PRIMARY FREQUENCY RESPONSE

RELIABILITY, REGULATORY, AND JURISDICTIONAL CHALLENGES POSED BY OUR CHANGING RESOURCE MIX

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I. INTRODUCTION

Our changing resource mix increases the need for primary frequency response, the electric system's ability to stabilize its frequency following a contingency, while reducing our capability to meet that need. The Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC") have already taken actions to evaluate and address this growing problem, including the establishment of a new reliability standard that requires balancing authorities ("BAs") to achieve sufficient primary frequency response performance during frequency deviations. Spurred by concerns that it can't wait for NERC's 2018 report on the effectiveness of the newly effective reliability standard, FERC's recent Notice of Inquiry[1] identifies wide-ranging potential actions, including compensation for, and new interconnection-wide mechanisms to optimize, primary frequency response. While there are limitations on FERC's jurisdiction to address this problem, there are a number of alternatives within FERC's jurisdictional toolbox. But if FERC considers such solutions to be inadequate, it could lead to attempts to expand FERC's jurisdiction.

II. FREQUENCY RESPONSE AND THE PROBLEMS POSED BY OUR CHANGING RESOURCE MIX

What is Frequency Response?

Maintaining grid frequency within predetermined boundaries above and below 60 Hz is critical to reliability.[2] When the frequency deviates beyond those boundaries as a result of a system contingency such as the sudden loss of a large generator, the consequences can be severe—

[1] *Essential Reliability Services and the Evolving Bulk-Power System – Primary Frequency Response*, Notice of Inquiry, 154 FERC ¶ 61,117 (2016) ("Frequency Response NOI" or "NOI").

[2] Office of Elec. Reliability, FERC, LBNL-4142E, Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation at 7 (2010) ("LBNL Study"), http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf.

both load and generation can trip (i.e., automatically disconnect), potentially leading to cascading outages.[3]

Frequency response is a measure of an electric system's "ability to arrest and stabilize frequency deviations . . . following the sudden loss of generation or load."[4] The amount of frequency response in an interconnection "is affected by the collective responses of generation and load resources throughout the entire Interconnection."[5]

Inertial response, primary frequency response, and secondary frequency response all contribute to stabilizing the interconnection following a frequency deviation. Inertial response describes the ability of rotating generators (and loads) to resist changes in frequency.[6] The less inertia a power system has, the faster its frequency will fall after a loss of generation.[7] Within seconds after a change in frequency, primary frequency response acts to stabilize the frequency.[8] Individual generators or loads provide primary frequency response autonomously and automatically.[9] Secondary frequency response, which usually begins 30 seconds or more after a frequency disturbance and can last for several minutes, "involves changes to the MW output of resources on automatic generation control (e.g., regulation resources) that respond to dispatch instructions."[10]

Because FERC and NERC have increasingly focused on primary frequency response, and FERC's recent Frequency Response NOI signals the possibility of further regulatory action, this paper examines the technical, regulatory, and jurisdictional issues related to primary frequency response. An important goal of primary frequency response is to prevent the interconnection frequency from falling below the first stage of underfrequency load shedding ("UFLS") set points.[11] The less primary frequency response an interconnection has, the higher the likelihood of the interconnection's frequency falling below those set points, resulting in loss of load. Any resource in the interconnection can provide primary frequency response.[12] While a resource located far from a contingency may not respond quite as quickly as a closer resource, the

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[3] Frequency Response NOI, P 3.
[4] *Id.* P 4.
[5] *Id.* There are three US interconnections: the Eastern Interconnection, the Western Interconnection, and the Electric Reliability Council of Texas ("ERCOT").
[6] LBNL Study at 13.
[7] *Id.* at 14.
[8] *Id.* at 9.
[9] *Id.*; *see also Third-Party Provision of Primary Frequency Response Service*, Order No. 819, 80 Fed. Reg. 73,965, 73,967 (Nov. 27, 2015), FERC Stats. & Regs. ¶ 31,375, P 14 (2015) ("Order 819" or "Frequency Response MBR Rule") (defining primary frequency response service as "a resource standing by to provide autonomous, pre-programmed changes in output to rapidly arrest large changes in frequency until dispatched resources can take over").
[10] Frequency Response NOI, P 7 (citing LBNL Study at 9-11).
[11] *Id.* P 6.
[12] Order 819, P 18.

difference in response time is minimal.[13] FERC has also concluded that the sale of primary frequency response typically does not require any transmission reservation or scheduling.[14]

Capability and Performance of Generators Providing Primary Frequency Response

Primary frequency response is mostly provided by conventional, synchronous generators, such as hydro, coal, and natural gas units.[15] Those units have turbine governors that sense frequency changes and automatically adjust the generator's output to counteract the frequency change.[16] Non-synchronous resources, like wind and solar, can provide primary frequency response if they install appropriate control devices.[17] Some loads can provide primary frequency response.[18]

Until recently, the cost of installing appropriate control devices on non-synchronous generators to provide primary frequency response has been high. Thus, most existing wind and solar generation lack this capability. Retrofitting units to install that capability is also expensive. Due to advances in technology, however, installing the control devices on new non-synchronous generators has become affordable.

Even if a generator has the capability to provide primary frequency response, it remains up to the generator operator to determine whether the resource will actually provide primary frequency response. Generator operators can disable the turbine governors or equivalent control device, or configure those devices in ways that limit or prevent the generator from providing primary frequency response.

Even if a generator has appropriately configured capability to provide primary frequency response, the generator's ability to actually perform during a frequency deviation depends on whether it has "headroom."[19] Headroom refers to the difference between a generator's current output and its maximum output. If a generator has no headroom at the time of the frequency deviation, its governor (or equivalent control device) will not be able to increase the generator output to provide primary frequency response.

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[13] Office of Elec. Reliability, FERC, LBNL-4143E, Power and Frequency Control as it Relates to Wind-Powered Generation at 26-27 (2010) ("LBNL Generation Study"), http://www.ferc.gov/CalendarFiles/20110120114503-Power-and-Frequency-Control.pdf.

[14] Order 819, P 32. FERC notes that transmission capacity may need to be reserved in some situations, for example if the resource selling primary frequency response is located in a transmission-constrained area.

[15] Nuclear generators and some new natural gas generators do not provide governor response. LBNL Study at 9.

[16] *See* NERC, Frequency Response Initiative Report: The Reliability Role of Frequency Response at 12 (2012) ("NERC FRI Report"), http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf; LBNL Study at 9.

[17] Frequency Response NOI, P 18.

[18] *Id.* P 6.

[19] Frequency Response NOI, P 12.

The headroom requirement is an obstacle to the provision of primary frequency response by non-synchronous resources, which are typically dispatched to provide their full output, and thus do not have any headroom. Headroom can be reserved—for both synchronous and non-synchronous resources—but that reserved capacity would not be dispatched for energy or other ancillary services. An important policy question is whether resources should be compensated for reserving headroom to provide primary frequency response, or whether resources should be required to reserve headroom as a condition of interconnection.

Impacts of Our Changing Resource Mix on Primary Frequency Response

In the past decades, the nation's mix of generation resources has changed significantly. In 2000, traditional synchronous generators provided 98% of the nation's electricity capacity.[20] In 2011, that number fell to 94%, reflecting a 400% increase in non-hydro renewables.[21] Since then, non-hydro renewables—particularly wind and solar—have been growing at an increasing rate.[22] The U.S. Energy Information Administration projects that by 2040 non-hydro renewables will account for as much as 15% of the total electricity mix.[23]

Reducing the share of conventional synchronous generators in an interconnection creates two related problems: it reduces inertia, and it reduces the availability of primary frequency response. As discussed above, when an interconnection has less inertia, its frequency falls more quickly in response to a loss of generation or transmission.[24] Such an interconnection would therefore need more primary frequency response to prevent the frequency from falling below the first stage of UFLS set points. But the changing generation mix also reduces the available primary frequency response, exacerbating the problem.

As a result of this changing resource mix, all three interconnections have seen a significant decline in primary frequency response performance. NERC studies have shown that the Eastern Interconnection's primary frequency response performance during frequency

[20] U.S. Energy Information Administration, Annual Energy Review 2011, Table 8.11a (2012) (the capacity mix in 2000 was 599 GW of fossil fuels, 98 GW of nuclear, 99 GW of hydro, and 15 GW of non-hydro renewables) http://www.eia.gov/totalenergy/data/annual/pdf/aer.pdf.

[21] *Id.* (the capacity mix in 2011 was 791 GW of fossil fuels, 101 GW of nuclear, 101 GW of hydro, and 60 GW of non-hydro renewables).

[22] NERC, 2015 Summer Reliability Assessment at 7 (2015) (showing a 17-18% increase in wind and solar in a single year from 2014 to 2015), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015_Summer_Reliability_Assessment.pdf.

[23] U.S. Energy Information Administration, Annual Energy Outlook 2015 at 25 (2015) (total renewable share will increase to as much as 22% and non-hydro renewables will account for more than two-thirds of total renewables), http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

[24] LBNL Study at 14.

disturbances dropped significantly between 1995 and 2012, with a particularly steep decline beginning in 2007.[25]

The situation has begun to stabilize. NERC studies have shown that all three U.S. interconnections had adequate levels of primary frequency response in 2015.[26] The Western Interconnection and ERCOT have performed consistently well during frequency disturbances between 2012 and 2015; the Eastern Interconnection's primary frequency response performance actually improved slightly from 2012 to 2015.[27] Nevertheless, concerns about a continued decline remain.[28]

III. NERC'S ACTIONS TO ADDRESS FREQUENCY RESPONSE

Early Efforts

As early as 1991, NERC[29] began noticing a decline in primary frequency response and commissioned an Electric Power Research Institute ("EPRI") study on the subject.[30] The study found that "the frequency response of the interconnections was declining at rates greater than would be expected with the growth of demand and generating capacity" but that "the decline had not reached a point at which reliability was being compromised."[31] A decade later, NERC proposed a frequency response standard[32] and, in 2004, published a whitepaper intended to create an understanding of the need for a standard.[33] In 2005, that standard was submitted to FERC and was approved as a mandatory reliability standard in 2007.[34]

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[25] NERC, State of Reliability 2015 at 9 (2015) http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015%20State%20of%20Reliability.pdf.

[26] *Id.*

[27] *Id.*

[28] The changing generation mix poses additional reliability concerns beyond frequency response, including voltage support and ramping capability. While those impacts are beyond the scope of this paper, we note that NERC and FERC are taking actions to study and address those impacts as well. *See* NERC, ERSTF Concept Paper (2014) ("ERSTF Concept Paper"), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf; *see also* Reactive Power Requirements for Non-Synchronous Generation, Order No. 827, 155 FERC ¶ 61,277 (2016) (requiring all newly interconnecting non-synchronous generators to provide reactive power at the high-side of the generator substation as a condition of interconnection).

[29] At that time, NERC was the North American Electric Reliability Council, a voluntary, industry-sponsored reliability organization whose mission was to ensure that the bulk-power system in North America is reliable, adequate, and secure. NERC and regional reliability organizations developed reliability policies, criteria, and guides. NERC changed its name to the North American Electric Reliability Corporation on January 1, 2007.

[30] NERC FRI Report at 22.

[31] *Id.*

[32] At that time, prior to the Energy Policy Act of 2005 and NERC's designation as the FERC-approved Electric Reliability Organization, NERC's standards were not mandatory.

[33] NERC, Frequency Response Standard Whitepaper (2004), http://www.nerc.com/docs/oc/rs/Frequency_Response_White_Paper.pdf.

[34] *See infra* Part IV.

NERC continued to analyze the frequency response issue in the 2000s, and in 2010, NERC launched the Frequency Response Initiative to comprehensively address the issue. That initiative culminated in the October 2012 NERC FRI Report summarizing all of NERC's analyses and proposing metrics and mechanisms to measure frequency response. The NERC FRI Report supported the development of Reliability Standard BAL-003-1, which (as discussed below) will become enforceable later this year.

Essential Reliability Task Force

NERC's 2013 Long-Term Reliability Assessment recommended that NERC develop a primer on "essential reliability services" to serve as a reference for regulators and policymakers, and to inform, educate, and build awareness on the reliability ramifications of a changing resource mix.[35] In 2014, NERC established the Essential Reliability Services Task Force ("ERSTF") to develop that primer, educate the industry and regulators about essential reliability services, and develop approaches for tracking essential reliability services.[36] The primer identified three categories of essential reliability services: frequency support (including inertia, primary frequency response, and secondary frequency response), ramping capability, and voltage support.[37]

The ERSTF followed up in 2015 with a comprehensive report on essential reliability services, including recommendations on how to measure those services and actions that should be taken to maintain reliability.[38] With respect to primary frequency response, the ERSTF recommended that NERC track certain measures of primary frequency response and investigate trends, and that all new resources should have the capability to support frequency.[39] The ERSTF explained that governors have been standard on conventional generators for decades, that comparable capabilities are now available for non-synchronous resources, and that it is necessary to ensure these capabilities are present in the future resource mix.[40]

The ERSTF also concluded that distributed energy resources ("DERs") "are poised to reach levels that will have significant influence on [Bulk Power System ("BPS")] operations either on an individual or aggregated basis."[41] It recommended "that NERC establish a working group to further examine the ability to forecast, visibility, control, and participation of DERs as an active

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[35] NERC, 2013 Long-Term Reliability Report at 2 (2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013_LTRA_Final.pdf.
[36] NERC, ERSTF Scope (2014), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Scope_ERSTF_Final.pdf.
[37] *See* ERSTF Concept Paper.
[38] NERC, ERSTF Measures Framework Report (2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.
[39] *Id.* at vi.
[40] *Id.*
[41] *Id.* at 21.

part of the BPS."[42] In response, NERC established a Distributed Energy Resource Task Force ("DERTF") to "develop a report focused specifically on operational and planning impacts of [DERs]" and to "examine potential reliability implications."[43]

NERC Alerts on Primary Frequency Response and Primary Frequency Response Guidelines

In September 2010, NERC issued a Recommendation Alert requesting information about the configuration of governors in the Eastern Interconnection, and 43% of generators failed to provide the information.[44] NERC determined that many generators failed to provide that information "possibly because they may lack the resources or knowledge to determine that information."[45] Based on additional surveys and studies, NERC determined that a significant portion of the generators in the Eastern Interconnection had configured their governors in ways that inhibit or prevent primary frequency response.[46]

In February 2015, NERC issued an Industry Advisory[47] alerting industry to review their governor settings and to ensure that they met certain parameters.[48] In December 2015, NERC's Operating Committee issued a Guideline recommending specific governor configurations "that will potentially enable resources to provide better frequency response to the [Bulk Electric System]."[49] This Guideline is "strictly voluntary," though generators are "highly encouraged" to adopt its recommendations to promote the highest levels of reliability.[50]

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[42] *Id.*

[43] NERC DERTF Scope (2016), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/DERTF_Scope_Final.pdf.

[44] NERC, Eastern Interconnection Frequency Initiative Whitepaper at 3 (2013), http://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/2015%20Alerts/EI%20Frequency%20Initiative%20Whitepaper.pdf.

[45] NERC, Industry Advisory: Generator Governor Frequency Response at 2 (2015) ("NERC Industry Advisory"), http://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/2015%20Alerts/NERC%20Alert%20a-2015-02-05-01%20Generator%20Governor%20Frequency%20Response.pdf.

[46] *Id.*

[47] NERC may, pursuant to Rule 810 of its Rules of Procedure, issue Industry Advisories "to advise certain segments of the owners, operators and users of the Bulk Power System of findings and lessons learned." NERC, Rules of Procedure at 71 (2016), http://www.nerc.com/FilingsOrders/us/RuleofProcedureDL/NERC_ROP_Effective_20160504.pdf. Unlike NERC's "Recommendations" or "Essential Actions," an Industry Advisory is "purely informational" and does not recommend or require a specific action. *See infra* Part VI.

[48] *See* NERC Industry Advisory.

[49] NERC, Reliability Guideline: Primary Frequency Control at 3 (2015) ("Guideline"), http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Primary_Frequency_Control_final.pdf.

[50] *Id.* at 1. This Guideline is a work in progress, and will be revised in the future to describe governor or control system configurations for additional types of units. NERC, Operating Committee Meeting Presentations at 59 (Mar. 8-9, 2016), http://www.nerc.com/comm/OC/AgendasHighlightsMinutes/March_2016_OC_Meeting_Presentations.pdf.

IV. FERC'S ACTIONS ON FREQUENCY RESPONSE

FERC has addressed primary frequency response using both its reliability authority under Section 215 of the Federal Power Act ("FPA") and its economic regulation authority under FPA Sections 205 and 206.[51] On the reliability side, FERC directed NERC to define the amount of primary frequency response each balancing authority must have, and approved Reliability Standard BAL-003-1, which implements that directive. On the economic regulation side, FERC held a workshop on compensation for primary frequency response, and authorized third-party market-based sales of primary frequency response. Recently, FERC issued its Frequency Response NOI to investigate what additional steps are needed to ensure the grid continues to have enough primary frequency response.

Order 693 – Directive on Frequency Response

As part of NERC's transition to being the FERC-approved Electric Reliability Organization pursuant to the Energy Policy Act of 2005, FERC in 2007 issued Order 693, approving dozens of NERC's initial reliability standards, making them mandatory and enforceable, but directing NERC to make significant changes to many.[52] One of the standards NERC had proposed was BAL-003-0, which was intended to provide a consistent method for calculating Frequency Bias, a value Balancing Authorities use in their Area Control Error algorithm that allows them to contribute secondary frequency response to an interconnection.[53] While approving BAL-003-0, FERC expressed concern that the standard did not define the amount of primary or secondary frequency response each balancing authority would need for reliable operation of the grid.[54] Noting the frequency oscillations in ISO New England during the August 14, 2003 blackout that could have (but didn't) cause cascading outages, FERC directed NERC to revise the BAL-003 standard to "define[] the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved."[55]

Order 794 – Reliability Standard BAL-003-1

In response to Order 693 and informed by its ongoing study of frequency response, NERC proposed revisions to the BAL-003 standard in March 2013.[56] Unlike the previous BAL-003 standard, which had focused on secondary frequency response, the proposed version

[51] 16 U.S.C. §§ 824d, 824e, 824*o*.

[52] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 Fed. Reg. 16,416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242 (2007) ("Order 693"), *aff'd*, Order No. 693-A, 72 Fed. Reg. 40,717 (July 25, 2007), 120 FERC ¶ 61,053 (2007).

[53] *See* Reliability Standard BAL-003-0 (2005), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=BAL-003-0&title=Frequency Response and Bias&jurisdiction=United States.

[54] Order 693, P 372.

[55] *Id.* P 375; *see also id.* P 372.

[56] *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 78 Fed. Reg. 3,723 (Jan. 23, 2014), 146 FERC ¶ 61,024 (2014) ("Order 794").

addressed both primary and secondary frequency response.[57] A key goal of the new version was to determine whether a BA has sufficient frequency response for reliable operation.[58] One mechanism for achieving that goal is the creation of a Frequency Response Obligation that each BA (or group of BAs that form a Frequency Response Sharing Group ("FRSG"))[59] must achieve. NERC specifies certain frequency events that are reportable, and each BA or FRSG must report annually on its primary frequency response performance during those events. The median annual performance during those reportable events is the BA or FRSG's Frequency Response Measure, which must be equal to or lower than its Frequency Response Obligation.

In January 2014, FERC expressed several concerns about NERC's proposed standard, but ultimately approved it without any directives to further modify the standard.[60] Although FERC, in approving the proposed standard without change, relied on NERC's assessment that "sufficient frequency response resources would be available for balancing authorities to comply with . . . BAL-003-1,"[61] FERC clearly remained concerned. It directed NERC to submit two reports, and concluded that "the prudent course is to have NERC complete the directed report[s]" and then "determine whether additional action is warranted."[62] FERC also directed NERC to "immediately report" if it learns that a lack of resource availability is impeding BAs' ability to satisfy their primary frequency response obligations.[63]

The first report, due July 2017, will evaluate the Eastern Interconnection Frequency Response Obligation during the expected light-load conditions, and make recommendations on whether further action is required.[64] During light-load conditions, the system may have less inertia (increasing the need for primary frequency response) and non-synchronous resources may make up a larger percentage of the online generation (reducing the amount of primary frequency response available). Thus, FERC required NERC to assess the extent to which a contingency during a light-load condition may pose more severe primary frequency response problems than a contingency during a heavy-load condition.

The second report, due July 2018, will address the availability of resources for BAs to meet their Frequency Response Obligation.[65] FERC noted that BAL-003-1 allocates the Frequency

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[57] *Id.* PP 7-9.
[58] *Id.* P 15.
[59] A Frequency Response Sharing Group is a "group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members." NERC, Glossary of Terms Used in NERC Reliability Standards at 46 (2016), http://www.nerc.com/files/glossary_of_terms.pdf.
[60] Order 794, P 22.
[61] *Id.* P 62.
[62] *Id.* P 63.
[63] *Id.*
[64] *Id.* P 79.
[65] The second report will also address a technical issue of how to calculate a BA's Frequency Response Measure. BAL-003-1 simply takes the median value of the BA's performance during all reportable events. NERC must report on whether using a linear regression methodology, rather than a simple median, would more accurately reflect the BA's performance. *Id.* PP 32-34.

Response Obligation to BAs, but does not impose any obligation on resources that are capable of providing primary frequency response.[66] FERC expressed concern that "the ability of balancing authorities and Frequency Response Sharing Groups to meet the obligation is untested."[67] FERC therefore required NERC to provide "data indicating whether actual frequency response was sufficient to meet each balancing authority's Frequency Response Obligation" and "recommendations to ensure that frequency response can be maintained at all times within each balancing authority's footprint" if any BA does not meet its Frequency Response Obligation.[68]

2014 Primary Frequency Response Workshop

In April 2014, FERC convened a workshop on Third-Party Provision of Reactive Supply and Voltage Control and Regulation and Frequency Response Services.[69] The intent of the workshop was to receive input on the technical, economic, and market issues concerning the provision of reactive supply and voltage control services (i.e., those provided under Schedule 2 of FERC's Open Access Transmission Tariff ("OATT")) and regulation and frequency response services (provided under OATT Schedule 3).[70]

In Order 888,[71] FERC had determined that primary frequency response services and regulation service should be combined as a single ancillary service under Schedule 3 of the OATT. At that time, most resources providing regulation service were also providing primary frequency response.[72] FERC Staff has said that historically, "almost all synchronized generation" provided primary frequency response and generally did not receive a "separate, unbundled payment" for that service.[73] But by 2014, FERC Staff had begun evaluating whether additional market

[66] *Id.* P 50.
[67] *Id.* P 60.
[68] *Id.*
[69] *Third-Party Provision of Reactive Supply and Voltage Control and Regulation and Frequency Response Services*, Docket No. AD14-7, Notice of Workshop (Feb. 20, 2014) ("Notice of Workshop"), eLibrary No. 20140220-3071.
[70] *Id.*
[71] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Standard Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 Fed. Reg. 21,539 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) ("Order 888"), *clarified*, 76 FERC ¶ 61,009 (1996), *modified*, Order No. 888-A, 62 Fed. Reg. 12,274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 62 Fed. Reg. 64,688 (Dec. 9, 1997), 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).
[72] *Id.* at 5.
[73] *Third-Party Provision of Reactive Supply and Voltage Control and Regulation and Frequency Response Services*, Final Agenda at 3 (Apr. 22, 2014) ("Final Agenda"), eLibrary No. 20140424-4006.

mechanisms are necessary for primary frequency response.[74] FERC Staff posed four main questions to its workshop panel on primary frequency response:[75]

1. In light of changed circumstances, should there now be payment for appropriate performance (i.e., for providing frequency response service) or should some level of performance be more strongly required in interconnection agreements?
2. How should cost-based payments for frequency response service be structured?
3. Should the Commission create a new frequency response ancillary service in the OATT, subdivide the existing Schedule 3 Regulation and Frequency Response ancillary service into two services with separate cost-based rates, or leave stand-alone frequency response service entirely to market mechanisms in the bilateral and organized markets?
4. If frequency response service is either recognized through the OATT or incorporated into an Independent System Operator ("ISO")/Regional Transmission Organization ("RTO") organized market, how should self-supply of frequency response be established and measured?

Order 819 - Frequency Response Market-Based Rates

Based on its April 2014 workshop, FERC proposed in February 2015 a rule that would allow the sale of primary frequency response service at market-based rates by public utilities with market-based rate authority for sales of energy and capacity.[76] FERC adopted that proposal as a final rule in November 2015, despite comments urging further study.[77] The Frequency Response MBR Rule did not require any entity to purchase primary frequency response from third parties, nor did it require the development of organized markets for primary frequency response. Rather, the rule was limited to issues associated with market power screening for voluntary, bilateral sales by public utility sellers of primary frequency response service.[78] The Frequency Response MBR Rule noted that balancing authorities would soon have obligations to maintain a minimum level of primary frequency response under the BAL-003-1 standard, and that, while most balancing authorities should be able to meet those obligations using their own resources, some might be interested in purchasing primary frequency response from others.[79]

The Frequency Response MBR Rule addressed three technical issues related to the sale of primary frequency response.[80] First, FERC found that any resource in an interconnection can

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[74] Notice of Workshop at 5.
[75] Final Agenda at 3-4.
[76] *Third-Party Provision of Primary Frequency Response Service*, Notice of Proposed Rulemaking, 80 Fed. Reg. 10,426 (Feb. 26, 2015), FERC Stats. & Regs. ¶ 32,705 (2015).
[77] *See* Order 819.
[78] *Id.* P 13.
[79] *Id.* P 10.
[80] The rule focused on how these technical issues affect FERC's market power screens, but FERC's consideration of those issues also has significance for how public utilities will sell—and be compensated for—primary frequency response. Although sales of primary frequency response by public power are not subject to FERC's jurisdiction, FERC's approach to those technical issues will drive the market.

provide primary frequency response and have the same ability (admittedly with some delay) to dampen harmful changes in interconnection-wide frequency.[81] Second, FERC recognized that "it may be necessary to further develop or refine existing communications protocols" to provide the necessary data to sell primary frequency response from one balancing authority to another, but noted that the existing information sharing systems and protocols "should be able to accommodate the more detailed information associated with primary frequency response transactions without requiring an unreasonable amount of effort from affected parties."[82] Third, FERC found that "in the vast majority of cases the sale of primary frequency response service should not require any transmission reservation or scheduling because, by definition, individual frequency responses would not be sustained for long enough periods to trigger a need for transmission service or schedule changes."[83]

Frequency Response Notice of Inquiry

In February 2016, FERC issued a Notice of Inquiry seeking comment on the need to reform its regulations for the provision and compensation of primary frequency response.[84] It appears that FERC's concern about the availability of resources to provide primary frequency response has grown since it approved the BAL-003-1 standard in January 2014. FERC now "believes that it is prudent to take a proactive approach to better understand the issues related to primary frequency response performance and determine what additional actions beyond Reliability Standard BAL-003-1 may be appropriate."[85] FERC cited "the ongoing evolution of the nation's generation resource mix" and NERC's February 2015 Industry Advisory as factors that led to that conclusion.[86]

The Frequency Response NOI asks approximately fifty questions, suggesting that FERC wants to develop a record to support action to better ensure the sufficiency of primary frequency response during frequency disturbances. The Frequency Response NOI expresses concern about two problems. First, not all generators have the *capability* to provide primary frequency response. As discussed above, non-synchronous resources cannot provide primary frequency response unless they have the correct equipment installed. Second, even when generators do have the capability, some are not configured to *actually provide* primary frequency response during disturbances. As also discussed above, resources with primary frequency response capability must have "headroom" to actually provide primary frequency response, which non-synchronous resources typically lack because they are dispatched at their maximum output.

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[81] *Id.* P 25.
[82] *Id.* P 26.
[83] *Id.* P 32. FERC recognized that in some cases transmission would need to be scheduled or that available transfer capability could be affected by third-party sales of primary frequency response, but stated that those issues would be assessed when a balancing authority evaluates a particular transaction or if an RTO voluntarily chooses to develop an organized market for primary frequency response. *Id.* P 34.
[84] *See* Frequency Response NOI.
[85] *Id.* P 30.
[86] *Id.*

FERC has various tools it could use to address these problems: impose requirements on generators through jurisdictional interconnection agreements, impose requirements on generators through reliability standards, and create incentives for generators through compensation or other market mechanisms. The NOI asks about each of them.

The first set of questions focuses on whether to amend the *pro forma* Large Generator Interconnection Agreement ("LGIA") and Small Generator Interconnection Agreement ("SGIA") agreements to impose primary frequency response requirements on all newly interconnecting generation resources, including non-synchronous generators. The Frequency Response NOI asks whether new generators should be required to have primary frequency response capabilities as a precondition of interconnection, as well as whether new generators should be required to configure their governors (or equivalent control devices) to actually provide primary frequency response.

The second set is about whether to impose primary frequency response requirements for existing resources. The Frequency Response NOI asks if existing generators should be required to have primary frequency response capabilities, and if so, how that requirement should be imposed (i.e., through transmission tariffs or a reliability standard). The NOI asks about the costs of retrofitting existing units, including non-synchronous generators, to have such capabilities. It also asks if existing generators should be required to be configured to actually provide primary frequency response.

The final questions are about procurement and compensation mechanisms for primary frequency response. The Frequency Response NOI notes that currently "there are few, if any, entities receiving compensation for selling primary frequency response as a stand-alone product."[87] It also observes that the Frequency Response MBR Rule was intended "to foster competition in the sale of primary frequency response service."[88] The NOI asks whether resources should be compensated for providing primary frequency response capability, performance, or both. FERC also asks whether it would be appropriate for RTOs to create a product for primary frequency response service, and whether it should be sold as an ancillary service separate from regulation service.[89] In addition, the NOI asks whether it would be viable to implement an interconnection-wide optimization mechanism for primary frequency response.

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[87] *Id.* P 35.
[88] *Id.* P 36.
[89] *Id.* P 54. Currently, primary frequency response service and regulation service are bundled as a single service under Schedule 3 of the OATT. *See supra* Part IV.

V. FERC JURISDICTION TO ADDRESS FREQUENCY RESPONSE PROBLEMS

FERC Authority under FPA Sections 201, 205, and 206

FERC has jurisdiction over (1) the transmission of electric energy in interstate commerce, (2) the sale of electric energy at wholesale, and (3) all facilities for such transmission or sale of electric energy.[90] But it does not have jurisdiction over facilities used for the generation of electric energy or used in local distribution.[91] FERC regulates the rates and charges for jurisdictional transmission or wholesale sales, as well as any rule or practice "affecting" such rates.[92] FERC's Section 205 and Section 206 authority does not apply to "non-public utilities" including states, political subdivisions of states, agencies or instrumentalities of a state or political subdivision, or a corporation wholly owned by one or more of the foregoing.[93]

In Order 888, FERC's landmark action ordering public utilities to offer open access transmission service, FERC clarified its interpretation of the federal/state jurisdictional boundaries over transmission and local distribution.

- FERC recognized a bright line test for unbundled wholesale transmission—transmission of electric energy being sold for resale, regardless of voltage. [94] "[A]ny facilities of a public utility used to deliver electric energy in interstate commerce to a wholesale purchaser, whether such facilities are labeled 'transmission,' 'distribution' or 'local distribution,' are subject to the Commission's jurisdiction under sections 205 and 206."[95]
- Recognizing its exclusive jurisdiction over transmission in interstate commerce, FERC determined that where a state adopts retail competition—"unbundles" the retail sale into separate transmission and power sales—FERC has jurisdiction over unbundled retail transmission service. However, acknowledging it lacked jurisdiction over "facilities used in local distribution," FERC did not establish a bright line test between transmission and local distribution used for this purpose. Instead, it established a seven-factor test to identify

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[90] FPA § 201(b), 16 U.S.C. § 824(b).
[91] *Id.*
[92] FPA §§ 205, 206, 16 U.S.C. §§ 824d, 824e.
[93] FPA § 201(f), 16 U.S.C. § 824(f). Sections 210, 211, 211A, and 212 provide FERC limited jurisdiction over transmission and interconnections by non-public utility transmission owners. 16 U.S.C. §§ 824i-824k. In addition, non-public utility transmission owners that take service under a public utility's OATT are subject to "reciprocity" obligations to provide their public utility transmission provider (or, in the case of service from an ISO/RTO, all transmission owning members of that ISO/RTO) comparable transmission service. *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-A, 73 Fed. Reg. 2984, 2988 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261, P 37 (2007), *order on reh'g*, Order No. 890-B, 73 Fed. Reg. 39,092 (July 8, 2008), 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 74 Fed. Reg. 12,540 (Mar. 25, 2009), 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 74 Fed. Reg. 61,511 (Nov. 25, 2009), 129 FERC ¶ 61,126 (2009).
[94] *See* Order 888, 61 Fed. Reg. at 21,626, FERC Stats. & Regs. ¶ 31,036, at 31,783.
[95] *Id.*, Appendix G, 61 Fed. Reg. at 21,731, FERC Stats. & Regs. ¶ 31,036, at 31,980.

> whether a facility is a local distribution facility subject to state jurisdiction or a facility engaged in interstate transmission subject to FERC jurisdiction.[96]

Order 888's jurisdictional demarcation was affirmed by the courts.[97]

In Order 2003, FERC's order establishing standardized procedures and agreements for interconnection of large generators, the scope of FERC jurisdiction was again a central question.[98] FERC asserted jurisdiction over the terms of a generator interconnection if (1) the generator connects to a facility that, at the time of the interconnection request, is included in a public utility's OATT (i.e., transmission facilities used to transmit electric energy in interstate commerce either at wholesale or for unbundled retail sales, and ''distribution'' facilities that are used for wholesale sales in interstate commerce); *and* (2) the interconnection is for the purpose of facilitating a jurisdictional wholesale sale of electric energy.[99] FERC claimed jurisdiction even if the facility to which the generator was interconnecting was also being used in local distribution, and (presumably because the interconnection must be for purposes of a wholesale sale) declined to apply its seven-factor test to whether an interconnection should be subject to its standard generator interconnection procedures. FERC did not claim jurisdiction over most net metered generators; it would assert jurisdiction only "if the Generating Facility produces more energy than it needs and makes a net sale of energy to a utility over the applicable billing period."[100]

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[96] *Id.*, 61 Fed. Reg. at 21,625-27, 21,731-32, FERC Stats. & Regs. ¶ 31,036, at 31,781-84, 31,981-82. The seven factor test involves evaluating on a case-by-case basis whether the facilities in question correspond with seven specific indicators of local distribution:

(1) Local distribution facilities are normally in close proximity to retail customers.
(2) Local distribution facilities are primarily radial in character.
(3) Power flows into local distribution systems, it rarely, if ever, flows out.
(4) When power enters a local distribution system, it is not reconsigned or transported on to some other market.
(5) Power entering a local distribution system is consumed in a comparatively restricted geographical area.
(6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.
(7) Local distribution systems will be of reduced voltage.

Id., 61 Fed. Reg. at 21,731, FERC Stats. & Regs. ¶ 31,036, at 31,981.

[97] *Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom New York v. FERC*, 535 U.S. 1 (2002) ("*TAPS v. FERC*").

[98] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 68 Fed. Reg. 49,846 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003), *modified*, 68 Fed. Reg. 69,599 (Dec. 15, 2003) ("Order 2003"), *clarified*, 69 Fed. Reg. 2,135 (Jan. 14, 2004), 106 FERC ¶ 61,009 (2004), *order on reh'g*, Order No. 2003-A, 69 Fed. Reg. 15,932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004) ("Order 2003-A"), *order on reh'g*, Order No. 2003-B, 70 Fed. Reg. 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order 2003-C, 70 Fed. Reg. 37,661 (June 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. NARUC v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 128 S. Ct. 1468 (2008).

[99] Order 2003-A, PP 710, 730.

[100] *Id.* P 747.

In *National Ass'n of Regulatory Utility Commissioners v. FERC*, the D.C. Circuit affirmed Order 2003's jurisdictional determination, finding it "applies to jurisdictional transactions only."[101] The court found that by "establishing standard [interconnection] agreements FERC has exercised its jurisdiction over the *terms* of those relationships" between parties "with respect to electricity flowing over facilities."[102] Because FERC has jurisdiction over "*all aspects* of wholesale sales . . . regardless of the facilities used," FERC had not exceeded its jurisdictional bounds.[103] The court stated that "FERC is exerting jurisdiction over transactions, based on the transactions' satisfaction of the Act's jurisdictional criteria [and] thus has had no occasion to decide whether a facility as such should be classified as jurisdictional or not."[104]

In Order 2006, FERC adopted standard generator interconnection procedures and agreements for small generators.[105] FERC stated that its jurisdiction to do so was identical to the jurisdiction it asserted under Orders 888 and 2003.[106] FERC expected that "the vast majority of small generator interconnections will be with state jurisdictional facilities" and emphasized that its order "in no way affects rules adopted by the states for the interconnection of generators with state-jurisdictional facilities."[107] But FERC noted that if a small generator "seeks to interconnect[] with a facility under federal jurisdiction, a state program cannot displace federal rules for interconnections."[108]

In addition to its jurisdiction over all aspects of wholesale electric energy sales, "[t]he FPA has delegated to FERC the authority—and, indeed, the duty—to ensure that rules or practices 'affecting' wholesale rates are just and reasonable."[109] Recognizing that this "affecting" jurisdiction could "extend FERC's power to some surprising places" including markets for "steel, fuel, and labor" and possibly even "markets in just about everything," the Supreme Court's *FERC v. EPSA* decision adopted "a common-sense construction of the FPA's language, limiting FERC's 'affecting' jurisdiction to rules or practices that *directly* affect the wholesale rate."[110] The Court held that FERC's regulation of rates paid for retail demand response sold into [wholesale] markets fell within FERC's jurisdiction "with room to spare."[111]

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[101] *Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277, 1280 (D.C. Cir. 2007).
[102] *Id.* (emphasis in original).
[103] *Id.* (emphasis in original) (citing *TAPS v. FERC*, 225 F.3d at 696).
[104] *Id.*, 475 F.3d at 1282.
[105] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 70 Fed. Reg. 34,189 (June 13, 2005), FERC Stats. & Regs. ¶ 31,180 (2005) ("Order 2006"), *order on reh'g*, Order No. 2006-A, 70 Fed. Reg. 71,760 (Nov. 30, 2005), FERC Stats. & Regs. ¶ 31,196 (2005) ("Order 2006-A"), *order on clarification*, Order No. 2006-B, 71 Fed. Reg. 42,587 (July 27, 2006), FERC Stats. & Regs. ¶ 31,221 (2006).
[106] Order 2006, P 481.
[107] Order 2006-A, P 105.
[108] *Id.*
[109] *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 764 (2016) ("*FERC v. EPSA*") (citing FPA §§ 205(a) and 206(a), 16 U.S.C. §§ 824d(a) and 824e(a)).
[110] *Id.* (internal quotation and citation omitted).
[111] *Id.* at 774.

FERC Authority under FPA Section 215

The Energy Policy Act of 2005 gave FERC additional jurisdiction for electric reliability. It added Section 215 of the Federal Power Act, which gives FERC (and NERC, as the Commission-approved Electric Reliability Organization) authority to establish and enforce reliability standards "to provide for reliable operation of the bulk-power system"[112] so that "instability, uncontrolled separation, or cascading failures of [the bulk power] system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."[113] For purposes of approving and enforcing compliance with such standards, FERC and NERC are given jurisdiction over *all* "users, owners, and operators" of the bulk-power system.[114] The term "bulk-power system" is defined as "facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)" and "electric energy from generation facilities needed to maintain transmission system reliability" but "does not include facilities used in the local distribution of electric energy."[115]

Although the "bulk-power system" defines the outer limit of FERC and NERC's reliability authority, FERC has not further defined the term "bulk-power system." FERC has, however, approved the definition of the "Bulk Electric System" ("BES"), which NERC uses for a variety of purposes. The term BES is used in NERC's Statement of Compliance Registry Criteria to determine which entities must be registered in NERC's compliance registry and thus subject to reliability compliance obligations.[116] The term also affects the scope of many reliability standards because they either refer directly to the BES or they refer to a term, like Facilities, that is defined in the NERC Glossary with reference to the BES.[117]

The Bulk Electric System definition, as approved in Order 773,[118] begins with a "core" definition, then provides a list of five facility configurations that are included in the definition and a list of four configurations that are excluded. It also provides a case-by-base exception process to include or exclude specific facilities that were otherwise captured by the core definition and the bright-line inclusions and exclusions. The core definition is "all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or

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[112] FPA § 215(a)(3), 16 U.S.C. § 824*o*(a)(3).
[113] FPA § 215(a)(4), 16 U.S.C. § 824*o*(a)(4).
[114] FPA § 215(b)(1), 16 U.S.C. § 824*o*(b)(1). Section 215 is excluded from Section 201(f)'s general exemption of public power from regulation under Part II of the FPA. 16 U.S.C. § 824(f).
[115] FPA § 215(a)(1), 16 U.S.C. § 824*o*(a)(1).
[116] NERC, Rules of Procedure, Appendix 5B, Statement of Compliance Registry Criteria (effective Oct. 15, 2015), http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/Appendix_5B_RegistrationCriteria_20151015.pdf ("NERC Registry Criteria").
[117] NERC Glossary of Terms at 42.
[118] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 78 Fed. Reg. 804 (Jan. 4, 2013), 141 FERC ¶ 61,236 (2012)("Order 773"), *clarified on reh'g*, Order No. 773-A, 78 Fed. Reg. 29,210 (May 17, 2013), 143 FERC ¶ 61,053 (2013), *compliance deadline extended*, 143 FERC ¶ 61,231 (2013), *clarified*, 144 FERC ¶ 61,174 (2013), *review denied sub nom. New York v. FERC*, 783 F.3d 946 (2d Cir. 2015).

higher." *Id.* P 12. The BES definition explicitly excludes "facilities used in the local distribution of electric energy." *Id*.

The BES definition's specific inclusions encompass generator resources "with gross individual nameplate rating greater than 20 MVA or gross plant/facility aggregate nameplate rating greater than 75 MVA" and "[d]ispersed power producing resources with aggregate capacity greater than 75 MVA." *Id.* P 13. The definition explicitly excludes behind-the-meter generating resources "on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 75 MVA; and (ii) standby, back-up, and maintenance power services are provided" by a Balancing Authority, another generator, or under terms approved by an applicable regulatory authority. *Id.* P 18.

FERC's reliability jurisdiction may be broader than the BES definition. FERC has said that the statutory bulk-power system definition "reaches farther than those facilities that are included in NERC's [pre-existing] definition of the bulk electric system."[119] NERC's current BES definition might be coincident with the statutory term bulk-power system, but neither FERC nor the courts have addressed that issue. In addition, FPA Section 215 allows FERC and NERC to impose standards on all "users" of the bulk-power system, although the extent of that jurisdiction is untested.[120]

VI. POTENTIAL SOLUTIONS

Primary frequency response affects bulk-power system reliability as well as interstate transmission service and wholesale sales, and thus fits within both FERC's reliability and economic regulation jurisdiction. However, while frequency response has an interconnection-wide impact, the problem is being caused—and must be solved—by individual generators, some of which are clearly within FERC's jurisdiction and some of which are not. Distributed energy resources that do not make wholesale sales are difficult for FERC to reach under its economic regulation authority, and if too small to qualify as BES generators, would be outside the authority FERC has asserted under its reliability authority.

Addressing the primary frequency response problem is further complicated by the fact that grid reliability can be maintained as long as there is sufficient primary frequency response available in an interconnection. Requiring *all* generators to provide primary frequency response may not

[119] Order 693, P 76.

[120] 16 U.S.C. § 824*o*. FERC has repeatedly declined to define the jurisdictional term "user of the Bulk-Power System." Order 693, P 116 ("we are concerned that any attempt to define the term at this time will either be overly broad so as not to provide any helpful guidance or overly narrow so as to exclude entities that should be covered."); *see also Rules Concerning Certification of the Electric Reliability Organization and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 71 Fed. Reg. 8662, P 99 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204 (2006), *corrected*, 71 Fed. Reg. 11,505 (Mar. 8, 2006), *on reh'g*, Order No. 672-A, 71 Fed. Reg. 19,814, P 13 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006), *modified*, 73 Fed. Reg. 21,814 (Apr. 23, 2008), 123 FERC ¶ 61,046 (2008).

be necessary from a reliability perspective, but imposing requirements on some but not all generators to have the capability may raise questions of discrimination.

Market-based solutions may be possible, but it can be difficult to measure and compensate a resource for providing primary frequency response. While primary frequency response can be provided by any resource in an interconnection, there are some technical barriers associated with purchasing primary frequency response service from resources in distant balancing areas.

In short, solving the primary frequency response problem may not be easy. Nevertheless, steps can be taken that would help address the problem that will fall within FERC jurisdiction. Other actions, however, may stretch the limits of FERC's jurisdiction.

Requiring New Generators to Install Primary Frequency Response Capability using Generator Interconnection Agreements

One action that FERC could take immediately, without pushing technical or jurisdictional boundaries, would be to require changes to the *pro forma* LGIA and SGIA to require all newly interconnecting generators, including non-synchronous generators, to install primary frequency response capability.[121] Comments submitted in response to FERC's Frequency Response NOI indicate that the cost of installing primary frequency response "capability is low for wind plants, if implemented on a prospective and not retroactive basis."[122] In contrast, retrofitting existing non-synchronous generators to provide primary frequency response capability could be costly. So imposing a primary frequency response capability requirement on new generators now would be an effective, "no regrets" way to prevent the erosion of the interconnection's collective primary frequency response capability as the resource mix evolves.

Imposing a *capability* requirement, but not a *performance* requirement, is appropriate at this time. As noted in Part III above, NERC's studies show that all the interconnections currently have sufficient primary frequency response. If future studies show that additional primary frequency response performance is required for BAs to maintain reliability, FERC can evaluate the most appropriate mechanisms to incent or require that capability to be activated. However, it would need to consider the significant technical challenges associated with measuring performance. NERC's current Primary Frequency Control Guideline recognizes that multiple methods of performance measurement exist, that performance verification "can be time

[121] The American Public Power Association ("APPA"), the Transmission Access Policy Study Group ("TAPS"), and the Large Public Power Council ("LPPC") supported this solution in their comments on the Frequency Response NOI. Comments of the American Public Power Association, Large Public Power Council, and Transmission Access Policy Study Group, Docket No. RM16-6-000 (Apr. 25, 2016), eLibrary No. 20160425-5258 ("APPA/LPPC/TAPS NOI Comments").

[122] *See, e.g.,* Comments of the American Wind Energy Association at 13, Docket No. RM16-6-000 (Apr. 25, 2016), eLibrary No. 20160425-5299.

consuming and requires subject matter expertise," and that any one of several factors "can reduce the confidence in or totally invalidate the performance sample."[123]

NERC's Tools Beyond Standards

FERC has statutory authority to direct development of reliability standards applicable to BES generators. However, it would be premature for FERC to direct NERC to develop new reliability standards for primary frequency response in advance of NERC's July 2018 report directed in Order 794. There is no showing that such a standard is needed.

On the other hand, NERC has other tools that it can employ to improve primary frequency response performance if the need arises.[124] NERC can issue three levels of Alerts to place industry on notice of any findings, analysis, or recommendations related to primary frequency response: Level 1 (Advisories) are purely informational and can educate generator owners and operators about primary frequency response issues; Level 2 (Recommendations) are specific actions that NERC could recommend generator owners and operators to consider; and Level 3 (Essential Actions) are specific actions that NERC determines are essential to take to ensure reliability.[125] NERC can also publish guidelines to educate generator owners and operators.[126]

NERC Alerts can be—and in fact already have been—an effective tool to address frequency response issues as they emerge. There is anecdotal evidence that NERC's 2015 Industry Advisory on primary frequency response prompted some generator owners to check and correct their governor settings to improve primary frequency response performance.[127] NERC's Primary Frequency Control Guideline has also garnered industry attention. In other contexts, NERC has demonstrated that its Alerts can result in significant reliability improvements.[128]

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[123] Guideline at 11, 13.

[124] For example, NERC Board Member and Chairman-Elect Roy Thilly stated at FERC's 2016 Reliability Conference "that standards are not the only tools in the tool box. There are alerts. There's lessons learned. There's conferences. There's exercises like GridEx. There's a variety of ways to get at reliability issues that are not standards, and that's important to recognize when we look at cost." Transcript of June 1, 2016 Commission-Led Reliability Technical Conference at 61:25-62:5, Docket No. AD16-15-000 (June 1, 2016), eLibrary No. 20160601-4009 ("Transcript of 2016 Reliability Conference").

[125] NERC Rules of Procedure, Rule 810, at 71-72 (May 4, 2016), http://www.nerc.com/FilingsOrders/us/RuleofProcedureDL/NERC_ROP_Effective_20160504.pdf.

[126] This action was recommended in comments filed by APPA, TAPS, and LPPC. APPA/LPPC/TAPS NOI Comments at 7-9.

[127] *See id.* at 7.

[128] For example, NERC issued a Level 2 Recommendation Alert in October 2010 asking transmission owners to verify that the methodology used to determine facility ratings is based on actual field conditions, and to remediate any discrepancies between as-built and actual conditions. In 2015, NERC reviewed the actions taken by registered entities in response to the Alert, and confirmed that "mitigation work had occurred and that the discrepancies no longer existed." NERC, Maintaining Transmission Line Ratings Consistent with As-Built Conditions: Good Utility Practices at v (Dec. 2015), http://www.nerc.com/pa/rrm/bpsa/Facility%20Ratings%20Alert%20DL/Maintaining_Transmission_Line_Ratings_Good_Utility_Practices_December_2015.pdf. *See* Transcript of 2016 Reliability Conference at

Coordinating FERC Rules, State Rules, NERC Actions, and IEEE Standards

While all generators can contribute to providing primary frequency response (if they install the necessary equipment), many generators fall outside of FERC's jurisdiction. As discussed above, states have jurisdiction over distributed energy resources that do not participate in wholesale markets and most net metered generators. Many distributed energy resources likely fall below existing thresholds for BES generation subject to NERC standards. Especially as reliance on such resources grows with our changing resource mix, FERC may be tempted to attempt to stretch its jurisdictional limits to impose requirements on generators that it has not previously regulated to address concerns as to the adequacy of primary frequency response. Such action is certainly not as justified today, and may not be necessary to achieve its objectives.

Alternatives that respect jurisdictional boundaries are available. Rather than seek to directly reach those generators, FERC can work collaboratively with state regulators, NERC, and standard setting bodies like the Institute of Electrical and Electronics Engineers ("IEEE") to coordinate rules on primary frequency response. FERC's approach to small generator interconnection rules is illustrative.

FERC claimed that Order 2006, which adopted rules for interconnecting small generators making wholesale sales and connecting to facilities under a FERC-jurisdictional OATT, "harmonizes state and federal practices by adopting many of the best practices interconnection rules recommended by the National Association of Regulatory Utility Commissioners (NARUC)."[129] FERC intended this "to minimize the federal-state division and promote consistent, nationwide interconnection rules."[130] FERC also expressed hope that would be "helpful in formulating their own interconnection rules."[131]

Similarly, FERC recently adopted amendments to the *pro forma* SGIA to require newly interconnecting small generating facilities (i.e., < 20 MW) to ride through abnormal frequency and voltage events and not disconnect during such events.[132] As in Order 2006, FERC stated that its amendments are not intended to interfere with state interconnection procedures, but expressed the hope that its new rule will be helpful when states update their own interconnection rules.[133] Interestingly, FERC did not adopt any specific technical standard for this "ride through" requirement, instead allowing transmission providers to establish technical standards that are consistent with good utility practice and comparable to standards applied by

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14:8-10 (NERC CEO Gerry Cauley stating that NERC's Right of Way Clearance Alert resulted "in a much safer condition for the public" and improved reliability).

[129] Order 2006, P 4.

[130] *Id.*

[131] *Id.* P 8.

[132] *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, Order No. 828, 81 Fed. Reg. 50,290 (Aug. 1, 2016), 156 FERC ¶ 61,062 (2016).

[133] *Id.* P 34.

the transmission provider to large generating facilities.[134] FERC pointed to IEEE's efforts to develop a new standard that, when finalized, may require manufacturers to build ride through capability into small generators, and "may be used as a technical guide" for meeting FERC's requirements.[135] That IEEE standard would also apply to small generators, including distributed energy resources, that are not interconnecting under a FERC-jurisdictional SGIA.

FERC's approaches in Order 2006 and its ride through rule could provide a blueprint for developing solutions for primary frequency response that would influence requirements for all generation while respecting jurisdictional limits.

Potential Market Solutions

A wide range of market solutions could incent generators to provide primary frequency response service during frequency disturbances. By imposing a primary frequency response obligation on BAs, BAL-003-1 already provides the foundation for such approaches. BAs now have a strong incentive—in the form of potential penalties for reliability standard violations—to ensure they have sufficient primary frequency response capability that actually performs when needed. If a BA believes that it will not have sufficient primary frequency response, then it can procure additional primary frequency response service from generators.

Market solutions, however, should be voluntary. FERC should not impose a compensation requirement on BAs that do not need additional primary frequency response. Instead, FERC could facilitate the provision of and compensation for primary frequency response. FERC's Frequency Response MBR Rule, which authorized market-based rate sales of primary frequency response by any sellers with market-based rate authority for energy and capacity, is one step in that direction. Another step that FERC could consider is to split Schedule 3 of the OATT (Regulation and Frequency Response) to treat primary frequency response as a standalone ancillary service.

As BAs gain experience complying with BAL-003-1, they will have the opportunity to assess the sufficiency of the primary frequency response available to them, to take advantage of the Frequency Response MBR Rule and existing procurement mechanisms, or propose others that are appropriate to achieving a least-cost means of meeting primary frequency response obligations in a particular region. Under such a structure, generators will have the opportunity to sell primary frequency response to BAs that seek to procure it, but would have no obligation to do so. Voluntary sales will also provide a platform and incentive for understanding and overcoming the practical and technical challenges to measurement and compensation of primary frequency response.

Although facilitating voluntary markets for sales of primary frequency response would be within FERC's jurisdiction, doing so could expand the number of generators that FERC regulates. For

[134] *Id.* P 25.
[135] *Id.* P 34.

example, if such sales become feasible and attractive, a generator that is not otherwise making wholesale sales of electric energy may choose to sell primary frequency response into wholesale markets. Such sales would likely trigger FERC's economic regulation, either as a sale of electric energy at wholesale, or as rules or practices that *directly* affect the wholesale rate under FERC's "directly affecting" jurisdiction described in *FERC v. EPSA*.[136]

Jurisdictional and Other Challenges

All of the potential solutions above would respect the limitations on FERC's jurisdiction. And they could go a long way toward addressing concerns. But if nevertheless FERC considers those solutions to be inadequate, it could lead to attempts to stretch FERC's authority, which would raise difficult practical and jurisdictional, if not political, problems.

One such potential action, as suggested in the Frequency Response NOI, would be creating an interconnection-wide optimization mechanism for primary frequency response. Requiring the creation of an interconnection-wide organization to direct individual BAs and RTOs as to how to dispatch resources so that the provision of primary frequency response can be optimized would be unnecessarily complex and would disrupt existing market structures (both organized and traditional). In addition, such an action, which raises the ghost of FERC's ill-fated "Standard Market Design NOPR,"[137] would be inconsistent with the Commission's now well-established policy in favor of voluntary RTOs.[138]

There are also some indications that FERC and NERC may attempt to reach distributed energy resources that are not currently subject to FERC's economic regulation or reliability jurisdiction. NERC has found that distributed energy resources are growing to levels that could have significant influence on BPS operations, and has established a working group to evaluate the reliability impacts of distributed energy resources.[139] At a recent FERC reliability technical conference, panelists expressed concern over the blurring of jurisdictional lines with respect to distributed energy resources and the changing resource mix.[140] And, because FERC has already expressed concern about the availability of resources that provide primary frequency response, the growing levels of distributed energy resources (that may or may not provide primary frequency response) could be the target of greater FERC scrutiny.

However, any FERC action to impose primary frequency obligations on distributed energy resources would raise difficult and controversial jurisdictional issues. FERC economic

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[136] E.g., a generator providing primary frequency response must maintain headroom (i.e., withhold some electric energy) and increase energy output for a few seconds during contingencies.
[137] FERC ultimately withdrew its proposed "Standard Market Design" rule, which would have required establishment in RTOs in all regions, after considerable industry and political backlash. *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, 112 FERC ¶ 61,073 (2005).
[138] *Duke Energy Ohio, Inc.,* 133 FERC ¶ 61,058, P 47 (2010), *reh'g denied*, 134 FERC ¶ 61,235 (2011).
[139] *See supra* Part III.
[140] Transcript of 2016 Reliability Conference at 69, 76.

regulation authority extends to wholesale sales of electric energy, the facilities used for those sales, and practices directly affecting the rates and charges for jurisdictional transmission or wholesale sales.[141] As discussed above, a distributed energy resource that voluntarily sells primary frequency response to a BA may well be engaged in a sale for resale or a practice directly affecting wholesale rates, providing FERC jurisdiction over the rates to be paid. But it would be a jurisdictional stretch, and an intrusion into state regulatory domain, for FERC to impose primary frequency response-related interconnection requirements on generators that are connected to local distribution facilities and that are not participating in FERC's wholesale markets.

Expanding FERC's Section 215 authority to distributed energy resources would also be problematic. Most distributed energy resources under 20 MW are not part of the BES. Thus, they are currently beyond the reach of NERC's mandatory reliability standards. However, concerns that the aggregate impact of such generation on primary frequency response [142] could conceivably cause FERC to consider whether a reliability standard that reaches distributed energy resources is necessary to prevent instability, uncontrolled separation, or cascading failures as a result of sudden disturbances.[143] Because such small generators would not be owners or operators of the bulk-power system, the jurisdiction would have to be asserted on the theory that they are "users" of the BPS.[144] However, such a theory would have no limiting principle. Clearly Congress did not intend to grant FERC and NERC authority over every rooftop solar panel (or every toaster for that matter).

VII. CONCLUSION

Primary frequency response will clearly receive increasing attention from FERC and NERC in the near future. Hopefully, in taking action to address the need for primary frequency response, FERC will use one or more of the tools available to it that respect existing jurisdictional boundaries. But if FERC remains concerned about the growing exposure of the grid to severe consequences, including cascading outages, due to the insufficient primary frequency response as our resource mix continues to change, there is a real risk that FERC will attempt to exercise jurisdiction over more distributed energy resources.

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[141] *See supra* Part V.

[142] *See* NERC, Special Report: Potential Bulk System Reliability Impacts of Distributed Resources at 1 (2011) ("[Distributed] resources all have different characteristics which in large numbers may aggregately affect the bulk system.") www.nerc.com/docs/pc/ivgtf/IVGTF_TF-1-8_Reliability-Impact-Distributed-Resources_Final-Draft_2011.pdf; *see also* NERC Registry Criteria at 10 (even if an entity is "individually . . . unlikely to have a material impact on the reliability of the Bulk Power System" it may be registered "irrespective of other considerations" if it is "part of a class of entities…that in aggregate have been demonstrated to have such an impact").

[143] *See* FPA § 215(a)(4), 16 U.S.C. § 824*o*(a)(4).

[144] FPA § 215(b)(1), 16 U.S.C. § 824*o*(b)(1). FERC may also explore indirect methods reaching distributed energy resources, for example by imposing obligations on BAs or registered Distribution Providers, who in turn could take actions to require or incentivize distributed energy resources to provide primary frequency response. But that too would raise difficult jurisdictional questions.

The same forces creating pressure for FERC to push the limits of its existing Federal Power Act may also propel Congressional efforts to rethink those boundaries. On June 10, 2016, House Committee on Energy and Commerce Chairman Fred Upton (R MI) and its Energy and Power Subcommittee Chairman Ed Whitfield (R KY) wrote FERC Chairman Norman Bay seeking input on threshold questions that could be the prelude to Congress undertaking "a more comprehensive review" of the Federal Power Act given changes in the industry.[145] Among the noted drivers of these changes are that "[i]ncreased deployment of energy efficient technologies, demand-side management programs, and distributed generation . . . have played a role, while an ever-increasing array of advanced grid technologies – energy storage, microgrids, electric vehicles, and rooftop solar – are beginning to make their mark." The letter cites the Supreme Court's *FERC v. EPSA* decision and its decision in *Hughes v. Talen*[146] as "affirm[ing] the traditional 'bright line' of the Commission's jurisdiction over products and practices that 'directly affect' wholesale sales and rates, with the states reserving jurisdiction over retail matters," while "carefully choosing not to opine" further, as "evidence to the notion that the electricity landscape is changing, with the potential to . . . blur jurisdictional boundaries."[147] The letter seeks FERC's perspective on fundamental questions including:[148]

> How do new technologies, programs, incentives and policy changes at the state and federal levels affect the jurisdictional "bright line"? Is that line becoming increasingly blurred as a result of such changes?
>
> Does the Federal Power Act continue to be well-suited for today's electricity sector? Is it well-suited for the electricity system of the future?

In his five-page reply to these and other questions, FERC Chairman Bay highlighted both the Frequency Response MBR Rule and the Frequency Response NOI.[149] He expressed his hope that FERC would soon propose specific actions on the primary frequency response issue, and that "[a]ctions such as these can help maintain grid reliability while accommodating the policy preferences adopted under other federal or state laws."[150]

As Congress's inquiry moves forward, the need for primary frequency response could provide ammunition to re-write jurisdictional lines. Primary frequency response could therefore be the camel's nose that opens FERC's jurisdictional tent.

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145 Rep. Fred Upton and Rep. Ed Whitfield, Comments at 3 (June 13, 2016), eLibrary No. 20160614-0017 ("Upton Whitfield Comments").
146 *Hughes v. Talen Energy Mktg. LLC,* 136 S. Ct. 1288 (2016) (affirming pre-emption of Maryland's resource procurement mechanism).
147 Upton Whitfield Comments at 2.
148 *Id.* at 3.
149 Chairman Norman C. Bay, Letter to the Honorable Ed Whitfield (Aug. 30, 2016), eLibrary No. 20160901-0023.
150 *Id.* at 4.