DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM16–6–000; Order No. 842]

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

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final action.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is modifying the *pro forma* Large Generator Interconnection Agreement (LGIA) and *pro forma* Small Generator Interconnection Agreement (SGIA) to require newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. These changes are designed to address the potential reliability impact of the evolving generation resource mix, and to ensure that the relevant provisions of the *pro forma* LGIA and *pro forma* SGIA are just, reasonable, and not unduly discriminatory or preferential.

DATES: This final action will become effective May 15, 2018.

FOR FURTHER INFORMATION CONTACT:

Jomo Richardson (Technical Information), Office of Electric Reliability, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–6281, *Jomo.Richardson@ferc.gov.*

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

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United States of America

Federal Energy Regulatory Commission

Before Commissioners: Kevin J. McIntyre, Chairman; Cheryl A. LaFleur, Neil Chatterjee, Robert F. Powelson, and Richard Glick.

Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response—Docket No. RM16–6–000

Order No. 842

Final Action

(Issued February 15, 2018)

1. In this final action, the Commission modifies the *pro forma* Large Generator Interconnection Agreement (LGIA) and the *pro forma* Small Generator Interconnection Agreement (SGIA), pursuant to its authority under section 206 of the Federal Power Act (FPA), to ensure that rates, terms and conditions of jurisdictional service remain just and reasonable and not unduly discriminatory or preferential.[1] The modifications require new large and small generating facilities, including both synchronous and non-synchronous, interconnecting through a LGIA or SGIA to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. The Commission also establishes certain uniform minimum operating requirements in the *pro forma* LGIA and *pro forma* SGIA, including maximum droop and deadband parameters and provisions for timely and sustained response.

2. These requirements apply to newly interconnecting generation facilities that execute, or request the unexecuted filing of, an LGIA or SGIA on or after the effective date of this final action. These requirements also apply to existing large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of this final action. These requirements do not apply to existing generating facilities,[2] a subset of combined heat and power (CHP) facilities, or generating facilities regulated by the Nuclear Regulatory Commission (NRC). In addition, the Commission does not impose a headroom requirement for new generating facilities, and does not mandate that new generating facilities receive compensation for complying with the primary frequency response requirements.

3. The modifications address the Commission's concerns that the existing *pro forma* LGIA contains limited primary frequency response requirements that apply only to synchronous generating facilities and do not account for recent technological advancements that now enable new non-synchronous generating facilities to have primary frequency response capabilities. Further, the Commission believes that it is unduly discriminatory or preferential to impose primary frequency response requirements only on new large generating facilities but not on new small generating facilities. The reforms adopted here impose comparable primary frequency response requirements on both new large and small generating facilities.

I. Background

A. Frequency Response

4. Reliable operation of an Interconnection[3] depends on maintaining frequency within predetermined boundaries above and below a scheduled value, which is 60 Hertz (Hz) in North America. Changes in frequency are caused by changes in the balance between load and generation, such as the sudden loss of a large generator or a large amount of load. If frequency deviates too far above or below its scheduled value, it could potentially result in under frequency load shedding (UFLS), generation tripping, or cascading outages.[4]

5. Mitigation of frequency deviations after the sudden loss of generation or load is driven by three primary factors: inertial response, primary frequency response, and secondary frequency response.[5] Primary frequency response actions begin within seconds after system frequency changes and are 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.[6] Primary frequency response actions are intended to arrest abnormal frequency deviations and ensure that

[1] 16 U.S.C. 824e.

[2] As discussed below in Section II.G, we will not impose primary frequency response requirements on existing generating facilities that do not submit new interconnection requests that result in an executed or unexecuted interconnection agreement at this time.

[3] An Interconnection is a geographic area in which the operation of the electric system is synchronized. In the continental United States, there are three Interconnections, namely, the Eastern, Texas, and Western Interconnections.

[4] UFLS is designed to be activated 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. *See Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards,* Notice of Proposed Rulemaking, 76 FR 66220 (Oct. 26, 2011), FERC Stats. & Regs. ¶ 32,682, at PP 4–10 (2011).

[5] In the Notice of Inquiry issued in Docket No. RM16–6–000 on February 8, 2016, the Commission provided detailed discussion of how inertia, primary frequency response, and secondary frequency response interact to mitigate frequency deviations. *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response,* 154 FERC ¶ 61,117, at PP 3–7 (2016) (NOI). *See also Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation,* Lawrence Berkeley National Laboratory, at 13–14 (Dec. 2010), *http://energy.lbl.gov/ea/certs/pdf/lbnl-4142e.pdf* (LBNL 2010 Report).

[6] NOI, 154 FERC ¶ 61,117 at P 6. The Commission also noted that regulation service is different than primary frequency response because generating facilities that provide regulation respond to automatic generation control signals and regulation service is centrally coordinated by the system operator, whereas primary frequency response service, in contrast, is autonomous and is not centrally coordinated. Schedule 3 of the *pro forma* Open Access Transmission Tariff (OATT) bundles these different services together. *See id.* n.66.

system frequency remains within acceptable bounds. An important goal for system planners and operators is for the frequency nadir,[7] during large disturbances, to remain above the first stage of UFLS set points within an Interconnection.

6. Frequency response is a measure of an Interconnection's ability to arrest and stabilize frequency deviations following the sudden loss of generation or load, and is affected by the collective responses of generation and load throughout the Interconnection. When considered in aggregate, the primary frequency response provided by generators within an Interconnection has a significant impact on the overall frequency response. Reliability Standard BAL–003–1.1 defines the amount of frequency response needed from balancing authorities [8] to maintain Interconnection frequency within predefined bounds and includes requirements for the measurement and provision of frequency response.[9] While Reliability Standard BAL–003–1.1 establishes requirements for balancing authorities, it does not include any requirements applicable to individual generator owners or operators.[10]

7. Unless otherwise required by tariffs or interconnection agreements, generator owners and operators can independently decide whether to configure their generating facilities to provide primary frequency response.[11] The magnitude and duration of a generating facility's response to frequency deviations is generally determined by the settings of the facility's governor [12] (or equivalent controls) and other plant-level (*e.g.,* ''outer-loop'') control systems.[13] In particular, the governor's droop and deadband settings have a significant impact on the unit's provision of primary frequency response. In addition, plant-level controls, unless properly configured, can override or nullify a generator's governor response and return the unit to operate at a scheduled pre-disturbance megawatt set-point.[14] In 2010, NERC conducted a survey of generator owners and operators and found that only approximately 30 percent of generating facilities in the Eastern Interconnection provided primary frequency response, and that only approximately 10 percent of generating facilities provided sustained primary frequency response.[15] This suggests that many generating facilities within the Eastern Interconnection disable or otherwise set their governors or plant-level controls such that they provide little to no primary frequency response.[16]

8. Declining frequency response performance has been an industry concern for many years. NERC, in conjunction with the Electric Power Research Institute (EPRI), initiated its first examination of declining frequency response and governor response in 1991.[17] More recently, as noted in the NOI, while the three U.S. Interconnections currently exhibit adequate frequency response performance above their Interconnection Frequency Response Obligations,[18] there has been a decline in the frequency response performance of the Western and Eastern Interconnections from historic values.[19]

B. Prior Commission Actions

9. In Order Nos. 2003 [20] and 2006,[21] the Commission adopted standard procedures for the interconnection of large and small generating facilities, including the development of standardized *pro forma* generator interconnection agreements and procedures. The Commission required public utility transmission providers [22] to file revised OATTs containing these standardized provisions, and use the LGIA and SGIA to provide non-discriminatory interconnection service to Large Generators (*i.e.,* generating facilities having a capacity of more than 20 MW) and Small Generators (*i.e.,* generators having a capacity of no more than 20 MW). The *pro forma* LGIA and *pro forma* SGIA have since been revised through various subsequent proceedings.[23]

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

[8] NERC's 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.'' NERC's Glossary of Terms is available at: *http://www.nerc.com/files/glossary_of_terms.pdf.*

[9] *Frequency Response and Frequency Bias Setting Reliability Standard,* Order No. 794, 146 FERC ¶ 61,024 (2014).

[10] The Commission has also accepted Regional Reliability Standard BAL–001–TRE–01 (Primary Frequency Response in the ERCOT Region) as mandatory and enforceable, which does establish requirements for generator owners and operators with respect to governor control settings and the provision of primary frequency response within the Electric Reliability Council of Texas (ERCOT) region. *North American Electric Reliability Corporation,* 146 FERC ¶ 61,025 (2014).

[11] *See* NOI, 154 FERC ¶ 61,117 at PP 18–19.

[12] A governor is an electronic or mechanical device that implements primary frequency response on a generating facility via a droop parameter. Droop refers to the variation in real power (MW) output due to variations in system frequency and is typically expressed as a percentage (*e.g.,* 5 percent droop). Droop reflects the amount of frequency change from nominal (*e.g.,* 5 percent of 60 Hz is 3 Hz) that is necessary to cause the main prime mover control mechanism of a generating facility to move from fully closed to fully open. A governor also has a deadband parameter which represents a minimum frequency deviation (*e.g.,* ±0.036 Hz) from nominal system frequency (*i.e.,* 60 Hz in North America) that must be exceeded in order for the generating facility to provide primary frequency response.

[13] These controls are known as plant-level or outer-loop controls to distinguish them from more direct, lower-level control of the generator operations.

[14] For more discussion on ''premature withdrawal'' of primary frequency response, *see* NOI, 154 FERC ¶ 61,117 at PP 49–50.

[15] *See* NERC, *Frequency Response Initiative Report: The Reliability Role of Frequency Response* (Oct. 2012), *http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf* (NERC Frequency Response Initiative Report) at 95. For the purposes of this final action, as indicated below in the revised *pro forma* language in Section K, sustained response refers to a generating facility responding to an abnormal frequency deviation outside of the deadband parameter, and holding (*i.e.,* not prematurely withdrawing) the response until system frequency returns to a value that is within the deadband.

[16] However, as noted below, some commenters note that nuclear generating facilities are restricted by their NRC operating licenses regarding the provision of primary frequency response.

[17] NERC Frequency Response Initiative Report at 22.

[18] The Interconnection Frequency Response Obligations are established by NERC and are designed to require sufficient frequency response for each Interconnection (*i.e.,* the Eastern, ERCOT, Quebec, and Western Interconnections) to arrest frequency declines even for severe, but possible, contingencies.

[19] NOI, 154 FERC ¶ 61,117 at P 20.

[20] *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), *cert. denied,* 552 U.S. 1230 (2008).

[21] *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).

[22] A public utility is a utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce, as defined by the FPA. *See* 16 U.S.C. 824(e) (2012). A non-public utility that seeks voluntary compliance with the reciprocity condition of an OATT may satisfy that condition by filing an OATT, which includes a LGIA and SGIA. *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 840–845.

[23] *E.g., Small Generator Interconnection Agreements and Procedures,* Order No. 792, 145 FERC ¶ 61,159 (2013), *clarifying,* Order No. 792–A, 146 FERC ¶ 61,214 (2014); *Reactive Power Requirements for Non-Synchronous Generation,* Order No. 827, FERC Stats. & Regs. ¶ 31,385 (2016) (cross-referenced at 155 FERC ¶ 61,277) (2016); *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities,* Order No. 828, 156 FERC ¶ 61,062 (2016).

C. Notice of Inquiry

10. On February 18, 2016, the Commission issued the NOI to explore issues regarding essential reliability services and the evolving Bulk-Power System.[24] In particular, the Commission asked a broad range of questions on the need for reform of its requirements regarding the provision of and compensation for primary frequency response. The Commission explained that there is a significant risk that, as conventional synchronous generating facilities retire or are displaced by increased numbers of variable energy resources (VERs),[25] which typically do not contribute to system inertia[26] or have primary frequency response capabilities, the net amount of frequency responsive generation online will be reduced.[27]

11. In the NOI, the Commission also explained that these developments and their potential impacts could challenge system operators in maintaining system frequency within acceptable bounds following system disturbances.[28] Further, the Commission explained that Reliability Standard BAL–003–1.1 and the *pro forma* LGIA and *pro forma* SGIA do not specifically address a generator's ability to provide frequency response.[29] The Commission noted, however, that while in previous years many non-synchronous generating facilities[30] were not designed with primary frequency response capabilities, the technology now exists for new non-synchronous generating facilities to install primary frequency response capability.[31]

12. Accordingly, the Commission requested comments on three main sets of issues. First, the Commission sought comment on whether amendments to the *pro forma* LGIA and *pro forma* SGIA are warranted to require all new generating facilities, both synchronous and non-synchronous, to have primary frequency response capabilities as a precondition of interconnection.[32] Second, the Commission sought comment on the performance of existing generating facilities and whether primary frequency response requirements for these facilities are warranted.[33] Finally, the Commission sought comment on compensation for primary frequency response.[34]

D. Notice of Proposed Rulemaking

13. On November 17, 2016, the Commission issued a Notice of Proposed Rulemaking that proposed to revise the *pro forma* LGIA and the *pro forma* SGIA to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection.[35] The Commission also proposed to establish certain operating requirements in the *pro forma* LGIA and *pro forma* SGIA, including maximum droop and deadband parameters, and provisions for timely and sustained response.

14. The Commission sought comment on the proposed: (1) Requirements for new large and small generating facilities to install, maintain, and operate a governor or equivalent controls; (2) requirements for droop and deadband settings of 5 percent and ±0.036 Hz, respectively; (3) requirements for timely and sustained response, and in particular whether the proposed requirements will be sufficient to prevent plant-level controls from inhibiting primary frequency response; (4) requirement for droop parameters to be based on nameplate capability with a linear operating range of 59 to 61 Hz; and (5) exemptions for new nuclear units. The Commission also sought comment on its proposal to not impose a generic headroom requirement or mandate compensation related to the proposed reforms.

15. Twenty-eight entities submitted comments in response to the NOPR and are listed in Appendix A to this final action.

E. Notice of Request for Supplemental Comments

16. On August 18, 2017, the Commission issued a Notice of Request for Supplemental Comments (Supplemental Notice) to augment the record on the potential impacts of the NOPR proposals on electric storage resources[36] and small generating facilities.[37] In particular, the Commission stated that the NOPR did not contain any special consideration or provisions for electric storage resources, and that some commenters raised concerns that, by failing to address electric storage resources' unique technical attributes, the proposed requirements could pose an unduly discriminatory burden on electric storage resources.[38] In response to commenters' concerns, the Commission asked several questions to augment the record on possible impacts to electric storage facilities.[39]

17. In addition, the Commission stated that the NOPR proposed that small generating facilities be subject to new primary frequency response requirements in the *pro forma* SGIA, and that some commenters raised concerns that small generating facilities could face disproportionate costs to install primary frequency response capability,[40] while other commenters requested that the Commission consider adopting a size limitation.[41] In response to commenters' concerns, the Commission asked several questions to augment the record on small generating facilities.[42]

18. Twenty entities submitted comments in response to the notice of

[24] NOI, 81 FR 9182 (Feb. 24, 2016), 154 FERC ¶ 61,117.

[25] The term VER is defined as a device for the production of electricity that is characterized by an energy source that: (1) Is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. *See, e.g., Integration of Variable Energy Resources,* Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 210, *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).

[26] 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. *See* NOI, 154 FERC ¶ 61,117 at PP 3–7 for a more detailed discussion of how inertia, primary frequency response, and secondary frequency response interact to mitigate frequency deviations.

[27] NOI, 154 FERC ¶ 61,117 at P 12.

[28] *Id.* P 14.

[29] *Id.* P 41.

[30] Non-synchronous generating facilities are "connected to the bulk power system through power electronics, but do not produce power at system frequency (60 Hz)." They "do not operate in the same way as traditional generators and respond differently to network disturbances." *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097, at P 1 n.3 (2015) (citing *Interconnection for Wind Energy,* Order No. 661, FERC Stats. & Regs. ¶ 31,198, at P 3 n.4 (2005)). Wind and solar photovoltaic generating facilities as well as electric storage resources are examples of non-synchronous generating facilities.

[31] NOI, 154 FERC ¶ 61,117 at P 43.

[32] *Id.* PP 2 and 44–45.

[33] *Id.* PP 2, 46, and 52.

[34] *Id.* PP 2, 53–54.

[35] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response,* Notice of Proposed Rulemaking, 81 FR 85176 (Nov. 25, 2016), 157 FERC ¶ 61,122 (2016) (NOPR).

[36] For the purposes of this final action, we define an electric storage resource as a resource capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid. This definition is also used in a concurrently-issued Final Rule, published elsewhere in this issue of the **Federal Register**, concerning electric storage resources entitled *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* 162 FERC ¶ 61,127 (2018).

[37] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response,* Notice of Request for Supplemental Comments, 82 FR 40081 (Aug. 24, 2017), 160 FERC ¶ 61,011 (2017).

[38] *Id.* P 4.

[39] *Id.* P 6.

[40] *Id.* P 8.

[41] *Id.* P 9.

[42] *Id.* P 10.

request for supplemental comments and are listed in Appendix B to this final action.

II. Discussion

19. For the reasons discussed below, the Commission adopts the NOPR proposal and will require newly interconnecting large and small generating facilities that interconnect pursuant to the *pro forma* LGIA or *pro forma* SGIA, to install, maintain, and operate a functioning governor or equivalent controls capable of providing primary frequency response. The reforms adopted here build upon Order Nos. 2003 and 2006 by accounting for the effect upon primary frequency response from the ongoing changes to the nation's generation resource mix, including significant retirements of conventional generating facilities and an increasing proportion of VERs interconnecting to the Bulk-Power System.[43] Another important consideration is that the frequency response performance of the Eastern and Western Interconnections, while currently adequate, has significantly declined from historic values.[44] NERC has found that ''increasing levels of non-synchronous resources installed without controls that enable frequency response capability, coupled with retirement of conventional generating facilities that have traditionally provided primary frequency response, have contributed to the decline in primary frequency response.'' [45] Finally, the record in this proceeding indicates that VER equipment manufacturers have made significant technological advancements in developing primary frequency response capability for VERs, and that the costs of this capability have declined over time.[46] For all of these reasons, we find that the *pro forma* LGIA and *pro forma* SGIA are no longer just and reasonable, and are unduly discriminatory or preferential, and thus need to be revised to ensure that all newly interconnecting large and small generating facilities have primary frequency response capability as a condition of interconnection.[47]

20. We find that the current requirements for governor controls in the *pro forma* LGIA do not reflect NERC's currently recommended operating practices or recent advances in technology for non-synchronous generating facilities, as discussed below.

21. First, Article 9.6.2.1 of the *pro forma* LGIA does not address the settings of governors or equivalent controls (*i.e.,* deadband and droop), nor does Article 9.6.2.1 address plant-level controls, which if not properly coordinated on a generating facility, can lead to the premature withdrawal of primary frequency response during disturbances. Furthermore, the substantial body of knowledge regarding the operation of generator governors and plant control systems amassed by NERC and industry stakeholders since the *pro forma* LGIA was promulgated under Order No. 2003 raises concerns that Article 9.6.2.1 of the *pro forma* LGIA allows too much discretion for generator owners and operators. For example, in 2012, NERC found that a number of generators implemented deadband settings that were so wide as to effectively disable themselves from providing primary frequency response, and also that many generators provide frequency response in the wrong direction during a disturbance.[48] In addition, in 2015, NERC observed that: (1) For many conventional steam plants, deadband settings exceeded ±0.036 Hz; (2) several generating facilities failed to sustain primary frequency response; and (3) the vast majority of the gas turbine fleet was not frequency responsive.[49]

22. Second, existing Article 9.6.2.1 of the *pro forma* LGIA states that ''speed governors,'' if installed, must be operated in automatic mode. However, instead of utilizing traditional speed governors to implement primary frequency response capability, many new non-synchronous generating facilities interconnecting to the grid, such as wind, solar, and electric storage resources, utilize enhanced inverters and other plant control technology that can be designed to include primary frequency response capability.[50] We find that due to these recent technological advancements that allow new large non-synchronous generating facilities to install primary frequency response capability at low cost, as well as the expected overall increase of the proportion of the resource mix that are non-synchronous generating facilities, it is unduly discriminatory and preferential to only require synchronous generators to provide primary frequency response. The references to ''speed governors'' in existing Article 9.6.2.1 of the *pro forma* LGIA, which are only applicable to large synchronous generating facilities, are outdated and should be expanded to include both synchronous and non-synchronous generators.

23. Investigation by various NERC task forces and subcommittees has led to a voluntary NERC Primary Frequency Control Guideline that includes recommended droop and deadband settings for generating facilities within all three U.S. Interconnections.[51] However, as noted in the NOPR, the *pro forma* LGIA and *pro forma* SGIA do not currently reflect these updated recommended practices by NERC for governor and plant control system settings of generating facilities.[52]

24. We also find that revisions to the *pro forma* LGIA and *pro forma* SGIA are necessary to provide for the continued reliable operation of the Bulk-Power System by addressing the potential adverse impacts on primary frequency response of the nation's evolving generation resource mix described in the NOI.[53] As noted in the NOPR,

[43] Section 215(a)(1) of the 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 (cross-referenced at 118 FERC ¶ 61,218), *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[44] *See* NOPR, 157 FERC ¶ 61,122 at P 36 (citing NERC Frequency Response Initiative Industry Advisory—Generator Governor Frequency Response, at slide 10 (Apr. 2015), *http://www.nerc.com/pa/rrm/Webinars%20DL/Generator_Governor_Frequency_Response_Webinar_April_2015.pdf. See also* NERC Frequency Response Initiative Report at 22, and LBNL 2010 Report at xiv–xv).

[45] NERC Comments at 5. NERC's Essential Reliability Services Task Force has determined that primary frequency response is an ''essential reliability service.'' 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 (Apr. 2014), *http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Scope_ERSTF_Final.pdf.*

[46] NOPR, 157 FERC ¶ 61,122 at PP 28, 36.

[47] 16 U.S.C. 824e. The Commission routinely evaluates the effectiveness of its regulations and policies in light of changing industry conditions to determine if changes in these conditions and policies are necessary. *See, e.g.,* Order No. 764, FERC Stats. & Regs. ¶ 31,331.

[48] NERC Frequency Response Initiative Report at 92, 96–97.

[49] NOI, 154 FERC ¶ 61,117 at P 50 (citing 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.).*

[50] *See* Electric Power Research Institute, *Recommended Settings for Voltage and Frequency Ride-Through of Distributed Energy Resources* at 27(May 2015), *http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006203. See also* National Renewable Energy Labs (NREL), *Advanced Grid-Friendly Controls Demonstration Project for Utility-Scale PV Power Plants,* at 1–2 (Jan. 2016), *http://www.nrel.gov/docs/fy16osti/65368.pdf.*

[51] *See* NERC's Primary Frequency Control Guideline.

[52] NOPR, 157 FERC ¶ 61,122 at P 39.

[53] NOI, 154 FERC ¶ 61,117 at PP 13–17 (citing to the Essential Reliability Services Task Force Measures Report at iv).

NERC's Essential Reliability Services Task Force concluded that primary frequency response capability should be required of all new generating facilities.[54] However, the *pro forma* LGIA and the *pro forma* SGIA do not currently require generating facilities to install such capability.

25. Further, the limited references to primary frequency response in the Commission's requirements apply only to large generating facilities. Based on the absence of a technical or economic basis for the different requirements imposed on small and large generating facilities, and the significant technological advancements that manufacturers have made in developing primary frequency response capability for VERs, we find that the absence of any similar provisions in the current *pro forma* SGIA is unduly discriminatory or preferential.

26. The Commission has previously acted under FPA section 206 to remove inconsistencies between the *pro forma* LGIA and *pro forma* SGIA when there is no economic or technical basis for treating large and small generating facilities differently.[55] As discussed more fully below in Section II.H.7, the record developed in this proceeding indicates that small generating facilities are capable of installing and enabling governors or equivalent controls at a low cost and in a manner comparable to large generating facilities.[56] Given these low-cost technological advances, we do not anticipate that these additional requirements added to the *pro forma* SGIA will present a barrier to entry for small generating facilities. Thus, in light of the need for additional primary frequency response capability and an increasingly large market penetration of small generating facilities, we believe that there is a need to add these requirements to the *pro forma* SGIA to help ensure adequate primary frequency response capability.

27. Accordingly, we find that revising the *pro forma* LGIA and *pro forma* SGIA to require all new generating facilities to install, maintain, and operate a functioning governor or equivalent controls, consistent with the exceptions and operating requirements described below, is just and reasonable. Doing so will help to ensure adequate primary frequency response capability as the generation resource mix continues to evolve, ensure fair and consistent treatment for all types of generating facilities, help balancing authorities meet their frequency response obligations pursuant to Reliability Standard BAL–003–1.1, and help improve reliability, particularly during system restoration and islanding situations.[57]

A. Requirement To Install, Maintain, and Operate Equipment Capable of Providing Primary Frequency Response

1. NOPR Proposal

28. In the NOPR, the Commission proposed to revise the *pro forma* LGIA and *pro forma* SGIA to include requirements for new large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection.[58] In particular, the Commission explained that the proposed revisions would require new large and small generating facilities to install, maintain, and operate a functioning governor or equivalent controls, which the Commission proposed to define as the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the generating facility's real power output in accordance with the proposed maximum droop and deadband parameters and in the direction needed to correct frequency deviations.[59]

2. Comments

29. The proposed requirement for new generating facilities to install the necessary equipment for primary frequency response capability as a condition of interconnection received broad support from commenters.[60] For example, APPA et al. state that requiring newly interconnecting generating facilities to install governors or equivalent control devices is a relatively low-cost way to prevent the erosion of the Interconnections' collective frequency response capability as the generation resource mix evolves.[61] APPA et al. state that primary frequency response capability should be a standard feature and part of the ''rules of the road'' for all new generating facilities, similar to how all new cars come equipped with anti-lock brakes.[62] Bonneville asserts that the trend of declining frequency response capability will continue with a changing generation resource mix (namely, the integration of large amounts of VERs), unless provisions are put in place to ensure that adequate primary frequency response capability is available in the future.[63] As a result, Bonneville believes that it is necessary to require newly interconnecting generating facilities to have primary frequency response capability.[64] EEI states that now that the technology is available and economical for non-synchronous generation facilities, it supports the proposed requirement for these facilities to install the equipment needed to provide primary frequency response.[65]

30. NERC states that it has determined that increasing levels of non-synchronous generating facilities installed without controls that enable frequency response capability, coupled with retirement of conventional generating facilities that have traditionally provided primary frequency response, has contributed to the decline in primary frequency response.[66] NERC further states that a changing generation resource mix will further alter the dispatch of generating facilities, potentially resulting in operating conditions where frequency response capability could be diminished unless a sufficient amount of frequency responsive capacity is included in the dispatch.[67] NERC asserts that the NOPR's proposed revisions would apply measurable, clear requirements to newly interconnecting synchronous and non-synchronous generating facilities.[68] Tri-State comments that primary frequency response requirements for all generating facilities are necessary to address the

[54] NOPR, 157 FERC ¶ 61,122 at P 15.

[55] *See* Order No. 828, 156 FERC ¶ 61,062 (revising the *pro forma* SGIA such that small generating facilities have frequency and voltage ride through requirements comparable to large generating facilities).

[56] *See, e.g.,* IEEE–P1547 Working Group NOI Comments at 1, 5, and 7; ISO–RTO Council Supplemental Comments at 7; SoCal Edison Supplemental Comments at 3; WIRAB Supplemental Comments at 7. Moreover, the Commission notes that other commenters stated costs of installing primary frequency response capability are generally low, but did not differentiate between small and large generating facilities. *See, e.g.,* APPA, *et al.* Comments at 6; California Cities Comments at 2; EEI Comments at 13; Indicated ISOs/RTOs Comments at 3–5; SoCal Edison Comments at 2.

[57] NOPR, 157 FERC ¶ 61,122 at P 43.

[58] *Id.* P 44.

[59] *Id.* P 47.

[60] APPA et al., Bonneville, California Cities, EEI, ESA, Competitive Suppliers, First Solar, Idaho Power (for generating facilities larger than 10 MW), ISO–RTO Council, MISO TOs, NERC, PG&E, SoCal Edison, SVP, Tri-State, Xcel, and WIRAB support the requirement for new generating facilities to install governors or equivalent controls. In addition, AWEA states that it does not oppose a primary frequency response capability requirement.

[61] APPA et al. Comments at 6.

[62] *Id.*

[63] Bonneville Comments at 2.

[64] *Id.*

[65] EEI Comments at 2.

[66] NERC Comments at 5.

[67] *Id.*

[68] *Id.*

decline in frequency response and are in the best interest of industry.[69] ISO–RTO Council adds that a number of Regional Transmission Operators (RTOs) and Independent System Operators (ISOs) have, for several years, had similar requirements to those proposed in the NOPR, and as a result, the Commission's proposal does not create significant burdens as it merely extends these existing ''best practices'' nationwide.[70] SVP states that the NOPR proposals should not create a major hardship in terms of costs or other burdens related to installing frequency response capability.[71] SoCal Edison states that there is neither a technological nor an economic reason not to require primary frequency response capability of small and/or non-synchronous generating facilities.[72]

31. On the other hand, some commenters do not support a requirement for new generating facilities to install, maintain, and operate primary frequency response capability as a condition of interconnection.[73] For example, API states that primary frequency response operation may not be required from *all* generating facilities since it is possible for balancing authorities to have a sufficient number of existing generating facilities with primary frequency response capability.[74] APS argues that more time is needed to measure and understand the effect of Reliability Standard BAL–003–1.1 on frequency response before mandating primary frequency response capability.[75] Chelan County adds that while it may be true that it is more cost effective to install primary frequency response capability during a generating facility's initial construction (as opposed to retrofitting an already-existing generating facility) and the costs of doing so may be nominal, the Commission should not require generating facilities to provide primary frequency response as a condition of interconnection.[76] NRECA asserts that the proposal could have adverse impacts on deployment of non-traditional generation sources without conferring reliability benefits that warrant such risks.[77] Therefore, NRECA asserts that if the Commission proceeds to require primary frequency response capability as a condition of interconnection, then the Commission should provide for flexibility to balance the reliability needs with possible costs and the desire to encourage new generating facilities by: (1) Considering a size threshold, whereby new generators under a certain size are not required to have primary frequency response capability; (2) establishing penetration level thresholds for primary frequency response requirements; or (3) allowing for a waiver process.[78]

32. In addition, some of these commenters request that the Commission reconsider its proposal to mandate the installation of specific equipment on all new generating facilities (or the operation of such equipment as proposed in the NOPR) as a condition of interconnection, and to instead direct market-based or cost-based approaches to ensure adequate levels of primary frequency response.[79]

3. Commission Determination

33. We adopt the NOPR proposal to revise the *pro forma* LGIA and *pro forma* SGIA to include requirements for new large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection, with certain exemptions and special accommodations as discussed below in Section II.H.

34. We adopt the NOPR proposal to define ''functioning governor or equivalent controls'' as the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the generating facility's real power output in accordance with maximum droop and deadband parameters and in the direction needed to correct frequency deviations.[80]

35. The proposal to require new generating facilities to install equipment capable of providing primary frequency response received broad support from commenters.[81] We find compelling these commenters' observations that requiring newly interconnecting generating facilities to install governors or equivalent control devices is a low cost way to address the erosion of the Interconnections' collective frequency response capability as the generation resource mix evolves. As assessments by NERC, the Essential Reliability Services Task Force, and others confirm, ongoing changes to the generation resource mix are altering the composition and dispatch of generating facilities across the daily and seasonal demand spectrum. The resulting operating conditions have affected frequency response capability and the amount of frequency responsive capacity online at any given moment. We believe that the revisions to the *pro forma* LGIA and *pro forma* SGIA adopted here will address this problem by providing that the future generation resource mix has frequency responsive capacity available for dispatch by system operators to maintain system reliability.

36. We acknowledge that some commenters do not support a requirement for all newly interconnecting generating facilities to install, maintain, and operate governors or equivalent controls.[82] Some of these commenters only support a requirement for newly interconnecting generating facilities to install primary frequency response capability as a condition of interconnection, but do not support including the proposed operating requirements in the *pro forma* LGIA and *pro forma* SGIA.[83] These commenters either advocate for regional flexibility (*i.e.,* allowing the transmission provider or the balancing authority to establish regional requirements) or request exemption or special accommodation of the requirements for particular technology types (*e.g.,* electric storage resources and CHP facilities). Comments that request regional flexibility for individual transmission providers or balancing authorities to establish operating requirements are addressed below in Section II.B. Comments that request a special accommodation for certain types of generating facilities, including but not limited to electric storage and CHP facilities are addressed below in Section II.H.

[69] Tri-State Supplemental Comments at 3.

[70] ISO–RTO Council Comments at 2.

[71] SVP Comments at 2.

[72] SoCal Edison Comments at 2.

[73] *See, e.g.,* API Comments at 2; APS Supplemental Comments at 12; Chelan County Comments at 1; NRECA Comments at 2; Public Interest Organizations Comments at 4; R Street Comments at 2; SDG&E Comments at 1; Sunflower and Mid-Kansas Comments at 2.

[74] API Comments at 4.

[75] APS Supplemental Comments at 12.

[76] Chelan County Comments at 1.

[77] NRECA Comments at 6.

[78] *Id.* at 8–9.

[79] *See, e.g.,* API Comments at 2; Chelan County Comments at 1; Public Interest Organizations Comments at 4; R Street Comments at 2–3; SDG&E Comments at 1, 3–4.

[80] NOPR, 157 FERC ¶ 61,122 at P 47.

[81] APPA et al., Bonneville, California Cities, EEI, ESA, Competitive Suppliers, First Solar, Idaho Power (for generating facilities larger than 10 MW), ISO–RTO Council, MISO TOs, NERC, PG&E, SoCal Edison, SVP, Tri-State, Xcel, and WIRAB support the requirement for new generating facilities to install governors or equivalent controls.

[82] *See, e.g.,* API Comments at 2; APS Supplemental Comments at 12; Chelan County Comments at 1; NRECA Comments at 2; Public Interest Organizations Comments at 4; R Street Comments at 2; SDG&E Comments at 1; Sunflower and Mid-Kansas Comments at 2.

[83] *See, e.g.,* AES Companies Comments at 6; EEI Comments at 8; MISO TOs Comments at 10–11; SoCal Edison Comments at 2–3; Xcel Comments at 7.

37. Rather than uniform requirements in the *pro forma* LGIA and *pro forma* SGIA, some commenters prefer market-based or cost-based compensation mechanisms to ensure sufficient primary frequency response capability, and urge the Commission to consider the economic impacts of the proposed requirements on load. Comments related to compensation are addressed below in Section II.E. Comments related to the impacts on load are addressed below in Section II.H.8.

38. Finally, some commenters assert that the Commission should: (1) Consider a size threshold; (2) establish penetration level thresholds for primary frequency response requirements; (3) allow for a waiver process; and (4) establish primary frequency response pools. These comments are addressed below in Sections II.H and II.J.

39. Accordingly, as a result of this final action, new large and small generating facilities, will be required to install, maintain, and operate a functioning governor or equivalent controls with certain exemptions or accommodations for nuclear generating facilities, electric storage facilities, and combined heat and power facilities as discussed below.

B. Including Operating Requirements for Droop and Deadband in the Pro Forma LGIA and Pro Forma SGIA

1. NOPR Proposal

40. In the NOPR, the Commission proposed to include *minimum* operating requirements for droop and deadband for governors or equivalent controls.[84] In particular, the Commission proposed to require new generating facilities to install, maintain, and operate governor or equivalent controls with the ability to operate with a maximum 5 percent droop and ±0.036 Hz deadband parameter, consistent with NERC's recommended guidance.[85]

41. The Commission also proposed to require the droop parameter to be based on the nameplate capability of the generating facility and linear in operating range between 59 and 61 Hz.[86] The Commission explained that this provision is reasonable because it would allow for new generating facilities that remain connected during frequency deviations (and have operating capability, *e.g.,* headroom;[87] or floor-room[88] at the time of the disturbance) to provide a proportional response within this range of frequencies.[89]

42. The Commission also proposed that if the interconnection customer[90] disables its governor or equivalent controls for any reason, it shall notify the transmission provider's system operator, or its designated representative, and shall make Reasonable Efforts[91] to return the governor or equivalent controls to service as soon as practicable.[92] In addition, the Commission proposed that the interconnection customer must provide the status and settings of the governor or equivalent controls to the transmission provider upon request.[93]

2. Comments

a. Whether To Include Operating Requirements for Primary Frequency Response in the Pro Forma LGIA and Pro Forma SGIA

43. Several commenters support the NOPR proposal to include operating requirements (*i.e.,* droop, deadband, and timely and sustained response) in the *pro forma* LGIA and *pro forma* SGIA,[94] while other commenters either object to specific, uniform governor control setting requirements, prefer a market-based approach, or seek limited or full exemptions based on unique operating characteristics.[95] Several commenters agree that a maximum 5 percent droop and ±0.036 Hz deadband for newly interconnecting generating facilities is technically feasible.[96]

44. Among those supporting the proposed operating requirements, NERC asserts that the ''proposed minimum operating conditions should help ensure that frequency response capability is installed as well as available and ready to respond, regardless of the mix of resources in the dispatch,'' and ''should lead to tighter control and frequency stability.''[97] ISO–RTO Council states that, absent unique local requirements such as lower and more responsive droop values in some remote areas of the grid, NERC's guidelines provide a sound baseline and are consistent with current requirements in some regions, including ISO New England, Inc. (ISO–NE), New York Independent System Operator, Inc. (NYISO), and PJM Interconnection, L.L.C. (PJM).[98] While it supports the NOPR proposal, WIRAB also notes the relevance of regional differences, and recommends that the Commission ensure that NERC and the Regional Entities continue to monitor frequency response capability in each region and develop best practices that highlight regional differences in the electricity resource mix and the need for primary frequency response.[99] Further, WIRAB suggests that NERC and the Regional Entities periodically reevaluate the required maximum droop and deadband settings.[100]

45. While it disagrees with a general mandate for primary frequency response capability, in the event the Commission proceeds with a requirement for new generating facilities to install primary frequency response capability, NRECA supports the specific proposed operating requirements.[101]

46. Some commenters express concern that uniform, specific governor control settings in the *pro forma* LGIA and *pro forma* SGIA may fail to account for regional differences and unique operating characteristics of certain generating facilities and resource types, and could add unnecessary costs. These commenters assert that the *pro forma* LGIA and *pro forma* SGIA should only obligate new generating facilities to install and maintain governors or equivalent controls, and not establish specific operating requirements that

[84] NOPR, 157 FERC ¶ 61,122 at P 48.

[85] *Id.*

[86] *Id.* P 50.

[87] For the purposes of this final action, headroom refers to the difference between the current operating point of a generating facility and its maximum operating capability, and represents the potential amount of additional energy that can be provided by the generating facility in real-time. *See* NOPR, 157 FERC ¶ 61,122 at n.27.

[88] For the purposes of this final action, floor-room refers to the difference between the current operating point of a generating facility and its minimum operating capability, and represents the potential amount of additional energy that can be withdrawn by the generating facility in real-time. Stated differently, a generating facility with floor-room will have the capability to reduce its MW output in response to a frequency deviation.

[89] *See* NOPR, 157 FERC ¶ 61,122 at P 50.

[90] The phrase ''interconnection customer'' shall have the meaning given it in the definitional sections of the *pro forma* LGIA and *pro forma* SGIA.

[91] The *pro forma* LGIA and *pro forma* SGIA state that reasonable efforts ''shall mean, with respect to an action required to be attempted or taken by a Party under the Standard Large Generator Interconnection Agreement, efforts that are timely and consistent with Good Utility Practice and are otherwise substantially equivalent to those a Party would use to protect its own interests.'' *Pro forma* LGIA Art. 1 (Definitions). *Pro forma* SGIA Attachment 1 (Glossary of Terms).

[92] NOPR, 157 FERC ¶ 61,122 at P 52, proposed Section 9.6.4 of the *pro forma* LGIA and Section 1.8.4 of the *pro forma* SGIA.

[93] Proposed Section 9.6.4.1 of the *pro forma* LGIA and 1.8.4.1 of the *pro forma* SGIA.

[94] APPA et al., AWEA, Bonneville, California Cities, Competitive Suppliers, First Solar, Idaho Power (for generating facilities larger than 10 MW), ISO–RTO Council, NERC, PG&E, SVP, and WIRAB state that they either support or do not object to the inclusion of the proposed operating requirements in the *pro forma* LGIA and *pro forma* SGIA.

[95] AES Companies; API; EEI; ELCON; ESA; MISO TOs; R St. Institute; SoCal Edison; NRECA; and Xcel.

[96] *See, e.g.,* AWEA Comments at 4; Bonneville Comments at 3; ISO–RTO Council Comments at 4–5; NERC Comments at 6; NRECA Comments at 2–3.

[97] NERC Comments at 5.

[98] ISO–RTO Council Comments at 4–5.

[99] WIRAB Comments at 3.

[100] *Id.*

[101] NRECA Comments at 2.

must be used.[102] While supporting revisions to the *pro forma* LGIA and *pro forma* SGIA to obligate newly interconnecting generators to install governors or equivalent controls to provide primary frequency response, EEI opposes including operating requirements. EEI asserts that tariffs, rather than interconnection agreements, are a more effective means of establishing operating requirements, since there are significant differences among generating facility types and interconnections as well as cost considerations, and because interconnection agreements ''do not provide the necessary controls to ensure compliance.'' [103] EEI further states that operating requirements for new generating facilities are better determined by individual balancing authorities on an as-needed basis or through voluntary guidance from NERC.[104] EEI also requests that, rather than mandating specific operating requirements, the Commission conduct a series of regional technical conferences to ''allow for a more holistic evaluation of all [essential reliability services]'' [105] and provides details regarding the proposed focus and scope of such conferences.[106]

47. MISO TOs object to ''rigid standards that do not allow for changes in technology or in the applicable NERC standards or guidelines.'' [107] Rather, MISO TOs contend that flexibility can be achieved through a generic requirement for appropriate settings consistent with good utility practices. MISO TOs believe this approach would minimize the need to modify the *pro forma* LGIA and *pro forma* SGIA and expedite the implementation of needed changes for primary frequency response.[108] AES Companies also oppose the proposed operating requirement for droop and deadband settings, and believe that this requirement should not be a uniform standard that is applied to all new generating facilities.[109] AES Companies assert that NERC provides a primary frequency control guideline rather than a Reliability Standard because the guideline may need to differ based on the type of generating facility.[110]

48. While it generally agrees with the specific proposed droop and deadband settings, NRECA supports allowing flexibility in the requirements ''to the extent new generating facilities have differing operating, technical or other characteristics which make compliance with these standardized requirements unduly burdensome or impossible.'' [111] APS, MISO TOs, SoCal Edison, Xcel and NYTOs add that the Commission should defer to balancing authorities or transmission providers to establish specified operating requirements for governor or equivalent controls.[112] Xcel states that regional system differences could justify different primary frequency response standards.[113] While the Commission should require that primary frequency response capabilities be installed on all new facilities, any final action should be flexible enough to allow for regional differences.[114]

49. Some commenters that oppose including the proposed operating requirements in the *pro forma* LGIA and *pro forma* SGIA state that market-based procurement of primary frequency response service (in regions of the country with organized markets) would better ensure that the right amount and quality of primary frequency response service is available at a lower cost to consumers.[115] Also, NRECA is concerned that the costs of the Commission's proposal could outweigh the reliability benefits and delay the development of the types of alternative technologies supported by the Commission.[116]

b. Whether To Incorporate a Reference to a Future NERC Reliability Standard in the Pro Forma LGIA and Pro Forma SGIA

50. ISO–RTO Council asserts that revisions to the *pro forma* LGIA and *pro forma* SGIA should account for the possibility that NERC may develop a reliability standard with more stringent specific droop and deadband parameters, and as a result, the *pro forma* LGIA and *pro forma* SGIA should be written to allow for this eventuality without a need to amend the *pro forma* agreements.[117] ISO–RTO Council asserts that a possible future reliability standard with more stringent droop and deadband parameters should supersede the *pro forma* interconnection requirements.[118] Specifically, ISO–RTO Council recommends that the Commission require new generating facilities to comply with the more stringent of the following requirements: (1) A maximum 5 percent droop and ±0.036 Hz deadband parameter and a droop parameter to be based on the nameplate capability of the unit and linear in operating range between 59 to 61 Hz as proposed in the NOPR; or (2) an approved NERC Reliability Standard providing for more stringent parameters.[119]

c. Requirements for Droop and Deadband

51. Some commenters question the NOPR proposal to base a generating facility's droop parameter on its nameplate capacity. EEI asserts that the proposal is problematic because the mandated response from generating facilities is based on MW and Reactive Curves, and not mega volt-ampere (MVA) nameplate ratings.[120] Similarly, ISO–RTO Council urges the Commission to consider that nameplate capability of a unit may not be consistent with the rated capacity of a generating facility for purposes of obtaining interconnection service or for participation in an organized market.[121] In addition, ISO–RTO Council believes that the Commission should clarify that efficiency improvements to a resource increasing its output (*e.g.,* duct burners that allow for increased output from a steam generator) should be considered when calculating a generating unit's droop parameter.[122]

52. While it supports the NOPR proposal for the droop parameter to be linear in the operating range between 59 to 61 Hz, WIRAB recommends that the Commission allow generating facilities to use faster, non-linear settings over the proposed linear operating range.[123] WIRAB explains that a linear setting over the proposed operating range will result in a 5 percent droop across the entire range, but that non-linear droop parameters may lead to faster responses.[124] More specifically, WIRAB explains that rather than a linear 5 percent droop across the entire operating range, ''nonlinear or

[102] *See, e.g.,* AES Companies Comments at 6; EEI Comments at 8; MISO TOs Comments at 10–11; SoCal Edison Comments at 2–3; Xcel Comments at 7.

[103] EEI Comments at 9, 11.

[104] *Id.* at 11–12.

[105] *Id.* at 12.

[106] *Id.* at 4, n.5.

[107] MISO TOs Comments at 9.

[108] *Id.* at 11.

[109] AES Companies Comments at 6.

[110] *Id.*

[111] NRECA Comments at 3.

[112] APS Supplemental Comments at 5–6; MISO TOs Comments at 2; SoCal Edison Comments at 3; Xcel Comments at 7; NYTOs Supplemental Comments at 3–4.

[113] Xcel Comments at 7.

[114] *Id.*

[115] *See, e.g.,* AES Companies Comments at 9; API Comments at 4; ELCON Supplemental Comments at 12, in support of R St Institute's Comments; Public Interest Organizations Comments at 2; R St Institute Comments at 4; SDG&E Comments at 5–6.

[116] NRECA Comments at 3.

[117] ISO–RTO Council Comments at 5.

[118] *Id.*

[119] *Id.* at 5–6.

[120] EEI Comments at 14.

[121] ISO–RTO Council Comments at 6.

[122] *Id.*

[123] WIRAB Comments at 7.

[124] *Id.*

piecewise droop parameters,'' such as a 5 percent droop between 60.036 and 61.000 Hz and a 3 percent droop between 59.964 and 59.000 Hz, ''may help to restore system frequency to normal faster and improve system resiliency.'' [125] On the other hand, EEI recommends that the Commission not include in the *pro forma* interconnection agreements the proposed requirement for the droop characteristic to be linear in the operating between 59 to 61 Hz.[126] In support of its position, EEI contends that: (1) The proposed frequency range includes the deadband, where governors do not operate; and (2) actual generating facility response to frequency deviations may not be linear.[127]

53. Regarding deadband parameters, NERC suggests that the Commission consider replacing the proposed requirements with the NERC Primary Frequency Control Guideline's recommendation [128] concerning the implementation of the deadband within the droop curve.[129] Specifically, NERC recommends that deadbands should be implemented without a step to the droop curve, *i.e.,* once frequency deviates outside the deadband, then change in the generating facility's MW output starts from zero and then proportionally increases with the input signal (*i.e.,* frequency).[130]

d. Requirements for the Status and Settings of the Governor or Equivalent Controls

54. NERC recommends that the Commission require the interconnection customer to provide the status and settings of the governor or equivalent controls and plant level controls not only to the transmission provider (or its designated system operator) but also to the relevant balancing authority upon request, and notify the balancing authority when it needs to take the governor or equivalent controls and plant level controls out of service.[131] In support, NERC asserts that, as the entity with a compliance obligation under Reliability Standard BAL–003–1.1 for providing frequency response, the balancing authority needs to know the status and settings of the governor or equivalent controls and plant level controls in order to assess whether there is an appropriate amount of frequency response available.[132] NERC explains that providing this information to the balancing authority would support efforts to help ensure sufficient frequency response and compliance with Reliability Standard BAL–003–1.1.[133]

55. Regarding the disabling of an interconnection customer's governor or equivalent controls, Bonneville asserts that the proposed revisions to the *pro forma* LGIA and *pro forma* SGIA appear to give the interconnection customer complete discretion to take its governor or equivalent controls out of service, provided it gives the transmission provider notice.[134] To ensure the availability of frequency response when the balancing authority needs it, Bonneville suggests that such discretion be limited to operational constraints, ''including, but not limited to, ambient temperature limitations, outages of mechanical equipment, or regulatory requirements.'' [135]

3. Commission Determination

a. Whether To Include Operating Requirements for Primary Frequency Response in the Pro Forma LGIA and Pro Forma SGIA

56. We disagree with commenters that argue the Commission should not establish minimum uniform operating requirements for primary frequency response.[136] Instead, we find that the establishment of minimum uniform operating requirements for all newly interconnecting generating facilities is preferable to the fragmented and inconsistent primary frequency response settings currently in place throughout the Eastern and Western Interconnections.[137] Assessments by NERC's Essential Reliability Services Task Force demonstrate that a lack of uniform, mandatory primary frequency response requirements has created the opportunity for generator owners/operators to implement operating settings that undermine the purpose and intent of Article 9.6.2.1 of the *pro forma* LGIA to promote and ensure the adequate provision of primary frequency response.[138] Article 9.6.2.1 of the *pro forma* LGIA requires a generating facility to operate its speed governors and voltage regulators in automatic operation mode when the facility is capable of such operation. Further, as the Commission observed in the NOPR, ''[w]hile technological advancements have enabled wind and solar generating facilities to now have the ability to provide primary frequency response, this functionality has not historically been a standard feature that was included and enabled on non-synchronous generating facilities.'' [139] Nothing in the record indicates that the Commission's observation was incorrect.

57. We believe it is necessary to make these changes to the *pro forma* LGIA and *pro forma* SGIA now in order to ensure that the future generation mix will be capable of providing primary frequency response, and to arrest the general long-term declining trend for this essential reliability service. Adopting these requirements now is more prudent than waiting until the lack of primary frequency response undermines grid reliability, a point acknowledged by NERC's Essential Reliability Services Task Force.

58. Accordingly, we find that it is just and reasonable to include the proposed operating requirements of a maximum droop setting of 5 percent and deadband setting of ±0.036 Hz for primary frequency response in the *pro forma* LGIA and *pro forma* SGIA. We acknowledge that the needs of individual regions and balancing authority areas may warrant the adoption of different operating requirements in the future.[140] Therefore, the operating requirements for the *pro forma* LGIA and *pro forma* SGIA we adopt here are *minimum* interconnection requirements for new generating facilities based on the

[125] *Id.*

[126] EEI Comments at 14–15, 17.

[127] *Id.* at 14.

[128] NERC Primary Frequency Control Guideline at 6.

[129] NERC Comments at 6.

[130] *Id.*

[131] *Id.*

[132] *Id.* at 6–7.

[133] *Id.*

[134] Bonneville Comments at 4.

[135] *Id.* at 4–5.

[136] *See, e.g.,* AES Companies Comments at 6; EEI Comments at 8; MISO TOs Comments at 10–11; SoCal Edison Comments at 2–3; Xcel Comments at 7.

[137] The ERCOT Interconnection has uniform minimum requirements for primary frequency response, as generating facilities in Texas Reliability Entity Inc. are required to comply with the requirements of Regional Reliability Standard BAL–001–TRE–01.

[138] *See* NOPR, 157 FERC ¶ 61,122 at P 8. There, the NOPR explains that a 2010 NERC survey found that ''only approximately 30 percent of generators in the Eastern Interconnection provided primary frequency response, and that only approximately 10 percent of generators provided sustained primary frequency response. This suggests that many generators within the Interconnection disable or otherwise set their governors or outer-loop controls such that they provide little to no primary frequency response.''

[139] *Id.* P 13.

[140] *See, e.g.,* Order No. 827, FERC Stats. & Regs. 31,385 (''Due to technological advancements, the cost of providing reactive power no longer represents an obstacle to the development of wind generation.''). *See also* Order No. 828, 156 FERC ¶ 61,062 at P 8 (modifying the *pro forma* SGIA to require interconnecting small generating facilities to ride through abnormal frequency and voltage events and not disconnect during such events because ''the impact of small generating facilities on the grid has changed.'').

Primary Frequency Control Guideline developed by NERC through a broad-based stakeholder process.[141] NERC's Primary Frequency Control Guideline ''reflect[s] the most advanced set of continent-wide best practices and information available in support of frequency response capability.'' [142]

59. We disagree with the view of NRECA that this action is premature because, at present, primary frequency response at the Interconnection level may be acceptable.[143] Rather, we find, as stated by NERC, that increasing levels of generating facilities without primary frequency response capability, combined with the retirement of those generating facilities that have traditionally provided primary frequency response, ''has contributed to the decline in primary frequency response.'' [144] Further, we agree with NERC's Essential Reliability Services Task Force, which concluded that it is prudent and necessary to ensure that the future generation mix includes primary frequency response capabilities and recommends that all new generators support the capability to manage frequency.[145]

60. AES Companies and MISO TOs contend that NERC ''provides guidelines rather than standards because these guidelines may need to differ based on the type of resource,'' [146] and that NERC's Primary Frequency Control Guideline was adopted rather than a Reliability Standard because ''there are many current and anticipated reasons to deviate from'' the Guideline.[147] We disagree and are persuaded instead by NERC and other commenters that minimum requirements are needed.[148]

61. We find ample support in the record to support this approach. For example, in its comments on the NOPR, NERC states that ''the Commission's proposed revisions to the *pro forma* interconnection agreements are consistent with the results of recent NERC reliability assessment recommendations.'' [149] Further, NERC supports the Commission's proposal, stating that ''the NOPR's proposed minimum operating conditions should help ensure that frequency response capability is installed as well as available and ready to respond, regardless of the mix of resources in the dispatch'' and notes its support for including the proposed droop and deadband settings in the *pro forma* LGIA and *pro forma* SGIA.[150]

62. We disagree with EEI's assertion that the primary frequency response operating requirements should not be included in the *pro forma* LGIA and *pro forma* SGIA because the *pro forma* interconnection agreements lack ''the necessary controls to ensure compliance.'' [151] While this final action does not establish specific compliance procedures for new generating facilities, transmission providers are not prohibited from proposing such procedures in a FPA section 205 filing.[152] Also, the *pro forma* LGIA and *pro forma* SGIA contain Commission-approved directives that are legally enforceable obligations.[153] In any event, EEI's suggestion that transmission providers would neither detect nor address possible interconnection customer non-compliance with the new operating requirements is speculative and without support in the record.

63. EEI, MISO TOs, and SoCal Edison request that the Commission not include the proposed operating requirements in the *pro forma* LGIA and *pro forma* SGIA, but instead defer to transmission providers or balancing authorities to establish operating requirements addressing reliability needs identified in regional studies.[154] For the reasons discussed above, we find that it is prudent to establish minimum uniform operating requirements as the foundational element of a framework for ensuring the adequacy and timeliness of primary frequency response. However, as noted immediately below and discussed in more detail in Section II.I below, the Commission establishes, with an addition and clarification, methods for proposing variations to this final action.[155]

64. While we are establishing uniform operating requirements, we also note that there is flexibility built into both the requirements themselves and the Commission's processes. First, we clarify that the requirements we adopt herein are *minimum* requirements. Thus, if an interconnection customer wishes to implement more stringent deadband and droop settings, it may do so.[156] Second, as also discussed in the next section, we have clarified the final action to allow for the possibility of a NERC Reliability Standard that has more stringent parameters than the requirements adopted here. Third, as discussed in Section II.I below, we continue the Commission's historic practice of allowing RTOs/ISOs to propose independent entity variations, as well as permitting other transmission providers to propose changes that are ''consistent with or superior to'' the *pro forma* language. Finally, in the event of a unique circumstance affecting specific resources, the transmission provider may file a non-conforming LGIA or SGIA, or the interconnection customer may request that the transmission provider file an unexecuted LGIA or SGIA.

65. Regarding EEI's request to conduct regional conferences, we do not believe that they are necessary at this time since: (1) The Commission has determined that minimum operating requirements are appropriate to include in the *pro forma* LGIA and *pro forma* SGIA; and (2) EEI's request to focus on other essential reliability services besides primary frequency response is beyond the scope of this proceeding.

66. Comments that reference compensation in lieu of including uniform operating requirements in the *pro forma* LGIA and *pro forma* SGIA are addressed below in Section II.E.

b. Whether To Include a Reference to a Future NERC Reliability Standard in the Pro Forma LGIA and Pro Forma SGIA

67. The Commission is persuaded by ISO–RTO Council's request to include in the *pro forma* LGIA and *pro forma* SGIA provisions that address any future NERC Reliability Standard that provides for more stringent parameters. The Commission agrees that the *pro forma* LGIA and *pro forma* SGIA (as applied to newly interconnecting generation facilities) should be written to allow for

[141] The Preamble to NERC's Primary Frequency Control Guideline states that ''[t]hese guidelines are coordinated by the technical committees and include the collective experience, expertise and judgment of the industry. The objective of this reliability guideline is to distribute key best practices and information on specific issues critical to maintaining the highest levels of BES reliability.'' *See* NERC Primary Frequency Control Guideline at 1.

[142] NERC Comments at 6.

[143] NRECA Comments at 7.

[144] NERC Comments at 5.

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

[146] AES Comments at 6.

[147] MISO TOs Comments at 11.

[148] *See, e.g.,* Bonneville Comments at 3; NERC Comments at 5; ISO–RTO Council Comments at 4–5.

[149] NERC Comments at 5.

[150] *Id.* at 5–6.

[151] EEI Comments at 11.

[152] 16 U.S.C. 824d (2012).

[153] *See NSTAR Elec. & Gas Corp.* v. *FERC,* 481 F.3d 794, 800 (D.C. Cir. 2007).

[154] EEI Comments at 12; MISO TOs Comments at 9; SoCal Edison Comments at 3.

[155] *See* P 233 below, describing the following variation methods: (1) Variations based on Regional Entity reliability requirements; (2) variations that are ''consistent with or superior to'' the final action; and (3) ''independent entity variations'' filed by RTOs/ISOs.

[156] *See* NOPR, 157 FERC ¶ 61,122 at P 8 (''The Commission notes that these proposed requirements are minimum requirements; therefore, if a new generating facility elects, in coordination with its transmission provider, to operate in a more responsive mode by using lower droop or tighter deadband settings, nothing in these requirements would prohibit it from doing so'').

the adoption of a future Reliability Standard with stricter operating requirements (droop and deadband parameters) without a need to further amend interconnection agreements.

68. Accordingly, as discussed below, we are modifying the NOPR proposal to allow for the possibility of a future NERC Reliability Standard that includes equivalent or more stringent operating requirements for droop, deadband, and/or timely and sustained response that would supersede the operating requirements for droop, deadband, and timely and sustained response adopted in this final action. We believe this approach will provide for the harmonization of the reliability-related provisions of the *pro forma* LGIA and *pro forma* SGIA with any future Reliability Standard, and will avoid potential conflicts between Reliability Standards and tariff provisions.[157]

69. We clarify that interconnection customers that are required to comply with this final action will be required to do so until such time as the Commission approves a NERC Reliability Standard with equivalent or more stringent parameters.[158] If the Commission approves such a NERC Reliability Standard, interconnection customers subject to this final action will be required to comply with the operating requirements of the Reliability Standard if it applies to them. However, interconnection customers that are not Applicable Entities of the Reliability Standard will continue to be required to comply with the operating requirements contained within the *pro forma* LGIA and *pro forma* SGIA as adopted in this final action.

c. Requirements for Droop and Deadband

70. We adopt the NOPR proposal to require newly interconnecting generating facilities to install, maintain, and operate a governor or equivalent with a maximum 5 percent droop and ±0.036 Hz deadband and for the droop characteristic to be based on the nameplate capacity.

71. As a threshold matter for this requirement, we clarify the term ''nameplate capacity.'' Some commenters raise concerns with the proposal to base the droop parameter on the nameplate capacity of a generating facility.[159] EEI asserts that basing droop characteristics on nameplate capacity is problematic since ''resource response is based on MW and Reactive curves, and not MVA nameplate ratings.'' [160] In response to this concern, we clarify that the use of the term ''nameplate capacity'' refers to the maximum MW rating of the facility as defined by the Energy Information Administration (EIA).[161] We note that EIA's definition of ''nameplate capacity'' utilizes units of MWs, not MVAs as suggested by EEI. In response to ISO–RTO Council's request for clarification on whether efficiency improvements to a generating facility that increase its output should be factored into the calculation of the droop parameter,[162] we clarify that if a modification to a generating facility causes its nameplate capacity to increase or decrease, then droop parameter should be based on the updated nameplate capacity value.

72. The droop parameter is historically based on the percent change in frequency that would cause a 100 percent change in valve or gate position. This has been translated to the percent change in frequency that would cause a 100 percent change in power output, where a 100 percent change in power output is equivalent to the generator's nameplate capacity. The droop parameter also represents the slope of the MW response in proportion to the frequency deviation.

73. By requiring the droop parameter to be based on nameplate capacity, the Commission intends for a generating facility's expected MW response to frequency deviations to be a percentage of its nameplate capacity, and proportional to the magnitude of the frequency deviation. In particular, the magnitude of a generating facility's MW response to a frequency deviation will depend both on its nameplate capacity and on the magnitude of the frequency deviation. Generating facilities with larger nameplate capacities will provide more MW of primary frequency response per Hz of Interconnection frequency error compared to generating facilities with an equivalent percent droop parameter that have lower nameplate capacities. Accordingly, nameplate capacity is the ''basis'' of the droop parameter since this value will be used to calculate the expected proportional MW response to frequency deviations.

74. ISO–RTO Council points out that the nameplate capacity of a generating facility may not be consistent with its rated capacity for the purposes of obtaining interconnection service or for participation in an organized market. In addition, we recognize that during some operating conditions, the maximum steady state operating limit (*e.g.,* maximum sustainable MW limit) of a generating facility may be less than its nameplate capacity. Therefore, we clarify that for the purposes of calculating the expected amount of primary frequency response that is provided in response to frequency deviations, the calculation should still be based on a generating facility's full nameplate capacity even if the level of requested interconnection service or the steady state operating limit is below that nameplate capacity. We find that this approach is consistent with EPRI's statement that the droop setting is historically based on the percent change in frequency that would cause a 100 percent change in power output (where a 100 percent change in power output is equivalent to the nameplate capacity).[163] As an example, in the case of a generating facility with a 5 percent droop, as the Interconnection's frequency error changes from 0 to 3 Hz and as the system frequency transitions outside of the deadband parameter, the expected change in the generating facility's MW output should range from 0 MW to full nameplate capacity.

75. We clarify that this final action will not require a generating facility that responds to frequency deviations to provide and sustain a value of primary frequency response that causes its MW output to exceed its maximum steady state operating limit.[164] For example, under-frequency conditions outside of the deadband parameter would result in an automatic increase in the generating facility's MW output. However, if the calculated incremental MW value that would be provided as primary

[157] *See* 18 CFR 39.6 (2017). This regulation requires the Commission to issue an order within 60 days, unless it otherwise orders, following notification of a conflict between a Reliability Standard and any function, rule, order, tariff, rate schedule or agreement accepted, approved, or ordered by the Commission. If the Commission determines a conflict exists it will either direct the Transmission Organization to file a modification of the function, rule, order, tariff, rate schedule or agreement under FPA section 206 or the Electric Reliability Organization to file a modification to the conflicting Reliability Standard.

[158] For example, such a Reliability Standard may have requirements for tighter droop (maximum 4 percent droop) and/or deadband settings (*e.g.,* ±0.017 Hz).

[159] EEI Comments at 14; ESA Comments at 3–4.

[160] EEI Comments at 14.

[161] EIA defines nameplate capacity as ''[t]he maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in MW and is usually indicated on a nameplate physically attached to the generator.'' *See* EIA Glossary, *https://www.eia.gov/tools/glossary/index.php?id=G.*

[162] ISO–RTO Council Comments at 6.

[163] EPRI Supplemental Comments at 5.

[164] For example, a generating facility's maximum steady state operating limit may be capped at the MW level of interconnection service requested. Or, during certain periods of an operating year, ambient temperature conditions reduce the maximum sustainable MW output level to below nameplate capacity.

frequency response per the droop parameter would cause the generating facility to exceed its maximum steady state operating limit, the interconnection customer would be permitted to limit the increase in the generating facility's MW output such that its MW output (after primary frequency response has been provided) does not exceed its maximum steady state operating limit, since doing so may cause facility-level reliability concerns. Should a generating facility's maximum operating limit per its interconnection agreement be less than its nameplate capacity, nothing in this final action would require an interconnection customer to violate the terms of its interconnection agreement. In such a situation, an interconnection customer would be permitted to limit the increase in the generating facility's MW output such that its MW output does not exceed the maximum operating limit as described in the interconnection agreement.

76. Similarly, over-frequency conditions would result in an automatic reduction in a generating facility's MW output. However, if the calculated value of primary frequency response would cause the facility's MW output to drop below its minimum operating MW limit, an interconnection customer will be permitted to limit the decrease in the facility's MW output such that the facility does not operate below its minimum steady state operating limit.

77. In addition, we are persuaded by NERC's suggestion to require the deadband parameter to be implemented without a step to the droop curve. We note that NERC's Primary Frequency Control Guideline references a 2013 IEEE Power & Energy Society (IEEE–PES) Technical Report stating that a droop curve (with a deadband) can be implemented in a generator governor in two possible ways: ''Stepped'' or ''non-stepped.'' [165] In its report, IEEE–PES points out that these two methodologies of implementing the deadband parameter can potentially have significantly different results in the response of a generating facility's governor control system to changes in system frequency.[166] According to IEEE–PES, if the deadband is implemented under the stepped approach, as soon as system frequency transitions outside of the deadband parameter (*e.g.,* ±0.036 Hz), the generating facility will experience a sudden spike (increase or decrease) in its MW output, which IEEE–PES warns can be undesirable.[167] To account for this issue, NERC recommends in its Primary Frequency Control Guideline [168] and its comments to the NOPR [169] that the deadband should be implemented without a step to the droop curve. Under the non-stepped approach of implementing the deadband parameter, once frequency transitions outside of the deadband, the incremental change in the generating facility's MW output will start from zero and then increase linearly to the generating facility's nameplate capacity and in proportion to the Interconnection's frequency error.[170]

78. In consideration of this additional information, we agree with NERC and modify the NOPR proposal to require the deadband parameter to be implemented without a step. Accordingly, we are requiring the droop curve to be implemented in a manner such that as frequency transitions outside of the deadband (both for under-frequency and over-frequency conditions), the generating facility's expected MW response should start from 0 MW and increase linearly to the nameplate capacity of the generating facility, as the Interconnection's frequency error changes from 0 Hz to the generating facility's percentage droop multiplied by 60 Hz (*e.g.,* in the case of a 5 percent droop, this would be 3 Hz).

79. In response to EEI's concerns that: (1) The proposed frequency range of 59 to 61 Hz includes the deadband where governors do not operate; and (2) not all generating facilities respond in a linear manner, we are modifying the NOPR proposal and adopt in this final action that the droop parameter should be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter. This is because the range of frequency values within the deadband do not trigger the operation of the governor or equivalent controls, and the slope of the droop curve that relates change in frequency to change in MW output should only apply to the range of frequencies outside of the deadband, *i.e.,* those frequencies where the generating facility's MW output is expected to change in proportion to frequency deviations. Regarding EEI's concern that not all generating facilities respond in a linear manner, we acknowledge that non-linear responses can and may occur. However, we believe that the existence of non-linear responses will not undermine the effectiveness of this final action. We expect that interconnection customers will take Reasonable Efforts to maximize and ensure their ability to provide a linear response in accordance with the droop parameter.

80. While we agree with WIRAB that the use of non-linear or piecewise droop parameters may lead to faster responses, we decline to adopt WIRAB's request to, on a generic basis, require prospective interconnection customers to implement non-linear or piecewise droop curves. While we require the droop curve to be linear (*e.g.,* 5 percent) in the range of frequencies outside of the deadband between 59 to 61 Hz (*i.e.,* the response for both under-frequency and over-frequency conditions should be based on a maximum 5 percent droop), consistent with the NOPR proposal, we find that nothing in these requirements prohibit the implementation of asymmetrical droop settings (*i.e.,* different droop settings for under-frequency and over-frequency conditions), provided that each segment has a percent droop value of no more than 5 percent.[171] For example, our requirements would not prohibit the implementation of a droop curve that has a five percent droop for over-frequency conditions (*e.g.,* between 60.036 and 61.000 Hz) and a 3 percent droop for under-frequency conditions (*e.g.,* between 59.964 and 59.000 Hz).[172]

d. Requirements for the Status and Settings of the Governor or Equivalent Controls

81. We agree with NERC that the balancing authority should know the status and settings of the governor or equivalent controls and plant level controls in order to assess whether there is an appropriate amount of frequency reserve available.[173] In addition, the Commission agrees with NERC that providing this information to the balancing authority ''would support [balancing authority] and [frequency response sharing group] efforts to help ensure sufficient frequency response and their compliance with Reliability Standard BAL–003–1.1.'' [174]

82. Accordingly, we are modifying in this final action the NOPR proposal to require the interconnection customer to provide its relevant balancing authority with the status and settings of the

[165] NERC Primary Frequency Control Guideline at 6, referencing *Dynamic Models for Turbine-Governors in Power System Studies* at Appendix B: Deadband, IEEE–PES (Jan 2013), *http://sites.ieee.org/fw-pes/files/2013/01/PES_TR1.pdf* (IEEE–PES Report).

[166] IEEE–PES Report at Appendix B.

[167] *Id.*

[168] NERC Primary Frequency Control Guideline at 6.

[169] NERC Comments at 6.

[170] *Id.*

[171] *See* NOPR, 157 FERC ¶ 61,122 at n.126.

[172] *See* WIRAB Comments at 7.

[173] NERC Comments at 6–7.

[174] *Id.*

governor or equivalent controls upon request or when the interconnection customer operates the generating facility with its governor or equivalent controls not in service. We determine that this is just and reasonable because it will help improve situational awareness by helping the balancing authority assess whether there is an appropriate amount of frequency responsive capacity online.

83. Regarding the process for an interconnection customer to disable its governor or equivalent controls, we share Bonneville's concern that the interconnection customer should not be allowed to operate its generating facility with its governor or equivalent controls not in service by merely notifying the transmission provider.[175] While we believe that it is not necessary to require the interconnection customer to meet specific operational conditions (*e.g.,* maintenance or outages of mechanical equipment) as a precondition to disabling the governor or equivalent controls as Bonneville suggests,[176] we are modifying the NOPR proposal to provide additional clarity on this issue.

84. Specifically, we revise the *pro forma* LGIA and *pro forma* SGIA to require the interconnection customer to make Reasonable Efforts to keep outages of the generating facility's governor or equivalent controls to a minimum whenever it is operated in parallel with the Transmission System. The interconnection customer shall immediately notify the transmission provider and relevant balancing authority of its need to operate the generating facility without the governor or equivalent controls in service.

85. Accordingly, we will modify the *pro forma* LGIA and *pro forma* SGIA to state that when providing notice to the transmission provider of its intent to disable its governor or equivalent controls, the interconnection customer's notice shall include: (1) The operating status of the governor or equivalent controls (*i.e.,* whether it is currently out of service or when it will be taken out of service); (2) the reasons why the governor or equivalent controls are unable to be operated in service; and (3) a reasonable estimate as to when the governor or equivalent controls will be returned to service. The interconnection customer will be required to then make Reasonable Efforts to return its governor or equivalent controls to service as soon as practicable and notify the transmission provider and balancing authority when it has done so.

[175] Bonneville Comments at 4.

[176] *Id.*

C. Requirement To Ensure the Timely and Sustained Response to Frequency Deviations

1. NOPR Proposal

86. In the NOPR, the Commission proposed to prohibit all new large and small generating facilities from taking any action that would inhibit the provision of primary frequency response, except under certain conditions, including but not limited to, ambient temperature limitations, outages of mechanical equipment, or regulatory requirements.[177] The Commission explained that the lack of coordination between governor and plant-level control systems can result in premature withdrawal of primary frequency response by allowing additional plant control systems to reverse the action of the governor to return the unit to operating at a pre-selected target set-point.[178] The Commission noted that NERC's Primary Frequency Control Guideline explains that ''in order to provide sustained primary frequency response, it is essential that the prime mover governor, plant controls and remote plant controls are coordinated.'' [179]

87. Accordingly, the Commission proposed to require new generating facilities that respond to frequency deviations to not inhibit primary frequency response, such as by coordinating plant-level control equipment with the governor or equivalent controls.[180] In particular, the Commission proposed to include new Sections 9.6.4.2 of the *pro forma* LGIA and 1.8.4.2 of the *pro forma* SGIA to require that the real power response of new large and small generating facilities ''to sustained frequency deviations outside of the deadband setting is provided without undue delay . . . until system frequency returns to a stable value within the deadband setting of the governor or equivalent controls.'' [181]

2. Comments

88. Several commenters support including the proposed provisions for timely and sustained response in the *pro forma* LGIA and *pro forma* SGIA.[182] NERC supports the minimum operating conditions proposed in the NOPR because ''[s]uch requirements for the capability of 'timely and sustained response to frequency deviations' should promote reliability and help avoid a scenario where the transforming resource mix reduces frequency response capability.'' [183] ISO–RTO Council asserts that requiring primary frequency response to be sustained until frequency returns within the deadband parameter ''is consistent with the current requirements of PJM and ISO–NE, as well as CAISO.'' [184]

[177] NOPR, 157 FERC ¶ 61,122 at P 49.

[178] *Id.*

[179] *Id.* (citing NERC Primary Frequency Control Guideline at 4).

[180] *Id.*

[181] *Id.* PP 52–53.

[182] Bonneville Comments at 2, First Solar Comments at 4; Idaho Power Comments at 1–2; ISO–RTO Council Comments at 5; NERC Comments at 5–6; WIRAB Comments at 5.

89. While acknowledging the importance of timely and sustained frequency response, EEI does not believe that such requirements should be included in the *pro forma* LGIA and *pro forma* SGIA because ''the requirements do not consider the resource type or available capacity in requiring sustained response and therefore impose operating requirements for all governors or equivalent controls.'' [185] EEI recommends that the Commission ''limit its modifications of the *pro forma* LGIA and SGIA requirements to address resource capability (but not operational requirements) in order to allow regional needs and markets to address the issue of timely and sustained response for frequency deviations.'' [186] Also, EEI believes that individual balancing authorities should determine operating requirements ''on an as-needed basis or through compliance guidance'' from NERC.[187] AES Companies agree, asserting that it is prudent for each balancing authority to determine appropriate criteria for timely and sustained response, because ''the criteria for sustained and timely response may differ from system to system due to operating conditions, resource mix and more.'' [188]

90. EEI raises an additional concern, stating that ''requirements to provide timely and sustained frequency response cannot be implemented in a manner that is fair and non-discriminatory'' because interconnection agreements ''do not provide the necessary controls to ensure compliance . . . [or] effectively or fairly ensure compensation to those entities providing this support.'' [189] EEI states that without a generic headroom requirement, a uniform requirement for timely primary frequency response ''unfairly discriminates between those

[183] NERC Comments at 5–6.

[184] ISO–RTO Council Comments at 5.

[185] EEI Comments at 9.

[186] *Id.*

[187] *Id.* at 12.

[188] AES Companies Comments at 14.

[189] EEI Comments at 11.

resources that are capable of providing timely response due to their design or current operating status over resources that are not capable of providing a timely response.'' [190] As an example, EEI states that renewables may not be able to provide a timely response to under-frequency deviations if they are operating at capacity or due to other technical limitations.[191]

91. WIRAB and EEI recommend certain modifications to the NOPR proposal for timely and sustained response. Both recommend that the Commission explicitly prohibit in the *pro forma* LGIA and *pro forma* SGIA the interconnection customer from blocking or otherwise inhibiting the ability of the governor or equivalent controls to respond.[192]

92. In the NOPR, the Commission proposed to require that the real power response of new large and small generating facilities to sustained frequency deviations outside of the deadband setting is provided without undue delay . . . until system frequency returns to a stable value within the deadband setting of the governor or equivalent controls.'' [193] WIRAB recommends that the term ''without undue delay'' be defined to require the generating facility to ''provide immediate frequency response when system frequency deviates outside of the required deadband settings, and that no grace period be allowed that can postpone the response.'' [194] Additionally, WIRAB recommends that ''stable value'' be defined as the ''settled frequency response value achieved when frequency has rebounded and settled—after hitting the nadir—but possibly before reaching the normal frequency of 60 Hz.'' [195] Also, WIRAB recommends that ''[o]utside controls should not override a generator's frequency response until the system frequency has settled.'' [196] WIRAB states that its recommended changes would ensure a consistent, timely, and sustained response from generating facilities providing primary frequency response.[197]

93. AWEA asks the Commission to clarify that its proposed prohibition of actions ''inhibiting'' response does not restrict the ability of wind and other generating facilities to adjust the speed of their response in coordination with system operators to ensure a fair and coordinated response that best meets the needs of the system as a whole.[198] AWEA explains that the fast controls inherent in modern wind turbines allow them to respond to frequency deviations more quickly and accurately than many conventional generators, and that some generating facilities can respond so fast that slower-responding facilities cannot provide a coordinated response.[199] AWEA argues that there should be flexibility to ensure a fair and coordinated response (*i.e.,* allow wind generating facilities to respond more slowly than their full design capability) that meets the needs of the system and does not result in a disproportionate share of the response—and cost burden—being provided by facilities that can respond more rapidly (such as very fast-responding wind plants).[200] Accordingly, AWEA recommends that the Commission clarify that adjustments to the response speed of non-synchronous generating facilities, when done to ensure coordinated response for the system operator and fair distribution of cost impacts across generating facility types, do not ''inhibit'' response within the meaning of the NOPR, or if it does, are within the scope of the operational constraints permitted under the NOPR.[201]

3. Commission Determination

94. We determine that it is just and reasonable to include a requirement for timely and sustained response in the *pro forma* LGIA and *pro forma* SGIA. As stated in the NOI, premature withdrawal of primary frequency response ''has the potential to degrade the overall response of the Interconnection and result in a frequency that declines below the original nadir.'' [202] We are persuaded by the reliability assessments performed by NERC confirming a general decline in primary frequency response that, unless adequately addressed, could worsen as the generation resource mix continues to evolve.[203] The requirement for timely and sustained response would address that decline and more specifically would address concerns raised by NERC and others about the premature withdrawal of primary frequency response following a system disturbance, which is a significant concern in the Eastern Interconnection and a somewhat smaller issue in the Western Interconnection.[204] This phenomenon stems from generating facilities that do not sustain the response until system frequency returns to within the deadband parameter; instead they withdraw the response soon after it is provided.[205] In adopting this requirement, we agree with commenters who stated that there should be a clear requirement for primary frequency response to be timely and sustained.[206]

95. We are not persuaded by EEI's and AES Companies' view that timely and sustained response requirements should be part of regional solutions rather than be included in the *pro forma* LGIA and *pro forma* SGIA. NERC's assessments and conclusions do not indicate that the fundamental concerns about declining primary frequency response or the premature withdrawal of primary frequency response are unique or limited to individual regions. In addition, we note that frequency response is an Interconnection-wide phenomenon. Accordingly, we find that minimum, uniform primary frequency response requirements, including timely and sustained response, are just and reasonable.

96. EEI comments that without a provision to ''fairly ensure adequate compensation,'' and a mandate that each new generating facility operate with headroom at all times, the proposed requirements for timely and sustained primary frequency response ''cannot be implemented in a manner that is fair and non-discriminatory.'' [207] EEI asserts that ''requiring all resources to have a timely operating response, but

[190] *Id.*

[191] *Id.*

[192] EEI Comments at 18–19; WIRAB Comments at 5–6.

[193] NOPR, 157 FERC ¶ 61,122 at PP 52–53.

[194] WIRAB Comments at 5.

[195] *Id.* at 5–6. WIRAB notes that NERC describes this settled frequency value in its Interconnection Frequency Response Obligation calculation used in Reliability Standard BAL–003–1.1 and labels the value ''Value B'' in the calculation. *Id.* at n.8.

[196] *Id.* at 6.

[197] *Id.* at 5.

[198] AWEA Comments at 8–9.

[199] *Id.*

[200] *Id.* at 9.

[201] *Id.*

[202] *See* NOI, 154 FERC ¶ 61,117 at P 49.

[203] *See* NERC Comments at 5. NERC states that it ''has determined that increasing levels of non-synchronous resources installed without controls that enable frequency response capability, coupled with retirement of conventional resources that have traditionally provided primary frequency response, has contributed to the decline in primary frequency response'' and that ''a changing resource mix will further alter the dispatch of resources and combinations of resources . . . potentially resulting in systems operating states where frequency response capability could be diminished unless a sufficient amount of frequency responsive capacity is included in the dispatch.''

[204] *See* NOI, 154 FERC ¶ 61,117 at PP 49–50. *See also Frequency Response and Frequency Bias Setting Reliability Standard,* Notice of Proposed Rulemaking, 78 FR 45479 (July 29, 2013), 144 FERC ¶ 61,057, at PP 35–38 (2013).

[205] In the NOI, the Commission stated that primary frequency response withdrawal ''has the potential to degrade the overall response of the Interconnection and result in a frequency that declines below the original nadir.'' *See* NOI, 154 FERC ¶ 61,117 at P 49.

[206] *See, e.g.,* Bonneville Comments at 2; ISO–RTO Council Comments at 5; NERC Comments at 5–6; WIRAB Comments at 6.

[207] EEI Comments at 11.

failing to require necessary headroom, unfairly discriminates between those resources that are capable of providing a timely response due to their design or current operation status over resources that are not capable of providing a timely response.'' [208] We disagree. We are imposing operating requirements on all newly interconnecting generating facilities (with limited exemptions) but not mandating headroom or compensation for any generating facilities. Any headroom maintained by these facilities is not required by this final action, and does not render our operating requirements unduly discriminatory. If future conditions necessitate a headroom requirement, we will then consider any appropriate compensation.

97. As noted in Section II above, one of the Commission's concerns with the current lack of clear, uniform primary frequency response requirements is NERC's finding indicating that a number of generator owners/operators have implemented operating settings that have effectively removed the availability of their generating facilities from providing timely and sustained primary frequency response (*e.g.,* wide deadband settings, uncoordinated plant-level controls).[209] The reforms adopted in this final action, to be applied uniformly to new generating facilities, are intended to eliminate these practices. Accordingly, the Commission determines that the requirements are just, reasonable and not unduly discriminatory or preferential.

98. Further, while it is true that generating facilities that are operated with no headroom at the time of an under-frequency deviation will provide little or no response in the upward direction, they will still be available to support the reliability of the power system by responding in the downward direction during abnormal over-frequency system conditions. Since the timing of an abnormal frequency deviation outside of the deadband parameter—and when a generating facility will thus be required to respond—is unpredictable, it is possible that these generating facilities will have operating capability in the upward direction to respond to some abnormal under-frequency deviations.

99. We agree with the suggestions of EEI and WIRAB to explicitly prohibit interconnection customers from blocking or otherwise inhibiting the governor's or equivalent controls' ability to respond.[210] Accordingly, as discussed below in Section II.K.3, the Commission will modify in this final action the NOPR proposal to require interconnection customers to not block or otherwise inhibit the governor or equivalent controls' ability to respond.

100. AWEA, ESA, and WIRAB ask the Commission to clarify the proposed timely and sustained response provisions, and their comments raise the following questions: (1) How soon should a generating facility begin to provide primary frequency response following a disturbance; and (2) how long, at a minimum, should the response be sustained?

101. Regarding how soon a generating facility should begin to provide primary frequency response following a disturbance, the Commission agrees with WIRAB that the definition of ''without undue delay'' should be clarified.[211] Accordingly, we clarify that the NOPR proposal for generating facilities to respond ''without undue delay'' is intended to address the concern that an interconnection customer could program an intentional delay of several seconds or minutes to effectively avoid contributing to the support of power system reliability following a disturbance. Following the sudden loss of generation or load, primary frequency response must be delivered as promptly as possible, within the physical characteristics of the generating facility, in order to avoid, for example, Interconnection frequency declining to a level where UFLS relays are activated or to a lower level where generation under-speed protection relays activate, resulting in additional generation trips or cascading outages. Accordingly, in response to WIRAB's request to clarify when a generating facility should respond to a frequency deviation, we will modify the NOPR proposal and adopt in this final action the requirement that generating facilities respond *immediately* after system frequency deviates outside of the deadband parameter, to the extent that they have available operating capability in the direction needed to correct frequency deviation at the time of the disturbance.[212]

102. We agree with WIRAB that no grace period should be allowed that can postpone the response. Accordingly, we deny AWEA's request to coordinate response times between interconnection customers and system operators.[213] Instead, we require generating facilities to respond immediately, consistent with the technical capabilities of the generating facility and its control equipment.

103. Regarding the minimum period of time that a response should be sustained, we will not establish in this final action a minimum timeframe in minutes that the response to frequency deviations should be sustained since the amount of time that Interconnection frequency remains outside of the deadband varies by event.

104. We determine that rather than using the term ''stable'' used in the NOPR concerning the sustained response requirement, it is preferable to require primary frequency response to be sustained until such time that system frequency returns to a value within the deadband. Therefore, we find that WIRAB's recommendation to adopt its definition of ''stable value'' is moot. Accordingly, we clarify that with the exception of certain operational constraints described in Section 9.6.4.2 of the *pro forma* LGIA and Section 1.8.4.2 of the *pro forma* SGIA, generating facilities that respond to abnormal and sustained frequency deviations outside of the deadband parameter are required to provide and sustain primary frequency response until system frequency has returned to a value within the deadband parameter. If frequency recovers to within the deadband but suddenly deviates outside of the deadband parameter again, the interconnection customer will be required to provide and sustain its response until such time that frequency returns to a value within the deadband.

105. Comments related to electric storage resources pertaining to the timely and sustained response provisions are addressed below in Section II.H.2.

D. Proposal Not To Mandate Headroom

1. NOPR Proposal

106. In the NOPR, the Commission clarified that the proposed requirements did not impose a generic headroom requirement, but sought comment on such a requirement.[214] The Commission stated its belief that the reliability benefits from the proposed

[208] *Id.*

[209] *Id.* PP 8–9, 39.

[210] EEI Comments at 16, 18–19; WIRAB Comments at 5–6.

[211] *See* WIRAB Comments at 5.

[212] The Commission accepted similar tariff language proposed by CAISO. *See Cal. Indep. Sys. Operator Corp.,* 156 FERC ¶ 61,182, at P 17 (2016) (accepting, among other things, CAISO's proposed changes to s Section 4.6.5.1 of its tariff, which provides in pertinent part that ''Participating Generators with governor controls that are synchronized to the CAISO Controlled Grid must respond immediately and automatically.'').

[213] *See* AWEA Comments at 8–9 (describing efforts to coordinate the fast response times of wind facilities with system operators).

[214] NOPR, 157 FERC ¶ 61,122 at P 51.

modifications to the *pro forma* LGIA and *pro forma* SGIA do not require imposing additional costs that would result from a generic headroom requirement.[215]

2. Comments

107. Several commenters state that the Commission should not create a mandatory headroom requirement.[216] Idaho Power asserts that a generic headroom requirement is not necessary at this time.[217] AWEA, Public Interest Organizations, and SDG&E state that there are significant opportunity costs involved in maintaining headroom.[218] WIRAB adds that not every generating facility needs to provide primary frequency response all the time; instead the decision of whether a generating facility provides primary frequency response and the necessary amount of headroom should be determined by economic considerations rather than by generic requirements.[219] EEI supports the NOPR proposal not to include a generic headroom requirement in the *pro forma* LGIA and *pro forma* SGIA ''since these requirements go beyond capability (*i.e.,* equipment specifications.)'' [220] However, EEI also asserts that *not* requiring headroom while requiring all primary frequency responses to be timely and sustained would be discriminatory, because all generating facilities are not capable of timely responses.[221] We address this assertion above in Section II.C.3.

108. AWEA requests that the Commission consider expanding on the NOPR proposal by finding that it would be unjust and unreasonable for a transmission provider to impose a requirement for all generating facilities to reserve headroom to provide primary frequency response due to the large inefficiency and cost of such a requirement.[222] ESA asserts that it interprets the Commission's proposal as an explicit prohibition against requiring interconnection customers to reserve headroom as a condition of interconnection.[223]

3. Commission Determination

109. We will not mandate a headroom requirement at this time. We continue to believe that the reliability benefits from the proposed modifications to the *pro forma* LGIA and *pro forma* SGIA do not require imposing additional costs that would result from a generic headroom requirement.[224]

110. We decline to address AWEA's request to find it unjust and unreasonable for a transmission provider to impose a requirement for all generating facilities to reserve headroom to provide primary frequency response. Instead, in response to AWEA and ESA, we clarify that this final action does not prohibit a transmission provider from arguing to the Commission that headroom should be required as a condition of interconnection in a particular factual circumstance and proposing an associated compensation mechanism. We will evaluate any such filings on a case-by-case basis. Finally, we revise proposed Article 9.6.4 of the *pro forma* LGIA and Article 1.8.4 of the *pro forma* SGIA to delete the following reference: ''Nothing shall require the generating facility to operate above its minimum operating limit, below its maximum operating limit, or otherwise alter its dispatch to have headroom to provide primary frequency response.'' We believe that this phrase is unnecessary and that it is clear without it that we are not requiring headroom as a condition of interconnection.

E. Proposal Not To Mandate Compensation

1. NOPR Proposal

111. The Commission did not propose to mandate compensation related to the new primary frequency response requirements, stating ''the Commission has previously accepted changes to transmission provider tariffs that similarly required interconnection customers to install primary frequency response capability or that established specific governor settings, without requiring any accompanying compensation.'' [225] Further, the Commission clarified that the absence of a compensation mandate is not intended to prohibit a public utility from filing a proposal for primary frequency response compensation under section 205 of the FPA.[226]

2. Comments

112. Many commenters support not mandating compensation.[227] On the other hand, a few commenters reject the NOPR's overarching approach, asserting instead that a market-based approach or a centralized forward procurement process is needed.[228] Other commenters qualify their support of the NOPR's approach to compensation on future efforts to establish forward procurement or market mechanisms.[229]

113. Some commenters believe that compensation issues are best decided at the regional level.[230] ISO–RTO Council asserts that not mandating compensation is reasonable because ''[f]undamentally, the costs of providing primary frequency response by all registered generators should be viewed simply as a cost of reliable generator operation (similar to, for example, maintenance, staffing, metering, software, and communications).[231] APPA et al. agrees, stating that primary frequency response capability should be a standard feature of new generating facilities.[232] APPA et al. also notes that the Commission recently recognized imposing requirements for generating facilities with governor controls without additional compensation is a just and reasonable condition of participation in wholesale markets.[233] In addition, SoCal Edison believes that the costs of primary frequency response capability are already adequately recovered through existing bilateral or market-based capacity contracts.[234]

114. AWEA states that the cost of attaining primary frequency response capability for new generators is low [235] but asserts that the Commission's decision not to address compensation for primary frequency response capability in the proposed rulemaking is not a major concern, so long as there is no headroom requirement.[236] California Cities compares primary frequency response with a number of interconnection requirements for generating facilities in which the recovery of capital costs and operating

[215] *Id.*

[216] EEI, Public Interest Organizations, AWEA, ESA, ISO–RTO Council, Xcel, Idaho Power, WIRAB, NERC, First Solar.

[217] Idaho Power Comments at 2.

[218] AWEA Comments at 2; Public Interest Organizations Comments at 4; SDG&E Comments at 2.

[219] WIRAB Comments at 9.

[220] EEI Comments at 13.

[221] *Id.* at 11.

[222] AWEA Comments at 3.

[223] ESA Comments at 2.

[224] NOPR, 157 FERC ¶ 61,122 at P 44.

[225] *Id.* P 55 (citing *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097 at n.58; *Cal. Indep. Sys. Operator Corp.,* 156 FERC ¶ 61,182, at PP 10–12 and 17 (2016); *New England Power Pool,* 109 FERC ¶ 61,155 (2004), *order on reh'g,* 110 FERC ¶ 61,335 (2005)).

[226] *Id.*

[227] ISO–RTO Council; WIRAB; Xcel; PG&E; APPA et al.; EEI; MISO TOs; NRECA; California Cities; and SoCal Edison.

[228] AES; SDG&E; API; Chelan County; R St. Institute; and CESA.

[229] AWEA; ELCON; Public Interest Organizations; and First Solar.

[230] Xcel Comments at 7; PG&E Comments at 2; EEI Comments at 11; MISO TOs Comments at 14.

[231] ISO–RTO Council Comments at 10.

[232] APPA et al. Comments at 6.

[233] *Id.* (citing *Cal. Indep. Sys. Operator Corp.,* 156 FERC ¶ 61,182 at P 17 (2016)).

[234] SoCal Edison Comments at 4.

[235] AWEA Comments at 1.

[236] *Id.* at 9.

expenses are not necessarily ensured.[237] California Cities states that developers of new generating facilities have the opportunity to recover capital costs for primary frequency response capability in the same ways they recover other capital costs associated with generation resources and can factor the costs of primary frequency response into their economic assessment of project viability under anticipated market conditions and into their negotiations for capacity sales.[238]

115. ELCON supports not mandating compensation, expressing its expectation that such costs should be low, observing that the administrative costs of a compensation scheme may outweigh the costs of providing mandated service.[239] Further, ELCON joins APPA et al. in noting that this is consistent with prior Commission decisions requiring the installation of primary frequency response capability or specifying governor settings, without mandating compensation.[240] ELCON emphasizes that its comments regarding compensation are limited to the currently proposed limited applicability of new requirements to new generation facilities because a broader approach would trigger more significant costs and should focus on market-based solutions such as that under Order No. 819.[241]

116. In support of compensation, several commenters state that the proposed requirements are inefficient or uneconomic because, among other points, they require new generating facilities to install and operate a governor or equivalent controls when the necessary primary frequency response could be provided at lower cost by another generating facility (*e.g.,* battery storage or existing generating facility).[242] These commenters believe that market-based procurement will create opportunities for transmission providers to obtain higher-quality frequency response at a lower cost compared to a mandatory primary frequency response requirement for all newly interconnecting generating facilities. Rather than the mandatory requirements proposed in the NOPR, some commenters prefer market-based compensation to incent the ''right'' level of primary frequency response.[243]

117. Other commenters believe that generating facilities should not be required to provide primary frequency response without compensation for their costs of providing the service.[244] SDG&E asserts that the NOPR proposals will not address the Commission's concerns regarding the decline in primary frequency response because ''uncompensated costs are at the root of poor historical performance.'' [245] Further, AWEA raises concerns that it is unjust and unreasonable to mandate that new generation incur investment and maintenance costs to be primary frequency response capable without being provided a real opportunity to recover such costs.[246] Competitive Suppliers assert that ''[a]ll resources that provide essential reliability services such as primary frequency response *and* inertia should be explicitly compensated rather than mandating generators provide them without distinct and additional compensation.'' [247] Competitive Suppliers urge the Commission to address compensation in a final rule or additional NOPR.[248] First Solar encourages the Commission to require compensation for the configuration and additional communication, software and control technologies required to operate the equipment at a solar PV generation facility to provide essential reliability services.[249] First Solar believes that the Commission should also require ISOs and RTOs develop a funding mechanism and operational and market rules to accommodate the headroom requirements for these facilities to provide frequency response.[250]

118. ESA raises concerns that, without compensation, the primary frequency response requirement for electric storage ''may produce disproportionate adverse economic impacts.'' [251] Therefore, ESA recommends that the Commission ''direct RTOs/ISOs to use pay-for-performance principles to price primary frequency response provision.'' [252] ESA relies on Order No. 755, where the Commission found that frequency regulation compensation practices that do not compensate performance result in rates that are unjust, unreasonable, and unduly discriminatory or preferential. ESA contends that the same argument applies to frequency response compensation.[253]

3. Commission Determination

119. We will not mandate compensation for primary frequency response service in this final action. We are not persuaded by comments that assert: (1) Generating facilities should not be required to provide a service if there is not explicit compensation; (2) market-based compensation would be more efficient than the NOPR proposal; (3) inertia should be compensated in this final action; and (4) that frequency regulation compensation under Order No. 755 requires that primary frequency response be compensated. We address each of these points below.

120. Commenter assertions that the Commission is improperly requiring the provision of a service without compensation are misplaced. While we are requiring newly interconnecting generating facilities to install equipment capable of providing frequency response and adhere to specified operating requirements, we are not mandating headroom, which is a necessary component for the provision of primary frequency response service. In addition, as stated in the NOPR, ''[t]he Commission has previously accepted changes to transmission provider tariffs that similarly required interconnection customers to install primary frequency response capability or that established specified governor settings, without requiring any accompanying compensation.'' [254] Further, we agree

[237] California Cities Comments at 4.

[238] *Id.*

[239] ELCON Comments at 6.

[240] *Id.* n.4 (citing *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097 at n.58; *Cal. Indep. Sys. Operator Corp.,* 156 FERC ¶ 61,182, at PP 10–12 and 17 (2016); *New England Power Pool,* 109 FERC ¶ 61,155 (2004), *order on reh'g,* 110 FERC ¶ 61,335 (2005)).

[241] *Id.* at 7.

[242] AES Companies Comments at 9; API Comments at 4; AWEA Comments at 11; ELCON Supplemental Comments at 12, in support of R St Institute's Comments; Competitive Suppliers Comments at 4; ESA Comments at 6; Public Interest Organizations Comments at 2; R St Institute Comments at 4; SDG&E Comments at 5–6 and SDG&E Supplemental Comments at 2–3. Public Interest Organizations, in their Comments at 5–6, refer to the need to remove settlement system ''disincentives'' to the provision of primary frequency response by existing generators, which the Commission interprets as a request for compensation for providing this service.

[243] API Comments at 3–4; Chelan County Comments at 1–2; Public Interest Organizations Comments at 6–7; R St Institute's Comments at 2–3; and SDG&E Comments at 3.

[244] AWEA Comments at 10; ELCON Supplemental Comments at 12–13 (over longer term); Competitive Suppliers Comments at 3, 5; ESA Comments at 6–7; First Solar Comments at 4; MISO TOs Comments at 5 (compensation should be determined regionally); and SDG&E Comments at 3.

[245] SDG&E Comments at 3.

[246] AWEA Comments at 10.

[247] Competitive Suppliers Comments at 5.

[248] *Id.*

[249] First Solar Comments at 4.

[250] *Id.*

[251] ESA Comments at 4.

[252] *Id.* at 6.

[253] ESA Comments at 6–7 (citing *Frequency Regulation Compensation in Organized Wholesale Power Markets,* Order No. 755, FERC Stats. & Regs. ¶ 31,324, at P 2 (2011) (crossed referenced at 137 FERC ¶ 61,064).

[254] NOPR, 157 FERC ¶ 61,122 at P 55 (citing *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097 at n.58; *Cal. Indep. Sys. Operator Corp.,* 156 FERC ¶ 61,182 at PP 10–12 and 17; *New England Power Pool,* 109 FERC ¶ 61,155, *order on reh'g,* 110 FERC ¶ 61,335). The Commission reiterated this approach in *Indianapolis Power & Light Company* v.

Continued

with California Cities that there are interconnection requirements for generating facilities in which the recovery of capital costs and operating expenses are not necessarily ensured.

121. On balance, we find that the record indicates that the cost of installing, maintaining, and operating a governor or equivalent controls is minimal.[255] Also, the greatest cost associated with providing primary frequency response results from maintaining headroom, as noted by several commenters.[256] No commenter provided any evidence suggesting that the costs of providing primary frequency response are greater than those indicated in the NOPR.[257] While the Commission has approved specific compensation for discrete services that require substantial identifiable costs, such as for frequency regulation and operating reserves, the Commission has not required specific compensation for all reliability-related costs. We agree with those commenters who observe that minimal reliability-related costs such as those incurred to provide primary frequency response, are reasonably considered to be part of the general cost of doing business, and are not specifically compensated.

122. With regard to requests for the Commission to mandate market-based compensation, we are not persuaded by assertions that mandatory market-based mechanisms for the procurement of primary frequency response capability are just and reasonable at this time given the record before us. While some economic efficiency may be gained from acquiring primary frequency response from the subset of generation that is most economically efficient at providing this service, we believe that the time and costs of developing a market in RTO/ISO regions or bilaterally purchasing the service in non-RTO/ISO regions should be carefully considered. ISO–RTO Council asserts, for example, that the administrative costs of developing and implementing market-based compensation of primary frequency response are likely to outweigh the incremental efficiency benefits.[258] Similarly, SDG&E states that, to develop a market, each RTO/ISO will have to address issues such as developing complex software to operate the market and verifying generator performance in sub-minute intervals, which may require the installation of high-quality metering equipment such as phasor measurement units.[259] Nonetheless, an RTO/ISO may propose such an approach upon an adequate showing under section 205, if it so chooses.

123. With regard to Competitive Suppliers' view that the Commission should mandate explicit compensation for inertial response, we decline to adopt such a requirement.[260] We recognize the reliability value of inertial response, as it helps to slow the rate of change of frequency during frequency deviations. In addition, very low levels of inertial response within an Interconnection increase the risk that the speed of primary frequency response delivery will be too slow to prevent large frequency deviations from exceeding pre-determined thresholds for load shedding or automatic generator trip protection. However, no commenter asserts that inertial response trends on the Eastern and Western Interconnections are approaching levels that could threaten reliability. In addition, because inertial response is provided automatically by the rotating mass of synchronous machines as system frequency deviates and is not controllable, synchronous generating facilities do not incur additional incremental costs to provide inertial response. Indeed, neither Competitive Suppliers nor any other commenter has indicated what, if any, incremental costs must be incurred to provide inertial response. Accordingly, we conclude that compensation for inertial response compensation is not warranted at this time.

124. We disagree with ESA's contention that the treatment of frequency regulation under Order No. 755 requires compensation of primary frequency response in this final action. In *Indianapolis Power,* the Commission rejected a similar request for primary frequency response compensation based on Order No. 755, finding that ''Order No. 755 is inapposite, as that order involved an existing market, where the Commission found that the frequency regulation compensation practices of RTOs and ISOs resulted in rates that are unjust, unreasonable, and unduly discriminatory or preferential.'' [261] For similar reasons, Order No. 755 is inapposite here.

125. AES and MISO TOs request that the Commission allow for the development of primary frequency response pools, self-supply of primary frequency response, and transferred primary frequency response markets.[262] We conclude that existing requirements (*e.g.,* contracts for frequency response service under Order No. 819,[263] and recent Commission action regarding transferred frequency response [264]) already address two of these options. Also, a Frequency Response Sharing Group under Reliability Standard BAL–003–1.1, is an option currently available to balancing authorities.

126. Finally, nothing in this final action is meant to prohibit a public utility from filing a proposal for primary frequency response compensation under section 205 of the FPA.[265]

F. Application to Existing Generating Facilities That Submit New Interconnection Requests That Result in an Executed or Unexecuted Interconnection Agreement

1. NOPR Proposal

127. In the NOPR, the Commission proposed to apply the revisions to the *pro forma* LGIA and *pro forma* SGIA to new generating facilities that execute or request the unexecuted filing of interconnection agreements on or after the effective date of any final action issued.[266] The Commission also proposed to apply the requirements to any large or small generating facility that has an executed or has requested the filing of an unexecuted LGIA or SGIA as of the effective date of any final action, but that takes any action that requires the submission of a new interconnection request on or after the effective date of any final action.[267] The Commission sought comment on the

Midcontinent Indep. Sys. Operator, Inc., 158 FERC ¶ 61,107, at PP 36–37 (2017) (*Indianapolis Power*) (denying Indianapolis Power's request that the Commission find MISO's Tariff to be unjust, unreasonable, and unduly discriminatory or preferential because it does not compensate suppliers of primary frequency response).

[255] *See* NOPR, 157 FERC ¶ 61,122 at PP 62–71; *see also* ISO–RTO Council Comments at 9 (stating ''the incremental cost to provide frequency response is minimal''); ELCON Comments at 6 (citing ''the low costs triggered by the NOPR's limited applicability to only new generating facilities''); AWEA Comments at 1 (stating ''the cost of attaining [primary frequency response] capability for new generators is low.'').

[256] *See* AWEA Comments at 9; Public Interest Organizations Comments at 4.

[257] *See* NOPR, 157 FERC ¶ 61,122 at P 41 (stating that ''small generating facilities are capable of installing and enabling governors at *low cost* in in a manner comparable to large generating facilities.'').

[258] *See* ISO–RTO Council Comments at 9–10. *See also* ELCON Comments at 6.

[259] *See* SDG&E Comments at n.6.

[260] *See* Competitive Suppliers Comments at 5.

[261] *Indianapolis Power,* 158 FERC ¶ 61,107 at P 37.

[262] AES Comments at 5; MISO TOs Comments at 11.

[263] *Third-Party Provision of Primary Frequency Response Service,* Order No. 819, FERC Stats. & Regs. ¶ 31,375 (2015) (cross-referenced at 153 FERC ¶ 61,220).

[264] *Cal. Indep. Sys. Operator Corp.,* 156 FERC ¶ 61,182, *order on clarification, compliance, and rehearing,* 158 FERC ¶ 61,129 (2017).

[265] *See* NOPR, 157 FERC ¶ 61,122 at P 55.

[266] *Id.* P 54.

[267] *Id.*

proposed effective date, including whether the proposed application of the requirements would be unduly burdensome.[268]

2. Comments

128. Most commenters addressing this issue agree with the proposed effective date and applicability, with some suggesting additional action would be helpful.[269] While Bonneville supports the Commission's proposed effective dates, it observes that ''if significant modifications are made to the generating facility, the cost of including primary frequency response capability may not add much to the cost of the modifications themselves.'' [270] Therefore, Bonneville believes that the Commission should ''explore defining what constitutes a 'significant modification''' and require existing generating facilities to include primary frequency response capability when making one.[271] California Cities support the Commission's proposal because the proposal is sufficiently narrow as to only include those generating facilities that make a substantial change.[272]

129. Other commenters, however, believe that the NOPR proposal should go further. ISO–RTO Council states that it ''is unaware of any limitations that would render the Commission's proposed effective date infeasible or unduly burdensome'' and therefore it supports the proposed effective date.[273] However, ISO–RTO Council suggests that the Commission expand the application of the primary frequency response capability and operating requirements to both conforming and non-conforming interconnection agreements resulting from new interconnection requests by existing generating facilities.[274] ISO–RTO Council explains that under the NOPR proposal, an existing interconnection customer that ''takes an action that requires the submission of a new interconnection request resulting in the execution of a conforming interconnection agreement would not be obligated under the Commission's proposed requirements because the interconnection agreement would not be filed.'' [275] Therefore, ISO–RTO Council recommends that the proposed requirements apply to any existing interconnection customer that takes any action that requires the submission of a new interconnection request that results in the execution of an interconnection agreement, regardless of whether the agreement is filed, or the filing of an unexecuted interconnection agreement after the effective date of any final action.[276]

130. Xcel contends that the Commission's proposal does not go far enough to ensure future generating facilities are capable of providing primary frequency response.[277] Xcel's concern pertains to the possibility of a generating facility obtaining an interconnection agreement for more generation than is initially installed. In this situation, new generating facilities installed years after the effective date of the final action would not be required to install primary frequency response capability because a new interconnection agreement for subsequent phases is not required.[278] Therefore, Xcel asks the Commission to consider requiring that any new generating facility added to expand an existing large or small generating facility more than two years after the effective date of the final action be required to provide primary frequency response, even if no new interconnection agreement is required.[279]

131. SVP raises concerns that the proposed reforms could apply to existing generating facilities if interconnection customers amend their interconnection agreements for minor updates involving no material substantive changes to the interconnected facilities or to the interconnection itself.[280] SVP explains that as a licensee of three hydropower projects, each with a generating capacity of less than 20 MW, SVP has for over 30 years continually procured interconnection service for these facilities through an interconnection agreement with PG&E.[281] SVP states that it is coordinating with PG&E and CAISO to reformat the existing agreements and that it may execute and file an amended agreement after the effective date of the final action with no material changes to the facilities or to the interconnection.[282] SVP seeks clarification that the proposed reforms will not apply to existing facilities with existing interconnection agreements that execute new form agreements if there are no material substantive changes to the interconnected facilities or to the interconnection itself.[283]

3. Commission Determination

132. With the clarifications noted below, we adopt the NOPR proposal to apply the primary frequency response requirements adopted herein to all newly interconnecting generating facilities as well as to all existing large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of this final action.[284] In response to SVP's request, we clarify that where the submission of a new interconnection request by an existing generating facility results in an executed or unexecuted interconnection agreement by that existing generating facility, such event would be considered the triggering event that would impose the requirements of this final action. Accordingly, should an existing interconnection customer sign a new or amended interconnection agreement for reformatting purposes only those existing generating facilities would not be subject to the requirements of this final action.[285]

133. Bonneville suggests that the Commission should ''explore defining what constitutes a 'significant modification' '' to existing generating facilities that would subject them to the primary frequency response requirements adopted in this final action. It is unclear what Bonneville means by ''significant modification.'' However, we note that under the *pro forma* LGIP, a ''material modification'' [286] to an existing generating facility would result in an interconnection request requiring a new interconnection agreement, thereby

[268] *Id.*

[269] Idaho Power Comments at 2; WIRAB Comments at 8–9; First Solar Comments at 4; Bonneville Comments at 3; California Cities Comments at 3–4; ISO–RTO Council Comments at 8.

[270] Bonneville Comments at 3.

[271] *Id.*

[272] California Cities Comments at 3–4.

[273] ISO–RTO Council Comments at 8.

[274] *Id.*

[275] *Id.*

[276] *Id.*

[277] Xcel Comments at 6.

[278] *Id.*

[279] *Id.* Xcel states that this approach should not apply to an uprate of an existing facility.

[280] SVP Comments at 5–6.

[281] *Id.* at 4–5.

[282] *Id.* at 5.

[283] *Id.*

[284] NOPR, 157 FERC ¶ 61,122 at P 63.

[285] Article 1 of the *pro forma* LGIA defines an interconnection request as: ''an interconnection customer request, in the form of Appendix 1 to the Standard Large Generator Interconnection Procedures, in accordance with the Tariff, to interconnect a new Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Generating Facility that is interconnected with the Transmission Provider's Transmission System.'' Sections 30.9 and 30.10 of the *pro forma* LGIA provide that the LGIA and its appendices may be amended by mutual agreement of the parties and do not state that a new interconnection request must be submitted in order to do so.

[286] The *pro forma* LGIA defines a Material Modification as: ''those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date.''

subjecting the existing generating facility to the requirements adopted in this final action.[287] The Commission has not adopted a bright-line definition of what constitutes a material modification; rather, that is a fact-specific inquiry.[288] Bonneville has not persuaded us that we should adopt such a bright line now. Bonneville provides no information regarding how many, if any, modification requests by existing generating facilities would not be deemed material, and would therefore not trigger the requirements of this final action, since the interconnection customer would not be required to submit a new interconnection request or execute a new interconnection agreement. Accordingly, we are not persuaded by Bonneville of the need to include a definition for the new term ''significant modification'' at this time.

134. Similarly, Xcel provides no support for its suggestion that a significant number of new generating facilities, covered by a prior interconnection agreement, may be built two or more years following the effective date of this final action and therefore should be subject to the primary frequency response requirements.[289] Accordingly, we decline to adopt Xcel's suggestion to require ''new generating facilities that are interconnected two years or more after the effective date of the Final Rule [to] also meet these requirements, even if a new interconnection agreement is not required.'' [290]

135. Further, the Commission believes that ISO–RTO Council's request that ''the Commission expand the application of the primary frequency response requirements to both conforming and non-conforming interconnection agreements resulting from new interconnection requests by existing generators'' is unnecessary.[291] ISO–RTO Council's concern relates to the NOPR's use of the phrase ''filing of an executed or unexecuted interconnection agreement.'' [292] We note that if an interconnection customer executes a new conforming interconnection agreement for an existing generating facility as a result of a new interconnection request, the agreement would not be filed at the Commission but instead reported in Electric Quarterly Reports (EQRs). However, a conforming new or amended LGIA or SGIA would need to conform to the specific transmission provider's most recently revised *pro forma* LGIA and *pro forma* SGIA, which would include the requirements of this final action. The Commission clarifies that the final action is intended to apply to all existing generating facilities that submit a new interconnection request that results in an executed or unexecuted interconnection agreement, regardless of whether that agreement is filed at the Commission or merely reported in EQRs.

G. Application to Existing Generating Facilities That Do Not Submit New Interconnection Requests That Result in an Executed or Unexecuted Interconnection Agreement

1. NOPR Proposal

136. In the NOPR, the Commission sought comment on the proposal to apply the proposed reforms only to newly interconnecting generating facilities. In particular, the Commission sought comment on whether additional primary frequency response performance or capability requirements for existing facilities are needed, and if so, whether the Commission should impose those requirements by: (1) Directing the development or modification of a reliability standard pursuant to section 215(d)(5) of the FPA; or (2) acting pursuant to section 206 of the FPA to require changes to the *pro forma* OATT.[293]

2. Comments

137. Most commenters oppose applying the proposed primary frequency response requirements to existing generating facilities.[294] Several commenters argue that requiring existing generating facilities to install and operate governors or equivalent controls would be overly expensive and unnecessarily burdensome.[295] Specifically, AWEA contends that a retroactive primary frequency response requirement would be particularly costly for older wind turbines with fixed blades that cannot physically provide primary frequency response, newer wind turbines that would still require substantial hardware and software changes, and turbines from vendors that are out of business.[296] Moreover, some commenters argue that a blanket requirement is unnecessary given generally adequate levels of frequency response at this time.[297]

138. NERC and the NYTOs contend that it is too soon after the implementation of Reliability Standard BAL–003–1.1 to determine whether it is necessary or appropriate to impose requirements for primary frequency response on existing generating facilities.[298]

139. On the other hand, Bonneville and ISO–RTO Council support reforms that would apply to existing generating facilities, suggesting that the Commission direct NERC to develop a Reliability Standard for frequency response. While Bonneville states that the cost to retrofit existing generators may be prohibitive, it contends that a standard similar to TRE's regional Reliability Standard BAL–001–TRE–01, which requires generator owners/operators in the Texas region to set their governors to meet performance requirements, would ensure both capability and performance.[299] ISO–RTO Council argues that the development of a Reliability Standard will spread frequency response requirements over many generating facilities in a non-discriminatory manner and help facilitate compliance with Reliability Standard BAL–003–1.1.[300]

140. Other commenters suggest that the Commission should wait to apply the proposed reforms to existing generation facilities until further research is completed. APPA et al. state that NERC's required report on the availability of generating facilities to provide frequency response,[301] due in July 2018, will better inform the Commission whether further action is needed on existing generating facilities.[302] WIRAB states that while it does not believe new or modified Reliability Standards are currently needed, it recommends that the Commission ''direct NERC and the Regional Entities to measure and monitor frequency response, particularly governor response and withdrawal, in Event Analysis and track resulting trends,'' [303] and develop guidelines and best practices that reflect regional differences.[304] WIRAB states

[287] *See pro forma* LGIP Sec. 4.4.3.

[288] *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 168.

[289] Xcel Comments at 6.

[290] *Id.* at 4.

[291] ISO–RTO Council Comments at 8.

[292] *See* NOPR, 157 FERC ¶ 61,122 at PP 46, 54, 63.

[293] NOPR, 157 FERC ¶ 61,122 at PP 3, 57.

[294] PG&E, APPA et al., AWEA, NRECA, WIRAB, ELCON, Competitive Suppliers, TVA, Public Interest Organizations, and Sunflower and Mid-Kansas oppose expanding the applicability of the reforms to existing generating facilities.

[295] APPA et al. Comments at 7–8; NRECA Comments at 10; Public Interest Organization Comments at 4; ELCON Comments at 5–6.

[296] AWEA Comments at 4.

[297] NRECA Comments at 10; WIRAB Comments at 10–12; Competitive Suppliers Comments at 6.

[298] NERC Comments at 8; NYTOs Supplemental Comments at 3–4.

[299] Bonneville Comments at 3–4.

[300] ISO–RTO Council Comments at 13.

[301] Order No. 794, 146 FERC ¶ 61,024 at P 3.

[302] APPA et al. Comments at 3–4.

[303] WIRAB Comments at 10.

[304] *Id.* at 4.

that NERC's Frequency Response Annual Analysis Report ''can easily be expanded to track trends, model and analyze frequency response in each of the interconnections over a 10-year time horizon, and to make recommendations regarding current and future frequency response needs.'' [305] WIRAB states that if significant declines in frequency response occur, such as decreasing frequency nadirs or continued evidence of governor withdrawal, the Commission could then direct NERC and the Regional Entities to develop or modify their mandatory reliability standards and/or update NERC's Primary Frequency Control Guideline to ensure frequency response is preserved.[306]

141. In order to encourage regional flexibility and periodic updating of the proposed maximum droop and deadband settings, WIRAB recommends that the Commission direct NERC and the Regional Entities ''to monitor frequency response capability in each region, revisit and revise NERC's droop and deadband setting guidelines as needed, and generated best practices'' to encourage generating facilities to ''appropriately tighten regional droop and deadband settings as needed to maintain system reliability.'' [307] Further, WIRAB recommends that the Commission periodically reexamine the specific droop and deadband settings, which should not be viewed as a ''once-and-for-all decision.'' [308] In support of its position, WIRAB reminds the Commission that NERC's Primary Frequency Control Guideline states that tighter deadband settings of approximately ±0.017 Hz can be successfully implemented and encouraged efforts to lower deadband settings to that level.[309]

142. Similarly, ISO–RTO Council requests the monitoring of the need for existing generators to provide primary frequency response. ISO–RTO Council acknowledges that NERC and the industry have already taken steps to ensure sufficient primary frequency response, including the development of Reliability Standard BAL–003–1.1, publishing an operating guide for generating facilities, outreach to governor and controls manufacturers, conducting webinars, as well as outreach to the North American Generator Forum.[310] ISO–RTO Council asserts that the Commission should not delay the issuance of the final action by requiring the development of a Reliability Standard for existing generating facilities.[311] Instead, it maintains such requirements should be evaluated and, if necessary, proposed in a future proceeding.[312]

3. Commission Determination

143. We will not impose primary frequency response requirements on existing generating facilities that do not submit new interconnection requests that result in an executed or unexecuted interconnection agreement. We conclude that applying the proposed requirements only to newly interconnecting generating facilities will adequately address the Commission's concerns regarding primary frequency response. We are persuaded by commenters that requiring existing generating facilities that have not submitted a new interconnection request to install and operate governors or equivalent controls would be overly expensive and unnecessarily burdensome.[313] The record indicates that costs of installing primary frequency response capability is minimal for newly interconnecting generating facilities, and as such, we do not believe that a mandate for compensation is needed at this time. However, the record also indicates that the expense to some existing facilities may be cost prohibitive,[314] for example if retrofits are needed, and accordingly we believe that applying the requirements to existing generating facilities may be unduly burdensome.

144. We agree that NERC, the Regional Entities, and other affected industry stakeholders should continue to measure and monitor the impact of Reliability Standard BAL–003–1.1 on generating facility frequency response performance, and the amount and adequacy of primary frequency response generally. We note that Order No. 794 required NERC to file in July 2018 the results of a study on the availability of existing generating facilities to provide primary frequency response.[315] We expect that NERC's July 2018 report will inform the Commission if additional action is warranted regarding the need to impose additional requirements on existing generating facilities.

145. NERC's July 2018 report will afford an opportunity for all interested parties to consider WIRAB's recommendation to expand the scope of NERC's Frequency Response Annual Analysis Report and/or State of Reliability Report to ''track trends, model and analyze frequency response in each of the [I]nterconnections over a 10-year time horizon, and to make recommendations regarding current and future frequency response needs.'' [316] The July 2018 report may also provide insight into whether NERC should consider tracking and reporting the resulting trends of frequency response performance at the regional level (*e.g.,* at the regional entity or balancing authority level), and if necessary, develop guidelines and/or best practices that reflect regional differences.[317] This will allow the Commission to access future standards directives, as necessary.

146. We also encourage NERC to review, and if necessary, update its Primary Frequency Control Guideline as appropriate to reflect changes in the generation resource mix, particularly as it pertains to the technical attributes of non-synchronous generating facilities.

147. In addition, NERC and the Regional Entities should also continue to monitor the operation and impact of the operating requirements for droop, deadband, and sustained response adopted in this final action, and recommend to the Commission any changes to those settings (*e.g.,* lower droop values or tighter deadband settings) in the future that may become appropriate in light of changed circumstances.

H. Requests for Exemption or Special Accommodation

1. Combined Heat and Power Facilities

a. NOPR Proposal

148. In the NOPR, the Commission proposed to apply the primary frequency response capability and operating requirements to all newly interconnecting generating facilities, including CHP facilities.

b. Comments

149. ELCON and API contend that the special characteristics of industrial CHP generating facilities warrant an exemption or special accommodation from the proposed revisions to the *pro forma* LGIA and *pro forma* SGIA.[318]

[305] *Id.* at 10.

[306] *Id.* at 11.

[307] *Id.* at 4.

[308] *Id.*

[309] *Id.* at 4–5.

[310] ISO–RTO Council Comments at 11, n.23.

[311] *Id.*

[312] *Id.*

[313] APPA et al. Comments at 7–8; NRECA Comments at 10; Public Interest Organization Comments at 4; ELCON Comments at 5–6.

[314] *See, e.g.,* Bonneville Comments at 3.

[315] Order No. 794, 146 FERC ¶ 61,024 at P 3.

[316] *See* WIRAB Comments at 10.

[317] NERC already tracks frequency response performance at the Interconnection-wide level in its annual State of Reliability Report.

[318] ELCON Comments at 8–9; API Comments at 4–5. The Commission notes that API states that CHP and cogeneration facilities are interchangeable. *See* API Comments at 2. However, this final action uses

Continued

ELCON is concerned that, because of the unique connection between their generation and industrial equipment, the mandatory nature of the new primary frequency response requirements could adversely impact the manufacturing processes of its member companies. ELCON asserts that the generation equipment in CHP facilities ''which are part and parcel of the load itself, cannot be treated as if they were conventional, stand-alone generators, and forcing them to act as stand-alone generation will compromise and potentially harm the manufacturing process by interfering with the steam balance.'' [319]

150. In particular, ELCON explains that ''[g]eneration equipment that is integrated with industrial process equipment is operated to optimize the overall manufacturing process including the safe operation of critical infrastructure'' and that ''[r]equiring all industrial generation to provide primary frequency response without respect to the operational needs of the manufacturing process may jeopardize the reliability and safe operation of both.'' [320]

151. ELCON explains that there are a ''wide variety of configurations and capacities in the universe of CHP generators that are dedicated to an industrial process,'' with some CHP industrial facilities designed to generate in excess of their load having ''the flexibility to provide [primary frequency response] to the extent their industrial process would not be impacted.'' [321] ELCON also notes that other CHP facilities are sized to match their industrial load, ''which in reality means sized to the steam or thermal requirement of the host manufacturing process.'' [322] ELCON asserts that ''[s]uch facilities cannot reasonably provide [primary frequency response] service without compromising the efficiency, reliability and safe operation of the manufacturing process.'' [323]

152. For example, ELCON states that an increasing number of manufacturers are installing turbines at their industrial facilities to obtain lower emissions and other benefits [324] that are susceptible to a loss of combustion during certain types of frequency excursions. ELCON explains that such events could have severe consequences, including load curtailment and suspension, a manufacturing shutdown, and execution of emergency procedures to de-pressure and stabilize equipment.[325] ELCON states that additional implications of such events include ''the loss of production, possibly for an extended period, additional maintenance and repair costs for equipment, additional personnel costs, excess emissions during shutdown and startup procedures, and although the shutdown process is designed to be executed safely and effectively, some increased potential for safety, health, and environmental consequences.'' [326] During under-frequency conditions, the provision of primary frequency response results in increased MW output, which ELCON explains may result in a level of steam production that exceeds the operating requirements of the manufacturing process.[327]

153. To address these concerns, ELCON states that ''the proposed LGIA and SGIA language should be revised to explicitly exclude imposition of mandatory primary frequency response obligations on industrial CHP units and other similarly-situated forms of industrial behind-the-meter generation.'' [328] ELCON proposes the following new language for the *pro forma* LGIA, Section 9.6.4.3 and *pro forma* SGIA, Section 1.8.4.3 to specifically exempt ''industrial behind-the-meter generation that is sized-to-load (*i.e.,* the industrial load and the generation are near-balanced in real-time operation and the generation is controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirement of its host industrial facility).'' [329] ELCON asserts, however, that an exemption from the mandatory primary frequency response obligation still could allow certain industrial processes that are capable of providing primary frequency response to opt-in to such arrangements.[330]

154. API supports ELCON's exemption request, adding that CHP facilities bring certain benefits such as high efficiency and lowered emissions and that the proposal may present a barrier to entry for such generating facilities.[331] API contends that adjusting operating levels for reasons outside of the manufacturing process, such as in response to instructions of the balancing authority, ''risks a decline in CHP efficiency and may introduce substantial risks to the manufacturing process.'' [332] Accordingly, API requests that the final action exempt all CHP technologies from maintaining and operating automatic turbine-generator governors as a condition of interconnection, regardless of whether they are sized for load or not.[333]

c. Commission Determination

155. The Commission exempts newly interconnecting CHP facilities that are sized to serve on-site load and have no material export capability from the operating requirements of this final action. However, considering the low costs associated with governor installation, we will require all newly interconnecting CHP facilities, including those sized-to-load, to install a governor or equivalent control equipment capable of providing primary frequency response as a condition of interconnection as proposed in the NOPR.[334] We believe that it is prudent to require newly interconnecting CHP facilities to install primary frequency response capability now in the event that there is an increased need in the future for primary frequency response capability. Further, we adopt, with certain modifications, the definition of ''sized-to-load'' contained in ELCON's proposed new language for the *pro forma* LGIA and *pro forma* SGIA.[335] In particular, we define CHP facilities that are ''sized-to-load'' as those generating facilities that are behind-the-meter generation that are sized-to-load (*i.e.,* the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirement of its host facility).[336] We believe that ELCON's request to limit the definition of ''sized-to-load'' only to industrial CHP facilities is too narrow.

156. We agree with ELCON and API that CHP facilities sized-to-load present

only the term ''CHP'' to avoid confusion with ''cogeneration facility,'' which is a defined term under the Public Utility Regulatory Policies Act of 1978. *See* 18 CFR 292.203(b) and 292.205 (2017).

[319] ELCON Comments at 9.

[320] *Id.* at 8.

[321] ELCON Supplemental Comments at 2–3.

[322] *Id.*

[323] *Id.*

[324] Combustion turbines operating in ''lean-burn'' mode use a higher air to fuel ratio (*i.e.,* excess air is allowed into the process) to reduce NOx emissions.

[325] ELCON Supplemental Comments at 4.

[326] *Id.* at 4–5.

[327] *Id.* at 6. ELCON raises an additional concern that mandating primary frequency response could discourage the development of CHP facilities ''because of the added investment cost, operational risk, efficiency loss and regulatory burden.'' *Id.* at 9.

[328] *Id.* at 9.

[329] *Id.* at 11.

[330] *Id.*

[331] API Comments at 5.

[332] *Id.*

[333] *Id.* at 4.

[334] ELCON noted ''the low costs triggered by the NOPR's limited applicability to only new generation facilities'' when agreeing with the Commission's proposal not to mandate compensation. ELCON Comments at 6.

[335] *See* ELCON Supplemental Comments at 11.

[336] *Id.*

unique concerns regarding the efficiency, reliability, and safe operation of their industrial processes that warrant this exemption. For example, ELCON notes that an increasing number of interconnection customers with CHP facilities are using turbines susceptible to a loss of combustion during certain types of frequency excursions, and that such events could have severe consequences, including load curtailment and suspension, a manufacturing shutdown, and execution of emergency procedures to de-pressure and stabilize equipment.[337] Additionally, during under-frequency conditions, the provision of primary frequency response results in increased MW output, which ELCON explains may result in a level of steam production that exceeds the operating requirements of the manufacturing process.[338]

2. Electric Storage Resources

a. NOPR Proposal

157. The NOPR proposed to apply the primary frequency response capability and operating requirements to all new generating facilities, including electric storage resources, without exception.

b. Comments

i. NOPR Comments

158. While most comments on the NOPR did not specifically request an exemption for electric storage resources, some commenters suggest changes to the proposed *pro forma* LGIA and *pro forma* SGIA provisions to accommodate electric storage resources. In particular, ESA argues that the proposed requirements disproportionately affect electric storage resources in four ways.[339] First, ESA states that the use of a nameplate capacity basis for primary frequency response will require storage to provide more frequent and greater magnitude of primary frequency response service than traditional generating facilities.[340] For example, ESA argues if a traditional generating facility with a nameplate capacity of 100 MW has a minimum set point of 40 MW, the primary frequency response service will be based on the 60 MW of capacity above that minimum set point. However, ESA states that electric storage has no minimum set point and is capable of operating at the full range of its capacity for withdrawals and injections.[341]

159. Second, ESA claims that whereas traditional generating facilities start-up and shut-down as a part of normal operations and are not required to provide primary frequency response while offline, electric storage resources are, by contrast, ''always online'' even when not charging or discharging.[342] Therefore, ESA suggests that electric storage resources will be available, on a more frequent basis, to provide primary frequency response than other generating facilities that go offline.[343] Third, ESA states that different electric storage technologies have different optimal depths of discharge, and exceeding the optimal depth of discharge accelerates the degradation of the facility and increases operations and maintenance costs. ESA asserts that this scenario indicates the potential of the use of nameplate capacity as the basis for primary frequency response to result in a disproportionate impact on electric storage resources.[344]

160. Fourth, ESA notes that unlike traditional generating facilities, electric storage is energy limited. Thus, ESA argues that the requirement to sustain output in proposed section 9.6.4.2 of the *pro forma* LGIA poses unique regulatory and financial exposure, such as NERC violations and lost revenues in future intervals, especially when a storage resource is at a low state of charge subsequent to the provision of energy or ancillary services.[345]

161. ESA claims that, for these reasons, the proposal is unduly discriminatory by potentially burdening storage, and recommends that the NOPR proposal be modified to: (1) Establish a minimum set point for primary frequency response service; and (2) include inadequate state of charge as an explicit operational constraint exempting storage from maintaining sustained output.[346] Absent these requested changes, ESA requests a complete exemption for electric storage resources.[347]

162. AES Companies request a complete exemption from the proposed NOPR requirements for electric storage resources including but not limited to battery storage devices providing one or more ancillary services.[348] AES Companies assert that the proposed requirement of a maximum five percent droop setting, if imposed, would unnecessarily limit the benefits that electric storage resources specifically designed for primary frequency response can contribute to grid stability.[349] AES Companies also state that a five percent droop setting ignores the majority of the primary frequency response capacity that an electric storage resource was designed to deliver by directing the resource to deliver only a fraction of its benefits.[350] AES Companies further argue for an exemption from the requirement to dedicate a portion of the capacity of an electric storage resource for the provision of primary frequency response.[351] AES Companies state that droop parameters should be specific to the technology, and that requiring, for instance, a lithium ion battery to provide primary frequency response at its full capacity would require a droop approaching 0 percent.[352]

ii. Supplemental Comments

163. Supplemental commenters are split on whether electric storage resources should be subject to the operating requirements proposed in the NOPR. Tri-State, ISO–RTO Council, Berkshire, NERC, and WIRAB support applying the proposed requirements to electric storage resources. SoCal Edison opposes the proposed operating requirements, but explains that if the Commission adopts the proposal, it should be applicable to all newly interconnecting generating facilities on a technology neutral basis so that such requirements will be implemented in a non-discriminatory fashion.[353]

164. However, Sunrun, AES Companies, and CESA comment that electric storage resources would bear a disproportionate impact compared to other resources due to the proposed droop and sustained response requirements, and therefore request an exemption or an accommodation from the proposed requirements. Several other commenters reiterate their initial NOPR comments that operating requirements for primary frequency response should not be included in the *pro forma* LGIA and *pro forma* SGIA, stating that a market-based approach to

[337] ELCON Supplemental Comments at 4.

[338] *Id.* at 6. ELCON raises an additional concern that mandating primary frequency response could discourage the development of CHP facilities ''because of the added investment cost, operational risk, efficiency loss and regulatory burden.'' *Id.* at 9.

[339] ESA Comments at 3.

[340] *Id.* at 3–4.

[341] *Id.*

[342] *Id.* at 4.

[343] *Id.*

[344] *Id.* at 3–4.

[345] *Id.* at 4.

[346] *Id.* at 4–5.

[347] *Id.* at 5.

[348] *See* AES Companies Comments at 17, 19 (*i.e.,* specified changes to the *pro forma* language).

[349] *Id.* at 6. AES Companies contend that a five percent droop will limit the amount of capacity that an electric storage resource can dedicate to primary frequency response service.

[350] *Id.*

[351] *Id.* at 6. The Commission notes that in the NOPR, it did not propose any mandatory headroom requirements.

[352] AES Companies Comments at 7.

[353] SoCal Edison Supplemental Comments at 2.

primary frequency response, or regional flexibility in facilitating the provision of primary frequency response (*e.g.,* allowing balancing authorities to determine which generating facilities should supply primary frequency response) would lead to more efficient and cost effective outcomes.[354]

165. A number of commenters reference either technical or economic challenges that would be unique to electric storage resources under the proposed requirements. Sunrun, ESA, and CESA state that electric storage resources have a finite lifecycle, and that compliance with the proposed operating requirements for timely and sustained response may limit the lifetime of an electric storage resource.[355] These commenters also assert that different electric storage technologies will have different depths of discharge and may face different challenges under the proposed operating requirements.

166. ESA argues that the proposed droop and sustained response requirements would impose adverse conditions on electric storage resources because they would bear a disproportionate impact on the provision of primary frequency response capability compared to other generating facilities. In particular, ESA asserts that because electric storage resources are energy-limited, it is inappropriate to require electric storage resources to provide sustained response because doing so would constrain electric storage resources from effectively managing their fuel supply (*i.e.,* state of charge), potentially reducing their ability to fulfill service obligations and creating an effective headroom requirement.[356]

167. ESA restates its NOPR comment that droop is calculated as a percent of nameplate capacity above a minimum set point, and because electric storage resources lack such a set point, storage resources will be required to provide proportionally greater primary frequency response service.[357] In addition, ESA states that if an electric storage resource is charging when called upon to provide primary frequency response, the switch to discharging means that the electric storage resource will provide both the injected energy and the removal of an effective ''load,'' creating a response significantly greater than contemplated in the proposed droop settings.[358] However, EPRI states that this concern can be mitigated if the Commission makes certain clarifications in the final action. In particular, EPRI states that the NOPR requirement setting the droop curve at no more than five percent, based on nameplate capacity, can be assumed to refer to a slope equating to a five percent change in frequency causing a change in the full discharge capacity (not discharge capacity plus charge capacity) of the electric storage resource.[359] Both AES Companies and ESA comment that the proposed deadband and timely response requirements do not pose challenges or adverse operational impacts for most electric storage resources.[360]

168. Additionally, ESA claims that since electric storage resources are always ''online,'' as opposed to generating facilities that start-up and shut-down (*i.e.,* go offline), electric storage resources would be available to provide primary frequency response on a more frequent basis, and would therefore be expected to provide more primary frequency response service than generating facilities that go offline.[361] On the other hand, APS states that while it acknowledges that electric storage resources could provide more primary frequency response than other resources, such provision will be limited by the obligations and operational characteristics and design of such resources, similar to all other resource types. In particular, if there is to be a minimum state of charge below which electric storage resources would not have to provide primary frequency response, these resources may not be providing primary frequency response of greater magnitude than other resources.[362]

169. Several commenters assert that there is little substantive difference between the operating constraints faced by electric storage resources and the operational characteristics that limit the capacity of other types of generating facilities to provide primary frequency response.[363] For example, NERC asserts that ''run-of-river hydro units may have insufficient river flow, thermal units may have discharge temperature limitations on cooling water, gas turbines may need to be derated during the summer, pumped storage may not have yet refilled storage reservoirs, and units may be in the middle of coming on or going off-line.'' [364] NERC states that while several types of generating facilities have technical limitations that may inhibit their ability to provide primary frequency response under certain circumstances, these operating constraints should not preclude any generating facility from maintaining primary frequency response capability.[365] A number of supplemental commenters state that any determination regarding accommodations to mitigate such operational constraints, including, for example, the threshold limit below which an electric storage resource should be required to provide primary frequency response or allowed to disconnect from the grid during low frequency events, must be made on a case-by-case basis and can be done during the interconnection process.[366] Further, APS comments that the operational wear and tear on electric storage resources and its impact on the overall life expectancy of an electric resource is not significantly different than the potential impact of wear and tear on other generating facilities.[367]

170. ISO–RTO Council also believes that possible accommodations or exemptions for electric storage resources and small generators are unwarranted, stating that such measures could allow such resources to avoid solving the very problem to which such resources contribute and the NOPR rules were intended to address.[368] ISO–RTO Council asserts that the proposed requirements are consistent with the recommendations and guidelines contained in NERC's Primary Frequency Control Guideline, and are similar to the current requirements of PJM, ISO–NE, and CAISO for electric storage resources and/or small generators to install, maintain and operate primary frequency response related equipment as a condition of interconnection ''that have not required exemptions for either electric storage resources or small generators.'' [369] ISO–RTO Council

[354] *See, e.g.,* EEI Comments at 4–5.

[355] Sunrun Supplemental Comments at 2; ESA Supplemental Comments at 4; CESA Supplemental Comments at 11.

[356] ESA Supplemental Comments at 3.

[357] *Id.* at 4.

[358] *Id.*

[359] EPRI Supplemental Comments at 6.

[360] AES Companies Supplemental Comments at 23; ESA Supplemental Comments at 6.

[361] ESA Supplemental Comments at 7.

[362] APS Supplemental Comments at 6.

[363] *See, e.g.,* APS Supplemental Comments at 4; NERC Supplemental Comments at 5, stating that operating constraints should not preclude any new generating facility from maintaining primary frequency response capability.

[364] NERC Supplemental Comments at 5.

[365] *Id.*

[366] *See, e.g.,* APS Supplemental Comments at 5, 7; EPRI Supplemental Comments at 12–13; NRECA Supplemental Comments at 3; NERC Supplemental Comments at 5, stating that interconnection customers should evaluate any ''technical limitations on a unit-by-unit basis and coordinate with their NERC Balancing Authority and Interconnection Agreement Transmission Provider/Transmission Owner, as appropriate.''

[367] APS Supplemental Comments at 7.

[368] ISO–RTO Council Supplemental Comments at 2.

[369] *Id.* at 3.

further notes that primary frequency response capability requirements that already exist in ''areas with substantial penetration of renewable resources'' in the European Union have not had ''negative impacts.'' [370]

171. EPRI states that the unique characteristics of electric storage resources should not directly affect the current requirements for droop settings.[371] Specifically, EPRI comments that there is a limited amount of additional power required (2 percent of nameplate or less for a 0.1 Hz frequency deviation) and a limited amount of time it must be sustained (generally five minutes or less, maximum about seven minutes).[372] EPRI concludes that the energy required to provide sustained frequency response is very small in relation to the energy that the electric storage resource would be providing otherwise.[373]

172. While ESA supports an exemption for electric storage resources, it suggests several accommodations to the proposed requirements to mitigate the potentially adverse impact of the proposed requirements on electric storage resources. ESA asserts that electric storage resources should have a means to effectively ''go offline,'' similar to generating facilities on shut down, and that the language ''whenever the Large Generating Facility is operated in parallel with the Transmission System'' in Section 9.6.2.1 should be interpreted to mean providing services to the grid and should exclude simply being idle.[374] WIRAB adds that it would not be just and reasonable to require an electric storage resource to enable primary frequency response while in standby mode when other generating facilities are not subject to a similar requirement.[375]

173. ESA also suggests that electric storage resources should be exempt from requirements for providing sustained primary frequency response when such a resource does not have enough energy stored to provide sustained frequency response at required capacity when a frequency deviation occurs (*i.e.,* inadequate state of charge).[376] ESA states that this exemption for ''inadequate state of charge'' should be included along with the allowances for ambient temperature limitations, outages of mechanical equipment, and regulatory requirements in the proposed tariff language of Section 9.6.4.2. WIRAB agrees that the concept of energy limitation should be included as an exemption to sustained response in proposed Section 9.6.4.2 of the *pro forma* LGIA and 1.8.4.2 of the *pro forma* SGIA, but clarifies that this exemption should not apply only to electric storage resources because other generating facilities also face energy limitations.[377]

174. ESA states that, in lieu of other mechanisms to accommodate electric storage resources, operators of electric storage resources could specify an operating range outside of which electric storage resources would not be required to provide and/or sustain primary frequency response.[378] Doing so, according to ESA, would prevent the excessive wear and tear impacts on electric storage resources, as well as potentially mitigate inadequate state of charge for sustained response.[379] However, ESA states that even with this approach to mitigate adverse impacts of primary frequency response requirements, electric storage resources would continue to face constraints on state of charge management and a reduction in capability to provide other energy and ancillary services, primarily as a result of the unpredictable nature of abnormal frequency deviations.[380] APS comments that establishing a minimum set point or an operating range are both workable solutions, and argues that the Commission should allow flexibility in determining the approach on a case-by-case basis.[381] APS states that an operating range could be established through collaboration and evaluation during the interconnection process and included in the interconnection agreement.[382] EPRI comments that a static operating range could lead to inefficiencies.[383] AES Companies does not support the use of an operating range.[384]

175. SDG&E believes that markets for primary frequency response have the potential to eliminate nearly all the issues addressed by the questions in the Commission's Request for Supplemental Comments.[385] Berkshire recommends that the Commission acknowledge in the final action that electric storage resources are not always utilized as generation or accounted for as generation assets, and that the Commission consider holding a technical conference to discuss alternative applications for electric storage resources apart from providing primary frequency response within a prescribed bandwidth.[386]

c. Commission Determination

176. In consideration of the unique physical and operational characteristics of electric storage resources, we will require transmission providers to include in their *pro forma* LGIA and *pro forma* SGIA specific accommodations for electric storage resources and place limitations on when electric storage resources will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2, 9.6.4.3, and 9.6.4.4 of the *pro forma* LGIA and Sections 1.8.4, 1.8.4.1, 1.8.4.2, 1.8.4.3, and 1.8.4.4 of the *pro forma* SGIA, as applicable.

177. Specifically, as discussed in further detail below, this includes the identification of an operating range within which electric storage resources will be required to provide primary frequency response, the identification of particular operating circumstances when electric storage resources will not be required to provide primary frequency response, and the inclusion of energy limitations in the list of exemptions from the requirement to provide primary frequency response.

178. We disagree with SoCal Edison, ISO–RTO Council, and WIRAB that suggest electric storage resources should be subject to the same requirements for primary frequency response as all other resources.[387] We find that the provision of primary frequency response in accordance with the requirements of this final action may present challenges for some electric storage resources. Specifically, we are persuaded by ESA's comments that requiring an electric storage resource to sustain its output without any consideration for whether the electric storage resource has sufficient state of charge could result in depths of discharge that could accelerate the degradation of an electric storage resource. However, while we agree that electric storage resources could experience disproportionate harm from the proposed requirements under some circumstances, we are also persuaded by EPRI's suggestion that those harms would be modest and can be mitigated with certain

[370] *Id.* at 4 (citing ENTSO–E requirements for Generators, Chapter 1, Article 13).

[371] EPRI Supplemental Comments at 4.

[372] *Id.*

[373] *Id.*

[374] ESA Supplemental Comments at 8.

[375] WIRAB Supplemental Comments at 6.

[376] ESA Supplemental Comments at 10.

[377] WIRAB Supplemental Comments at 5.

[378] ESA Supplemental Comments at 12–13.

[379] *Id.* at 13.

[380] *Id.*

[381] APS Supplemental Comments at 9.

[382] *Id.* at 8–9.

[383] EPRI Supplemental Comments at 15.

[384] AES Companies Supplemental Comments at 38.

[385] SDG&E Supplemental Comments at 3–4

[386] Berkshire Supplemental Comments at 2–3.

[387] ISO-RTO Supplemental Comments at 4–5; SoCal Edison Supplemental Comments at 2; WIRAB Supplemental Comments at 3.

accommodations.[388] In particular, EPRI notes that ''the energy required to provide sustained primary frequency response is very small in relation to the energy that the electric storage resource would be providing otherwise due to provision of energy or other ancillary services such that the risk of running into state of charge limits would already be known and not likely impacted by provision of primary frequency response by itself.'' [389]

179. We are persuaded by ESA's comment that allowing operators of electric storage resources to specify an operating range ''would prevent the excessive wear and tear impacts on electric storage as well as potentially mitigate inadequate state of charge for sustained response.'' [390] Therefore, while acknowledging the limited degree of the amount of energy that will be required to provide sustained response,[391] we find that, on balance, limiting the circumstances under which electric storage resources are required to provide primary frequency response will adequately alleviate the potential for excessive wear and tear that may have otherwise been experienced by electric storage resources.

180. Specifically, we will require electric storage resources to identify in their interconnection request an operating range for the basis of the provision of primary frequency response. This operating range will represent the minimum and maximum states of charge between which an electric storage resource will be required to provide primary frequency response. The operating range for each electric storage resource will need to be agreed to by the interconnection customer and transmission provider, in consultation with the applicable balancing authority or any other relevant parties as appropriate, consider the system needs for primary frequency response, and the physical limitations of the electric storage resource as identified by the developer and any relevant manufacturer specifications, and be established in Appendix C of the *pro forma* LGIA (''Interconnection Details'') or Attachment 5 of the *pro forma* SGIA (''Additional Operating Requirements for the Transmission Provider's Transmission System and Affected Systems Needed to Support the Interconnection Customer's Needs''). We find that this operating range addresses concerns regarding excessive wear and tear on electric storage resources, mitigates the concerns about inadequate state of charge, and effectively allows electric storage resources to identify a minimum and maximum set point below and above which they will not be obligated to provide primary frequency response comparable to synchronous generation as suggested by ESA.[392]

181. However, we do not agree with ESA that electric storage resources should not be required to specify the details of an inadequate state of charge parameter in their interconnection agreements.[393] We find that requiring an electric storage resource to identify the states of charge at which it is unable to inject or receive additional energy to provide primary frequency response is necessary to mitigate the adverse impacts on electric storage resources while still requiring them to provide this essential reliability service when they are technically capable to do so. While we believe that the interconnection customer will have the best information regarding the physical capabilities of the electric storage resource and any limitations that should be placed on its operations due to manufacturer specifications, we also believe that the transmission provider will have the best information with respect to: (1) The expected magnitude of frequency deviations; (2) the expected duration that system frequency will remain outside of the deadband parameter; and (3) the expected incidence of frequency deviations outside of the deadband parameter. This information from the transmission provider is necessary for the interconnection customer to calculate the anticipated obligations to provide primary frequency response for an electric storage resource in terms of the energy requirements for individual incidents, as well as increased electricity throughput (*i.e.,* cycling) over the life of the electric storage resource. We note that both the physical limitations of the electric storage resource, as identified by the interconnection customer, and the expected primary frequency response system requirements, as identified by the transmission provider, may be necessary to determine the appropriate operating range for an electric storage resource. Therefore, we find that it is necessary to provide the interconnection customer with the ability to propose an operating range with its initial interconnection request, but also allow the transmission provider and/or balancing authority to consider the system needs for primary frequency response prior to reaching an agreement on the final operating range among the parties in a LGIA or SGIA. We also find that the transmission providers must treat electric storage resources in a not unduly discriminatory or preferential manner when determining the appropriate operating range.

182. Because the requirements for primary frequency response may change over time, the Commission is persuaded by commenters that it is appropriate to provide transmission providers with flexibility to determine whether the operating ranges established in the interconnection agreements for electric storage resources are static or dynamic values.[394] We understand that system conditions and contingency planning can change, which may alter the anticipated incidence, magnitude, and duration of frequency deviations. Additionally, the capabilities of electric storage resources to provide primary frequency response may change due to degradation, repowering, or changes in service obligations, and these may also need to be considered when revisiting a dynamic operating range.[395] If a transmission provider decides to implement a dynamic operating range for an electric storage resource to provide primary frequency response, it must also determine how frequently the operating range will be reevaluated and the factors that may be considered when reevaluating it either on a case-by-case basis in Appendix C of the *pro forma* LGIA and Attachment 5 of the *pro forma* SGIA, or as a standard approach filed in compliance with this final action. To the extent that the interconnection customer and the transmission provider

[388] ''If an electric storage resource is not providing any online service, it should not be required to provide primary frequency response to align with the rules designated in the NOPR.'' EPRI Supplemental Comments at 8; ''Resources claiming artificial minimum set points during operational time frames that they would not provide primary frequency response during over-frequency events can be managed on a case-by-case basis, if sufficient primary frequency response capability is otherwise available.'' EPRI Supplemental Comments at 10; ''The [operating] range should be provided if there are any ''rough zones'' for any technologies where primary frequency response is not controllable, not possible, or would lead to extraordinary damage or wear-and-tear costs.'' EPRI Supplemental Comments at 15.

[389] EPRI Supplemental Comments at 4.

[390] *See* ESA Supplemental Comments at 12–13.

[391] *See* EPRI Supplemental Comments at 4, stating that ''the energy required to provide sustained primary frequency response is very small in relation to the energy that the electric storage resource would be providing otherwise due to provision of energy or other ancillary services.''

[392] *See* ESA Supplemental Comments at 12–13.

[393] *See* ESA Supplemental Comments at 11.

[394] *See, e.g.,* APS Supplemental Comments at 8; EPRI Supplemental Comments at 15; ESA Supplemental Comments at 13.

[395] A dynamic operating range will allow the minimum and maximum state of charge values that define the operating range to change over time based on changing system needs and/or electric storage resource capabilities.

cannot agree on these issues, the interconnection customer has the right to request the filing of an unexecuted interconnection agreement to seek Commission resolution.

183. Additionally, we agree with comments that suggest certain electric storage technologies are always online and capable of providing primary frequency response, and that without any accommodation, those resources could be required to provide sustained primary frequency response more frequently than other generating facilities that start up and shut down (*i.e.,* go offline).[396] Therefore, we find that it is appropriate to place limitations on when electric storage resources are required to provide primary frequency response. In particular, we agree with EPRI that ''[if] an electric storage resource is not providing any online service, it should not be required to provide primary frequency response.'' [397] To require an electric storage resource to provide a service under conditions that other generating facilities are not required to provide it would raise discrimination concerns. Therefore, we revise the *pro forma* LGIA and *pro forma* SGIA to make clear that electric storage resources will only be required to provide primary frequency response when they are online and are dispatched to inject electricity to the grid and/or dispatched to receive electricity from the grid. We clarify that the requirement to provide primary frequency response will exclude situations when an electric storage resource is not dispatched to inject electricity to the grid and/or dispatched to receive electricity from the grid.

184. We also agree with WIRAB that electric storage resources and some other resources could face physical limitations that would make them unable to provide primary frequency response, and believe that accommodations for such limitations are appropriate.[398] While the previously discussed accommodations for electric storage resources are intended to limit adverse impacts of the primary frequency response requirements on them, we find that providing a specific exemption for physical energy limitations will not only further ensure that electric storage resources are not required to provide primary frequency response when they are physically unable to do so, but it will also prevent other resources that experience similar physical limitations from being required to provide the service when they are not able to. Conditions under which a resource is physically unable to provide primary frequency response could, for example, include an inability for an electric storage resource to increase its output because it does not have any stored energy (*i.e.,* its state of charge is equal to zero), or an inability for a wind or solar generating facility to increase output because there is not sufficient wind or solar energy to allow an increase in MW output.

185. Moreover, we find that including this exemption in the *pro forma* LGIA and *pro forma* SGIA is consistent with our finding that it is not necessary to establish a headroom requirement for primary frequency response. Because we are not requiring newly interconnecting generating facilities to maintain headroom to provide primary frequency response, we find that it is unjust and unreasonable to require the provision of primary frequency response from generating facilities that are physically unable to provide the service. Accordingly, we clarify that all generating facilities subject to this final action will be exempt from the timely and sustained frequency response requirements if they experience a physical energy limitation that would prevent them from fulfilling their obligations that would have otherwise been required under the parameters set forth in this final action. To implement this requirement, we modify the list of exemptions in Section 9.6.4.2 (Timely and Sustained Response) of the *pro forma* LGIA and Section 1.8.4.2 (Timely and Sustained Response) of the *pro forma* SGIA to include the term ''physical energy limitation.'' We define ''physical energy limitation'' to mean the circumstance when a resource would not have the physical ability, due to insufficient remaining charge for an electric storage resource or insufficient remaining fuel for a generating facility to satisfy its timely and sustained primary frequency response service obligation, as dictated by the magnitude of the frequency deviation and the droop parameter of the governor or equivalent controls. However, we also find that when a generating facility experiences a physical energy limitation, then the interconnection customer must be able to demonstrate to the transmission provider, and to the extent applicable, the relevant balancing authority, that such a physical energy limitation existed before or during an abnormal frequency deviation outside of the deadband parameter.

186. We find that ESA's comments that suggest a minimum set point should be used in the determination of the droop response are misplaced. A generating facility's minimum set point is not used in the calculation of the MW droop response. We clarify that for all generating facilities, the calculation of the MW droop response is based on a generating facility's nameplate capacity (*i.e.,* for a five percent droop curve, a generating facility would be expected to increase its output by 100 percent of its nameplate capacity for a five percent change in frequency). While it is true in theory that an electric storage resource may have a greater operating range over which to provide primary frequency response, from a practical standpoint the droop parameter limits the percentage of nameplate capacity that a generating facility will provide in response to abnormal frequency deviations.[399]

187. ESA contends that ''[i]f a storage resource is charging when called to provide [primary frequency response], the switch to discharging means that the storage [resource] will provide both the injected energy and the removal of an effective 'load,' creating a response significantly greater than contemplated in the proposed droop settings.'' [400] To address ESA's concern, we will require electric storage resources that are being dispatched to charge at the time of an abnormal frequency deviation to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which they are charging according to the droop parameter to satisfy the timely and sustained primary frequency response requirement. For example, if an electric storage resource is charging at two MW prior to an abnormal under-frequency deviation, and the calculated response per the droop parameter is to increase real-power output by one MW, the electric storage resource could satisfy its obligation by reducing its consumption by one MW (instead of completely reducing its consumption by the full two MW and then discharging at one MW, which would result in a net of three MW provided as primary frequency response). Further, if an electric storage resource is capable of switching from charging to discharging, or vice versa, within the time period that the primary frequency response is

[396] *See* ESA Supplemental Comments at 7.

[397] *See* EPRI Supplemental Comments at 8. EPRI states that the determination of a generating facility being online is ''it being connected to the grid and providing online services (energy or online ancillary services).''

[398] *See* WIRAB Supplemental Comments at 4.

[399] For example, as pointed out by EPRI, ''[a] [five percent] droop setting and 36mHz deadband equates to an individual resource having a frequency response of about [two percent of] nameplate capacity per tenth of a Hz at a tenth of a Hz frequency deviation.'' EPRI Supplemental Comments at 7.

[400] ESA Supplemental Comments at 3–4.

needed the resource should do so if necessary to meet its calculated response. For example, if an electric storage resource is charging at one MW prior to an abnormal under-frequency deviation, and the calculated response per the droop parameter is to increase real-power output by three MW, the electric storage resource could satisfy its obligation by switching from charging at one MW to discharging at two MW. We clarify that electric storage resources would not be required to change from charging to discharging, or vice versa, if they are not technically capable of making the transition during the period in which the primary frequency response is needed.

188. Regarding AES Companies' contention that a five percent droop setting ignores the majority of the primary frequency response capacity that an electric storage resource was designed to deliver,[401] we note that, as stated in the NOPR, the requirements adopted in this final action are *minimum* requirements; therefore, if a new generating or electric storage facility elects, in coordination with its transmission provider and/or balancing authority, to operate in a more responsive mode by using lower droop or tighter deadband settings, nothing in these requirements would prohibit it from doing so.[402]

189. Finally, we are not persuaded by Berkshire that a technical conference is needed at this time because there is sufficient evidence in the record to make a finding on this issue, as discussed in this final action.

3. Distributed Energy Resources

a. NOPR Proposal

190. In the NOPR, the Commission proposed to apply the primary frequency response capability and operating requirements to all newly interconnecting generating facilities interconnecting through an LGIA or SGIA.[403]

b. Comments

191. Several commenters assert that the final action should include special considerations for generating facilities connecting at the distribution level. Public Interest Organizations state that, in the NOI, SolarCity Corporation raised concerns that already-installed behind-the-meter generation and DERs could become subject to the *pro forma* SGIA should those DERs opt to participate in wholesale energy markets.[404] Public Interest Organizations request that the Commission clarify the circumstances in which DER participation in wholesale energy markets would trigger requirements in the SGIA because ''[u]nless warranted by a significant shortfall of primary frequency response service, requiring the retrofit of existing generators for primary frequency response capability under such circumstances would not be cost-effective.'' [405] TVA states that exceptions to the primary frequency response requirements could reasonably be justified for generating facilities interconnected only through lower voltage distribution systems.[406]

192. Xcel argues that dynamic frequency response at the distribution level can interfere with anti-islanding [407] protection methods, and that, unlike transmission-connected generation, generating facilities connected to the distribution system must meet the anti-islanding requirements of the Institute of Electrical and Electronics Engineers (IEEE) Standards to protect the distribution system.[408] Xcel explains that the IEEE anti-islanding standards may require that the primary frequency response of the facility be restricted or that suitable mitigation measures be installed.[409] Accordingly, Xcel asserts that the *pro forma* SGIA should require that the distribution system operator be notified of the primary frequency response capabilities of a generating facility to be connected to the distribution system, and that the distribution system operator must have the ability to place limitations on the primary frequency response of the generating facility if such limitations are required to ensure system reliability and power quality.[410]

c. Commission Determination

193. The requirements of this final action will apply to newly interconnecting DERs that execute, or request the unexecuted filing of, an LGIA or SGIA on or after the effective date of this final action. We find Public Interest Organizations' request that the Commission clarify the circumstances in which DER participation in wholesale energy markets would trigger requirements in the *pro forma* SGIA to be outside the scope of this proceeding.[411]

194. Xcel is concerned that dynamic frequency response at the distribution level can interfere with anti-islanding protection methods. The sustained response provisions adopted herein would require a generating facility, only to the extent that it is allowed to remain online and ride through a disturbance and has operating capability in the direction needed to counteract the frequency deviation, to provide and sustain its response.

195. The Commission in Order No. 828 provided flexibility to address anti-islanding concerns by finding that, if a transmission provider believes a particular facility has a higher risk of unintentional islanding due to specific conditions at that facility, the transmission provider may coordinate with the small generating facility to set ride through settings appropriate for those conditions, in accordance with Good Utility Practice and the appropriate technical standards.[412] For those facilities with a lower risk of forming an unintentional island, the Commission found that they can be held to a longer ride through requirement.[413]

196. We clarify that the sustained response provisions in the revisions to the *pro forma* LGIA and *pro forma* SGIA apply only when a generating facility is allowed to ride through, and do not supersede a generating facility's ride through settings, or require an interconnection customer to override anti-islanding protection or any protective relaying that has been set to

[401] AES Companies Comments at 6.

[402] NOPR, 157 FERC ¶ 61,122 at P 48.

[403] Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 7, *order on reh 'g,* Order No. 2006–A, FERC Stats. & Regs. ¶ 31,196, *order on clarification,* Order No. 2006–B, FERC Stats. & Regs. ¶ 31,221.

[404] Public Interest Organizations Comments at 3.

[405] *Id.* at 3–4.

[406] TVA Comments at 4.

[407] Islanding refers to the condition in which a DER continues to power a location even though electrical grid power from the electric utility is no longer present. Unintentional islanding can pose a hazard to utility personnel and customer equipment, and it may prevent automatic re-connection of devices. The currently effective version of IEEE–1547 standard requires that for an unintentional island in which the DER energizes a portion of the distribution system, the DER shall detect the island and cease to energize the system within two seconds of the formation of an island.

[408] Xcel Comments at 9; IEEE Standard 1547–2003, *Interconnecting Distributed Resources with Electric Power Systems* and IEEE Standard 1547a–2014, *Interconnecting Distributed Resources with Electric Power Systems Amendment 1.*

[409] Xcel Comments at 9.

[410] *Id.*

[411] CAISO, ISO–NE, MISO, NYISO, PJM, and SPP all have programs that allow demand response and/or certain demand-side resources to aggregate and participate in wholesale markets. The CAISO model requires a prospective DER aggregator to execute a Distributed Energy Resource Provider Agreement to accept and abide by the terms of the CAISO Tariff, but does not require the DER aggregator nor the aggregated DERs to execute an SGIA. *See Cal. Indep. Sys. Operator Corp.,* 155 FERC ¶ 61,229, at P 1 (2016) (conditionally accepting tariff provisions to facilitate participation of aggregations of distribution-connected or distributed energy resources in CAISO's energy and ancillary service markets).

[412] *See* Order No. 828, 156 FERC ¶ 61,062 at P 28.

[413] *Id.*

disconnect the generating facility during certain abnormal system conditions. Further, we clarify that for those abnormal system conditions in which a generating facility is *not* tripped offline by anti-islanding or protective relays and remains connected, to the extent it has the necessary MW operating capability in the appropriate direction to correct the frequency deviation, it would be expected to provide and sustain primary frequency response.

197. Accordingly, the obligations imposed for primary frequency response apply only to generating facilities allowed to ride through and, because the ride through settings will be coordinated between the interconnection customer and the transmission provider, we believe this should adequately address Xcel's anti-islanding concerns.

4. Nuclear Generating Facilities

a. NOPR Proposal

198. In the NOPR, the Commission proposed to exempt generating facilities regulated by the NRC due to their unique operating characteristics and regulatory requirements.

b. Comments

199. Several commenters support the exemption for nuclear generating facilities.[414] EEI and the MISO TOs agree with the proposed exemption, explaining that nuclear units are restricted by their NRC operating licenses on the amount of primary frequency response, if any, they can provide for safety reasons.[415] EEI also noted that in comments filed in response to the NOI, the Nuclear Energy Institute pointed out that nuclear plants are not well-suited to provide primary frequency response, and emphasized the role of the NRC as the safety regulator for commercial nuclear operations and its regulatory restrictions on NRC licenses.[416] MISO TOs assert that nuclear generating facilities generally have turbine controls, which are designed to maintain steam pressure and do not respond to grid frequency deviations, and that because primary frequency response is automatic, unsupervised and unplanned maneuvering of a nuclear reactor can lead to safety issues.[417]

200. On the other hand, other commenters believe that the Commission should not automatically exempt new nuclear generating facilities. WIRAB asserts that the Commission should require new nuclear generating facilities to seek individual exemptions, as needed, based on legitimate safety requirements in their NRC operating license.[418] WIRAB contends that in the future, new nuclear generating facilities in the U.S. may have the capability to safely and reliably respond to frequency deviations, and therefore the Commission should not provide an automatic exemption.[419]

201. Similarly, ISO–RTO Council believes that the Commission should not ''anticipate'' exemption requirements. Instead, ''any *pro forma* exemptions to the requirement to provide frequency response, including exemptions for new nuclear units, should be supported by applicable regulatory requirements, such as NRC rules and any regional requirements demonstrated by the nuclear owner to be applicable to the particular unit or type of unit.'' [420]

c. Commission Determination

202. We adopt the NOPR proposal to exempt nuclear generating facilities from the final action requirements, due to the unique regulatory and technical requirements of nuclear generating facilities. As explained in the NOPR, nuclear generating facilities have separate licensing requirements under the NRC, which often restrict or severely limit nuclear generating facilities from providing primary frequency response.[421] Further, nuclear generating facilities are designed to maintain internal steam pressure and are not intended to react to changes in the grid.[422]

203. We disagree with WIRAB's and ISO–RTO Council's view that an entire class of generating facilities should not be exempted from the *pro forma* requirements. We find that the unique regulatory and technical requirements of nuclear facilities justify an exemption. Requiring nuclear generating facilities to request unit-specific exemptions from providing a service that their licensing requirements already limit or restrict could result in an unreasonable administrative burden that can be avoided by allowing a general exemption in the *pro forma* LGIA and *pro forma* SGIA, and we do so here.

5. Wind Generating Facilities

a. NOPR Proposal

204. In the NOPR, the Commission did not propose to exempt new wind generating facilities from the new primary frequency response requirements. The Commission observed that while primary frequency response functionality has not been a standard feature on non-synchronous generating facilities, recent technological advancements have equipped wind generating facilities with this capability. The Commission further noted that wind generating facilities typically operate at their maximum operating output, and generally lack excess capacity (or headroom) to provide primary frequency response during under-frequency conditions.[423]

b. Comments

205. AWEA states that the Commission's proposed addition of a primary frequency response requirement to the *pro forma* LGIA and *pro forma* SGIA can be met at low cost for new wind projects, and therefore new wind turbines should not have difficulty complying with the Commission's proposal.[424] AWEA further states that it does not oppose the addition of the proposed primary frequency response capability requirement to interconnection standards for new non-synchronous generators, and that the proposed deadband and response rates for capability settings of maximum 5 percent droop and ±0.036 Hz deadband appear reasonable and consistent with industry practice.[425]

206. However, Sunflower and Mid-Kansas contend that, given current adequate frequency response performance and a lack of sufficient data in the record on the extent to which primary frequency response is needed from wind generating facilities, the Commission should not adopt a blanket requirement that includes wind generating facilities at this time. Sunflower and Mid-Kansas assert that the Commission should instead proceed with further analysis first, as contemplated by NERC, or at least allow for flexibility in the requirements.[426]

c. Commission Determination

207. We are not persuaded by Sunflower and Mid-Kansas to exempt wind generating facilities from the primary frequency response

[414] *See, e.g.,* AES Companies Comments at 7; MISO TOs Comments at 8, 13–14; EEI Comments at 14; NRECA Comments at 3; PG&E Comments at 2; SoCal Edison Comments at 4; TVA Comments at 3; Xcel Comments at 8.

[415] EEI Comments at 14; MISO TOs Comments at 13.

[416] EEI Comments at 14.

[417] MISO TOs Comments at 13–14.

[418] WIRAB Comments at 7–8.

[419] *Id.*

[420] ISO–RTO Council Comments at 7.

[421] NOPR, 157 FERC ¶ 61,122 at P 31.

[422] *Id.*

[423] NOPR, 157 FERC ¶ 61,122 at P 13.

[424] AWEA Comments at 4.

[425] *Id.* at 4–5.

[426] Sunflower and Mid-Kansas Comments at 4.

requirements of this final action. As discussed above, a key focus of this final action is the ongoing shift of the generation resource mix, with declining amounts of traditional synchronous generating facilities that historically have provided primary frequency response and increasing penetrations of non-synchronous generation, including wind generating facilities that historically have not been a significant source of primary frequency response. Unlike certain CHP or nuclear generating facilities, the record does not indicate that there is an economic, technical, or regulatory basis for a generic exemption for newly interconnecting wind generating facilities. In particular, we are persuaded by AWEA's assertion that the proposed primary frequency response capability requirements can be met at low cost for new wind projects, and that newly interconnecting wind facilities should not have difficulty complying with the proposed deadband of ±0.036 Hz and a maximum 5 percent droop parameter.[427] Accordingly, we will not exempt wind generating facilities from the requirements of this final action.

6. Surplus Interconnection

a. NOPR Proposal

208. In the NOPR, the Commission did not propose any provisions related to surplus interconnection service.[428]

b. Comments

209. ESA states that the Commission recently issued a NOPR which proposes to make available the use of surplus interconnection service, which is intended to maximize the use of existing interconnection service capacity and concerns generating facilities that are existing interconnection customers.[429] ESA contends that these forms of interconnections should not be considered ''new interconnection'' for the purposes of primary frequency response capability requirements, and requests that the Commission exempt surplus interconnection services from its proposed primary frequency response requirements.[430]

c. Commission Determination

210. We find that ESA's request that surplus interconnection service should not be considered ''new interconnection'' for purposes of this final action is premature, because the Commission has yet to issue any final action that addresses surplus interconnection service.[431]

7. Small Generating Facilities

a. NOPR Proposal

211. In the NOPR, the Commission proposed to apply the proposed requirements to newly interconnecting small generating facilities. The Commission stated that the record suggests that small generating facilities are capable of installing and enabling governors at low cost in a manner comparable to large generating facilities.[432] The Commission concluded that given recent technological advances, the Commission did not anticipate that requiring the *pro forma* SGIA to be amended to include requirements for primary frequency response capability would present a barrier for small generating facilities, and, given the need for additional primary frequency response capability and an increasingly large market penetration of small generating facilities, the Commission believed that there is a need to add these requirements to the *pro forma* SGIA to help ensure primary frequency response capability. In support, the Commission referenced PJM's recent changes to its interconnection agreements to require new large and small non-synchronous generating facilities to install enhanced inverters, which include primary frequency response capability requirements.[433]

b. Comments

i. NOPR Comments

212. Most commenters who generally supported the NOPR's proposal did not differentiate between small and large generators. APPA et al. contends applying the primary frequency response requirement to all generators is important, particularly given that non-synchronous generators and small generators are making up a growing share of the changing generation resource mix.[434] EEI states that it supports the Commission acting to remove inconsistencies between the *pro forma* LGIA and the *pro forma* SGIA because there is no economical or technical basis for treating large and small generating facilities differently when they are both capable of installing and enabling governors at comparable costs.[435]

213. Some commenters,[436] however, raise concerns that small generating facilities could face disproportionate costs to install primary frequency response capability. For example, the Public Interest Organizations argue that the Commission's discussion of the economic impact on small generating facilities of installing primary frequency response capability is limited, and claimed the cited evidence in the NOPR does not directly support the Commission's conclusion that ''small generating facilities are capable of installing and enabling governors at low cost in a manner comparable to large generating facilities.'' [437] In support of their position, Public Interest Organizations note SolarCity Corporation's concern that ''a requirement that all generating facilities have frequency response capability may cost more for some resources, including behind-the-meter and distributed energy resources.'' [438] Public Interest Organizations state that they therefore encourage the Commission to further investigate the cost for small renewable energy generating facilities to install frequency response capability before making the proposed revisions to the *pro forma* SGIA.[439]

214. Other commenters request the Commission adopt a size limitation for applying the NOPR requirements. For example, TVA requests an exemption for generating facilities under 5 MVA as long as they do not aggregate with facilities greater than 75 MVA or connect to the grid at 100 kV or above.[440] Similarly, Idaho Power and NRECA request that the Commission consider exempting generating facilities

[427] AWEA Comments at 4.

[428] *See Reform of Generator Interconnection Procedures and Agreements,* Notice of Proposed Rulemaking, 82 FR 4464 (Jan. 13, 2017), 157 FERC ¶ 61,212 (2016). Surplus interconnection service refers to an instance where an interconnection customer has an interconnection agreement which provides more interconnection service than it currently uses, and may wish to add resources, such as electric storage resources, which were not planned with part of the original interconnection request, or it may wish to sell surplus interconnection service without conveying the originally planned generating facility as part of the sale.

[429] ESA Comments at 5.

[430] *Id.*

[431] We further note that MISO's Net Zero Interconnection Service is an interconnection request that results in a GIA. As such, a generator connecting to the transmission system using Net Zero Interconnection Service would be expected to comply with this final action. *See* MISO Tariff Attachment X 3.3.1.1 (Additional Requirements for a Net Zero Interconnection Request application).

[432] NOPR, 157 FERC ¶ 61,122 at P 41 (citing IEEE–P1547 Working Group NOI Comments at 1, 5, and 7).

[433] *Id.* P 42.

[434] APPA et al. Comments at 5.

[435] EEI Comments at 8.

[436] *See* NRECA Comments at 8; Public Interest Organizations Comments at 3; TVA Comments at 4; Idaho Power Comments at 2.

[437] Public Interest Organizations Comments at 3 (citing NOPR, 157 FERC ¶ 61,122 at P 42).

[438] *Id.* at 3 (citing SolarCity Corporation's NOI Comments at 4).

[439] *Id.* at 3–4.

[440] TVA Comments at 4.

that are smaller than 10 MW. Idaho Power states that it would be difficult to determine compliance if the required response is too small.[441] NRECA suggests that small generating facilities might have a different cost-benefit analysis than large generating facilities, and asserts that there is not a sufficient record to conclude that the proposed requirement to install primary frequency response capability will not pose an undue burden on smaller generating facilities.[442]

ii. Supplemental Comments

215. NAGF, Tri-State, ISO–RTO Council, SoCal Edison, and WIRAB support applying the proposed requirements to small generating facilities.[443] ISO–RTO Council states that the proposed requirements are consistent with the current requirements of PJM, NYISO, ISO–NE, and CAISO, all of which require small generators to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection.[444] ISO–RTO Council contends that these requirements have been in place for several years, have not resulted in operational issues or challenges associated with such requirements, and have not required exemptions for small generators.[445]

216. Further, ISO–RTO Council asserts that ''providing an exemption or variation to the NOPR requirements for small generators and electric storage resources could allow such resources to avoid solving the very problem to which such resources contribute and the NOPR rules were meant to address.'' [446] In particular, ISO–RTO Council points out that the ongoing transformation of the generation resource mix involves the loss of the inertia and primary frequency response contributions from baseload and synchronous generating facilities that have and will retire. Since non-synchronous generators, small generators, distributed energy resources, and electric storage resources will comprise an increasing percentage of the future generation mix, ISO–RTO Council states that they should contribute their fair share of primary frequency response in accordance with the requirements proposed in the NOPR.[447]

217. EEI adds that as the market penetration of small generating facilities increases, there will be a growing need for primary frequency response from these non-traditional generating facilities.[448] EEI argues that ''[i]f the Commission exempts new small generating resources from installing primary frequency response capability now, then retrofitting them may be needed in the future to address reliability concerns, which will be more costly.'' [449] EEI states, however, that the potential costs for small generating facilities can be reduced if the Commission limits its proposal to solely installing primary frequency response capability and not adopting the proposed operating requirements for droop, deadband, and timely and sustained response in the *pro forma* LGIA and *pro forma* SGIA.[450]

218. APS suggests that all generating facilities should contribute to primary frequency response and opposes a blanket exemption for small generating facilities. Rather, APS suggests that determining whether and how small generating facilities contribute to primary frequency response should be a collaborative effort among the balancing authority, transmission provider, and interconnection customer.[451]

219. While AES Companies oppose the NOPR, they state that the size of any particular generating facility should not impact the solution implemented.[452] NRECA agrees that there should be flexibility for balancing authorities, RTOs/ISOs, or other public utility transmission providers to adopt requirements for primary frequency response capability in response to specific concerns in their regions in instances where generating facilities have particular operating or other characteristics which make it unreasonable from a cost-benefit or technical perspective to require primary frequency response capability as a condition precedent to interconnection.[453] SDG&E remains concerned that unnecessary capital costs will be incurred if the Commission chooses to require all new generators to have primary frequency response capability, and that generation owners will attempt to pass those costs along to consumers.[454]

220. Finally, Sunrun states that even inverters certified to UL 1741 SA [455] may or may not have certified frequency-watt response capability, as it is not required for California's phase one advanced inverter implementation, and even the most progressive state-level inverter function requirements may fall short of enabling primary frequency response capability, leaving a number of important unknowns to small systems also needing to aggregate and participate in wholesale markets.[456]

221. In response to the Commission's question about whether the costs for small generating facilities to install, maintain, and operate governors or equivalent controls are proportionally comparable to the costs for large generating facilities, NRECA states that a size threshold is necessary so that small generators will not be forced to forego interconnection because the cost of including primary frequency response capability outweighs the benefit of interconnection.[457] However, WIRAB states that costs for inverters capable of providing primary frequency response have declined. WIRAB submits that in 2013, the cost between a traditional inverter and an inverter capable of providing primary frequency response was less than 1 percent of the overall project. WIRAB adds that it is now standard practice to install such inverters for all utility scale, non-synchronous generating facilities because operational changes and updates can be made through software changes.[458] Further, WIRAB states that if the Commission determines that small generating facilities may experience disproportionate cost impacts associated with the proposed requirement, the Commission should establish an exemption that would allow small generators to provide a demonstration of disproportionate costs to its utility to be exempt from the primary frequency response requirements.[459] SoCal Edison agrees that given significant technological advances in generation facilities and equipment, including inverters, the proposed primary

[441] Idaho Power Comments at 2.

[442] NRECA Comments at 8.

[443] NAGF Supplemental Comments at 2; Tri-State Supplemental Comments at 3; ISO–RTO Council Supplemental Comments at 6; SoCal Edison Supplemental Comments at 2; WIRAB Supplemental Comments at 7.

[444] ISO–RTO Supplemental Comments at 3.

[445] ISO–RTO Council Supplemental Comments at 4.

[446] *Id.* at 2.

[447] *Id.* at 2, 3.

[448] EEI Supplemental Comments at 8.

[449] *Id.*

[450] *Id.* at 4.

[451] APS Supplemental Comments at 10–11.

[452] AES Companies Supplemental Comments at 42.

[453] NRECA Supplemental Comments at 2–3.

[454] SDG&E Supplemental Comments at 3–4.

[455] The UL 1741 Standard is intended for use with distributed energy resources. *See* UL 1741, Standard for Inverters, Converters, Controllers, and Interconnection System Equipment for Use with Distributed Energy Resources, *https://standardscatalog.ul.com/standards/en/standard_1741_2.* The Commission discusses the applicability of the final action to distributed energy resources in Section II.H.3.

[456] Sunrun Supplemental Comments at 3–4.

[457] NRECA Supplemental Comments at 4.

[458] WIRAB Supplemental Comments at 6–7.

[459] *Id.* at 7.

frequency response requirements for small generating facilities will not present a barrier to entry.[460]

222. In response to the Commission's question about whether PJM's recent modifications to its interconnection agreements address concerns regarding possible disproportionate costs resulting from applying the NOPR to all small generating facilities, ISO–RTO Council states that PJM has not experienced any decrease in the number of interconnection requests of small non-synchronous generators since requiring non-synchronous generating facilities to install enhanced inverters that include primary frequency response capability.[461] ISO–RTO Council states that in the last year, 30 new generating facilities were placed into service, and of those, 25 were small generating facilities and five were large generating facilities.[462]

c. Commission Determination

223. We will not exempt small generating facilities from the requirements. The Commission has previously acted under FPA section 206 to remove inconsistencies between the *pro forma* LGIA and *pro forma* SGIA where there is no economic or technical basis for treating large and small generating facilities differently.[463] The record indicates that small generating facilities are capable of installing and enabling governors or equivalent technologies at low cost in a manner comparable to large generating facilities; therefore it would be unduly discriminatory or preferential to not impose the requirements of this final action on small generating facilities. There is limited and unpersuasive information in the record indicating that certain small generating facilities would face disproportionate costs to install, maintain, and operate equipment capable of providing primary frequency response. Moreover, the record demonstrates that small generating facilities are technically capable of providing primary frequency response. No commenter provided evidence to suggest that imposing the requirements of this final action on small generators would be disproportionately costly or otherwise unduly burdensome.

224. In particular, we are persuaded by commenter assertions that that small generating facilities are making up a growing percentage of the generation resource mix,[464] and that as the market penetration of small generating facilities increases, there will be a growing need for primary frequency response from these generating facilities.[465] We are also persuaded by commenter assertions that there is no economical or technical basis for treating large and small generating facilities differently when they are both capable of installing and enabling governors at comparable costs.[466] Finally, we do not believe that the actions we take here will present a barrier to entry to small generating facilities. We note ISO–RTO Council's assertion that ''PJM has not experienced any decrease in the number of interconnections requests or interconnections of small non-synchronous generators since requiring nonsynchronous generating facilities to install enhanced inverters that include primary frequency response capability.'' [467]

8. Requests To Establish a Waiver Process and Consider Potential Impact on Load and New Technology

a. NOPR

225. In the NOPR, the Commission did not propose any waiver procedures.

b. Comments

226. NRECA requests that the Commission consider permitting transmission providers to establish ''penetration level thresholds'' for primary frequency response because ''[g]enerators can differ in their impact on the transmission grid based on factors such as size and technology.'' [468] NRECA contends that in areas with sufficient primary frequency response capability, including the cost of primary frequency response in new generating facilities may not necessarily be warranted and should therefore not be required as a condition of interconnection.[469] NRECA further asserts that the Commission should ''bear in mind that the costs for frequency response capability will be recovered from load. Customers should not have to pay for capability that is not necessary for reliability.'' [470]

227. Both NRECA and AES Companies express concern about the potential impact of the proposed requirements on new technologies and innovation. AES Companies assert that the proposed requirements for new generating facilities to install primary frequency response capability as well operate with specified droop and deadband settings will ''stymie the use of more efficient technology solutions as they become available and impose unnecessary costs on load.'' [471] Similarly, NRECA is concerned that the Commission's ''all-encompassing proposal'' could risk limiting ''the deployment of the sorts of technologies and innovation which the Commission has pledged to encourage, without conferring reliability benefits that warrant such risks.'' [472]

228. NRECA contends that the Commission should adopt ''a waiver process whereby if a new interconnecting generating facility is neither needed for primary frequency response capability, nor causes any harm to the reliability of the grid in this regard, primary frequency response capability would not be a condition of interconnection.'' [473]

c. Commission Determination

229. We decline to adopt a waiver process for new generating facilities. Considering the dynamic and evolving nature of primary frequency response, we are not persuaded by NRECA's suggestion that the current specific needs of individual balancing authority areas within each Interconnection should determine whether to adopt minimum uniform primary frequency response requirements as a condition of interconnection. While the level of primary frequency response capability may be adequate in certain individual areas, NERC assessments indicate that the Bulk-Power System as a whole has experienced a decline in primary frequency response. In this regard, we reject NRECA's suggestion that ''an imminent reliability threat'' must exist to justify new primary frequency requirements such as those we adopt in this final action.[474] We clarify that this final action is intended to ensure that the overall level of primary frequency response capability remains adequate as the generation resource mix continues to change. Accordingly, we decline NRECA's request to develop a generic waiver process to exempt newly interconnecting generating facilities from the requirements of this final action.

230. In addition, we disagree with NRECA and AES Companies that this

[460] SoCal Edison Supplemental Comments at 3.

[461] ISO–RTO Supplemental Comments at 6.

[462] *Id.* at 7.

[463] *See* Order No. 828, 156 FERC ¶ 61,062 (revising the *pro forma* SGIA such that small generating facilities have frequency and voltage ride through requirements comparable to large generating facilities).

[464] APPA et al. Comments at 5.

[465] EEI Comments at 8.

[466] SoCal Edison Comments at 3.

[467] ISO–RTO Council Supplemental Comments at 7.

[468] NRECA Comments at 8.

[469] *Id.*

[470] *Id.* at 9.

[471] AES Companies Comments at 12.

[472] NRECA Comments at 6.

[473] *Id.* at 8–9.

[474] *Id.* at 7.

final action will result in unreasonable or unnecessary costs to load, based on the record indicating that cost of installing primary frequency response capability for new generating facilities is minimal. As explained in Section II.E.2 above, many commenters agree that costs associated with primary frequency response are minimal for new generating facilities.

231. Finally, we find NRECA's and AES Companies' assertions regarding the potential adverse impact of the new primary frequency requirements adopted in this final action on technology and innovation to be speculative and unsupported. In this regard, we clarify that should the new primary frequency response requirements present obstacles to new, more efficient generating facilities that may be developed in the future, nothing in this final action prohibits prospective interconnection customers owning such facilities from seeking appropriate relief from the Commission.

I. Regional Flexibility

1. NOPR Proposal

232. In the NOPR, the Commission proposed that public utility transmission providers must either comply with the final action, demonstrate that previously-approved variations continue to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA as modified by the final action, or seek ''independent entity variations'' from the proposed revisions to the *pro forma* LGIA and *pro forma* SGIA.[475]

2. Comments

233. Some commenters object to the proposal to make operating requirements uniform, contending that such uniformity fails to account for differences across regions and generating facilities—particularly those utilizing new technology and fuel sources—and the actual need for primary frequency response.[476]

3. Commission Determination

234. As explained above in Section II.B.3.a, we disagree with commenters who support a completely regional approach. We believe that the most effective approach to addressing concerns regarding primary frequency response is to establish and maintain minimum, uniform requirements for all newly interconnecting generating facilities. However, we recognize that unique circumstances or needs of some individual regions or areas may warrant different operating requirements. Therefore, we adopt the NOPR proposal and will allow transmission providers to propose variations to the operating requirements adopted in this final action. Specifically, the following methods for proposing variations adopted in Order No. 2003 will be available here: (1) Variations based on Regional Entity reliability requirements; (2) variations that are ''consistent with or superior to'' the final action; and (3) ''independent entity variations'' filed by RTOs/ISOs.[477]

235. Finally, we clarify that the Commission will also consider requests for ''regional reliability variations,'' provided they are supported by references to regional Reliability Standards. In addition, in any such request, the transmission provider shall explain why these regional Reliability Standards support the requested variation, and shall include the text of the referenced Reliability Standards.[478]

J. Miscellaneous Comments

1. Uniform System of Accounts

a. Comments

236. Xcel states that the Commission should add a new account to the FERC Uniform System of Accounts to allow the identification and tracking of cost information associated with primary frequency response. Xcel argues that a new FERC account would allow for the collection of installed cost information ''so that the Commission can ensure that any rates reflect those costs and recover the costs form the appropriate customer base (*i.e.,* transmission versus production customers).'' [479]

b. Commission Determination

237. We deny this request. First, the costs of installing, maintaining, and operating a governor or equivalent controls is not significant and is captured by other accounts.[480] Second, synchronous generating facilities have installed, maintained, and operated governors for many years and Xcel has not demonstrated why changed circumstances require new accounts to capture these costs. It is also not clear why these existing accounts could not similarly be applied to non-synchronous generating facilities.

2. Capability of Load To Provide Primary Frequency Response

a. Comments

238. Union of Concerned Scientists asserts that while it believes that the NOPR proposal is ''an important step'' and the Commission should ''complete this rulemaking,'' the NOPR proposal ''omit[s] discussion of how the utility industry may draw on the capability of loads to provide frequency response.'' [481] Accordingly, Union of Concerned Scientists urges the Commission to ''guide utilities to include load resources in the development of primary frequency response services and requirements.'' [482] Union of Concerned Scientists maintains that the NOPR proposal is a necessary, but insufficient, step in addressing primary frequency response because: (1) The NOPR excludes load from consideration as a primary frequency response resource; and (2) the reliance on headrooT from generating facilities for the provision of primary frequency response results in a greater economic cost to generating facilities compared to the zero marginal cost of load as a resource for providing primary frequency response.[483]

b. Commission Determination

239. We decline in this final action to address the need for load resources to provide primary frequency response. While we note that there are many complicated issues related to the provision of primary frequency response by load resources, we find that these issues are beyond the scope of this proceeding, which is limited to modifications to the *pro forma* LGIA and the *pro forma* SGIA. We recognize that currently some load resources can and do provide some primary frequency response. Nothing in this final action is meant to discourage or prevent them from doing so.

3. Primary Frequency Response Obligations and Pools

a. Comments

240. AES Companies state that NERC's Essential Reliability Services Task Force recommended that all new generating facilities should support the capability to manage frequency control, not that they should provide primary

[475] NOPR, 157 FERC ¶ 61,122 at P 59. *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822–827.

[476] *See, e.g.,* APS Supplemental Comments at 5–6; MISO TOs Comments at 2; SoCal Edison Comments at 3; Xcel Comments at 7; NYTO Supplemental Comments at 3–4.

[477] Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822–827. A very similar approach was taken in Order No. 827, FERC Stats. & Regs. ¶ 31,385 at P 69 and Order No. 828, 156 FERC ¶ 61,062 at PP 40–41.

[478] *See* Order No. 2006, FERC Stats. & Regs. ¶ 31,180 at P 546.

[479] Xcel Comments at 9–10.

[480] Examples of these other accounts are described in Appendix C of this final action.

[481] Union of Concerned Scientists Comments at 3.

[482] *Id.* at 8.

[483] *Id.* at 7–8.

frequency response themselves.[484] As a result, AES Companies suggest that the Commission modify the NOPR proposal to allow the interconnection customer to demonstrate that they can provide its proportional share of primary frequency response, either through self-supply from other generating facilities within its fleet or via procurement from a third party.[485] AES Companies further suggest that utilities and other generation owners should then be allowed to form pools and/or aggregate their resources to meet an allocated proportionate share of their primary frequency response responsibility.[486]

b. Commission Determination

241. We reject AES Companies' suggestions. Adopting these suggestions would add complications and create substantial uncertainty for generating facilities providing primary frequency response, which will detract from one of the Commission's goals (*i.e.,* minimizing complexity and uncertainty with regard to primary frequency response).

K. Specific Revisions to the Pro Forma LGIA and Pro Forma SGIA

1. NOPR Proposal

242. To implement the proposed primary frequency response requirements, the Commission proposed in the NOPR to revise Sections 9.6 and 9.6.2.1 of the *pro forma* LGIA and add new Sections 9.6.4, 9.6.4.1, and 9.6.4.2 to the *pro forma* LGIA.[487] Similarly, the Commission proposed to revise Section 1.8 of the *pro forma* SGIA and add new Sections 1.8.4, 1.8.4.1, and 1.8.4.2 to the *pro forma* SGIA.[488]

2. Comments

243. As noted above in Sections II.B.2.a, II.B.2.b, II.B.2.c, II.C.2, II.H.1.b, and II.H.2.b of this final action, Bonneville, EEI, ELCON, NERC, ISO–RTO Council, and WIRAB request certain modifications to the proposed changes to *pro forma* LGIA and *pro forma* SGIA as discussed in the NOPR. AES Companies also request to modify Section 9.6 of the *pro forma* LGIA.[489]

3. Commission Determination

244. We deny AES Companies' request to modify Section 9.6 of the *pro forma* LGIA as the request is related to reactive power and thus beyond the scope of this proceeding. We also deny AES Companies other proposed modifications to the *pro forma* LGIA and *pro forma* SGIA.

245. Further, as explained in Sections II.B and II.C above, we conclude that EEI's requested modifications to the proposed revisions in the *pro forma* LGIA and *pro forma* SGIA that undermine uniformity are not consistent with the objectives explained herein and therefore are denied. However, we adopt EEI's requested language pertaining to timely and sustained response, particularly the phrase ''shall not block or inhibit governor or equivalent controls.''

246. In light of the above discussion, we revise the *pro forma* LGIA to modify Sections 9.6 and 9.6.2.1 and adds new Sections 9.6.4, 9.6.4.1, 9.6.4.2, 9.6.4.3, and 9.6.4.4. This section contains the totality of the revised revisions the *pro forma* LGIA. The revisions, with bracketed deletions from and italicized additions to the *pro forma* LGIA are as follows:

9.6 Reactive Power *and Primary Frequency Response*

9.6.2.1 [Governors and] *Voltage* Regulators. Whenever the Large Generating Facility is operated in parallel with the Transmission System [and the speed governors (if installed on the generating unit pursuant to Good Utility Practice)] and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its [speed governors and] voltage regulators in automatic operation. If the Large Generating Facility's [speed governors and] voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis. (Bracketed text is deleted, italicized text are additions.)

9.6.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term ''functioning governor or equivalent controls'' as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) With a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) Based on the nameplate capacity of the Large Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) Without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Large Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Large Generating Facility with the

[484] AES Companies Comments at 12.

[485] *Id.*

[486] *Id.*

[487] NOPR, 157 FERC ¶ 61,122 at P 52.

[488] *Id.* P 53.

[489] AES Companies Comments at 15.

Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with the provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities.

9.6.4.1 Governor or Equivalent Controls. Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) In coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) A maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) The operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Large Generating Facility's governor or equivalent controls to a minimum whenever the Large Generating Facility is operated in parallel with the Transmission System.

9.6.4.2 Timely and Sustained Response. Interconnection Customer shall ensure that the Large Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Large Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

9.6.4.3 Exemptions. Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement. Large Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 9.6.4, but shall be otherwise exempt from the operating requirements in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.4 of this Agreement.

9.6.4.4 Electric Storage Resources. Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Appendix C of its LGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.3 of this Agreement. Appendix C shall specify whether the operating range is static or dynamic, and shall consider (1) the expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Appendix C must establish how frequently the operating range will be reevaluated and the factors that may be considered during its reevaluation.

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 9.6.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

247. Similarly, the Commission modifies Section 1.8 of the *pro forma* SGIA and adds new Sections 1.8.4, 1.8.4.1, 1.8.4.2 and 1.8.4.3, and 1.8.4.4. This section contains the totality of the revised revisions the *pro forma* SGIA. The revisions, with italicized additions to the *pro forma* SGIA are as follows:

1.8 Reactive Power *and Primary Frequency Response*

1.8.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Small Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Small Generating Facility's real power output *in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating: (1) With a maximum 5 percent droop and ±0.036 Hz deadband; or (2) in accordance with the relevant droop, deadband, and timely and sustained response settings from an approved NERC Reliability Standard providing for equivalent or more stringent parameters. The droop characteristic shall be: (1) Based on the nameplate capacity of the Small Generating Facility, and shall be linear in the range of frequencies between 59 to 61 Hz that are outside of the deadband parameter; or (2) based an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. The deadband parameter shall be: the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Small Generating Facility's real power output in response to frequency deviations. The deadband shall be implemented: (1) Without a step to the droop curve, that is, once the frequency deviation exceeds the deadband parameter, the expected change in the Small Generating Facility's real power output in response to frequency deviations shall start from zero and then increase (for under-frequency deviations) or decrease (for over-frequency deviations) linearly in proportion to the magnitude of the frequency deviation; or (2) in accordance with an approved NERC Reliability Standard providing for an equivalent or more stringent parameter. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Small Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Small Generating Facility with the Transmission System, Interconnection Customer shall operate the Small Generating Facility consistent with the provisions specified in Sections 1.8.4.1 and 1.8.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Small Generating Facilities.*

1.8.4.1 Governor or Equivalent Controls. Whenever the Small Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Small Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall: (1) In coordination with Transmission Provider and/or the relevant balancing authority, set the deadband parameter to: (1) A maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent; or (2) implement the relevant droop and deadband settings from an approved NERC Reliability Standard that provides for equivalent or more stringent parameters. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider and/or the relevant balancing authority upon request. If Interconnection Customer needs to operate the Small Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider and the relevant balancing authority, and provide both with the following information: (1) The operating status of the governor or equivalent controls (i.e., whether it is currently out of service or when it will be taken out of service); (2) the reasons for removing the governor or equivalent controls from service; and (3) a reasonable estimate of when the governor or equivalent controls will be returned to service. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable. Interconnection Customer shall make Reasonable Efforts to keep outages of the Small Generating Facility's governor or equivalent controls to a minimum whenever the Small Generating Facility is operated in parallel with the Transmission System.

1.8.4.2 Timely and Sustained Response. Interconnection Customer shall ensure that the Small Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is automatically provided and shall begin immediately after frequency deviates outside of the deadband, and to the extent the Small Generating Facility has operating capability in the direction needed to correct the frequency deviation. Interconnection Customer shall not block or otherwise inhibit the ability of the governor or equivalent controls to respond and shall ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, physical energy limitations, outages of mechanical equipment, or regulatory requirements. The Small Generating Facility shall sustain the real power response at least until system frequency returns to a value within the deadband setting of the governor or equivalent controls. A Commission-approved Reliability Standard with equivalent or more stringent requirements shall supersede the above requirements.

1.8.4.3 Exemptions. Small Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 1.8.4, 1.8.4.1, and 1.8.4.2 of this Agreement. Small Generating Facilities that are behind the meter generation that is sized-to-load (i.e., the thermal load and the generation are near-balanced in real-time operation and the generation is primarily controlled to maintain the unique thermal, chemical, or mechanical output necessary for the operating requirements of its host facility) shall be required to install primary frequency response capability in accordance with the droop and deadband capability requirements specified in Section 1.8.4, but shall be otherwise exempt from the operating requirements in Sections 1.8.4, 1.8.4.1, 1.8.4.2, and 1.8.4.4 of this Agreement.

1.8.4.4 Electric Storage Resources. Interconnection Customer interconnecting an electric storage resource shall establish an operating range in Attachment 5 of its SGIA that specifies a minimum state of charge and a maximum state of charge between which the electric storage resource will be required to provide primary frequency response consistent with the conditions set forth in Sections 1.8.4, 1.8.4.1, 1.8.4.2 and 1.8.4.3 of this Agreement. Attachment 5 shall specify whether the operating range is static or dynamic, and shall consider: (1) The expected magnitude of frequency deviations in the interconnection; (2) the expected duration that system frequency will remain outside of the deadband parameter in the interconnection; (3) the expected incidence of frequency deviations outside of the deadband parameter in the interconnection; (4) the physical capabilities of the electric storage resource; (5) operational limitations of the electric storage resource due to manufacturer specifications; and (6) any other relevant factors agreed to by Transmission Provider and Interconnection Customer, and in consultation with the relevant transmission owner or balancing authority as appropriate. If the operating range is dynamic, then Attachment 5 must establish how frequently the operating range will be *reevaluated and the factors that may be considered during its reevaluation.*

Interconnection Customer's electric storage resource is required to provide timely and sustained primary frequency response consistent with Section 1.8.4.2 of this Agreement when it is online and dispatched to inject electricity to the Transmission System and/or receive electricity from the Transmission System. This excludes circumstances when the electric storage resource is not dispatched to inject electricity to the Transmission System and/or dispatched to receive electricity from the Transmission System. If Interconnection Customer's electric storage resource is charging at the time of a frequency deviation outside of its deadband parameter, it is to increase (for over-frequency deviations) or decrease (for under-frequency deviations) the rate at which it is charging in accordance with its droop parameter. Interconnection Customer's electric storage resource is not required to change from charging to discharging, or vice versa, unless the response necessitated by the droop and deadband settings requires it to do so and it is technically capable of making such a transition.

248. The Commission is also modifying the *pro forma* LGIP and *pro forma* SGIP to require newly interconnecting electric storage resources to include the details of the operating range in their interconnection request.

249. In particular, the Commission is modifying the following sections of the *pro forma* LGIP as indicated below:

Appendix 1 to LGIP Interconnection Request for a Large Generating Facility

5. Interconnection Customer provides the following information:

h. Primary frequency response operating range for electric storage resources.

Attachment A to Appendix 1 Interconnection Request

Unit Ratings

Primary frequency response operating range for electric storage resources:

Minimum State of Charge: ____
Maximum State of Charge: ____

250. Similarly, the Commission is modifying the following sections of the *pro forma* SGIP as indicated below. The revisions, with italicized additions to *pro forma* SGIP are as follows:

Attachment 2 Small Generator Interconnection Request (Application Form)

Small Generating Facility Information

Primary frequency response operating range for electric storage resources:

Minimum State of Charge: ____
Maximum State of Charge: ____

III. Compliance and Implementation

251. Section 35.28(f)(1) of the Commission's regulations requires every public utility with a non-discriminatory OATT on file to also have a *pro forma* LGIA and *pro forma* SGIA on file with the Commission.[490]

252. We reiterate that the requirements of this final action apply to all newly interconnecting large and small generating facilities that execute or request the unexecuted filing of a LGIA or SGIA on or after the effective date of this final action as well as all existing large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of this final action. We are not requiring changes to existing interconnection agreements that were executed, or filed unexecuted, prior to the effective date of this final action.

253. We require each public utility transmission provider that has a *pro forma* LGIA and/or *pro forma* SGIA within its OATT to submit a compliance filing within 70 days following publication of this final action in the **Federal Register**.[491] The compliance filing must demonstrate that it meets the requirements set forth in this final action.

254. Some public utility transmission providers may have provisions in their existing *pro forma* LGIAs and *pro forma* SGIAs or other document(s) subject to the Commission's jurisdiction that the Commission has deemed to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA or are permissible under the independent entity variation standard or regional reliability standard.[492] Where these provisions would be modified by this final action, public utility transmission providers must either comply with this final action or demonstrate that these previously-approved variations continue to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA as modified by this final action or continue to be permissible under the independent entity variation standard or regional Reliability Standard.[493]

255. We find that transmission providers that are not public utilities must adopt the requirements of this final action as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[494]

IV. Information Collection Statement

256. The following collection of information contained in this final action is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995, 44 U.S.C. 3507(d).[495] The Paperwork Reduction Act (PRA)[496] requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons, or contained in a rule of general applicability. OMB's regulations require the approval of certain information collection requirements imposed by agency rules.[497] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this proposal will not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number. Transmission providers and generating facilities are subject to the proposed revisions to the *pro forma* LGIA and *pro forma* SGIA.

257. This final action revises the Commission's *pro forma* LGIA and *pro forma* SGIA in accordance with § 35.28(f)(1) of the Commission's regulations,[498] and applies to all newly interconnecting large and small generating facilities that execute or request the unexecuted filing of a LGIA or SGIA on or after the effective date of this final action as well as all existing large and small generating facilities that

[490] 18 CFR 35.28(f)(1) (2017).

[491] For purposes of this final action, a public utility is a utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce, as defined by the FPA. *See* 16 U.S.C. 824(e). A non-public utility that seeks voluntary compliance with the reciprocity condition of an OATT may satisfy that condition by filing an OATT, which includes a LGIA and SGIA.

[492] *See* Order No. 792, 145 FERC ¶ 61,159 at P 270.

[493] *See* 18 CFR 35.28(f)(1)(i).

[494] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,760–63 (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).

[495] 44 U.S.C. 3507(d) (2012).

[496] 44 U.S.C. 3501–3520 (2012).

[497] 5 CFR 1320.11 (2017).

[498] 18 CFR 35.28(f)(1) (2017).

take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of this final action. Generating facilities subject to this final action will be required to install, maintain, and operate equipment capable of providing primary frequency response, consistent with certain operating requirements for droop, deadband, and timely and sustained response. The reforms adopted in this final action would require filings of *pro forma* LGIAs and *pro forma* SGIAs with the Commission. We anticipate the revisions required by this final action, once implemented, will not significantly change existing burdens on an ongoing basis. With regard to those public utility transmission providers that believe they already comply with the revisions adopted in this final action, they can demonstrate their compliance in the filing required 70 days after the effective date of this final action. The Commission will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[499] In the NOPR, the Commission used FERC–516B as a temporary ''placeholder'' information collection number.[500] The Commission is now using FERC–516 information collection because it is no longer pending at OMB in any actions.

258. While the Commission expects the revisions adopted in this final action will provide significant benefits, the Commission understands that implementation would entail some costs. The Commission solicited comments on the collection of information and the associated burden estimate in the NOPR. The Commission did not receive any comments concerning its burden or cost estimates.

Burden Estimate[501]: *Costs to Comply with Paperwork Requirements:* The estimated annual costs are as follows: FERC–516: 74 entities * 1 response/entity (10 hours/response * $74.50/hour) = $56,610.[502]

FERC 516 IN FINAL ACTION, RM16–6

	Number of respondents[503] (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden (hours) and cost ($) per response (4)	Total annual burden hours and total annual cost ($) (3) * (4) = (5)
LGIA & SGIA changes/revisions	74	1	74	10 hours; $765.00	740 hours; $56,610.00.
Total			74		740 hours; $56,610.00.

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

Action: Revision of currently approved collection of information.

OMB Control No.: 1902–0096.

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

Frequency of Information: One-time during year 1.

259. *Necessity of Information:* The Commission is modifying the *pro forma* LGIA and *pro forma* SGIA to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. Specifically, the Commission is modifying the *pro forma* LGIA by revising Sections 9.6 and 9.6.2.1 and adding new Sections 9.6.4, 9.6.4.1, 9.6.4.2 and 9.6.4.3, and is modifying the *pro forma* SGIA by revising section 1.8 and adding new Sections 1.8.4, 1.8.4.1, 1.8.4.2, and 1.8.4.3.

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

261. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], email: *DataClearance@ferc.gov,* Phone: (202) 502–8663, fax: (202) 273–0873.

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

V. Regulatory Flexibility Act

263. The Regulatory Flexibility Act of 1980 (RFA)[504] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

264. The Small Business Administration (SBA) revised its size

[499] 44 U.S.C. 3507(d).

[500] The reporting requirements in the NOPR were included under FERC–516B (OMB Control No. 1902–0286), because FERC–516 was pending review at OMB in an unrelated action. The reporting requirements in this final action are included under FERC–516 (OMB Control No. 1902–0096).

[501] Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, disclose or provide information to or for a Federal agency, including: The time, effort, and financial resources necessary to comply with a collection of information that would be incurred by persons in the normal course of their activities (*e.g.,* in compiling and maintaining business records) will be excluded from the ''burden'' if the agency demonstrates that the reporting, recordkeeping, or disclosure activities needed to comply are usual and customary.

[502] The estimates for cost per response are derived using the following formula: 2017 Average Burden Hours per Response * $76.50 per Hour = Average Cost per Response. The hourly cost figure of $76.50 is the average FERC employee wage plus benefits. We assume that respondents earn at a similar rate.

[503] The NERC Compliance Registry lists 80 entities that administer a transmission tariff and provide transmission service. The Commission identifies only 74 as being subject to the proposed requirements because 6 are Canadian entities and are not under the Commission's jurisdiction.

[504] 5 U.S.C. 601–612 (2012).

standards (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates. Under SBA's standards, some transmission owners will fall under the following category and associated size threshold: Electric bulk power transmission and control, at 500 employees.[505]

265. The Commission estimates that the total number of public utility transmission providers that would have to modify the LGIAs and SGIAs within their currently effective OATTs is 74.[506] Of these, the Commission estimates that approximately 27.5 percent are small entities. The Commission estimates the average cost to each of these entities would be minimal, requiring on average 10 hours or $765.00. According to SBA guidance, the determination of significance of impact ''should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors.'' [507] The Commission does not consider the estimated burden to be a significant economic impact. As a result, the Commission certifies that the reforms adopted in this final action would not have a significant economic impact on a substantial number of small entities.

266. The Commission estimates that the total annual number of new non-synchronous interconnections per year for the first few years of potential implementation under this rule would be approximately 200, representing approximately 5,000 MW of installed capacity. For this analysis, the Commission assumes that all new non-synchronous interconnections would be small entities.[508] The Commission estimates the average total cost to each of these entities would be minimal, requiring on average approximately $3,300 per MW of installed capacity for new equipment and software to meet the requirements of this rule, or an average of $82,500 per entity (this assumes 200 equally sized new non-synchronous interconnections of 25 MW, actual costs will vary proportionate to the size of the interconnection).[509] According to SBA guidance, the determination of significance of impact ''should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors.'' The Commission does not consider the estimated burden to be a significant economic impact on these entities because the cost is relatively minimal compared to the average capital cost per MW for wind and solar PV generation (approximately 0.20 and 0.19 percent of total capital costs for wind and solar, respectively).[510] Additionally, the Commission does not believe that there would be substantial additional costs for new synchronous generators because synchronous generators already come equipped with governors that provide the capability to provide primary frequency response. Finally, the Commission does not believe that there would be any overlap between entities that are public utility transmission providers and new non-synchronous interconnections. Accordingly, because the Commission believes that this rule would not have a significant economic impact on a substantial number of small entities that are public utility transmission providers and would not have a significant economic impact on a substantial number of small entities that are new non-synchronous interconnections, the Commission believes that this rule in its entirety would not have a significant economic impact on a substantial number of small entities.

VI. Environmental Analysis

267. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[511] As we stated in the NOPR, the Commission concludes that neither an Environmental Assessment nor an Environmental Impact Statement is required for the revisions adopted in this final action under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[512] The revisions adopted in this final action would update and clarify the application of the Commission's standard interconnection requirements to large and small generating facilities.

268. Therefore, this final action falls within the categorical exemptions provided in the Commission's regulations, and as a result neither an Environmental Impact Statement nor an Environmental Assessment is required.

VII. Document Availability

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

270. From the Commission's Home Page on the internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

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

VIII. Effective Date and Congressional Notification

272. The final action is effective May 15, 2018. However, as noted above, the requirements of this final action will apply only to all newly interconnecting large and small generating facilities that

[505] 13 CFR 121.201, Sector 22 (Utilities), NAICS code 221121 (Electric Bulk Power Transmission and Control) (2017).

[506] The NERC Compliance Registry lists 80 entities that administer a transmission tariff and provide transmission service. The Commission identifies only 74 as being subject to the proposed requirements because six are Canadian entities and are not under the Commission's jurisdiction.

[507] U.S. Small Business Administration, *A Guide for Government Agencies How to Comply with the Regulatory Flexibility Act,* at 18 (May 2012), *https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.*

[508] The threshold for solar and wind generation companies to be defined as small entities is having less than 250 employees. *See* 13 CFR 121.201, Sector 22 (Utilities).

[509] These costs are not relevant to the Paperwork Reduction Act.

[510] LBNL estimates that capital cost per MW of installed wind capacity is $1,690,000. *See* LBNL 2015 Wind Market Report (Aug. 2016), *https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf.* NREL estimates that the capital cost per MW of installed solar PV capacity is $1,770,000. *See* NREL U.S. Photovoltaic Prices and Cost Breakdowns (Sep. 2015), *https://www.nrel.gov/docs/fy15osti/64746.pdf.*

[511] *Regulations Implementing National Environmental Policy Act,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[512] 18 CFR 380.4(a)(15) (2017).

execute or request the unexecuted filing of an LGIA or SGIA on or after the effective date of this final action as well as all existing large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of this final action. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this final action is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. This final action is being submitted to the Senate, House, Government Accountability Office, and Small Business Administration.

By the Commission.

Issued: February 15, 2018.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

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

I. Appendix A: List of Substantive NOPR Commenters (RM16–6–000)

AES Companies	AES Corporation/AES Energy Storage/Dayton Power and Light Company/Indianapolis Power and Light Company.
APPA et al	American Public Power Association/Large Public Power Council/Transmission Access Policy Study Group.
AWEA	American Wind Energy Association.
API	American Petroleum Institute.
Bonneville	Bonneville Power Administration.
Chelan County	Chelan County Public Utility District.
California Cities	City of Anaheim/City of Azusa/City of Banning/City of Colton/City of Pasadena/City of Riverside.
EEI	Edison Electric Institute.
Competitive Suppliers	Electric Power Supply Association/Independent Power Producers of New York/New England Power Generators Association/Western Power Trading Forum.
ELCON	Electricity Consumers Resource Council.
ESA	Energy Storage Association.
First Solar	First Solar, Inc.
Idaho Power	Idaho Power Company.
ISO–RTO Council	ISO–RTO Council.
MISO TOs	Midcontinent Independent System Operator Transmission Owners.
NRECA	National Rural Electric Cooperative Association.
NERC	North American Electric Reliability Corporation.
PG&E	Pacific Gas and Electric Company.
Public Interest Organizations	Public Interest Organizations.
R Street	R Street Institute.
SDG&E	San Diego Gas & Electric Company.
SoCal Edison	Southern California Edison Company.
Sunflower and Mid-Kansas	Sunflower Electric Power Corporation and Mid-Kansas Electric Company, LLC.
SVP	City of Santa Clara doing business as Silicon Valley Power.
TVA	Tennessee Valley Authority.
Union of Concerned Scientists	Union of Concerned Scientists.
WIRAB	Western Interconnection Regional Advisory Body.
Xcel	Xcel Energy Services Inc.

II. Appendix B: List of Substantive Supplemental Commenters (RM16–6–000)

AES Companies	AES Corporation/AES Energy Storage/Dayton Power and Light Company/Indianapolis Power and Light Company.
APS	Arizona Public Service Company.
Berkshire	Berkshire Hathaway Energy.
CESA	California Energy Storage Alliance.
EEI	Edison Electric Institute.
EPRI	Electric Power Research Institute.
ESA	Energy Storage Association.
Idaho Power	Idaho Power Company.
ISO–RTO Council	ISO–RTO Council.
ITC	International Transmission Company.
MCAES	Magnum CAES, LLC.
NRECA	National Rural Electric Cooperative Association.
NYTOs	New York Transmission Owners.
NERC	North American Electric Reliability Corporation.
NAGF	North American Generator Forum.
SDG&E	San Diego Gas & Electric Company.
SoCal Edison	Southern California Edison Company.
Sunrun	Sunrun, Inc.
Tri-State	Tri-State Generation and Transmission Association, Inc.
WIRAB	Western Interconnection Regional Advisory Body.

III. Appendix C: Uniform System of Accounts

Governor controls and similar electric equipment can be recorded within the following Uniform System of Accounts account numbers by function:

Production Plant

a. steam production
- 313 Engines and engine-driven generators.
- 314 Turbogenerator units.
- 315 Accessory electric equipment.
- 316 Miscellaneous power plant equipment.

b. nuclear production
- 323 Turbogenerator units (Major only).
- 324 Accessory electric equipment (Major only).
- 325 Miscellaneous power plant equipment (Major only).

c. hydraulic production
- 333 Water wheels, turbines and generators.
- 334 Accessory electric equipment.
- 335 Miscellaneous power plant equipment.

d. other production
- 344 Generators.
- 345 Accessory electric equipment.
- 346 Miscellaneous power plant equipment.

Transmission Plant

353 Station equipment.

Distribution Plant

362 Station equipment.

[FR Doc. 2018–03707 Filed 3–5–18; 8:45 am]

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