Decarbonization 2.0: In an Era of Conflicting Jurisdictional Claims, What Stays, What Retires, Who Pays, and Who Decides?

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The electric power sector and the transportation sector are the greatest contributors to carbon dioxide ("CO_2") emissions in the United States.[1] The Environmental Protection Agency ("EPA") attempted to develop a comprehensive plan under President Obama to curb CO_2 emissions from electricity generating units with the Clean Power Plan ("CPP").[2] That plan presented thorny legal issues, whose merits have not been reached by any court. However, under President Trump, the EPA has issued proposals to repeal[3] and replace[4] the CPP. While states are no longer compelled to develop plans to reduce CO_2 emissions from electricity generating units (or face federal implementation of such a plan), states interested in reducing CO_2 emissions remain free to pursue those goals in whatever manner seems best to them—or at least up to the point where those actions infringe on federal law, especially the operations of Regional Transmission Organization ("RTO") and Independent System Operator ("ISO") organized markets in certain areas. Some states are doubling down on CO_2 emissions reduction, with impacts felt by utilities inside and outside the electricity markets established by the Federal Energy Regulatory Commission ("FERC" or "the Commission").

States will continue to play significant roles in the decarbonization of the electricity sector, and public power has the opportunity to help shape state policies. However, in EPA's advanced notice of proposed rulemaking to replace the CPP, EPA has asked for comment on state discretion to depart from EPA's emission guidelines—signaling a possible intent to preempt state authority in some areas.[5]

This paper reviews different types of decarbonization programs. We explain jurisdictional issues between states and FERC and then delve into their impacts on markets and the transmission grid, including discussion of utilities inside and outside of RTOs, and utilities inside and outside of centralized capacity markets. We also offer some strategies as to what public power utilities may do in light of these state-driven initiatives, as well as suggest best practices for utilities.

TYPES OF STATE PROGRAMS

States have developed a variety of programs for advancing decarbonization. Some focus on changing utility behavior, while others target customer behavior. Some states have adopted only one or two programs, while others have adopted almost all of them.

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[1] Jonathan L. Ramseur, *U.S. Carbon Dioxide Emissions Trends and Projects: Role of the Clean Power Plan and Other Factors*, Congressional Research Service (2017), https://fas.org/sgp/crs/misc/R44451.pdf.

[2] Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 80 Fed. Reg. 64,661, at 64,662 (Oct. 23, 2015).

[3] Repeal of Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units, 82 Fed. Reg. 48,035 (proposed Oct. 16, 2017).

[4] State Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, 82 Fed. Reg. 61,507 (proposed Dec. 28, 2017).

[5] *Id*. at 61,513.

Programs that impact generation mix include:

- **Renewable Portfolio Standards.** A majority of states have enacted Renewable Portfolio Standards ("RPS") that require utilities to acquire a certain amount of renewable generation (or achieve voluntary targets).[6] These RPS vary; some states include municipalities (potentially with lower requirements), and states define what types of generation qualify as renewable differently.[7]

- **Energy Efficiency Standards.** Similar to RPS, states may encourage or require utilities to achieve a certain percentage of electricity and/or natural gas reduction in sales from energy efficiency measures. These measures may include increasing efficiency of generation, as well as end-use energy efficiency options (discussed further below as load reducers).[8]

- **Storage.** Electric storage resources are those "capable of receiving electric energy from the grid and storing it for later injection of electric energy back to the grid."[9] In Order No. 841, FERC directed each RTO/ISO to file tariff revisions to implement a "participation model" to allow for storage resources to provide all capacity, energy, and ancillary services it is technically capable of providing.[10] Storage has potential applications in generation, transmission, and distribution.[11] The U.S. Department of Energy ("DOE") recently announced up to $30 million in funding for storage projects.[12]

- **Distributed Energy Resources.** Distributed energy resources ("DERs") are small resources located on the distribution system—usually less than 100 kV—that are geographically dispersed. FERC currently has an ongoing proceeding about DER aggregations and is evaluating how they can access RTO markets.[13]

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[6] Jocelyn Durkay, *State Renewable Portfolio Standards and Goals*, National Conference of State Legislature (August 1, 2017), http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

[7] *Id.*

[8] *See Energy Efficiency Standards and Targets*, Center for Climate and Energy Solutions, (Sep. 2016) https://www.c2es.org/document/energy-efficiency-standards-and-targets/.

[9] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 841, 83 Fed. Reg. 9580 (Mar. 6, 2018), FERC Stats. & Regs. ¶ 31,398, at 30,547 n.1 (2018) ("Order No. 841").

[10] *Id.* at 30,548.

[11] *See Energy Storage: Information on Challenges to Deployment for Electricity Grid Operations and Efforts to Address Them*, United States Government Accountability Office (2018), https://www.gao.gov/assets/700/691983.pdf.

[12] *Department of Energy Announces Funding to Support Long-Duration Energy Storage*, DOE (May 1, 2018), https://www.energy.gov/articles/department-energy-announces-funding-support-long-duration-energy-storage.

[13] *See* Notice Inviting Post-Technical Conference Comments, *Distributed Energy Resources—Considerations for Bulk Power Sys*., Docket No. AD18-10-000 (Apr. 27, 2018), eLibrary No. 20180427-3017 (inviting comments in response to a technical conference on the participation of DER aggregations in organized markets and on the broader potential effects of DERs on the bulk power system).

A recent FERC Staff report noted the increase in DER capacity in the U.S. is driven by regional policies as well as declining costs, desire for self-supply, and environmental considerations.[14] For example, distributed solar photovoltaic installations represented over 12 percent of new capacity additions in 2016.[15] The term DER has evolved to include storage, energy efficiency, and demand response resources.

Financial policies aimed at utilities include:

- **Carbon Pricing.** This approach imposes a charge in relation to CO_2 emissions, typically in the form of an emission trading system (cap-and-trade) or a carbon tax. The Regional Greenhouse Gas Initiative ("RGGI") is an example of such a program in which the nine (currently) participating states sell emission allowances through auctions and invest the proceeds in energy efficiency, renewables, and other programs.[16] California also participates in a program where carbon pricing is included in energy bids for all energy sold through the California Independent System Operator ("CAISO") market in California. So far, CAISO's only trading partners are provinces in Canada. Carbon pricing may be used in wholesale electricity markets to promote decarbonization goals, but FERC has not ordered this, and it is not clear that it has jurisdiction to do so (although it can act on filings proposing to do so).

- **Subsidies.** State and federal subsidies to promote technological innovation can help new technologies compete with more carbon-intensive forms of power generation. Some states have sought to apply subsidies to older forms of zero-emissions generation, such as nuclear plants. Subsidies may also influence consumer behavior; for example, many states and the federal government provide monetary (*e.g.*, tax credits) and non-monetary (*e.g.*, special driving lanes) benefits.[17]

[14] FERC, Distributed Energy Resources: Technical Considerations for the Bulk Power System Staff Report at 3, 6, *Distributed Energy Resources—Technical Considerations for the Bulk Power Sys*., Docket No. AD18-10-000 (February 20, 2018), eLibrary No. 20180220-4001 ("FERC Staff Report"). A 2016 New York report looked at DER compensation and valuation, including recommendations for different facilities. *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding*, No. 15-E-0751 (N.Y. Dep. of Pub. Serv. Oct. 27, 2016), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b59B620E6-87C4-4C80-8BEC-E15BB6E0545E%7d.

[15] FERC Staff Report at 5.

[16] *Welcome*, RGGI, https://www.rggi.org/ (last visited June 6, 2018).

[17] *Energy Commission Adopts Standards Requiring Solar Systems for New Homes*, *First in Nation*, California Energy Commission (May 9, 2018), http://www.energy.ca.gov/releases/2018_releases/2018-05-09_building_standards_adopted_nr.html.

Load reducers and programs directed at customer behavior include:

- **Demand Response.** Demand response is "[c]hanges in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized."[18] Demand response was included in the Energy Policy Act of 2005 as something to "be encouraged."[19] Demand response can be bid into RTO markets; FERC, however, has provided a mechanism for state and local regulators to prohibit demand response participation in RTO markets.

- **Energy Efficiency.** Energy efficiency ("EE") is essentially doing more with less, using energy-saving appliances or redesigned manufacturing products,[20] building codes for new construction, programs to replace refrigerators or water heaters with more efficient models, or more aggressive goals to create net-zero energy use buildings. Sometimes EE blurs into other types of programs. For example, California's new 2019 Building Energy Efficiency Standards go so far as to require all new or substantially renovated residences built after January 1, 2020 to include solar panels.[21] EE can be bid into RTO markets.

- **Alternative Rate-Making Methodologies.** Strategies that have the effect of slowing load growth or even reducing loads present obvious threats to utility financial viability and threaten unfair cost shifts to customers who cannot take advantage of them. When loads go down, the rate paid by remaining customers goes up. Alternative Rate-Making Methodologies aim to decouple utility revenues from the quantity of power sold.[22] Decoupling reduces the volatility of traditional pricing, ultimately reducing financial risk to the utility.[23] Another example, is time-based rate programs, which have variable pricing and may

[18] *National Assessment & Action Plan on Demand Response*, FERC (July 1, 2016), https://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential.asp.

[19] 16 U.S.C. § 2642(f).

[20] *See* Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64,100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 31,281, P 197, n.277 (2008) ("Order No. 719"), *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 ¶ 61,252 (2009).

[21] *Energy Commission Adopts Standards Requiring Solar Systems for New Homes*, *First in Nation*, California Energy Commission (May 9, 2018), http://www.energy.ca.gov/releases/2018_releases/2018-05-09_building_standards_adopted_nr.html.

[22] *Decoupling Policies*, Center for Climate and Energy Solutions (Nov. 2016), https://www.c2es.org/document/decoupling-policies/.

[23] *See Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities*, National Renewable Energy Laboratory at 5 (2009), https://www.nrel.gov/docs/fy10osti/46606.pdf.

provide incentives to ratepayers to reduce power consumption during peak periods and to shift it to times when prices are lower.[24]

- **Demand-Side Management.** This is a broad term that may include conservation, load management, and other activities to influence demand (including measures that might be considered energy efficiency or demand response as well).[25] Integrated demand-side management programs coordinate multiple approaches, including energy efficiency, demand response, distributed generation, storage, electric vehicle technologies, and time-based rate programs for utility customers.[26]

- **Direct Access and Community Choice Aggregations.** Direct Access and Community Choice Aggregations ("CCA") change the way retail customers buy power, by allowing them to shop among competing suppliers. These customers continue to rely on their local distribution provider for access to the distribution system and the broader grid. There is no inherent reason why these mechanisms must be linked with accessing low-emissions resources, and indeed, the earliest models tended to focus on customer savings through competition. However, many customers exercising retail choice are now often doing so expressly for the purposes of decarbonizing electricity. Many states offer Direct Access, usually as a byproduct of the restructuring of the utility industry and the movement into RTOs. CCAs are rarer, and are currently offered only in California, New York, Massachusetts, Ohio, New Jersey, Rhode Island and Illinois. In the case of CCAs, entire communities vote to use alternative suppliers. CCAs, Direct Access, and PV solar panels in California now serve over one fourth of the load of the three largest investor-owned utilities ("IOUs"), and are projected to serve about 85 percent by 2025.[27] The California Public Utilities Commission ("CPUC") has recently awakened to the jurisdictional implications of such a large percentage of retail load migrating to providers outside its jurisdiction, and has opened a docket to look at the implications.[28]

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[24] *Time-Based Pricing for Residential Customers: Questions & Answers*, Demand Response and Smart Grid Coalition (2007), https://www.smartgrid.gov/files/TimeBased_Pricing_for_Residential_Customers_Question_Answer_200706.pdf.

[25] *See Demand Response Discussion for the 2007 Long-Term Reliability Assessment*, North American Electric Reliability Corporation Reliability Assessment Subcommittee at 1 (2007), https://www.naesb.org/pdf2/dsmee052407w4.pdf.

[26] Jennifer Potter, Elizabeth Stuart, and Peter Cappers, *Barriers and Opportunities to Broader Adoption of Integrated Demand Side Management at Electric Utilities: A Scoping Study*, https://emp.lbl.gov/publications/barriers-and-opportunities-broader.

[27] *See Customer and Retail Choice, the Role of the Utility, and Evolving Regulatory Framework, Staff White Paper*, California Public Utilities Commission at 3 (2017), http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf.

[28] *See id*.

- **Green Pricing Programs.** Some states require utilities to offer "green pricing" options—typically premiums customers may pay for renewable generation—and some utilities offer these programs voluntarily.[29] Roughly 6.3 million electricity customers in the U.S. purchased about 95 million MWh of green power in 2016.[30] Green pricing programs include CCAs and direct access, discussed above. In 2017, Sacramento Municipal Utility District and Austin Energy were in the top ten utilities in terms of number of green power participants and sales.[31]

I. Who Has Jurisdiction Over These Programs?

The Federal Power Act ("FPA") puts regulation of "the sale of electric energy at wholesale in interstate commerce," including wholesale electricity rates and rules or practices "affecting" such rates, within the authority of FERC.[32] Regulation of "any other sale," including at retail, is left to the states.[33] Historically, that decision has left choices about retail service and a state's generation mix fully under the jurisdiction of state and local governments. However, these state programs affect both supply and demand, and FERC has created a set of markets in RTOs and ISOs predicated, more or less, on the principle of supply and demand. FERC views these programs as affecting prices and operation in its jurisdictional markets, and it has increasingly been asserting its jurisdiction over programs that it thinks tread impermissibly into federal authority. Although some of the more publicized cases have related to the centralized capacity markets in the east, FERC's jurisdictional reach is extending into all of the jurisdictional markets, with some potential to go further. The Commission's orders on demand response, storage, and energy efficiency resources ("EERs") are prime examples, and it is currently examining DERs.

A. Demand Response and the Supreme Court's Affirmation of FERC Jurisdiction

The retail/wholesale divide in the FPA is not always straightforward. The Supreme Court considered this jurisdictional quandary created by the "inextricably linked" wholesale and retail electricity markets in the context of demand response programs.[34] Changes in consumption patterns bid into the markets allow a grid operator to pay for this non-consumption rather than ramping up generation.

By way of background, FERC Order No. 719 required RTOs and ISOs to (1) accept bids from demand response resources on a basis comparable to other resources, (2) allow aggregators

[29] *See Green Pricing Programs*, Center for Climate and Energy Solutions (Mar. 2017), https://www.c2es.org/document/green-pricing-programs/.

[30] Eric O'Shaughnessy, Jenny Heeter, Jeff Cook, and Christina Volpi, *Status and Trends in the U.S. Voluntary Green Power Market*, National Renewable Energy Laboratory at v (2016), https://www.nrel.gov/docs/fy18osti/70174.pdf.

[31] *Top Ten Utility Green Pricing Programs*, National Renewable Energy Laboratory at 1 (2017), https://www.nrel.gov/analysis/assets/pdfs/utility-green-power-ranking.pdf.

[32] 16 U.S.C. 824(b), 824e(a).

[33] 16 U.S.C. 824(b).

[34] *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 766 (2016).

of retail customers to bid demand response on behalf of retail customers directly into the energy market, and (3) take other measures to consider and eliminate barriers to demand response in organized markets.[35] Notably, FERC provided an opt-in/opt-out mechanism for relevant electric retail regulatory authorities[36] ("RERRAs") in Order No. 719 so that the RERRA could prohibit an aggregator of retail customers from bidding demand response of retail customers into RTO/ISO markets. As modified in Order No. 719-A, RTOs are required to accept demand response resource bids from aggregators of retail customers located in large utilities (above 4 million MWh) unless the relevant RERRA opts out; RTOs must reject such bids from aggregators located in small utilities unless the RERRA opts in.

A few years later, FERC issued Order No. 745 concerning compensation for demand response to ensure "meaningful demand-side participation" in wholesale markets.[37] This essentially required demand response providers to be paid for reducing load just as if they had met that demand with generation. Several entities challenged Order No. 745, arguing, among other things, that FERC does not have jurisdiction to set the price for sales of retail demand response into wholesale markets.

Although the D.C. Circuit held that Order No. 745 violated the FPA because it constituted "direct regulation of the retail market,"[38] the Supreme Court disagreed and reversed. It explained that "FERC has the authority—and, indeed, the duty—to ensure that the rules or practices 'affecting' wholesale rates are just and reasonable," and that the rules governing wholesale demand response programs directly affect wholesale rates.[39] Observing that the wholesale and retail electricity markets are not "hermetically sealed from each other[,]" the Supreme Court found that because what FERC had done in Order No. 745 was regulation of "what takes place on the wholesale market, as part of carrying out its charge to improve how that market runes," the effect on retail rates did not matter for the purposes of the jurisdictional divide.[40] Thus, FERC's attention on demand response did not represent an intrusion into the sphere of the states.

B. FERC's Assertion of Jurisdiction Over Storage, EERS, and DERs

More recently, FERC has turned its attention to its authority to regulate the participation of storage resources, EERs, and DERs. In November 2016, FERC issued a Notice of Proposed Rulemaking on the participation of electric storage and DER aggregators in RTO markets.[41]

[35] Order No. 719, P 3.

[36] Examples would be state PUCs or municipal utility commissions or city councils.

[37] Demand Response Compensation in Organized Wholesale Energy Markets, Order No. 745, 76 Fed. Reg. 16,658 (Mar. 24, 2011), FERC Stats. & Regs. ¶ 31,322 (2011) ("Order No. 745"), *clarified*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012), *vacated sub nom. Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd*, 136 S. Ct. 760 (2016).

[38] *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C. Cir. 2014), *rev'd*, 136 S. Ct. 760 (2016).

[39] *Elec. Power Supply Ass'n v. FERC*, 136 S. Ct. 760, 774 (2016).

[40] *Id.* at 776.

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

Proposing to require RTOs to revise their tariffs to accommodate storage resources' participation in organized markets, and to provide an aggregator model for DERs similar to what it established for demand response resources. In Order No. 841,[42] FERC separated the issues of storage and DERs, issuing a final rule for storage resources and deferring action on DERs.

For storage resources, Order No. 841 directed RTOs to revise their tariffs to establish a participation model to facilitate the participation of storage resources in RTO markets, taking into account the physical and operational characteristics of these particular resources. FERC broadly asserted its jurisdiction over storage resources, stating that the new rule applies to "electric storage resources located on the interstate transmission system, on a distribution system, or behind the meter."[43] FERC rejected requests that it allow states to decide whether to allow storage resources located behind the meter or on distribution systems to participate in the RTO markets, and did not apply Order No. 719's RERRA opt-out/opt-in mechanism to storage resources.[44] It also rejected the recommendation that storage resources located behind the meter or on distribution systems must choose to participate in either the wholesale market or retail market, but not both.[45]

Nevertheless, FERC did leave some control in the hands of distribution utilities and RERRAs, stating that the rule applies only to those storage resources that are "contractually permitted" to inject energy back to the grid,[46] and that "[t]o the extent that the host distribution utility is unable—due to a lack of the necessary metering infrastructure and accounting practices—or unwilling to net out any energy purchases associated with a resource using the participation model for electric storage resources' wholesale charging activities from the host customer's retail bill, the RTO/ISO would be prevented from charging that resource using the participation model for electric storage resources electric wholesale rates for the charging energy for which it is already paying retail rates."[47]

In Order No. 841, FERC did not opine on its jurisdiction over DER aggregations, pending receipt of more information through a technical conference and comments. While much of the staff-led, two-day conference focused on technical and operational issues, the five FERC Commissioners led a panel discussion with state and local regulators. The state and local regulators generally agreed that the challenges associated with DERs participating in wholesale markets are solvable, although some asserted that states should be the ones deciding whether to allow DERs to participate. The FERC Commissioners specifically asked whether there should be an opt-out/opt-in mechanism, as FERC established for demand response resources (but not storage resources). Although some panelists stated that they could not envision their states being interested in opting out, others strongly argued in favor of the ability for RERRAs to do so. One idea raised during this panel was a more limited opt-out mechanism that would allow states to

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[42] Order No. 841.

[43] *Id.* P 29.

[44] *Id.* P 35.

[45] *Id.* P 320.

[46] *Id.* P 33.

[47] *Id.* P 326.

require that DERs choose to participate in either the wholesale market or retail market, but not both.

Another possible indication of how FERC may approach DERs is the Commission's recent declaratory order on EERs. This issue was raised in a petition for declaratory order filed by Advanced Energy Economy ("AEE"), in response to PJM Interconnection, LLC's ("PJM's) initiation of a stakeholder process that would have allowed RERRAs to bar, restrict, or otherwise condition the participation of EERs in the PJM capacity market. AEE sought declaratory rulings from FERC on the scope of FERC's jurisdiction over EERs and the authority of RERRAs with respect to third-party EER participation in RTO markets. Ultimately, FERC sided with AEE on the major jurisdictional questions, declaring that FERC:

> [(1)] has exclusive jurisdiction over the participation of EERs in wholesale markets; [(2)] that RERRAs may not bar, restrict, or otherwise condition the participation of EERs in wholesale electricity markets unless the Commission expressly gives RERRAs such authority; and [(3)] that Order No. 719 does not provide for a RERRA to exercise an opt-out and bar or restrict the sale into the wholesale electricity markets of EERs originating in their state or local area.[48]

FERC added that the RTO stakeholder process may be an appropriate way to develop proposed market rules implementing a RERRA opt-out mechanism,[49] but it declined to opine on what it would consider when evaluating any future requests for opt-out authority.[50] The Commission also emphasized that opt-out provisions were not required by the FPA and that FERC could, but is not required to, apply them where it deemed fit. On rehearing, FERC clarified that it: "(1) did not assert the authority to preempt the terms and conditions established by RERRAs for retail customers to receive retail service; (2) did not purport to authorize retail customers to violate any state or local laws; and (3) made no findings as to whether contracts regarding EERs are subject to state or local law."[51] But, the rehearing order also included language emphasizing the broad pre-emptive jurisdiction FERC is claiming over EERs. This, along with FERC's final rule on storage resources, suggests that FERC may similarly assert broad jurisdiction over DERs.

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[48] *Advanced Energy Economy*, 161 FERC ¶ 61,245, P 57 (2017) ("*AEE*"), *order denying reh'g and granting clarification in part* 163 FERC ¶ 61,030 (2018) ("*AEE reh'g*").

[49] *Id.* P 71.

[50] *Id.* P 72.

[51] *AEE reh'g*, P 42.

II. Grid and Market Impacts

The influx of renewables, storage, demand response, and DERs have had marked impacts on the electric grid and on the organized markets. Certainly, energy prices have fallen because many baseload resources cannot compete with lower cost, free-fuel resources, especially when some of the decarbonization measures reduce load. However, as coal and nuclear plants have retired, they have often been replaced in part with cheaper gas-fired resources. While gas-plants have lower emissions than coal plants, they have higher emissions than nuclear plants, so there is not always a net environmental benefit—an issue that some states are trying to address (discussed below). Nevertheless, even gas plants do not always make money in markets flooded with wind and solar energy.

Capacity markets, whether organized centrally or through bilateral contracts to meet an administrative standard, have not succeeded in stemming the retirements of resources, some of which the RTOs are not ready to lose. Capacity markets have also been the subject of litigation over conflicting FERC and state jurisdictional claims.

There have been changes on the grid as well. The intermittency of wind and especially solar resources require additional resources (often gas-fired or hydroelectric) to handle steeper ramps (for example, evening ramps when load increases as solar plants come offline at sundown). The movement of peak hours to later in the day has disrupted longstanding load and dispatch patterns.

Wind and solar resources located in areas remote from major load centers have necessitated the construction of long high-voltage transmission lines, accompanied by utility and regional disputes over cost allocation and swiftly followed by ratepayer complaints about rising transmission rates. Less load growth in many areas of the country makes rising transmission rates even more painful. Increasing levels of DER will require greater communication and coordination between distribution and transmission systems, which raises cost and reliability issues. There is also an economic justice issue. Many of the new technologies require significant upfront investment, meaning that they tend to be adopted first by ratepayers with the financial wherewithal to invest for long term benefits. This raises concerns about cost shifts to less well-off customers who may be forced to pick up costs for the existing transmission grid and for potentially stranded central station generation.

Finally, all of these changes produce political consequences and pushback, which may have a very significant impact on whether and how FERC's organized markets survive the next few years.

A. Centralized Capacity Markets

The organized energy markets were established on the principle of efficiency. In theory, competitive bidding and market optimization would result in the dispatch of the cheapest overall combination of resources necessary to serve load. When it became apparent that energy markets alone were not always encouraging the building of sufficient capacity for future loads, some states responded with resource adequacy programs and some RTOs and market participants came to FERC proposing the concept of centralized capacity markets. It is with regard to these centralized capacity markets where the jurisdictional disputes have been most severe and where cases have reached the appellate courts and even the Supreme Court. The core purpose of centralized capacity markets is to ensure resource adequacy by incentivizing investment in generation such that sufficient capacity will be available to meet the system's peak demands in the future.

When centralized capacity markets were first developed, the driving concern was that each region was able to procure a sufficient *quantity* of the resources at the lowest price possible. The original markets were intended to be technologically neutral, and did not directly take into account many qualitative aspects of generation, such as a resource's emission levels, fuel source, ramping capability, variability, etc. The markets were not designed to incorporate or address decarbonization goals. States and market participants that seek to incorporate decarbonization priorities into resource mix decisions have turned to proposals that seek to amend market design or offer out-of-market support. As these measures affect or have been alleged to affect prices in the organized markets, litigation has ensued.

1. State Control over Resource Mix

State efforts to change the future generation mix have met with varying results, often spurring challenges from competitors in the capacity market dissatisfied with the price impacts on the markets.

a) *Hughes v. Talen Energy Marketing, LLC*

The Supreme Court considered Maryland's subsidy program in *Hughes v. Talen Energy Marketing, LLC*.[52] In this program, Maryland, motivated by a concern for pending retirements (*i.e.*, not decarbonization), solicited offers for new generation and required retail utilities to accept the winning bid and enter into a twenty-year contract with the winning bidder (termed a "contract for differences"). The contract would then require the bidder to build a plant and bid it into the PJM market. The retail utilities would pay or receive the difference between the contract price and the PJM auction price. Incumbent generators challenged the program, arguing that it violated the Supremacy Clause by settling wholesale electricity rates and interfered with FERC's authority. The Fourth Circuit found that Maryland's program impermissibly intruded on the wholesale market, and the Supreme Court agreed.[53]

The Court held that "States may not seek to achieve ends, however legitimate, through regulatory means that intrude on FERC's authority over interstate wholesale rates, as Maryland has done here."[54] The Court distinguished the contract for differences from traditional bilateral contracts because it "operates within the auction."[55] While *Hughes* involved a gas plant, incentives for emissions-free generation may look similar to the program in *Hughes*, and the

[52] *Hughes v. Talen Energy Marketing, LLC*, 136 S. Ct. 1288 (2016).

[53] *Id.* at 1292.

[54] *Id.* at 1298.

[55] *Id.* at 1299.

Court noted the underlying concern about the impact of its decision on deployment of clean generation:[56]

> We reject Maryland's program only because it disregards an interstate wholesale rate required by FERC. We therefore need not and do not address the permissibility of various other measures States might employ to encourage development of new or clean generation, including tax incentives, land grants, direct subsidies, construction of state-owned generation facilities, or re-regulation of the energy sector. Nothing in this opinion should be read to foreclose Maryland and other States from encouraging production of new or clean generation through measures "untethered to a generator's wholesale market participation." Brief for Respondents 40. So long as a State does not condition payment of funds on capacity clearing the auction, the State's program would not suffer from the fatal defect that renders Maryland's program unacceptable.

This explicit narrowing of the holding leaves room for states to try other measures to influence generation mix.

Last year, the Second Circuit Court of Appeals upheld Connecticut's program that empowers its energy regulator to solicit proposals for renewable generation, select winning bids, and then direct utilities to enter into wholesale energy contracts with the winning bidders.[57] Allco, a solar developer and unsuccessful bidder, challenged the program on the grounds that it forced utilities to enter into wholesale power contracts and violated the Federal Power Act.[58] Allco also challenged Connecticut's implementation of its RPS, upset that RECs from its Georgia facility did not meet the legal requirements of Connecticut's RPS.

Although Allco argued that Connecticut's program was "economically identical" to the Maryland program in *Hughes*,[59] the court found an important distinction: Connecticut's program operates "independent of the auction" and "does not condition capacity transfers" on a FERC-jurisdictional auction and results in traditional bilateral contracts between utilities and generators.[60] Regarding the RPS, the court found that there was no violation of the dormant Commerce Clause, finding legitimate rationales for the geographic distinctions drawn by the RPS.[61] Thus, the court affirmed the dismissal of Allco's claims.

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[56] *Id.*

[57] *Allco Finance Ltd v. Klee*, 861 F.3d 82 (2d Cir. 2017), 138 S. Ct. 926 (2018).

[58] *Id.* at 91.

[59] *Id.* at 98.

[60] *Id.* at 99.

[61] *Id.* at 102-08.

b) Zero Emission Credit Programs

Several states have implemented programs to support qualifying nuclear facilities that are at risk of retirement for the zero-carbon attribute of their generation. These are attempts to incentivize existing zero emissions generation outside the wholesale market.

New York's Clean Energy Standard ("CES"), adopted in 2016, put in place an ambitious strategy "to achieve State environmental, public health, climate policy and economic goals."[62] The New York Department of Public Service adopted the goal that 50 percent of New York's electricity is to be generated by renewable sources by 2030 in order to reduce statewide greenhouse gas ("GHG") emissions by 40 percent in 2030.[63] The CES includes a Renewable Energy Standard ("RES") and a Zero-Emissions Credit ("ZEC") program. Under the CES, load-serving entities in New York are required "to serve their retail customers by procuring new renewable resources."[64] Renewable generators get credits for their generation, and then the New York State Energy Research and Development Authority ("NYSERDA") purchases the credits and sells them to load-serving entities.[65]

The CES Order, however, found that losing carbon-free nuclear generation (31 percent of New York's generation mix) before the development of new renewable resources by 2030 "would undoubtedly result in significantly increased air emissions due to heavier reliance on existing fossil-fueled plants or the construction of new gas plants to replace the supplanted energy."[66] The ZEC program targets this issue by pricing the zero-emissions attributes of nuclear generation through contracts between NYSERDA and qualifying nuclear facilities—Exelon's R.E. Ginna, Fitzpatrick, and Nine Mile Point plants—for the purchase of ZECs.[67] Load-serving entities are then required to buy a percentage of the ZECs from NYSERDA.[68]

Merchant generators challenged the CES Order that the ZEC program distorts NYISO auctions, is preempted under the FPA, and violates the dormant Commerce Clause. Last summer, a federal district court dismissed the challenge, finding that the plaintiffs did not have a cause of action under the FPA, but in any case the ZEC program "[b]y establishing a program that does not condition or tether ZEC payments to wholesale auction participation, New York has successfully threaded the needle left by *Hughes* that allows States to adopt innovative programs to encourage the production of clean energy."[69] The court found that the ZEC program

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[62] Order Adopting a Clean Energy Standard at 1, Nos. 15-E-0302, 16-E-0270 (N.Y. Pub. Serv. Comm'n Aug. 1, 2016), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b44C5D5B8-14C3-4F32-8399-F5487D6D8FE8%7d ("CES Order").

[63] *Id.* at 2.

[64] *Id.*

[65] Memorandum Opinion and Order at 5, *Coal. for Competitive Elec. v. Zibelman*, No. 16-CV-8164, 272 F. Supp. 3d 554, 561 (S.D.N.Y. 2017), http://consideringthegrid.com/wp-content/uploads/2017/07/SDNY-Order.pdf, *appeal pending* No. 17-2654 (2d Cir. argued Mar. 12, 2018) ("SDNY ZEC Order").

[66] CES Order at 19.

[67] *Id.* at 19-20.

[68] *Id.* at 20.

[69] SDNY ZEC Order at 29.

"does not thwart the goal of an efficient energy market; rather, it encourages through financial incentives the production of clean energy."[70] Plaintiff generators have appealed to the U.S. Court of Appeals for the Second Circuit, where the case is currently pending.

Illinois has implemented its own ZEC program as part of its Future Energy Jobs Act, which also includes energy efficiency, renewable energy, and training for new energy jobs.[71] Similar to the New York program, ZECs are awarded to certain qualifying nuclear plants following a procurement process, and then utilities must purchase a certain number of ZECs. ZECs are priced related to the federal government's measure of the social cost of carbon. Generators and Illinois consumers challenged the program, arguing that the ZEC program intruded on FERC's jurisdiction under the FPA in interfering with auction clearing prices in FERC-jurisdictional markets, as well as the dormant Commerce Clause argument. The district court in Illinois dismissed the challenges, finding that even if the plaintiffs' claims were "'proper cases' for private suits for injunctive relief,"[72] the ZEC program "falls within Illinois' reserved authority over generation facilities," and "Illinois has sufficiently separated ZECs from wholesale transactions such that the [FPA] does not preempt the state program under principles of field preemption."[73] Midcontinent Independent System Operator, Inc. ("MISO") had filed an *amicus* brief in support of dismissing the challenges to the Illinois ZEC program in which it explained that MISO's FERC-authorized resource adequacy and market programs are "designed to complement state initiatives like the one at issue in this case."[74] MISO described its programs and requirements as "complementary to any state-approved mechanism."[75]

The challenge to the Illinois program is currently pending before the Seventh Circuit. On May 29, 2018, the U.S. Department of Justice and FERC filed an *amicus* brief in support of the state program, arguing that the state program was not preempted and that the district court's dismissal of the challenge to the ZEC program should be upheld. FERC noted that it could take any necessary action to address the impact of the state program on its markets.[76]

New Jersey recently passed legislation to establish a 50 percent renewable energy standard by 2030 and to award ZECs to qualifying nuclear plants (New Jersey gets about

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[70] *Id.* at 32.

[71] *What is the Future Energy Jobs Act? An In-Depth Look Into Illinois' New Energy Legislation,* Citizens Utility Board (2017), https://citizensutilityboard.org/wp-content/uploads/2017/05/FEJA.pdf

[72] *Village of Old Mill Creek v. Star*, Nos. 17-CV-1163, 17-CV-1164, Slip Op. at 19, 2017 U.S. Dist. LEXIS 109368 (N.D. Ill. 2017), http://consideringthegrid.com/wp-content/uploads/2017/07/Village-of-Old-Mill-Creek-v.-Star.pdf, *appeals pending*, Nos. 17-2433, 17-2445 (7th Cir. argued Jan. 3, 2018).

[73] *Id.* at 33.

[74] Midcontinent Independent System Operator, Inc.'s Brief as Amicus Curiae in Support of Defendants' Motion to Dismiss at 1, *Elec. Power Supply Ass'n v. Star*, No. 17-CV-1164 (N. D. Ill. 2017), https://statepowerproject.files.wordpress.com/2017/02/il-zec-miso-amicus.pdf.

[75] *Id.* at 6-7.

[76] Brief for the United States and the Federal Energy Regulatory Commission as Amici Curiae in Support of Defendants-Respondents and Affirmance at 8, *Village of Old Mill Creek v. Star*, Nos. 17-2433, 17-2445 (7th Cir. May 29, 2018), https://statepowerproject.files.wordpress.com/2018/05/il-7th-us-brief2.pdf.

40 percent of its electricity from nuclear).[77] Connecticut enacted a law last fall that allows state energy officials to allow up to 75 percent of the output of the Millstone station in a competitive solicitation with other zero-carbon resources.[78] Pennsylvania and Ohio may soon adopt similar subsidy programs.

2. RTO/ISO Accommodation of State Policies

Obviously, out-of-market support may impact markets. For example, subsidized resources may bid into the market at a lower cost, depressing prices and deterring new entry. But if these resources must bid into a market that raises bids to "account for" the subsidies, consumers who provided out-of-market support to resources may end up paying twice. In light of these concerns, regions have attempted to craft policies that recognize the low-carbon attributes of certain types of generation while preserving market efficiencies. This requires a balance of promoting economically efficient markets with the ability of states to pursue legitimate state interests—in this case, reducing CO_2 emissions from power plants. Recently, RTOs have filed proposals attempting to strike that balance.

a) ISO New England

ISO New England, Inc. ("ISO-NE") proposed "Competitive Auctions with Sponsored Policy Resources" ("CASPR") to "better accommodate states' out-of-market procurements."[79] CASPR consists of a two-stage forward capacity auction that would first clear resources subject to existing mitigation mechanisms (*e.g.*, the Minimum Offer Price Rule ("MOPR")).[80] Then, in the second stage, existing capacity resources may voluntarily exit the markets permanently and sell their capacity supply obligations to sponsored policy resources that did not get capacity obligations in the first stage. That is, new resources, such as renewables, will bid to pay existing resources to retire.

[77] David Roberts, *The Latest State to Get Serious About Climate Change is . . . New Jersey?,* Vox (May 25, 2018), https://www.vox.com/energy-and-environment/2018/4/20/17255872/new-jersey-nuclear-renewable-energy-phil-murphy.

[78] Peter Maloney, *Dominion's Millstone Nuclear Plant Could Warrant Subsidies, Draft Report Says*, Utility Dive (Jan. 23, 2018), https://www.utilitydive.com/news/dominions-millstone-nuclear-plant-could-warrant-subsidies-draft-report-s/515406/. The economic rationale is being challenged. *See Millstone Nuclear Plant Most Profitable in the U.S., According to New MIT Study,* The Millstone Payout (Apr. 10, 2017) http://www.stopthemillstonepayout.com/press-center/2017/4/10/41017-millstone-nuclear-plant-most-profitable-in-the-us-according-to-new-mit-study.

[79] ISO-NE, Revisions to ISO New England Transmission, Markets and Services Tariff Related to Competitive Auctions with Sponsored Policy Resources at 1, *ISO New England Inc.,* Docket No. ER18-619-000 (Jan. 8, 2018), eLibrary No. 20180108-5125.

[80] A MOPR sets an administratively-determined floor for offers of certain new resources that are being offered into a capacity auction, even if the owners of the resource, bidding their actual costs, would have submitted a lower bid.

FERC accepted CASPR in an order noting the backdrop of "the larger issue of how to address the impact of state policies on wholesale markets."[81] FERC stated:[82]

> Ultimately, the purpose of basing capacity market constructs on these principles is to produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates. Where participation of resources receiving out-of-market state revenues undermines those principles, it is our duty under the FPA to take actions necessary to assure just and reasonable rates.

FERC said it intends to use the MOPR to address the impacts of state policies on wholesale capacity markets, although it acknowledges there may be other ways to peel the orange.[83] Commissioner LaFleur concurred in part, focusing her criticism on "the generic guidance set forth in the order regarding how the Commission should address the interplay of state policies and the wholesale markets."[84] She called the MOPR "an important tool" for use in "certain instances,"[85] but rejected it as a standard solution. Commissioner Glick dissented in part and concurred in part, also objecting to the order's general support for the MOPR and urging FERC and RTOs/ISOs "stop using the MOPR to interfere with state public policies."[86] He stated that FERC's policy of "'mitigating,' rather than facilitating, state public policy preferences,"[87] is the wrong role for the Commission to play.

Commissioner Powelson dissented entirely from the order on ISO-NE's proposal, calling CASPR "well intentioned" but doubting that CASPR's dual goals of accomplishing certain policy goals while protecting the wholesale market could coexist. He is concerned about out-of-market revenue skewing price signals in the market and causing the clearing price to not reflect total resource costs. The Commission's order accepting CASPR is currently pending on rehearing.

In another ISO-NE market action related to generation mix, on May 1, 2018, ISO-NE filed a waiver of certain provisions of its tariff related to its concern over Exelon's planned retirement of two natural gas combined cycle units, Mystic 8 and 9, located in Massachusetts.[88] Exelon, in its announcement of the retirement, had stated "[a]bsent any regulatory reforms to properly value reliability and regional fuel security, these units will not participate in the

[81] *ISO New England Inc.*, 162 FERC ¶ 61,205, PP 21, 72 (2018).

[82] *Id.* P 21.

[83] *Id.* P 22.

[84] *Id.* at 62,097.

[85] *Id.* at 62,098.

[86] *Id.* at 62,101.

[87] *Id.*

[88] ISO-NE, Petition of ISO New England Inc. for Waiver of Tariff Provisions, *ISO New England, Inc.*, Docket No. ER18-1509-000 (May 1, 2018), eLibrary No. 20180502-5089 ("ISO-NE Request for Waiver").

Forward Capacity Auction scheduled for February 2019."[89] Exelon also announced its purchase of the Distrigas LNG Terminal "to ensure the continued reliable supply of fuel to Mystic Units 8 and 9 while they remain operating."[90]

In its May 1st filing, ISO-NE stated that the loss of these units "presents unacceptable fuel security risks," compounded by the potential loss of the Distrigas Terminal once its largest customer was gone.[91] ISO-NE stated that its tariff allows it to retain retiring resources to resolve local transmission security issues but does not contemplate doing so for fuel security issues, and thus ISO-NE is seeking a waiver.[92] ISO-NE has asked for Commission action by July 2, 2018, because the deadline to decide whether to participate in the Forward Capacity Auction is July 6.[93]

b) PJM

PJM has submitted alternative proposed tariff revisions to address impacts of state public policies on the PJM capacity market.[94] PJM states that a state's selective subsidy of certain resources, while depending on the wholesale capacity market to meet its overall capacity needs, impacts other states that may not share the same policy perspectives, creates barriers to new competitive entry, and creates unjust and unreasonable rates for sellers that do not receive subsidies.[95]

PJM offers two (mutually exclusive proposals):[96]

- Option A: Accommodate state subsidies in a way that avoids impacts on wholesale prices by repricing a subsidized offer after it has cleared at its subsidized level, so that all offers that clear are paid a competitive price ("Capacity Repricing") or,

- Option B: Mitigate the impacts of state subsidies on wholesale prices by repricing subsidized offers through extension of the Minimum Offer Price Rule ("MOPR-Ex")[.]

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[89] *Exelon Generation Files to Retire Mystic Generating Station in 2022, Absent Any Regulatory Solution*, Exelon Corporation, http://www.exeloncorp.com/newsroom/exelon-generation-files-to-retire-mystic-generating-station-in-2022 (last visited June 6, 2018).

[90] *Id.*

[91] ISO-NE Request for Waiver at 3.

[92] *Id.* at 4.

[93] *Id.* at 6.

[94] PJM, Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market, *PJM Interconnection, LLC*, Docket No. ER18-1314-000 (April 9, 2018), eLibrary No. 20180409-5056.

[95] *Id.* at 4.

[96] *Id.* at 6.

Option A is PJM's preferred approach. PJM explains that "Capacity Repricing honors the state's legitimate policy choice to promote resources with certain attributes not otherwise valued in the current wholesale market rules; MOPR-Ex does not."[97] Under Option A, a resource receiving subsidies could clear in the first stage of the capacity auction and get a capacity commitment based on its unmitigated offer.[98] The subsidized offer would be repriced in the second stage. Capacity Repricing would replace the existing MOPR. Option B would reprice subsidized offers using an expanded version of the current MOPR.[99]

PJM cites the Commission's "first principles of capacity markets" identified in the CASPR order, stating that the performance of PJM's capacity market plainly "show these principles in action."[100] Commission action is pending.

Meanwhile, several owners of gas-fired generation have filed a complaint against PJM regarding market impacts of "below-cost offers for resources receiving out-of-market subsidies."[101] They allege that PJM's two pending proposals are inadequate and ask FERC to direct adoption of a so-called "Clean MOPR" that will apply to all subsidized resources with no categorical exemptions.

c) NYISO

The New York ISO ("NYISO") has issued a draft Carbon Pricing Straw Proposal to "harmonize" the state's decarbonization goals with wholesale market prices by incorporating a carbon price into the market.[102] The proposal follows extensive stakeholder meetings. The NYISO describes its concept:[103]

> The NYISO would apply a carbon price by debiting each energy supplier a carbon charge for its carbon emissions at the specified price as part of its settlement. Suppliers would embed these additional carbon charges in their energy offers (referred to as the supplier's carbon adder in $/MWh) and thus incorporate the carbon price into the commitment, dispatch, and price formation through the NYISO's existing processes.

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[97] *Id.* at 54.

[98] *Id.* at 51-52.

[99] *Id.* at 52-53.

[100] *Id.* at 8.

[101] CPV Power Holdings, LP, Complaint Seeking Fast Track Processing at 1, *CPV Power Holdings, L.P. v. PJM Interconnection, LLC*, Docket No. EL18-169-000 (May 31, 2018), eLibrary No. 20180531-5398.

[102] *Carbon Pricing Straw Proposal: A Report Prepared for the Integrating Public Policy Task Force*, NYISO (2018), http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg_ipptf/meeting_materials/2018-04-23/Carbon%20Pricing%20Straw%20Proposal%2020180430.pdf

[103] *Id.* at 4.

Imports would also be charged to avoid distortions. Whenever a carbon-emitting unit was the marginal unit, the energy clearing price would reflect the cost of the emissions (the carbon effect on locational based marginal pricing), and all suppliers would get the higher energy price, resulting in higher net revenues for low-emissions resources. Under this proposal, load would pay the full locational based marginal price, including the effect of the carbon charge, but would be allocated the carbon charge residuals collected from suppliers.[104]

Topics for further discussion include the interaction of any carbon pricing scheme with the CES order and with RGGI.[105] The NYISO and the New York Department of Public Service ("NYDPS") held a joint conference in September 2017 concerning the proposal (specifically concerning an analysis by the Brattle Group[106]).[107] The NYDPS has been accepting comments and alternate proposals.[108]

B. Energy Markets

While the impacts of the flood of renewables on centralized capacity markets have been much litigated, the effects on energy-only markets have not been extensively addressed at FERC, at least not yet. Certainly, the direct impacts are similar. As an example, California's energy market has faced lower energy prices, stagnant or declining load in many areas, steep evening ramps, shifts in the timing of peak hours, increased price volatility and retirements of fossil fuel-fired generation, primarily natural gas plants. It is worth noting that while many states have adopted one or two of the programs noted above, California has adopted almost all of them, which makes it difficult to assess the effects and cross-effects of any one approach.

California never adopted centralized capacity markets and so it provides a useful case study for looking at energy markets and an administrative resource adequacy construct. California ensures sufficient capacity through an administratively determined Resource Adequacy program where the CPUC, local regulatory authorities and the CAISO determine how much capacity is needed and load-serving entities make showings demonstrating that sufficient generating capacity is owned or contracted.

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[104] *Id.* at 9.

[105] *Issue Track 4: Interaction with Other State Policies and Programs*, NYISO (2018), http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg_ipptf/meeting_materials/2018-05-21/Carbon%20Pricing%20Interaction%20with%20State%20Programs_05_15_18.pdf.

[106] Samuel A. Newell, et al., *Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals*, The Brattle Group (2017), https://home.nyiso.com/wp-content/uploads/2017/10/2017-Brattle-NY-Carbon-Study.pdf.

[107] Notice of Conference, *In re Carbon Pricing in N.Y. Wholesale Markets,* No. 17-01821, (N.Y. Dep. of Pub. Serv. Sep. 6, 2017), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2D58F7E4-1541-4860-8FFE-3CADF0CB0004}.

[108] Notice on Process, Soliciting Proposals and Comments, and Announcing Technical Conference, *In re Carbon Pricing in N.Y. Wholesale Markets*, No. 17-01821, (N.Y. Dep. of Pub. Serv. Oct. 19, 2017), http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2135377E-AB41-485B-AE8A-EC1020DCFD38}.

However, if resources needed for reliability do not happen to be contracted bilaterally, and threaten to retire, the CAISO must make use of existing backstop provisions. After many of years of paring down the amount generation subject to reliability must-run (RMR) contracts in the CAISO system, CAISO last year designated three additional RMR units of gas-fired generation for a total of 852 MW, and more are expected to be designated this year. The increased use of plants under contract at cost-based rates is troubling.

Increased renewable penetration can also affect market rules. When ISOs and RTOs first began to form, most of them provided for "self-scheduling," a form of zero bidding where utilities can bid their owned generation into the market at as a price taker to ensure dispatch. RTOs typically cannot redispatch self-scheduled resources unless there are no other options. Self-scheduling ensures that generation owners can use the resources for which their ratepayers have paid, and has therefore been a scheduling option useful for public power, especially for generation units still under bond.

Problems began to arise with the increased penetration of wind and solar resources on the grid. Because wind resources in particular receive a production tax credit for each MWh they produce, owners of wind resources self-schedule their resources at the maximum capacity to ensure maximum revenue.

RTOs depend on economic bids to dispatch the grid efficiently, particularly to manage the steep ramps associated with intermittent renewables. Faced with larger quantities of non-dispatchable resources, RTOs and stakeholders propose carrots (rewards to induce economic bidding) and sticks (increased cost allocations to loads associated with self-scheduled resources) in an attempt to discourage self-scheduling. If enacted, such rules could shift costs among ratepayers in general and in particular for ratepayers of utilities attempting to self-schedule their own bonded generation to assure that it runs. Attempts to restrict or penalize self-scheduling are now recurring themes in CAISO stakeholder processes.

Carbon trading programs may be particularly well-suited to the energy markets. In California, CAISO bidders must include GHG adders for all energy delivered in the state. While this seems to be an obvious way to incorporate carbon costs into existing market structures, California and many other states have adopted both carbon trading and RPS, which can work at cross purposes in terms of market pricing. Also, things can get complicated in multi-state RTOs or regions, where differing approaches to carbon can greatly complicate dispatch.

RGGI, established in 2005, is an example of the incorporation of carbon costs into existing energy markets on a multi-state scale. The states participating in RGGI establish participation in regional CO_2 allowance auctions for covered resources. States put proceeds from the auctions into consumer benefit programs, such as energy efficiency. Generators include the value of the purchased allowances in their wholesale electricity offers.

C. Transmission Grid

State decarbonization policies have had a significant effect on the transmission system. The upgrades and additions to the transmission grid needed to facilitate these policies have often required significant transmission investments. These investments have been growing in recent years, driven by the expansion of the transmission system to integrate more renewables,[109] despite relatively low levels of electricity demand growth.[110] Areas well suited for utility scale renewable resources, particularly wind, are often located in remote areas far from load, and, as a result, new transmission lines are necessary to link these sites to load. Meaningful development of offshore wind could unleash another round of new construction.[111] An expanding grid and stagnant or declining loads result in higher transmission rates per customer.

Rising transmission rates have created problems in all the RTOs. In California, rapid escalation of the Transmission Access Charge ("TAC") has escalated adversarial involvement in PTO transmission rate cases, hampered CAISO efforts to regionalize the grid and generated complaints about transmission expenditures outside the CAISO planning process. Many RTOs have faced similar complaints, including regional disputes about the allocation costs for large transmission additions between RTOs to access wind-rich areas.

More innovatively, promoters of DERs have also sought to avoid have associated loads pay grid charges. CAISO is still in the midst of a stakeholder process to change the TAC initiated in part by advocates of DERs. The argument was that load-serving entities that invested in DERs should not have to pay the grid-wide TAC because they were not using the wider grid. Ratepayer representatives and load-serving entities expressed significant concerns about cost shifts. While CAISO has so far decided against making such a change, pressure continues at the state legislative and regulatory bodies to require it, notwithstanding obvious jurisdictional problems.

Other changes to the transmission system, as well as distribution systems, are needed to accommodate greater levels of DERs without negatively impacting reliability. As NERC has explained, although "[a]t low penetration levels, the effects of DER may not present a risk to [bulk power system] reliability . . . as penetrations increase, the effect of these resources can present certain reliability challenges that require attention."[112] Many of the challenges associated with greater DER integration stem from the lack of visibility of DERs to the transmission system. Traditionally DER generation has generally netted with demand when measured and modeled, obscuring the specific information pertaining to the distributed generation resources. For example, "CAISO has stated that it only becomes aware of the impact of rooftop solar when clouds block the sun and the demand previously served by rooftop solar suddenly disappears,"

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[109] Lori, Aniti, *Utilities Continue to Increase Spending on Transmission Infrastructure*, Energy Information Administration (February 9, 2018), https://www.eia.gov/todayinenergy/detail.php?id=34892.

[110] *Quadrennial Energy Review: Energy Transmission, Storage, and Distribution Infrastructure*, Department of Energy at 1-8 (2015), https://www.energy.gov/sites/prod/files/2015/07/f24/QER%20Full%20Report_TS%26D%20April%202015_0.pdf.

[111] *2016 Offshore Wind Technologies Market Report*, Department of Energy at 77 (2016), https://www.energy.gov/sites/prod/files/2017/08/f35/2016%20Offshore%20Wind%20Technologies%20Market%20Report.pdf.

[112] *Distributed Energy Resources: Connection Modeling and Reliability Considerations*, NERC at 4 (2017), https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf ("NERC DER Report").

creating modeling difficulties and the need for sudden ramping.[113] Accurate models and operating tools are also necessary for Automatic Under Frequency/Under Voltage Load Shedding Protection Schemes, and there have been "at least two major events . . . on the European power system where the disconnection of DERs played a role in system collapse."[114] Correcting these risks is likely to increase distribution system costs, with further disputes over which distribution customers should pay. In addition, most distribution systems were designed to deliver Central system resources to loads, and were never designed for two-way power flows. The costs of upgrading the distribution systems could be significant.

In order to avoid these risks as DER levels increase, it will become increasingly important to develop new processes to provide coordination between distribution and transmission entities and to give transmission system operators access to real-time data for DERs. DERs also offer an opportunity for positive impacts on the transmission system. Greater growth of DERs and energy efficiency could obviate the need for certain upgrades to transmission and distribution systems.[115] The North American Electric Reliability Corporation ("NERC") has noted that technological advances may allow DERs to transition from "do no harm" resources into resources that actively support reliability. [116] For instance, the aggregation of DERs can allow for the "'dispatch' [of] DER for system balancing, demand response, operating and contingency reserves, or to mitigate ramp rate concerns in the morning and evening."[117] NERC similarly notes that the capabilities of variable energy resources are rapidly evolving.

D. Distributed Resources and Interconnection Rules

As discussed above, the Commission has asserted jurisdiction over storage and energy efficiency resources on distribution systems and even behind the retail customer meters of FERC-jurisdictional utilities acting in RTO or ISO markets. It may eventually do the same for DERs. How far can FERC actually reach, and what role will be left for state and local regulators?

In Order 2006, FERC indicated that most generator interconnections to distribution facilities are likely state jurisdictional.[118] Some states have already taken steps to facilitate

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[113] FERC Staff Report at 14 (citing Aaron Larson, *How are Distributed Energy Resources Affecting Transmission System Operators?*, POWER Magazine (May 1, 2016), http://www.powermag.com/distributed-energy-resources-affecting-transmission-system-operators/?printmode=1).

[114] 2017 Long-Term Reliability Assessment, NERC at 35 (2017), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_12132017_Final.pdf.

[115] *Quadrennial Energy Review: Transforming the Nation's Electricity System: The Second Installment of the QER*, Department of Energy at 2-37 (2017), https://www.energy.gov/sites/prod/files/2017/02/f34/Quadrennial%20Energy%20Review--Second%20Installment%20%28Full%20Report%29.pdf.

[116] NERC DER Report at 4.

[117] *Id.* at 5.

[118] 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 on reh'g*, Order No. 2006-A, 70 Fed. Reg.

distributed resource interconnections. In California, the CPUC enacted Rule 21 that prescribes interconnection, operating, and metering rules for DERs, insofar as connected to jurisdictional utility distribution systems.[119] New York is implementing a new regulatory paradigm called Utility 2.0 that makes the retail distribution utility a platform to coordinate DER flows.[120] We do not yet know how far FERC will press on regulating DER access to RTO markets or how far it might seek to pre-empt state regulation, but it is actively exploring this issue.

First, while FERC has so far limited its new rulemaking proceedings on Storage and DER aggregation to RTO and ISO markets, utilities outside these markets should not assume that they are immune from FERC's activities. RTO footprints can shift (*e.g.*, until recently, there was consideration by the Mountain West states of joining Southwest Power Pool ("SPP"). And entities contemplating joining the CAISO Energy Imbalance Market ("EIM") in the West should pay attention to FERC's actions in these proceedings. The EIM may only be a real-time market, but it is still a wholesale market. If CAISO is successful in extending its Day Ahead Market into the EIM, it will be a more significant wholesale market. Given that FERC's assertion of jurisdiction over distribution-connected Storage Resources was premised, in part, on protecting organized wholesale markets, and that FERC's assertion of jurisdiction over interconnections to distribution facilities is based on the use of those facilities for wholesale transactions, how long before FERC considers extending these rules to distributed resources interconnected to, or behind the meters of, distribution utilities that are participating in the EIM? Utilities contemplating joining an RTO, ISO, or the EIM now have more to consider.

What about non-jurisdictional utilities? In theory, the Federal Power Act prevents FERC from regulating facilities used for generation or local distribution.[121] Moreover, Section 201(f)[122] exempts municipal utilities from most of FERC's rate regulation. However, the Commission can require otherwise non-jurisdictional utilities to provide transmission service under Sections 210, 211, 211a, and 212[123] of the Federal Power Act. Additionally, FERC has ordered non-jurisdictional utilities to provide reciprocal transmission service to any jurisdictional utility or RTO providing service to them.[124] However, this requirement would not apply unless the owner of the storage or DER was an RTO Transmission Owner or utility providing transmission service to the non-jurisdictional entity.

71,760 (Nov. 30, 2005), FERC Stats. & Regs. ¶ 31,196 (2005), *clarified*, 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).

[119] *Rule 21 Interconnection*, California Public Utility Commission, http://cpuc.ca.gov/General.aspx?id=3962 (last visited June 7, 2018).

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

[121] FPA § 201(b), 16 U.S.C. § 824(b). *FERC v. Elec. Power Supply Ass'n*, 136 S. Ct. 760, 775 (2016).

[122] 16 U.S.C. § 824(f).

[123] 16 U.S.C. §§ 824i-k.

[124] 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).

With regard to FERC-jurisdictional "public utilities," FERC applies a "bright line" test. Sales for resale are FERC-jurisdictional, regardless of voltage level.[125] However, because the FPA also states that FERC cannot regulate facilities used for local distribution, FERC has adopted a nuanced approach to when it will assert jurisdiction to order public utilities to interconnect with DERs: FERC asserts jurisdiction over DER interconnections to distribution facilities only if the facility was at that time included in the public utility Open Access Transmission Tariff ("OATT") and the service was for the purpose of facilitating a wholesale sale.[126] Accordingly, FERC's view is that it may not compel the first wholesale sale over purely distribution facilities, but once that line is crossed, it may order additional interconnections to the facilities in question. FERC affirmed this understanding in Rule 2006, where it stated that the small-generator interconnection rule "in no way affects rules adopted by the states for the interconnection of generators with state-jurisdictional facilities."[127]

E. Baseload Generation and Grid Resilience

State decarbonization efforts, as well as economic and technological developments, have prompted countervailing political efforts beyond the Trump Administration's proposals to repeal and replace the CPP. Most notable have been various federal efforts to prevent coal and nuclear resources from retiring in order to promote grid "resilience."[128]

In September of 2017, Secretary of Energy, Rick Perry, acting under section 403 of the Department of Energy Organization Act,[129] submitted proposed a rule for final action by

[125] Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,539, 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 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part 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).

[126] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 Fed. Reg. 49,846, 49,905 & 49,908 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146, PP 710, 730 (2003), *modified*, 68 Fed. Reg. 69,599 (Dec. 15, 2003), *clarified*, 69 Fed. Reg. 2135 (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 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 No. 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).

[127] Standardization of Small Generator Interconnection Agreements and Procedures, Order No. 2006-A, 70 Fed. Reg. 71,760, 71,771 (Nov. 30, 2005), FERC Stats. & Regs. ¶ 31,196, P 105 (2005), *clarified*, 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).

[128] As FERC recently explained, "there is currently no uniform definition of resilience used across the electric industry," although it is generally understood to be related, but separate, from the concept of reliability. *Grid Reliability & Resilience Pricing*, 162 FERC ¶ 61,012, P 22 (2018).

[129] 42 U.S.C. § 7173.

FERC.[130] This proposed rule would have allowed full cost recovery for "reliability and resiliency" resources, which must (1) be located in organized markets, (2) be able to provide essential energy and ancillary reliability services, and (3) have a 90-day supply of fuel on site.[131] In his letter to FERC, Secretary Perry wrote that such a rule was needed to "protect the American people from the threat of energy outages that could result from the loss of traditional baseload capacity."[132] According to Secretary Perry, markets have failed to adequately compensate coal and nuclear units for the resiliency benefits they provide, as a result, there have been significant losses of traditional baseload generation, to the detriment of reliability and resiliency.

FERC initiated a rulemaking proceeding on this proposal, and on January 8, 2018 it issued a unanimous order terminating that rulemaking.[133] FERC explained that FPA section 206 requires that before FERC can approve this rule, there must first be a showing that the existing RTO tariffs are unjust, unreasonable, unduly discriminatory or preferential; then, a proposal must be shown to be just, reasonable, and not unduly discriminatory or preferential.[134] FERC concluded that "the Proposed Rule did not satisfy those clear and fundamental legal requirements under section 206 of the FPA."[135] It explained that there had been no demonstration that the existing tariffs were unjust and unreasonable, and that "the extensive comments submitted by the RTOs/ISOs do not point to any past or planned generator retirements that may be a threat to grid resilience."[136] FERC also concluded that the proposed rule had not been demonstrated to be just, reasonable, and not unduly discriminatory, noting that "the Proposed Rule would allow all eligible resources to receive a cost-of-service rate regardless of need or cost to the system" and that the requirement that eligible resources have a 90-day on site fuel supply excluded other resources that may have resilience attributes.[137] Although it rejected DOE's proposed rule, FERC initiated a new proceeding to explore resilience issues and directed RTOs/ISOs to respond to a list of questions on (1) how the Commission should understand the term "resilience," (2) how RTOs/ISOs assess threats to resilience, and (3) how RTOs/ISOs mitigate threats to resilience.[138]

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[130] Secretary of Energy's Direction that the FERC Issue Grid Resiliency Rules Pursuant to the Secretary's Authority Under Section 403 of the Department of Energy Organization Act, *Grid Reliability & Resilience Pricing*, Docket No. RM18-1-000 (Sept. 28, 2017), eLibrary No. 20170929-5055.

[131] *Id.* at 7.

[132] *Id.* at 1.

[133] *Grid Reliability & Resilience Pricing*, 162 FERC ¶ 61,012 (2018).

[134] *Id.* P 14.

[135] *Id.*

[136] *Id.* P 15.

[137] *Id.* P 16.

[138] *Id.* PP 21-27.

A few months after FERC declined to adopt the DOE's proposed resilience rule, FirstEnergy Solutions Corp. ("FirstEnergy") requested that the DOE issue an emergency order under FPA section 202(c) to order PJM to enter into contracts providing full cost recovery for certain nuclear and coal-fired generators that have a 25-day fuel supply on site.[139] Section 202(c) allows for orders during times of war and emergencies that require "temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy [that] will best meet the emergency and serve the public interest."[140] Similar to the DOE's earlier proposed rule, FirstEnergy argued that there is an emergency in PJM due to PJM's failure to compensate nuclear and coal-fired generators for the full value of the benefits they provide. PJM, however, sent a response to the DOE opposing FirstEnergy's request and stating that there is no immediate threat to reliability in PJM.[141] The DOE has yet to act on FirstEnergy's request.

Most recently, there have been reports that President Trump has directed Secretary Perry to "prepare immediate steps" to stop the retirement of coal and nuclear plants.[142] A draft memo made public on June 1, 2018 laid out the case for preventing the retirement of "fuel-secure generation capacity" in order to "promote the national defense and maximize domestic energy suppl[y]."[143] In addition to relying on FPA section 202(c), the draft memo cites to section 101 of the Defense Production Act ("DPA") as a source of the DOE's authority to act. The DPA authorizes the President, or the Secretary of Energy acting by delegation from the President, to "require the allocation of, or the priority performance under contracts or orders (other than contracts of employment) relating to, materials, equipment, and services in order to maximize domestic energy supplies" under certain national security-related circumstances.[144] While rarely invoked, the Secretary of Energy issued an emergency order under the DPA during the California Energy Crisis that required natural gas sellers to perform and prioritize contracts to sell gas to PG&E for high priority use, such as for electric generation.[145] That emergency order, however, was only for a short duration.

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[139] FirstEnergy, Request for Emergency Order Pursuant to Federal Power Act Section 202(c) (2018), http://consideringthegrid.com/wp-content/uploads/2018/04/2018.03.29-First-Energy-202c-App.pdf.

[140] 18 U.S.C. § 824a(c)(1).

[141] PJM Interconnection, LLC, Response to FirstEnergy's Request for Emergency Order Pursuant to Federal Power Act Section 202(c) (2018), http://www.pjm.com/-/media/documents/other-fed-state/20180330-response-to-fe-solutions-request-for-emergency-relief.ashx.

[142] Gavin Bade, *Trump Orders Perry To Stop Coal, Nuclear Retirements*, Utility Dive (June 1, 2018), https://www.utilitydive.com/news/trump-orders-perry-to-stop-coal-nuclear-retirements/524805/.

[143] DOE, Draft Memo on Coal and Nuclear Subsidy Plan (2018), https://www.scribd.com/document/380740746/DOE-Coal-Nuke-Subsidy-Plan-1.

[144] 50 U.S.C. § 4511(c).

[145] *See Pac. Gas & Elec. Co.*, 94 FERC ¶ 61,048 (2001).

The outcome of these efforts—at least as of the time this paper was written—remains to be seen. Rehearing of FERC's order rejecting the DOE's proposed resilience rule is pending,[146] and the separate FERC proceeding on grid resilience remains open. Likewise, the Department of Energy has yet to act on either FirstEnergy's FPA section 202(c) request or President Trump's instructions. Federal action to support grid resilience by preventing the retirement of coal and nuclear resources could have major impacts on not only state decarbonization policies, but also the organized markets as a whole. While FERC can preempt state law that encroaches upon its own statutory mandate, it will have to accommodate any federal action that is not set aside by the courts. If such an order issues, there is little doubt that opponents will immediately go to court.

III. What Should a Public Power Utility Do?

Much depends on what your state is doing in these areas. Most states have not pushed ahead as far as California and New York, and if you are located in a state where policy is still evolving, you may be able to play a role in shaping it. One of the lessons from California and other early mover states is the need to focus on coordinated programs that work well together. Programs that undercut each other or abdicate state control of the process set the stage for trouble down the road and emergency legislation. For example, an aggressive RPS, requiring utilities to purchase large amounts of renewables, can undercut market prices in a carbon trading arrangement. A direct access or CCA program can undercut an RPS if utility load migrates to unregulated providers and utilities need to procure less generation. Even if your utility is not subject to state regulatory jurisdiction or state decarbonization policies, you have an interest in sensible state decarbonization policies and stable markets. The state legislative arena is also an appropriate place to advocate for policies that make it easier for your utility to comply or to seek help for stranded or transition costs.

Every utility should assess its own circumstances, including potential FERC requirements, the applicability of PURPA mandates,[147] state laws affecting interconnection obligations, local ordinances, or even local politics and customer interest that could require you to interconnect and provide service for at least a few projects. If there is likelihood of any such requests, the next step is for you to develop a strong set of interconnection procedures.

Having these procedures allows you to be ready to go when a request is received, and a well-written set of procedures allows your utility to obtain all the technical, financial, and legal information you need to process a request and to define your relationship with the interconnecting customer. Protecting the integrity of your system and your other customers must be a permanent concern. Many third-party DER and storage providers have taken the position at FERC that distribution systems can get all the information, safeguards, and ratepayer protection

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[146] Order Granting Rehearing for Further Consideration, *Grid Reliability & Resilience Pricing*, Docket Nos. AD 18-7-000, RM18-1-000 (Mar. 8, 2018), eLibrary No. 20180308-3056.

[147] The Public Utilities Regulatory Policies Act, or PURPA, imposes an obligation to interconnect with certain cogeneration and small renewable facilities. Although the details of this obligation are beyond the scope of this paper, this too is an area that may see future changes. FERC Chairman McIntyre announced at FERC's May 2018 open meeting that he has directed FERC staff "to re-energize" its review of what, if anything, the Commission should do to update its PURPA policies. Transcript of 1043rd Federal Energy Regulatory Commission Meeting, held May 17, 2018, at 7 https://www.ferc.gov/CalendarFiles/20180604094703-transcript.pdf.

they need through the generator interconnection procedures ("GIP") and pro-forma agreements. While FERC has not adopted that stringent a view, this emphasis by third-party providers demonstrates the clear need to make sure your GIP are in order.

Generator interconnection procedures are also the route to ensuring that there are contractual provisions in place to require these customers to be responsible for costs they cause, and to prevent cost shifting to your other customers. This is particularly important for those with legacy interconnection agreements with your transmission providers. If you are responsible for adverse impact studies and upgrade costs for power exiting your distribution system to the grid, you will wish to protect yourself and your other ratepayers from these costs.

Bear in mind that the FERC doctrine of comparability dictates that your utility must abide by the same rules you impose on third parties. You will have to live by any rules you adopt. Given that FERC is pressing hard on its asserted right to regulate third-party interconnections seeking to access the grid, following FERC requirements is vital, even for non-jurisdictional entities. If your procedures have not been updated lately, now is the time to do it.

Bear in mind that just because FERC asserts jurisdiction over something does not mean that it will necessarily wish to disrupt arrangements that are even-handed and involve sensible protections. Be specific about what technical, financial, metering, visibility and other requirements you need and why. FERC is less likely to have an appetite for upsetting sensible and even-handed procedures that look familiar to it because they track existing FERC policy.

Finally, listen to your customers. If they are interested in particular decarbonization strategies, your best defense may be to develop a strategy to provide those services yourself.