# FERC'S STORAGE AND DISTRIBUTED ENERGY RESOURCES AGGREGATION NOPR: JURISDICTIONAL CHALLENGES

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## I. INTRODUCTION

Distributed generation is not new. As the Department of Energy ("DOE") recognized in its 2007 report on *The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion*, it was the norm in the early 20th century during the initial phase of the electric power industry.[1] Economies of scale and scope in the production and delivery of electricity resulted in a general shift to central station generation. However, loads that need highly reliable power, such as hospitals, continued to install their own generating units for use in emergencies and outages. In 2007, DOE estimated that there was 200 GW of distributed generation installed across the country, almost all of which was either backup generators for emergencies or combined heat and power systems.

In recent years, improvements in technology and manufacturing have reduced the cost of certain types of distributed generation. And while grid-scale generation may still be more cost-effective in many circumstances,[2] the pace of distributed generation installations has increased dramatically. When DOE issued its report in 2007, there were fewer than 100,000 residential photovoltaic systems installed nationwide.[3] By the end of 2016, over 1.25 million such systems

[1] U.S. Dep't of Energy, Off. of Elec. Delivery & Energy Reliability, *The Potential Benefits of Distributed Generation and the Rate-Related Issues That May Impede Its Expansion: Report Pursuant to Section 1817 of the Energy Policy Act of 2005* (2007), https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/1817_Report_-final.pdf.

[2] *See*, *e.g.*, Severin Borenstein*, Is the Future of Electricity Generation Really Distributed* (May 6, 2015), http://www.theenergycollective.com/severinborenstein/2224146/future-electricity-generation-really-distributed.

[3] U.S. Dep't of Energy, Sunshot, *Q42016/Q12017 Solar Industry Update* at 35 (Apr. 25, 2017), https://www.nrel.gov/docs/fy17osti/68425.pdf ("Sunshot").

were in place, totaling about 7.4 GW.[4] In January 2017, the U.S. Energy Information Administration estimated that by 2040, distributed solar generation could potentially produce over 180 billion kWh annually.[5]

The rate of distributed generator installation varies from region to region,[6] however, and there is a wide variety of approaches being taken by distribution utilities and their regulators to address such units. In some areas, distributed generation is being handled on an *ad hoc* basis by individual distribution utilities and/or their relevant electric retail regulatory authorities ("RERRAs"). In contrast, the California Public Utilities Commission ("CPUC") has promulgated Rule 21, a tariff that describes the interconnection, operating, and metering requirements for generation facilities to be connected to a utility's distribution system, over which the CPUC has jurisdiction.[7] And New York has developed a completely new state regulatory paradigm, Utility 2.0, that treats the retail electric distribution utility as a platform for coordinating the flow of electricity from Distributed Energy Resources ("DERs"), instead of functioning as a monopoly distributor of retail power coming from a few large plants.[8] DER policies are changing rapidly at the state and local level and have not converged on a single model.[9]

So far, the Federal Energy Regulatory Commission ("FERC") has asserted only limited jurisdiction over distributed generation, and it has generally allowed state and local entities to

[4] Sunshot at 35; U.S. Energy Info. Admin., *Electric Power Monthly with Data for June 2017* at Table 6.1.B. (Aug. 2017), http://www.eia.gov/electricity/monthly/pdf/epm.pdf. According to the same *Electric Power Monthly*, the total estimated capacity of small scale photovoltaic facilities at the end of 2016 was 13.2 GW, including commercial and industrial facilities.

[5] U.S. Energy Info. Admin., *Annual Energy Outlook 2017 with projections to 2050* at 79-80 (Jan. 5, 2017), https://www.eia.gov/outlooks/aeo/pdf/0383(2017).pdf. The U.S. Energy Information Administration estimated that the United States would reach that level of distributed solar generation if the Clean Power Plan and state Renewable Portfolio Standards remained in place.

[6] During the period from early 2007 to late 2016, for example, the amount of interconnected solar photovoltaic capacity in the net energy metering programs of California's three investor-owned utilities increased from less than 150 MW to 5.7 GW. Cal. Distributed Generation Stat., *Statistics & Charts*, http://www.californiadgstats.ca.gov/charts/ (data current through June 30, 2017) (open "NEM Solar PV" tab).

[7] Cal. Pub. Util. Comm'n, *Rule 21 Interconnections*, http://www.cpuc.ca.gov/General.aspx?id=3962 (last visited Sept. 13, 2017).

[8] *Re Reforming the Energy Vision*, 319 P.U.R.4th 1 (N.Y. Pub. Serv. Comm'n 2015).

[9] Even in California, which has progressed further than most regions with respect to DER penetration and aggregation, the California Independent System Operator ("CAISO") has noted that existing state-jurisdictional tariffs and interconnection requirements may well continue to evolve in response to the development of DERs. In the CAISO's DER aggregation proposal accepted by FERC last year, in Docket No. ER16-1085, the CAISO emphasized that "[its] proposal will not interfere with or dictate the outcome of such efforts. Rather, the CAISO's proposal only serves to facilitate the participation of aggregations of distributed energy resources in the CAISO's markets that are compatible with the safe and reliable operation of distribution system." Cal. Indep. Sys. Operator Corp., Distributed Energy Resource Provider Initiative at 3 (Mar. 4, 2016), eLibrary No. 20160304-5258.

take the lead on their regulation. With the issuance of its new Notice of Proposed Rulemaking on Electric Storage and Distributed Energy Resources last year, that situation may be changing.

## II. FERC'S STORAGE/DISTRIBUTED ENERGY RESOURCES NOPR

On April 11, 2016, FERC's Office of Energy Policy and Innovation issued Data Requests to the six Regional Transmission Organizations and Independent System Operators (collectively, "RTOs"), and a Request for Comments to the public on the applicability of RTO rules to electric storage resources.[10] According to the Request for Comments (at 2),

> staff is interested in examining whether barriers exist to the participation of electric storage resources in the capacity, energy, and ancillary service markets in the RTOs and ISOs potentially leading to unjust and unreasonable wholesale rates. Staff also expects to examine, if potential barriers exist, whether any tariff changes are warranted.

The Data Requests and Request for Comments were divided into five topics:

1. The eligibility of electric storage resources to be market participants
2. Qualification criteria and performance requirements
3. Bid parameters for electric storage resources
4. Distribution-connected and aggregated electric storage resources
5. When electric storage resources are receiving electricity

On November 17, 2016, FERC issued a Notice of Proposed Rulemaking titled "Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators."[11] According to the NOPR (P 7), based on the responses provided to the April 2016 Data Requests, FERC has "become concerned that [electric storage] resources may face barriers that limit them from participating in organized wholesale electric markets." FERC proposes to address those concerns by requiring each RTO to revise its tariff to establish market rules that accommodate the participation of storage in the organized wholesale electric markets.

[10] FERC, Request to Comments (Apr. 11, 2016), eLibrary No. 20160411-3017. FERC Staff simultaneously issued letters to each of the RTOs requesting responses to an attached list of data requests: FERC, CAISO Request for Response (Apr. 11, 2016), eLibrary No. 20160411-3015; FERC, ISO-NE Request for Response (Apr. 11, 2016), eLibrary No. 20160411-3016; FERC, MISO Request for Response (Apr. 11, 2016), eLibrary No. 20160411-3021; FERC, NYISO Request for Response (Apr. 11, 2016), eLibrary No. 20160411-3020; and FERC, SPP Request for Response (Apr. 11, 2016), eLibrary No. 20160411-3018.

[11] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 81 Fed. Reg. 86,522 (Nov. 30, 2016), FERC Stats. & Regs. ¶ 32,718 (2016) ("NOPR").

Although not mentioned in the title of the NOPR, the proposed rule also defines a new term—Distributed Energy Resource—and proposes new requirements on RTOs with respect to DERs. As defined by FERC, DERs are:

> [A] source or sink of power that is located on the distribution system, any subsystem thereof, or behind a customer meter. These resources may include, but are not limited to, electric storage resources, distributed generation, thermal storage, and electric vehicles and their supply equipment.

*Id*., P 104. This broad definition encompasses storage (which is a mixture of both generation and load) connected to distribution facilities or behind retail meters. However, it also includes other generators, Demand Response Resources, and retail loads—basically every resource or load connected to the distribution network.

For DERs, the NOPR proposes to require each RTO to establish market rules concerning:[12]

1. Eligibility of DERs to participate in the organized wholesale electric markets through a "distributed energy resource aggregator," which the NOPR defines as "a type of market participant that can participate in the organized wholesale electric markets under the participation model that best accommodates the physical and operational characteristics of its distributed energy resource aggregation";[13]
2. Locational requirements for aggregations of DERs;
3. Distribution factors and bidding parameters for DER aggregations;
4. Information and data requirements for DER aggregations;
5. Modifications to the list of resources in a DER aggregation;
6. Metering and telemetry system requirements for distributed energy resource aggregations;
7. Coordination between the RTO, distributed energy resource aggregator, and the distribution utility; and
8. Market participation agreements for distributed energy resource aggregators.

FERC has not yet taken any action on the NOPR. Between the time that the NOPR was issued and February 13, 2017, when comments on the NOPR were due, FERC lost its quorum.

[12] *Id*. PP 5, 124-158.

[13] *Id*. P 124.

FERC's quorum was restored on August 10, 2017; but at the time this paper is being written, it is unclear whether action on the NOPR will be a priority of the new Commission.

## III. FERC'S RATE JURISDICTION OVER DISTRIBUTED ENERGY RESOURCES

This paper focuses on the NOPR's proposals for DERs. Utility-scale storage, primarily in the form of pumped storage, has participated in RTO wholesale markets since those markets were created. While the NOPR's proposals would require changes to RTO treatment of such facilities, particularly with respect to bidding parameters and eligibility to offer into markets for various RTO products, those changes do not stretch FERC's existing jurisdiction.

In contrast, depending on what FERC intends by the NOPR's proposed DER-related requirements, they may represent a major expansion by FERC into the regulation of distribution-connected resources and loads. For example, is FERC simply requiring that RTOs have market rules in place to handle offers from DERs, to the extent those resources are able to reach organized wholesale markets? Or would the proposed rule establish a new federal right, overriding or independent from state law, for DERs to interconnect to distribution networks and to sell to and buy from wholesale markets? Even if this particular NOPR is not intended to test the limits of FERC's jurisdiction, it raises basic questions as to where FERC regulation of distribution-connected resources and loads is headed, and how far such regulation can go, given the jurisdictional limits of the Federal Power Act ("FPA").

### A. Federal Power Act Provisions Relevant to FERC's Rate Jurisdiction over DERs

DERs do not fit neatly into the jurisdictional categories created by the Federal Power Act. The FPA provides that FERC has jurisdiction over the transmission of electric energy in interstate commerce, the sale of electric energy at wholesale, and all facilities for such transmission or sale of electric energy.[14] FERC, however, does *not* have jurisdiction over facilities used for the generation of electric energy or used in local distribution.[15] On one hand, DERs seem to fall outside FERC's jurisdiction because they are facilities used for the generation of electric energy that are interconnected to local distribution facilities, and their output is often consumed by an on-site retail customer. On the other hand, since any energy from a distributed generator that is not consumed on-site is functionally delivered to the host distribution utility for resale, DERs seem to potentially fall into FERC's exclusive jurisdiction over wholesale sales.

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[14] FPA § 201(b), 16 U.S.C. § 824(b).

[15] *Id.* FPA Section 201(b)(1) states that FERC, except as specifically provided in Parts II and III of the FPA, "shall not have jurisdiction . . . over facilities used for the generation of electric energy." The Supreme Court has also stated that the FPA "reserv[es] regulatory authority over retail sales (as well as intrastate wholesale sales) to the States." *FERC v. Elec. Power Supply Ass'n,* 136 S. Ct. 760, 775 (2016).

To add to the complexity, even if FERC asserts jurisdiction over a particular DER, that does not mean states and local governments have no authority over it. FERC's authority under Part II of the FPA is primarily economic—it regulates the rates and charges for jurisdictional transmission and wholesale sales, as well as any rule or practice "affecting" such rates.[16] But FERC's authority "shall not apply to any other sale of electric energy," and "extend[s] only to those matters which are not subject to regulation by the States."[17] It therefore excludes other aspects of DERs—such as siting, consumption of output by co-located load, and retail sales—that fall within the jurisdiction of the states.

The situation is even more complicated with respect to municipal utilities. FERC's FPA Section 205 and Section 206 authority does not apply to "non-public utilities," including states, political subdivisions of states, agencies, authorities, or instrumentalities of a state or political subdivision, or any corporation wholly owned by one or more of the foregoing.[18] However, FPA Sections 210, 211, 211A, and 212 provide FERC limited jurisdiction over transmission and interconnections by non-public utility transmission owners.[19] In addition, non-public utility transmission owners that take service under a public utility's Open Access Transmission Tariff are subject to "reciprocity" obligations that require them to provide comparable transmission service to their public utility transmission provider or, in the case of service from an RTO, all transmission-owning members of that RTO.[20]

### B. Precedent Relevant to FERC's Rate Jurisdiction over DERs

While current levels of interest in and deployments of DERs are new, disputes over the scope of FERC's jurisdiction over DERs are not.

#### 1. Net Metering for Distributed Generation

FERC has previously addressed its jurisdiction over DERs in the context of net metering. As explained in Order 2003-A:[21]

[16] FPA §§ 205-6, 16 U.S.C. §§ 824d-e. This paper does not address the issue of whether FERC has reliability jurisdiction over DERs under FPA § 215, 16 U.S.C. § 824*o*.

[17] FPA § 201(a)-(b)(1), 16 U.S.C. § 824(a)-(b)(1).

[18] FPA § 201(f), 16 U.S.C. § 824(f).

[19] 16 U.S.C. §§ 824i-k.

[20] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-A, 73 Fed. Reg. 2,984, 2,988 (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).

[21] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, 69 Fed. Reg. 15,932, 15,998 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160, P 744 (2004) ("Order 2003-A"), *see* n.32 *infra* for subsequent history.

> Net metering allows a retail electric customer to produce and sell power onto the Transmission System without being subject to the Commission's jurisdiction. A participant in a net metering program must be a net consumer of electricity— but for portions of the day or portions of the billing cycle, it may produce more electricity than it can use itself. This electricity is sent back onto the Transmission System to be consumed by other end-users. Since the program participant is still a net consumer of electricity, it receives an electric bill at the end of the billing cycle that is reduced by the amount of energy it sold back to the utility. Essentially, the electric meter ''runs backwards'' during the portion of the billing cycle when the load produces more power that it needs, and runs normally when the load takes electricity off the system.

In 1998, MidAmerican Energy Company petitioned FERC for a declaratory order stating that net metering requirements of the Iowa Utilities Board ("IUB") were preempted by federal law.[22] The IUB requirements, which applied to retail customers that also operated an alternate energy production facility, called for a single meter to measure both: (1) energy delivered by MidAmerican to the retail customer/alternate energy facility, and (2) energy delivered in the other direction by the alternate energy facility to MidAmerican. The single meter would offset the two quantities over the billing period and indicate the net quantity delivered by one to the other.[23] MidAmerican argued that the IUB's net billing requirement violated the Public Utilities Regulatory Policy Act ("PURPA"), because it would result in MidAmerican paying in excess of its avoided costs for power produced by alternate energy production facilities that are Qualifying Facilities ("QFs"). MidAmerican also claimed that for alternate energy production facilities that are not QFs, the IUB was setting the rate for wholesale sales by a public utility, which is preempted by the Federal Power Act.

FERC denied MidAmerican's petition. According to FERC,[24]

> In essence, MidAmerican is asking this Commission to declare that when, for example, individual homeowners or farmers install small generation facilities to reduce purchases from a utility, a state is preempted from allowing the individual homeowner's or farmer's purchase or sale of power from being measured on a net basis, *i.e*., that PURPA and the FPA require that two meters be installed in these situations, one to measure the flow of power from the utility to the homeowner or farmer, and another to measure the flow of power from the homeowner or farmer to the utility. MidAmerican argues that every flow of power constitutes a sale, and, in

[22] *MidAmerican Energy Co.*, 94 FERC ¶ 61,340 (2001).

[23] *Id.* at 62,261.

[24] *Id.* at 62,263 (footnote omitted).

> particular, that every flow of power from a homeowner or farmer to MidAmerican must be priced consistent with the requirements of either PURPA or the FPA. We find no such requirement.

FERC held that generally "no sale occurs when an individual homeowner or farmer . . . installs generation and accounts for its dealings with the utility through the practice of netting."[25] However, it asserted wholesale rate jurisdiction if the alternate energy production facility generated more electricity than the associated retail load consumed over the netting period: "[w]hen there is a net sale to a utility, and the [distributed generator] is not a QF, the [owner of the distributed generator] would need to comply with the requirements of the Federal Power Act."[26]

In its rulemaking on Standardization of Generator Interconnection Agreements and Procedures, FERC affirmed this approach. It expressly recognized that under net metering arrangements, there could be periods of time when the retail customer's generation produces more electricity than the retail customer can use, and its output is pushed onto the distribution utility's system to be consumed by other end-users. Order 2003-A, P 744. However, FERC held that it would assert jurisdiction over sales by such distributed resources only in limited circumstances (*id.* P 747, citing *MidAmerican*) (footnote omitted):

> [U]nder most circumstances the Commission does not exert jurisdiction over a net energy metering arrangement when the owner of the generator receives a credit against its retail power purchases from the selling utility. 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 would the Commission assert jurisdiction.

*See also Sun Edison LLC*, 129 FERC ¶ 61,146, P 19 (2009) (sales from a SunEdison distributed solar generation facility to an on-site end-use customer participating in a net

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[25] *Id.*

[26] *Id*. In reaching its conclusion in *MidAmerican*, FERC relied on its decision in *PJM Interconnection, L.L.C.*, 94 FERC ¶ 61,251 (2001), which addressed the netting of station power used at a generating facility. In *PJM*, FERC found th at there is no sale (for end-use or otherwise) between two different parties when a party uses its own generating resources for the purposes of self-supply of station power and accounts for such usage through netting. *Id.* at 61,890.

In two other station power cases, *S. Cal. Edison Co. v. FERC*, 603 F.3d 996 (D.C. Cir. 2010) and *Calpine Corp. v. FERC*, 702 F.3d 41 (D.C. Cir. 2012), the D.C. Circuit addressed the issue of whether FERC had authority to define the netting interval used to determine whether a generator had self-supplied its station power or drawn that power from the grid (in which case the generator would be charged retail rates for that power). In both cases, the D.C. Circuit held that FERC cannot set the netting period for the retail sale purposes, leaving that determination to state regulators. 702 F.3d at 50; 603 F.3d at 1,002. It is unclear, however, whether the court would likewise conclude that FERC cannot set the netting period with respect to sales for resale made by a distributed generator.

metering program are not FERC-jurisdictional sales unless there is a net sale to a utility), *order on reh'g*, 131 FERC ¶ 61,213 (2010).

FERC's net metering precedent established a hands-off policy toward small DERs installed behind the meters of retail customers, except in limited circumstances. As more DERs are deployed and their forms change, however, FERC will have new opportunities to address these issues,[27] and it might conclude that this deferential approach is no longer appropriate. In addition, the net metering cases FERC has decided to date have primarily involved challenges to the right of distributed generators to participate in retail net metering programs, rather than sell into the wholesale market as FERC-jurisdictional public utilities or as QFs under PURPA. FERC's rulings have generally *allowed* such owners of DERs to do so; but it is less clear that FERC would *require* DERs to participate in retail programs if they would prefer to sell into wholesale markets.

2. Treatment of QFs under PURPA

FERC has also held that for distributed generators that make net sales, but fall within the definition of a QF, states may regulate rates for those sales without running afoul of the FPA. In *California Public Utilities Commission*, FERC reviewed a California feed-in tariff initiative that required investor-owned utilities to offer to purchase, at a price to be set by the California Public Utilities Commission ("CPUC"), electricity that is generated by certain combined heat and power ("CHP") generators that met state size, efficiency, and emissions standards.[28] FERC held that "[b]ecause the [CPUC's decisions] are setting rates for wholesale sales in interstate commerce by public utilities, we find that they are preempted by the FPA." *Id.* P 64.

FERC noted, however, that a state commission may, pursuant to PURPA, determine avoided cost rates for QFs. And although the CPUC had not argued that its program was an implementation of PURPA, FERC found that:

[27] Recently, for example, FERC considered a petition for declaratory order filed by Southern Maryland Electric Cooperative and Choptank Electric Cooperative, which challenged Maryland Public Service Commission regulations pertaining to community solar generation systems. *S. Md. Elec. Coop. Inc.*, 157 FERC ¶ 61,118 (2016). Maryland's regulations implemented a pilot program for community solar, which allows renters and low- and moderate-income retail electric customers to hold interests in community solar systems and provides for "virtual net metering" that allows participants to offset their retail electric bills with generation credits from their community solar system interests. *Id.,* PP 4-5. Because the solar generation and retail customer do not share a meter, the Maryland PSC regulations call for offsets in dollars or in kWhs, with excess offset credits carried from month to month for up to a year. Excess offsets not used by the end of the year would then be paid for based on a formula set out in the regulations.

FERC dismissed the petition for declaratory order as premature—among other things, neither Southern Maryland Electric Cooperative nor Choptank Electric Cooperative were participating in the pilot program at that time. As a result, FERC did not rule on the merits of the Maryland virtual net metering program.

[28] *Cal. Pub. Util. Comm'n*, 132 FERC ¶ 61,047, *clarified and reh'g denied*, 133 FERC ¶ 61,059 (2010), *reh'g denied*, 134 FERC ¶ 61,044 (2011).

> [T]o the extent the CHP generators . . . obtain QF status, the CPUC's . . . feed-in tariff is *not* preempted by FPA, PURPA, or Commission regulations, . . . as long as the program meets certain requirements . . . (1) the CHP generators from which the CPUC is requiring the [California utilities] to purchase energy and capacity are QFs pursuant to PURPA; and (2) the rate established by the CPUC does not exceed the avoided cost of the purchasing utility.

*Id.* PP 65, 67. FERC later clarified that in establishing the level of avoided cost, the CPUC could "take into account obligations imposed by the state that, for example, utilities purchase energy from particular sources of energy or for a long duration." *Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059, P 26 (2010) ("*CPUC*"), *reh'g denied*, 134 FERC ¶ 61,044 (2001). In reaching this conclusion, FERC stated that to the extent this clarification could be read as inconsistent with its language in prior orders, FERC was overruling that prior language. *Id.* P 30.

FERC's ruling in *CPUC* gave states considerable flexibility to set avoided cost rates for sales for resale by distributed generators that are also QFs. And while FERC's order was protective of its exclusive jurisdiction over wholesale sales in general, the QF carve-out it recognized enabled states to set prices for many of the types of renewable and distributed generation that they are most interested in promoting. Such state regulation, however, depends on individual generators deciding to obtain QF status. For generators making net sales that are *not* QFs, FERC's ruling in *CPUC* leaves FERC—not the states—in charge of regulating the rates at which those sales are made.

### 3. FERC Jurisdiction over Distribution Facilities Used to Deliver Wholesale Transactions

If FERC wants to allow broader participation by distributed generators in wholesale markets, it will need to address—and may seek to depart from—other existing jurisdictional precedent. 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. For unbundled *wholesale* transmission—i.e., transmission of electric energy being sold for resale—FERC recognized a "bright-line" test to distinguish between federal and state jurisdiction, regardless of voltage.[29] According to FERC, "any 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,'

[29] *See, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order 888, 61 Fed. Reg. 21,540, 21,626 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 at 31,783 (1996), *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 FER ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Grp. v. FERC*, 225 P.3d 667 (D.C. Cir. 2000), a*ff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

are subject to the Commission's jurisdiction under sections 205 and 206."[30] Order 888's jurisdictional rulings were affirmed by the courts.[31]

FERC's jurisdiction over local distribution facilities that are being used for wholesale sales, however, does not necessarily include the ability to compel utilities to interconnect generation to distribution facilities in order to effect *new* wholesale transactions. In Order 2003, FERC specifically considered that issue.[32] Acknowledging the statutory tension associated with FERC jurisdiction over distribution facilities,[33] FERC asserted jurisdiction over the terms of a generator interconnection to such facilities only if: (1) the generator connects to a facility that, at the time of the interconnection request, is included in a public utility's OATT; *and* (2) the interconnection

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[30] Order 888, 61 Fed. Reg. at 2,713, FERC Stats. & Regs. ¶ 31,036, at 31,980. In addition to its jurisdiction over wholesale sales, FERC has jurisdiction over transmission in interstate commerce. For this purpose, FERC has applied a functional-technical test that takes into account the technical characteristics of the facilities used for the wheeling (in contrast to the bright-line functional test used for wholesale sales). Specifically, FERC established a seven-factor test to identify whether a facility is a local distribution facility subject to state jurisdiction or a facility engaged in interstate transmission subject to FERC jurisdiction. Order 888, 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. In Order 888, FERC determined that where a state adopts retail competition—i.e., "unbundles" the retail sale into separate transmission and power sales—FERC has jurisdiction over the unbundled retail transmission service. Order 888 calls for the seven factor test to be used to determine which facilities are subject to that jurisdiction. Order 888, 61 Fed. Reg. at 21,619-20, 21,625-27.

[31] *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*").

[32] *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) ("Order 2003-C"), *aff'd sub nom. NARUC v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 128 S. Ct. 1468 (2008).

[33] *See* Order 2003-C, P 52.

is for the purpose of facilitating a jurisdictional wholesale sale of electric energy.[34] FERC claimed jurisdiction over such interconnections, even if the facility to which the generator was interconnecting was also being used in local distribution.[35]

FERC rejected a request for rehearing that asked FERC to exercise broader jurisdiction over interconnections to local distribution facilities:[36]

> We concluded that applying our interconnection rules to facilities already subject to an OATT would properly respect the jurisdictional bounds recognized by the courts in upholding Order No. 888 and subsequent cases. To adopt SoCal Edison's position and interpret our authority more broadly, however, would allow a potential wholesale seller to cause the involuntary conversion of a facility previously used exclusively for state-jurisdictional interconnections and delivery, and subject to the exclusive jurisdiction of the state, into a facility also subject to the Commission's interconnection jurisdiction—a result that we believe crosses the jurisdictional line established by Congress in the FPA.

In *National Association of Regulatory Utility Commissioners v. FERC*, the D.C. Circuit affirmed Order 2003's jurisdictional determination, finding that because FERC has jurisdiction over "*all aspects* of wholesale sales . . . regardless of the facilities used," FERC had not exceeded its jurisdictional bounds.[37] 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."[38]

FERC has applied these principles since Order 2003. In *PJM Interconnection, L.L.C.*,[39] for example, PJM filed two unexecuted interconnection service agreements for wind generating

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

[35] FERC distinguishes between jurisdiction to directly regulate distribution facilities, versus jurisdiction over wholesale transactions occurring over distribution facilities. The Commission has clarified that when a "dual use" facility is involved—i.e., a facility used both for sales subject to FERC's jurisdiction and for sales subject to state jurisdiction—"the Commission may regulate the entire transmission component (rates, terms and conditions) of the wholesale transaction—whether the facilities used to transmit are labeled 'transmission' or 'local distribution,'" but "it may not regulate the 'local distribution' facility itself, which remains state-jurisdictional." Order 2003-C, P 53. *See also* Order 2003, P 804 n.129; *Detroit Edison Co. v. FERC*, 334 F.3d 48, 51 (D.C. Cir. 2003); *DTE Energy Co. v. FERC*, 394 F.3d 954, 962 (D.C. Cir. 2005).

[36] Order 2003-C, P 51 (footnotes omitted).

[37] *Nat'l Ass'n of Reg. Util. Comm'rs v. FERC*, 475 F.3d 1,277, 1,280 (D.C. Cir. 2007) (citing *TAPS v. FERC*, 225 F.3d 667, 696). The court did not rule on whether FERC's assertion of jurisdiction over distribution facilities was improperly narrow, but it characterized Order 2003's two-part test as "the exact opposite of boot-strapping." 475 F.3d at 1282.

[38] *Id.*

[39] 114 FERC ¶ 61,191, *reh'g denied*, 116 FERC ¶ 61,102 (2006).

plants seeking to interconnect to Commonwealth Edison's ("ComEd") distribution system. Although ComEd stated that it was willing to provide the interconnection service if the generators agreed to pay its annual Wholesale Distribution Charge, FERC rejected the unexecuted agreements on the grounds that FERC lacked jurisdiction over the proposed interconnections. According to FERC, there was no preexisting interconnection and wholesale transaction over the relevant local distribution facilities, and the facilities were not available under a Commission-approved Open Access Transmission Tariff. Therefore, the jurisdictional criteria established in Order 2003 were not satisfied.[40]

In reaching this conclusion, FERC rejected the generators' arguments that the relevant ComEd local distribution facilities met the Order 2003 standard, because there was an existing wholesale sale from a QF connected to ComEd's distribution system. According to FERC, although there was a sale for resale by the QF, there was no Commission-jurisdictional transmission service involved in that QF transaction, because ComEd purchased and took title to the QF's full output at the point of interconnection between the QF and ComEd's local distribution system.[41] FERC therefore concluded "that jurisdictional transmission service is not being provided over the local distribution facilities, and [the generation owner's] interconnections to these local distribution facilities are not subject to Commission jurisdiction under Order No. 2003."[42]

In Order 2006, FERC's rule on standardized small generator interconnection procedures and agreements,[43] FERC affirmed the jurisdictional test established by Order 2003 for new generator interconnections to distribution facilities.[44] FERC also stated that it expected that "the vast majority of small generator interconnections will be with state jurisdictional facilities," and emphasized that its small generator interconnection rule "in no way affects rules adopted by the states for the interconnection of generators with state-jurisdictional facilities."[45] FERC noted,

[40] According to FERC, that ruling was "without prejudice to ComEd filing for a wholesale distribution charge as part of a separate delivery service, rather than generator interconnection service, as proposed by the company, if ComEd's distribution system is used subsequently to provide wholesale delivery service." *Id*. P 18.

[41] *Id.* P 15, *citing W. Mass. Elec. Co.*, 61 FERC ¶ 61,182, 61,662 (1992), *aff'd*, *W. Mass. Elec. Co. v. FERC*, 165 F.3d 922 (D.C. Cir. 1999) (holding that Commission-jurisdictional transmission service takes place when a host utility does *not* purchase the output of a distribution-connected generator and instead transmits that output over its distribution facilities for delivery to a third party).

[42] *Id.*

[43] *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 70 Fed. Reg. 34,100 (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), *corrected*, 71 Fed. Reg. 53,965 (Sept. 13, 2006).

[44] Order 2006, P 481.

[45] Order 2006-A, P 105.

however, that if a small generator "seeks to interconnect[] with a facility under federal jurisdiction, a state program cannot displace federal rules for interconnections."[46]

4. "Affecting" Jurisdiction

In addition to its jurisdiction over transmission and wholesale electricity 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."[47] 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.'"[48] In *FERC v. EPSA*, 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."[49]

Based on *FERC v. EPSA*, the courts would likely hold that FERC has jurisdiction to determine how electricity products from DERs that have been delivered to the RTO grid are treated within the organized wholesale markets administered by RTOs. It is unclear, however, whether FERC's jurisdiction over rules or practices that "*directly* affect the wholesale rate" could be used to justify FERC regulation of all generator interconnections to local distribution facilities, or to require FERC-jurisdictional delivery service over such facilities for proposed wholesale sales, even if the facilities are not currently covered by an Open Access Transmission Tariff. Efforts by FERC to expand its jurisdiction in this manner would likely be highly controversial and subject to court challenge.

## IV. WHERE DOES THAT LEAVE DISTRIBUTION UTILITIES?

### A. Existing Precedent

For FERC-jurisdictional public utilities, precedent currently places the bulk of distributed generation outside FERC's jurisdiction. As discussed above, FERC has asserted jurisdiction over net-metered distributed generation only to the extent a net sale is made by the generator during the applicable billing period; and FERC has ruled that states have authority to determine avoided cost rates for distributed generators that are QFs. Moreover, even when FERC asserts jurisdiction over sales of the output of such distributed generators, FERC does not automatically claim jurisdiction over interconnection to, or delivery services over, the local distribution facilities to which the distributed generator is connected. If the host distribution utility purchases the generator's net output at the point of interconnection between the generator and the distribution

[46] *Id.*

[47] *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)).

[48] *Id.* at 774 (internal quotation and citation omitted).

[49] *Id.*

system, FERC has stated that no FERC-jurisdictional transmission has occurred that would enable FERC to assert jurisdiction for the purposes of requiring new wholesale interconnections to those distribution facilities. Therefore, in the absence of an open access wholesale distribution tariff like those filed by California public utilities,[50] new distributed generator interconnections will continue to be subject to state law requirements, rather than FERC rules.

The situation could change, however, once any distributed generator within the public utility's footprint wheels over the public utility's distribution system to make a wholesale sale. In that case, the distribution facilities used to deliver that generator's output to the RTO, regardless of voltage and technical characteristics, may become subject to FERC's wholesale sales jurisdiction. The wholesale transaction could potentially operate as a foot in the door, opening up those facilities to new FERC-jurisdictional interconnections of distributed generation. Under FERC's existing approach to "dual-use" facilities that serve both wholesale and retail delivery functions, owners of distributed generation connecting to such distribution facilities would likely have a choice: either interconnection under state rules and use of a retail net metering program, or interconnection under FERC's rules and wholesale sales. Regardless, the distribution public utility may need to be prepared to accept and process FERC-jurisdictional requests for interconnection service.

Such public utilities would also need to address the issue of delivery of distributed generation to the RTO grid and FERC jurisdiction over the rates, terms, and conditions for that service. Existing wholesale distribution tariffs, for example, provide for the distribution utility to charge a FERC-jurisdictional cost-based rate for delivery from distribution-connected generators to the RTO-controlled grid.[51] In the wholesale load connection context, FERC has stated that "[u]nlike the preference for rolled-in treatment of integrated network transmission or subtransmission facilities, distribution facilities are generally directly assigned, unless it can be shown that the distribution facilities are part of an integrated network."[52] It is unclear whether this pattern would also hold with respect to DERs, if they are scattered across a public utility's distribution system.

For municipal utilities, the jurisdictional implications of wholesale sales by individual distributed generators appear less dramatic. As discussed above, municipal utilities have reciprocity obligations, and FERC has some jurisdiction to order interconnections and transmission under FPA Sections 210, 211, 211A, and 212. Municipals, however, are not required to have Commission-approved Open Access Transmission Tariffs, or to adopt FERC's standardized generator interconnection agreements and procedures.

[50] *See*, *e.g.*, Pac. Gas & Elec. Co., Offer of Settlement (Mar. 31, 2015) ("PG&E Offer of Settlement"), eLibrary No. 20150331-5502; *Pac. Gas & Elec. Co.*, 152 FERC ¶ 61,010 (2010).

[51] *See*, *e.g.*, Pac. Gas & Elec. Co., Proposed Rate and non-rate Changes to the Wholesale Distribution Tariff, FERC Electric Tariff Volume No. 4 and Related Service Agreements for Wholesale Distribution Service, Transmittal Letter at 2 (Mar. 29, 2013), eLibrary No. 20130329-5091; PG&E Offer of Settlement.

[52] *Pinnacle West Capital Corp.*, 133 FERC ¶ 61,034, P 15 (2010).

## B. Looking Forward

Only one of the current FERC Commissioners was on the Commission at the time the Storage/DERs NOPR was issued; and it is unclear whether and how the newly constituted FERC will move forward on the rulemaking. FERC could choose to take no action; or it could, for example, issue a final rule based on the NOPR, act separately on the NOPR's proposals for transmission-connected storage, or issue a new or supplemental NOPR with a different proposal.

If FERC chooses to move forward to a final rule, it could also clarify that the NOPR's new requirements for DERs apply only to electricity products from DERs that have been delivered to the RTO grid, and that FERC is not altering its precedent on FERC's jurisdiction over local distribution facilities. In that case, the NOPR would require changes to RTO market rules, but, as discussed above, would leave regulation of DERs primarily to state and local RERRAs, recognizing the potential for evolution over time.

Given the expansion and growing industry interest in distributed generation, however, FERC may be unwilling to remain on the sidelines. For example, it could choose to revisit its decision in Order 2003 not to assert jurisdiction over new interconnections to distribution facilities, unless those facilities are subject to a Commission-approved OATT at the time of the interconnection request. But if FERC attempts to assert broad jurisdiction to compel distribution utilities to interconnect and provide delivery service to distributed generators, it may well face legal challenges that it has exceeded its authority under the FPA—as well as political opposition from the states. FERC's prior decisions regarding Demand Response Resources—another area where FERC sought to allow retail customers to participate in wholesale markets—suggest two other approaches that FERC might use.

### 1. Coordinating FERC and State Jurisdiction over Distributed Generation Through an Opt-In/Opt-Out Approach

In the context of Demand Response Resources, FERC addressed the linkage between wholesale and retail markets and the states' role in overseeing retail sales by allowing each state and local RERRA to prohibit the retail customers subject to its jurisdiction from making demand response bids into RTO wholesale markets.[53] A similar requirement could be created for distributed generators.

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[53] For large utilities (those that distributed more than 4 million MWh in the previous year), RTOs must "permit [a qualified aggregator of retail customers] to bid demand response on behalf of retail customers directly into the [RTO's] organized markets, *unless the laws and regulations of the relevant electric retail regulatory authority expressly do not permit a retail customer to participate*." *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 73 Fed. Reg. 64,100, 64,119 (Oct. 28, 2008), FERC Stats & Regs. ¶ 31,281, P 154 (2008) (emphasis added), *corrected*, 126 FERC ¶ 61,261 (2010), *on reh'g*, Order No. 719-A, 74 Fed. Reg. 37,776 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292 (2009), *on reh'g*, Order No. 719-B, 129 FERC ¶ 61,282 (2009). For small utilities (*i.e.*, those that distributed

It is unclear how the states would respond to such a veto power. A number of state public service commissions and other RERRAs have chosen not to allow wholesale-market bidding of Demand Response Resources from the retail loads they regulate. Moreover, even RERRAs that do allow such bidding from Demand Response Resources may be more reluctant to permit wholesale market participation by distribution-connected generators. Under the two-part jurisdictional test created by Order 2003, the existence of a wholesale transaction over local distribution facilities can permanently broaden FERC's jurisdiction over interconnections to, and delivery over, those facilities. Therefore, to the extent public utilities and RERRAs allow wholesale sales to be made from distributed generators in their footprints, the result could be an erosion of RERRA jurisdiction over new distributed generation. This expanded federal jurisdiction might make little practical difference—retail net metering programs are often very financially attractive, and retail customers that own distributed generation may have little financial incentive to seek access to RTO wholesale markets. RERRAs anxious to avoid federal incursions into their jurisdiction, however, may resist on principle.

### 2. Other Approaches

FERC might also contemplate more fundamental changes in how it approaches its jurisdiction over DERs. It has done so before with respect to Demand Response Resources, which are included within the NOPR's definition of DERs. In *EnergyConnect, Inc.*, 130 FERC ¶ 61,031 (2010), FERC changed how it characterized demand response, with significant implications for both FERC's jurisdiction and the transmission service Demand Response Resources need. Specifically, FERC ruled, contrary to prior decisions, that sales of demand response on the supply side of RTO wholesale markets does *not* cause the seller to be a public utility under the FPA (*id.* P 31) (footnotes omitted):

> We acknowledge that the Commission has previously characterized certain "purchases of demand reduction" as wholesale sales that "involve the sale for resale of energy that would ordinarily be consumed" by an end-use consumer. The Commission no longer relies on that characterization. As discussed above, the Commission's regulations now define "demand response" as "a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy."

Because FERC no longer characterized wholesale sales of demand response as sales of electricity for resale, it relied on its jurisdiction over rules and practices "affecting" rates and charges for jurisdictional transmission or wholesale sales to support its new requirements on

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4 million MWh or less in the previous year), such bids are not allowed *unless there is an ordinance/regulation from the RERRA expressly allowing them*. Order No. 719-A, P 60.

demand response. That basis for jurisdiction was upheld by the Supreme Court in *FERC v. EPSA*.

FERC's re-characterization of Demand Response Resources also implicitly changed the interconnection and delivery requirements associated with Demand Response Resources. If sales of demand response in wholesale markets are not sales of electricity, entities selling Demand Response Resources could participate in RTO markets without acquiring and paying for service to inject electricity into the distribution network or to deliver it over the distribution network to the RTO-controlled grid. As a result, Demand Response Resources, from a regulatory perspective, largely bypassed local distribution systems, eliminating the need for FERC to assert jurisdiction over those local distribution facilities.

This exact approach would presumably not work for distributed generators that seek to inject electric energy onto the grid and to sell that energy for resale in RTO markets. But if FERC considers distributed generation to be crucial to the viability of wholesale power markets, that could lead to attempts by FERC to stretch its authority.

## V. CONCLUSION

FERC's approach to the regulation of DERs touches on two of the biggest issues currently faced by FERC: the nation's changing resource mix and greater reliance on renewable and distributed generation; and the relationship between state and federal policies on, and regulation of, electric service. It is unclear, however, whether FERC's Storage/DERs NOPR was intended to propose significant changes to the *status quo* with respect to FERC's jurisdiction over DERs and local distribution facilities; and it remains to be seen whether the NOPR will be a priority for the new Commission.

Meanwhile, Congress has expressed an interest in DERs and their implications for federal and state jurisdiction over electric service. 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 to FERC 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.[54] 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."[55] The letter asked for FERC's perspective on:

[54] Letter of Rep. Fred Upton and Rep. Ed Whitfield to then FERC Chairman Norman C. Bay, FERC at 3 (June 13, 2016), eLibrary No. 20160614-0017.

[55] *Id.* at 1.

> 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?[56]

The Energy Subcommittee held a hearing on the history of the FPA in September 2016.[57] And in July and September 2017, the Energy Subcommittee of the House Committee on Energy and Commerce held three "Powering America Series" hearings on the state of the electric industry, the operation and effectiveness of wholesale electricity markets, and PURPA.[58] Distributed generation was discussed at the hearings. Additional hearings in the series are being scheduled.

Even if FERC decides to defer action on the NOPR, the issue of FERC authority over DERs is unlikely to go away.

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[56] *Id.* at 3.

[57] Energy & Commerce Comm., Federal Power Act: Historical Perspectives, https://energycommerce.house.gov/hearings/federal-power-act-historical-perspectives (last visited Sept. 13, 2017).

[58] Energy & Commerce Comm., Powering America, https://energycommerce.house.gov/powering-america/ (last visited Sept. 13, 2017).