources, to:

1.1. Install the capability necessary to provide primary frequency response?

1.2. Ensure that prime mover governors (or equivalent frequency control devices) are enabled and set pursuant to NERC's Primary Frequency Control Guideline (*i.e.,* droop characteristics not to exceed 5 percent, and dead band settings not to exceed ±0.036 Hz)?

1.3. Ensure that the MW response provided (when there is available headroom) in response to frequency deviations above or below the governor's dead band from 60 Hz is:

1.3.1. Sustained until system frequency returns to within the governor's dead band setting?

1.3.2. Provided without undue delay and responds in accordance with a specified droop parameter?

2. What are the costs associated with making a newly interconnecting generation resource capable of providing primary frequency response? Specifically, what are the pieces of equipment or software needed to provide primary frequency response, and what are the costs associated with those pieces of equipment or software? Are there significant differences between synchronous and non-synchronous resources in providing primary frequency response, (*e.g.,* the type of equipment necessary)?

3. Regarding question (1) above, are the governor control settings recommended by NERC's Primary Frequency Control Guideline the appropriate settings to include in the *pro forma* LGIA and SGIA? Why or why not?

4. Regarding new resources, including non-synchronous resources, are there physical, technical, or operational limitations/concerns to promptly providing sustained primary frequency response in the direction necessary to counteract under-frequency and over-frequency deviations? How should new requirements account for such limitations?

5. Are metrics or monitoring useful to evaluate whether new resources:

5.1. Operate with governors (or equivalent frequency control devices) enabled?

5.2. Set governor control settings as described in question (1) above?

5.3. Provide sustained MW response (when the unit has available headroom and system frequency deviates outside of the dead band) that is in the direction necessary to correct the frequency deviation and responsive in accordance with a specified droop parameter?

6. How would transmission providers verify that new resources provide adequate primary frequency response performance?

6.1. What information is necessary in order to facilitate performance verification?

6.2. What changes, if any, to existing infrastructure (including, but not limited to telemetry and software tools) would be required in order to verify primary frequency response performance?

6.3. What limitations based on resource type, if any, should be considered when evaluating primary frequency response performance?

7. How would transmission providers ensure compliance with the new rules?

7.1. Are penalties appropriate to ensure that new generating resources adhere to the new requirements described in question (1) above, and if so, how should such penalties be structured and implemented?

7.2. Are penalties appropriate only if a resource receives compensation for adhering to the new requirements described in question (1) above?

B. New Primary Frequency Response Requirements for Existing Resources

46. The Commission seeks comment on how it might address the issue of primary frequency response performance in existing generators. As discussed above, the Commission is considering amendments to the *pro forma* LGIA and SGIA that would apply prospectively and only to new generating resources and not the existing generating fleet. However, the Commission notes that NERC has also expressed concerns related to the primary frequency response performance of the existing generating fleet.

47. For example, in 2010, NERC conducted a governor response survey to gain insight into governor settings from several turbine governors across the three U.S. Interconnections.[80] Analysis revealed a wide disparity in the reported governor control settings. For example, NERC found that several generator owners or operators reported dead bands between 0.05 Hz and 0.3 Hz, which are wider than those prescribed by ERCOT'S BAL–001–TRE–01 Regional Standard or recommended by NERC's 2015 Generator Governor Frequency Response Industry Advisory [81] and Primary Frequency Control Guideline.[82]

48. In February 2015, NERC issued an Industry Advisory, which expressed its determination that a significant portion of generators within the Eastern Interconnection utilize governor dead bands or other control settings that

[76] NERC Long Term Reliability Assessment at 27 (November 2014), *http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf.*

[77] *Id.*

[78] *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097, at n.58 (2015).

[79] PJM Interconnection, L.L.C., Docket No. ER15–1193–000 (March 6, 2015) Transmittal Letter at 11.

[80] Frequency Response Initiative Report at 87.

[81] NERC Generator Governor Frequency Response Industry Advisory.

[82] NERC Primary Frequency Control Guideline Final Draft.

either inhibit or prevent the provision of primary frequency response.[83]

49. Furthermore, some generating units have controls that withdraw primary frequency response prior to the initiation of secondary frequency controls, which is a significant concern in the Eastern Interconnection and a somewhat smaller issue in the Western Interconnection. These controls are known as outer-loop controls to distinguish them from more direct, lower-level control of the generator operations. Primary frequency response withdrawal occurs when outer-loop controls deliberately act to nullify a generator's governor response and return the unit to operate at a pre-disturbance scheduled MW output. This is especially problematic when it occurs prior to the activation of secondary response, and has the potential to degrade the overall response of the Interconnection and result in a frequency that declines below the original nadir. NERC has observed that early withdrawal of primary frequency response continues to occur within the Eastern Interconnection.[84]

50. Furthermore, NERC's Resources Subcommittee has determined that the majority of gas turbines operate in some type of MW Set Point control mode.[85] According to the NERC Resources Subcommittee, the Eastern Interconnection Initiative has uncovered that in order for gas turbines to respond in MW Set Point control mode, an additional frequency algorithm has to be installed.[86] Moreover, NERC's Resources Subcommittee stated that ''the net result is that the gas turbine fleet that has been installed in the past 20+ years is not frequency responsive, [which] has to be corrected.'' [87] NERC has also observed that in many conventional steam plants, dead band settings exceed the maximum ±0.036 Hz dead band, and the resulting response is squelched and not sustained.[88]

51. As noted above, in December 2015, NERC's Operating Committee approved a Primary Frequency Control Guideline that contains recommended settings for generator governors and other plant control systems, and encourages generators within the three U.S. Interconnections to provide sustained and effective primary frequency response during major grid events in order to stabilize and maintain system frequency within allowable limits.[89] However, the Commission notes that NERC's Primary Frequency Control Guideline is not mandatory and enforceable and does not alter any approved Reliability Standards.

52. In light of the above discussion, the Commission seeks to further explore issues regarding the provision of primary frequency response by the existing generation fleet and seeks comment on the following questions:

1. Should the Commission implement primary frequency response requirements for existing resources, as discussed above for new generators? If so, what is an appropriate means of doing so (*e.g.,* changes to transmission provider tariffs or improvements to existing reliability standards)? How would transmission providers ensure that existing resources adhere to new primary frequency response requirements?

2. As noted above, some existing generating units set dead bands wider than those recommended by NERC's Primary Frequency Control Guideline, and some units have control settings set in a manner that results in the premature withdrawal of primary frequency response. Should the Commission prohibit these practices? If so, by what means?

3. What are the costs of retrofitting existing units, including non-synchronous resources, and with specific reference to such factors as equipment types and MW capacity, to be capable of providing sustained primary frequency response?

4. Regarding existing units, are there physical, technical, or operational limitations or concerns to promptly providing sustained primary frequency response in the direction necessary to counteract under-frequency and over-frequency deviations?

C. Requirement to Provide and Compensate for Primary Frequency Response Service

53. Without the explicit requirement to provide primary frequency response or appropriate compensation for the provision of such service, resource owners may choose to disable or otherwise reduce the provision of primary frequency response from their existing resources or not install the equipment on their new resources.[90]

54. The Commission seeks information on whether there is a need to establish or modify procurement and compensation mechanisms for primary frequency response, and whether these mechanisms will ensure that the resulting rates are just and reasonable. The Commission invites commenters to share their overall views, including the operational, technical and commercial impacts that may result from mandates to provide primary frequency response. To that end, the Commission seeks comment on the following questions:

1. Should all resources be required to provide minimum levels of: (1) Primary frequency response capability; and (2) primary frequency response performance in real-time?

1.1. ''Capability'' involves having a turbine governor or equivalent equipment that has the ability to sense changes in system frequency, and is enabled and set with appropriate governor settings (*e.g.,* droop and dead band), and assuming capacity (or ''headroom'') has been set aside, the physical ability to ramp the resource quickly enough in order to provide useful levels of primary frequency response to help arrest the frequency deviation.

1.2. ''Performance'' would involve putting the ''capability'' into actual service: *i.e.,* actually operating the resource with governors or equivalent equipment enabled, ensuring that governor controls (*e.g.,* droop and dead band) and other settings are properly set and coordinated, such that when capacity (or ''headroom'') has been set aside, the unit promptly provides sustained primary frequency response during frequency excursions, until system frequency returns to within the governor's dead band setting.

2. Is it necessary for every generating resource to install the capability necessary to provide primary frequency

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[83] NERC Generator Governor Frequency Response Industry Advisory.

[84] NERC 2015 Frequency Response Annual Analysis Report at vi (September 2015), *http://www.nerc.com/comm/OC/RS%20Landing%20Page%20DL/Related%20Files/2015_FRAA_Report_Final.pdf.*

[85] *See News from SERC's NERC Resources Subcommittee Rep—Primary Frequency Response* at 1 (May 2015), *https://www.serc1.org/docs/default-source/outreach/communications/resource-documents/serc-transmission-reference/201505---st/primary-frequency-response.pdf?sfvrsn=2.* MW set-point control mode automatically interrupts governor response in order for a generating unit to maintain a pre-disturbance dispatch.

[86] *Id.*

[87] *Id.*

[88] *See* NERC Generator Governor Frequency Response Advisory—Webinar Questions and Answers at 1 (April 2015), *http://www.nerc.com/pa/rrm/Webinars%20DL/Generator_Governor_Frequency_Response_Webinar_QandA_April_2015.pdf.*

[89] NERC Primary Frequency Control Guideline Final Draft.

[90] IEEE, *Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns* (May 2007) (citing *Cost of Providing Ancillary Services from Power Plants—Volume 1: A Primer,* EPRI TR–1 07270–V1, 4161, Final Report, March 1997), *http://resourcecenter.ieee-pes.org/pes/product/technical-reports/PESTR13.*

response? Or is it more appropriate for balancing authorities to identify and procure the amount of primary frequency response service that they need to meet their obligations under Reliability Standard BAL–003–1 and the optimum mix of resources to meet that need?

2.1. To the extent that balancing authorities are responsible for procuring adequate primary frequency response service, does the current framework for blackstart provide a useful guide for how primary frequency response service could be procured?

2.2. Does the Commission's recent rulemaking allowing third-party sales of frequency response services at market based rates allow balancing authorities to procure sufficient amounts of primary frequency response as required by BAL–003–1?

2.3. To the extent that balancing authorities centrally optimize primary frequency response, wherein an algorithm optimizes in the operating horizon the set of resources in which to allocate primary frequency response headroom: Should all newly interconnecting resources be required to install the necessary capability in these areas? Can balancing authorities predict far ahead of the operating horizon the least-cost set of resources from which it will optimize the provision of primary frequency response?

2.4. Would the costs of requiring all resources to have the capability to provide primary frequency response be significantly greater than the costs that would result from an Interconnection-wide or balancing authority-wide optimization of which generators should be capable of providing primary frequency response?

2.5. Would the costs of requiring all new resources to enable and set their governors, or equivalent equipment, to be able to provide primary frequency response in real-time be significantly greater than the costs that would result from an Interconnection-wide or balancing authority-wide optimization of which generators should provide primary frequency response in real-time?

2.6. Please discuss the viability of implementing an Interconnection-wide optimization mechanism.

2.7. Would requiring every resource to be capable of providing primary frequency response result in over-procurement or inefficient investment in primary frequency response capability to the detriment of customers?

2.8. Without rules to compel performance, how would balancing authorities ensure that the optimal set of resources chosen by an optimization algorithm actually enable governor controls with appropriate governor settings so that they provide sustained primary frequency response when capacity (or ''headroom'') has been reserved and frequency deviates outside of their dead band settings?

3. If generation resources were required to have minimum levels of primary frequency response capability or performance, should such resources be compensated for providing primary frequency response capability, performance, or both? If so, why? If not, why?

3.1. If payment is based on capacity (or ''headroom'') that is set aside for primary frequency response, how should such a capacity payment be structured and determined?

3.2. If payment is based on actual performance, either alone or in combination with a capacity-based payment, please discuss possible rate structures applicable to primary frequency response performance.

3.3. Will a market price provide resources with sufficient incentive to invest in primary frequency response capability and make the service available to the balancing authority in real-time, absent a requirement that resources maintain the capability to provide primary frequency response and perform as required?

4. Currently, how do RTOs/ISOs ensure that they have the appropriate amount of primary frequency response capability during operations?

4.1. Are resources contracted for primary frequency response outside of the market optimization and dispatch?

4.2. Alternatively, does the market optimization and dispatch incorporate primary frequency response in its optimization?

5. Would it be appropriate for RTOs/ISOs to create a product for primary frequency response service?

5.1. Should this product be similar to a capacity product for the procurement of primary frequency response capability from resources?

5.2. Should this product be similar to other ancillary service products in which certain resources would be selected in the day-ahead or real-time markets to provide primary frequency response?

5.3. Are there benefits to co-optimizing the capacity (or ''headroom'') allocated on generating units for primary frequency response with the market optimization and dispatch of RTOs/ISOs? If so, what are the challenges associated with doing so?

6. Are there benefits to separating Frequency Response Service under Schedule 3 and creating a separate ancillary service covering each individually? If so, how should a new *pro forma* Primary Frequency Response Ancillary Service be structured?

7. When compensating for primary frequency response, should compensation be different inside and outside of RTOs/ISOs?

8. What procurement requirements or compensation mechanisms could be used for primary frequency response from stored energy resources? When considering requirements or compensation for stored energy resources, how should possible additional costs or other concerns be addressed?

III. Comment Procedures

55. The Commission invites interested persons to submit comments, and other information on the matters, issues and specific questions identified in this notice. Comments are due April 25, 2016. Comments must refer to Docket No. RM16–6–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

56. 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.

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

58. 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.

IV. Document Availability

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

time) at 888 First Street NE., Room 2A, Washington, DC 20426.

60. 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.

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

By direction of the Commission.

Issued: February 18, 2016.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. RM11–6–000]

Billing Procedures for Annual Charges for Recompensing the United States for the Use, Occupancy, and Enjoyment of Federal Lands; Notice of Statement of Annual Charges for the Use of Government Lands for Fiscal Year 2016

By this notice, the Commission states that in accordance to the Final Rule issued on January 17, 2013 [1] the federal lands fee schedule of per-acre rates have been calculated for Fiscal Years (FY) 2016 through 2020. Pursuant to the Final Rule, the Commission re-calculates the federal lands fee schedule every five years by using the per-acre land values published in the National Agricultural Statistics Service (NASS) Census. The Commission established the FY 2016 through FY 2020 federal lands fee schedule based on data published in the 2012 NASS Census. In addition, the Commission determines a state-specific reduction that removes the value of irrigated lands on a state-by-state basis, plus a seven percent reduction to remove the value of buildings. An encumbrance factor of 50 percent along with a rate of return of 5.77 percent are calculated with the per-acre land values less the state-specific reduction to derive at the individual state/county per-acre federal land rates assessed to hydropower projects.

The FY 2016 federal lands fee schedule rates have significantly increased in comparison to the FY 2015 federal lands fee schedule rates issued on January 8, 2015 for a number of hydropower projects located in multiple states/counties. In particular, hydropower projects located in the Kenai Peninsula Area of Alaska land rates increased by 71 percent in comparison to land rates assessed in FY 2015. The FY 2016 increase of per-acre land rates was mainly attributed to the increase of per-acre land and building values published in the 2012 NASS Census. The per-acre land value for land in the Kenai Peninsula Area was increased from $1,328 in the 2007 NASS Census to $2,423 in the 2012 NASS Census. This increase along with factoring in the state-specific reduction, the 50 percent encumbrance factor, and the 5.77 percent rate of return ultimately resulted in a 71 percent increase of per-acre land rates assessed to hydropower projects located in the Kenai Peninsula Area. In addition, per-acre land values for San Bernardino County located in California, Boulder and Clear Creek Counties located in Colorado, and Blaine County located in Idaho all significantly increased as a result of the 2012 published NASS Census.

Conversely, the FY 2016 federal lands fee schedule rates have significantly decreased in comparison to the FY 2015 federal lands fee schedule rates issued on January 8, 2015 for a number of hydropower projects located in other locations as a result of the decreased per-acre land values published in the 2012 NASS Census. Specifically hydropower projects occupying federal lands in Alpine, Lake, and Riverside Counties located in California, Aleutian Islands Area located in Alaska, and Grays Harbor County located in Washington will receive as much as a 37 percent decrease in comparison to the federal lands annual charges issued in FY 2015.

If you have any questions regarding this notice, please contact Steven Bromberek at (202) 502–8001 or Norman Richardson at (202) 502–6219.

Dated: February 18, 2016.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

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[1] *Annual Charges for Use of Government Lands, Final Rule,* Order No. 774, 78 FR 5256 (January 25, 2013), 142 FERC Stats & Regs. ¶ 61,045 (2013).

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice Revising Post-Technical Conference Comment Schedule

	Docket Nos.
PJM Interconnection, L.L.C ...	ER15–2562–000, ER15–2563–000.
Consolidated Edison Company of New York, Inc. v. PJM Interconnection, L.L.C.	EL15–18–001.
Linden VFT, LLC v. PJM Interconnection, L.L.C.	EL15–67–000.
Delaware Public Service Commission and Maryland Public Service Commission v. PJM Interconnection, L.L.C.	EL15–95–000.
PJM Interconnection, L.L.C ...	ER14–972–003.
PJM Interconnection, L.L.C ...	ER14–1485–005, Not Consolidated.

In an order dated November 24, 2015,[1] the Commission found that the assignment of cost allocation for the projects in the filings and complaints listed in the caption using PJM's solution-based distribution factor (DFAX) cost allocation method had not been shown to be just and reasonable and may be unjust, unreasonable, or unduly discriminatory or preferential. The Commission directed its staff to establish a technical conference to explore both whether there is a definable category of reliability projects within PJM for which the solution-based DFAX cost allocation method may not be just and reasonable, such as projects addressing reliability violations that are not related to flow on the planned transmission facility, and whether an alternative just and reasonable *ex ante* cost allocation method could be established for any such category of projects.

The technical conference was held on January 12, 2016. At the technical conference, staff indicated that it would establish a schedule for post-technical conference comments after reviewing the technical conference transcript. On February 9, 2016 a technical conference transcript was place in the above-referenced dockets, and a post-technical conference comment schedule was established. On February 18, 2016, an errata transcript of the February 9, 2016 transcript was placed in the dockets. The schedule for post-technical conference comments is revised accordingly.

Post-technical conference comments, not to exceed 20 pages, are due on or before March 9, 2016.

[1] *PJM Interconnection, L.L.C., et al.*, 153 FERC ¶ 61,245 (2015).