UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing | Docket No. RM18-1-000

COMMENTS OF THE NATIONAL RURAL ELECTRIC COOPERATIVE ASSOCIATION

The National Rural Electric Cooperative Association (NRECA) submits these comments on the Secretary of Energy's proposed Grid Resiliency Pricing Rule, published in the Federal Register on October 10, 2017 (Proposed Rule).[1]

NRECA is the national service organization for America's electric cooperatives. The nation's member-owned, not-for-profit electric cooperatives constitute a unique sector of the electric utility industry—and face a unique set of challenges. NRECA represents the interests of the nation's more than 900 rural electric utilities responsible for keeping the lights on for more than 42 million people across 47 states. Affordable electricity is the lifeblood of the American economy, and for 75 years electric cooperatives have been proud to keep the lights on. Because of their critical role in providing affordable, reliable, and universally accessible electric service, electric cooperatives are vital to the economic health of the communities they serve.

America's electric cooperatives serve 56 percent of the nation, 88 percent of all counties, and 12 percent of the nation's electric customers, while accounting for approximately 11 percent of all electric energy sold in the United States. NRECA's member cooperatives include 63 generation and transmission (G&T) cooperatives and

[1] Grid Resiliency Pricing Rule, 82 Fed. Reg. 46,940 (Oct. 10, 2017) (notice of proposed rulemaking).

834 distribution cooperatives. The G&Ts are owned by the distribution cooperatives they serve. The distribution cooperatives provide power directly to the end-of-the-line consumer-owners. Both distribution and G&T cooperatives share an obligation to serve their members by providing safe, reliable, and affordable electric service.

SUMMARY OF COMMENTS

NRECA is pleased that the Secretary of Energy has initiated this proceeding—and in doing so, begun an important conversation about the need to reform the nation's centralized wholesale electricity markets. We share his concern that current centralized markets do not fully realize their promise and need reforms if they are to ensure a reliable, resilient supply of affordable electricity in the years ahead.

Electric cooperatives support maintaining an "all of the above," diverse portfolio of power-supply resources to maintain affordable, reliable, and safe power for their consumer-members. Fuel diversity is key to affordable and reliable electricity and stable prices. To that end, cooperatives rely upon resource portfolios that may include coal, nuclear, natural gas, wind, solar, hydropower, and other types of generating resources. Thus, numerous cooperatives own or partially own operating coal-fired generation resources, and eight G&T cooperatives have ownership shares in eight of the nation's operating nuclear generating plants. These resources are located in RTOs and in non-RTO regions. Cooperatives engage in long-term resource planning to provide the power-supply reliability, resilience, risk-management, and environmental attributes their member-consumers want. Their resource portfolios thus support grid reliability and resilience by having, among other attributes, fuel diversity and on-site fuel assurance.

NRECA substantially agrees with the Proposed Rule's premise that the centralized wholesale markets in ISOs and RTOs may not be compensating generating resources for all the grid resilience and reliability services they are providing.

But NRECA does not support the Proposed Rule in its current form, for two reasons. First, the Proposed Rule is unduly discriminatory and preferential, because the only resources eligible for compensation are those "not subject to cost of service rate regulation by any state or local regulatory authority."[2] Consumers served by utilities with ineligible resources—including the consumer-members of some electric cooperatives—would bear a disproportionate share of the ISO or RTO's costs for grid reliability and resilience services. Compensation for grid reliability and resilience services should be based on the technical ability to provide the services, not on state or local regulatory status.

Second, immediate implementation of the Proposed Rule's cost-of-service compensation for these resources poses risks of unintended distortions to the centralized wholesale markets and increased costs to consumers. This problem is amplified by the Proposed Rule's short compliance deadlines, which do not allow enough time for the Commission and the industry to address these complex market-design and implementation issues.

NRECA recommends that instead of adopting the Proposed Rule (or modifications to it) as a final rule by December 11, 2017, the Commission should promptly initiate further proceedings in this docket focused on the issues raised by the Proposed Rule. These further proceedings should focus on three matters:

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[2] Proposed Rule, 18 C.F.R. § 35.28(g)(10)(i)(E).

- Defining the grid reliability and resilience services needed by a regional grid operator from the region's generation resources;
- Developing reasonable resource-eligibility criteria tied to the ability of the generation resources to provide these needed services; and
- Arriving at just and reasonable and not unduly discriminatory or preferential methods of providing appropriate compensation for providing reliability and resilience services.

NRECA recommends that the Commission initiate these further proceedings by issuing a notice of inquiry or advanced notice of proposed rulemaking, promptly holding a technical conference or workshop, and inviting public comments. Then the Commission will be in a position to determine necessary further actions.

If the Commission moves forward with a final rule at this time, however, the Commission should clarify and modify several aspects of the Proposed Rule:

- Eliminate the unduly discriminatory and preferential provision compensating resources for their grid reliability and resilience services only if they are "not subject to cost of service rate regulation by any state or local regulatory authority."
- Clarify the definition of "essential energy and ancillary reliability services" that eligible resources must provide.
- Clarify the basis for requiring a 90-day fuel supply or, preferably, adopt reasonable supply requirements for different fuels.
- Clarify the requirement that fuel be "on site" and allow alternative ways of meeting this requirement.
- Eliminate the requirement that eligible resources must be "compliant with all applicable federal, state, and local environmental laws, rules, and regulations" and instead simply clarify that the final rule does not override or affect environmental laws, rules, and regulations applicable to a resource.
- Require that each ISO or RTO allocate the costs of compensating eligible resources for grid reliability and reliance services on a cost-causation basis in accordance with established Commission policy.
- Provide the ISOs and RTOs with flexibility in devising compliance proposals.
- Because the Proposed Rule's compliance deadlines are far too short, adopt reasonable compliance deadlines for the RTOs and ISOs to enable them to receive stakeholder input on their compliance proposals.

COMMENTS ON PROPOSED RULE

I. Cooperatives own and operate diverse generation resource portfolios to ensure reliable and resilient power supply to their consumer-members.

Electric cooperatives rely on a broad portfolio of fuels, including clean and renewable resources, and energy-efficiency efforts to maintain affordable, reliable, and safe power. Cooperatives support modernizing our nation's energy policy in ways that keep costs affordable, promote system reliability and avoid imposing undue burdens. The flexibility to use all energy resources, including abundant regional resources and energy-efficiency technologies, is important to meet future demand.

Given their typically low customer densities, electric cooperatives face unique challenges in ensuring reliable, affordable, safe and sustainable power for the communities they serve. Cooperatives support an energy policy that provides flexibility to use the best resources to meet future electricity demand, while controlling costs and keeping member-owners' rates as low as possible.

Electric cooperatives are actively expanding their portfolios to include an array of renewable energy resources. Today, cooperatives in 43 states use hydro as a source of power. In addition to using roughly 10 gigawatts of federal hydropower, cooperatives have developed an additional 692 megawatts of hydropower, mostly small hydro and run-of-the-river systems.

Cooperatives have expanded their wind energy capacity and, in the process, have developed ways to integrate this intermittent resource into the grid. Cooperatives in 37 states use wind as a source of power. Wind development has surged in the last 10 years and is now second only to hydro in cooperatives' renewable portfolio.

Increasingly, cooperatives are bringing solar power to regions of the country once considered unsuitable for solar development. Because solar power is flexible and scalable, it can provide power in remote areas unconnected to the grid. Today, cooperatives in 43 states use solar as a source of power. Cooperatives lead the electric utility industry in the development of community solar, with 144 cooperatives in 30 states offering community solar programs.

Electric cooperatives support maintaining an "all of the above," diverse portfolio of power supply resources. Fuel diversity is key to affordable and reliable electricity and stable prices.

As part of this effort, 29 G&T cooperatives and 13 distribution cooperatives own or partially own operating natural gas-fired generating plants—including combined-cycle, combustion-turbine, and steam units—with a total nameplate capacity of about 31,000 megawatts (MW). These resources are physically located in several ISOs and RTOs—the PJM Interconnection (PJM), the Midcontinent Independent System Operator (MISO) (both South and North), the Southwest Power Pool (SPP), the Electric Reliability Council of Texas (ERCOT)—and in non-RTO regions.

In addition, 35 G&T cooperatives and three distribution cooperatives today are owners or partial owners of operating coal-fired generation resources, with a total nameplate capacity of about 26,000 MW. These resources include units physically located in PJM, MISO (North and South), SPP, ERCOT, and in non-RTO regions.

Electric cooperatives also are partial owners of operating nuclear generating resources and are actively planning to participate in future units as a source of emissions-free, baseload generation. Specifically, eight G&T cooperatives are partial owners of eight of the nation's operating nuclear generating plants. The total nameplate nuclear capacity owned by these cooperatives is about 2,953 MW.[3] These eight nuclear plants, in seven states, are physically located in PJM, MISO (North and South), SPP, and in non-RTO regions. One of these G&T cooperatives, Oglethorpe Power Corporation, is a participant in the two nuclear units now under construction at Plant Vogtle in Georgia.[4] NRECA supports the development of federal policies that will ensure existing nuclear generating plants will continue to provide clean, reliable, safe and affordable electricity, and allow for the appropriate expansion of and investment in the next generation of new nuclear power plants. Nuclear provides an emissions-free, reliable, baseload source of power for electric cooperatives, which is needed as more intermittent sources of power are added to the grid. Also, the nation's nuclear power plants have continued to operate with increasing availability and safety, substantially contributing to keeping fuel costs for the generation of electricity as low as possible.

The generating-resource portfolios of electric cooperatives support grid reliability and resilience by having, among other attributes, fuel diversity and fuel assurance. Cooperatives incorporate fuel diversity and security in their long-term resource planning to provide the reliability and resilience their member-consumers want.

NRECA has long advocated that consumers will fare better in competitive wholesale power markets where load-serving entities (LSEs)[5] such as cooperatives can first meet their power-supply requirements through voluntary measures such as resource ownership and long-term bilateral contracts—i.e., self-supply their resources—and then

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[3] https://www.cooperative.com/public/maps/PublishingImages/nuclear/FullSizeNuclearMap.jpg

[4] https://www.electric.coop/oglethorpe-electric-cooperatives-vogtle-nuclear-plant/

[5] LSEs have a contractual or other legal obligation to serve load, and they include G&T and distribution cooperatives. *See* 16 U.S.C. § 824q.

turn to the RTO-administered centralized capacity markets for residual needs.[6] By themselves, centralized forward capacity markets are inadequate substitutes for the multi-attribute, long-term resource planning practiced by cooperatives on behalf of their member-consumers.

NRECA is pleased that the Secretary of Energy has initiated this proceeding. We share his concern that current centralized wholesale electricity markets do not fully realize their promise and need reforms if they are to ensure a reliable, resilient supply of affordable electricity in the years ahead. NRECA substantially agrees with the Proposed Rule's premise that the centralized wholesale markets in ISOs and RTOs may not be compensating generating resources for all the grid resilience and reliability services they are providing. Nonetheless, NRECA has concerns with the Proposed Rule.

II. NRECA's concerns with the Proposed Rule.

A. The Proposed Rule is unduly discriminatory and preferential.

The Proposed Rule defines "eligible grid reliability and resiliency resources" to include only resources "not subject to cost-of-service rate regulation by any state or local regulatory authority."[7] Thus, eligible resources would include merchant generating resources used only for wholesale sales subject to federal regulation (or for retail sales at unregulated or market-based rates). Most merchant generating resources are located in states that have deregulated retail electric service by investor-owned utilities.

[6] *See* Post-Technical Conference Reply Comments of NRECA, Docket No. AD17-11-000 (July 14, 2017); Initial Comments of NRECA, Docket No. AD17-11-000 (June 22, 2017); Post-Technical Conference Comments of NRECA, Docket No. AD13-7-000 (Jan. 8, 2014); Post-Technical Conference Comments of NRECA, Docket Nos. ER11-2875-000 *et al.* (Aug. 29, 2011).

[7] Proposed Rule, 18 C.F.R. §35.28(g)(10)(i)(E).

On the other hand, the definition of "eligible grid reliability and resiliency resources" excludes most generation resources in the numerous states in ISO and RTO regions that have maintained traditional rate regulation of vertically integrated utilities. These states have few merchant generating resources.

The definition of "eligible grid reliability and resiliency resources" could be interpreted to exclude the generation resources of most if not all cooperatives. Electric cooperatives are private entities organized under and governed by state law. In some states, electric cooperatives are subject to cost-of-service rate regulation by the state public utility commission.[8] The resources of a cooperative subject to state regulation would appear to be ineligible under the language of the Proposed Rule.

In other states, the public utility commission has no rate-regulatory authority over cooperatives, and state law authorizes the cooperative's governing board to establish the cooperative's rates. In such circumstances, the Commission has recognized that the cooperative's governing board is the local regulatory authority. Thus, the Commission's regulations governing ancillary services provided by aggregators of demand-response resources in RTO and ISO markets require the RTO or ISO to accept such bids "unless not permitted by the laws or regulations of the relevant electric retail regulatory authority,"[9] which the Commission stated can be "the governing board of a cooperative utility."[10] If the Commission were to apply the Proposed Rule's exclusion in the same

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[8] *See Arkansas Elec. Coop. Corp. v. Ark. Public Serv. Comm'n*, 461 U.S. 375 (1983) (Federal Power Act does not preempt state regulation of wholesale rates of cooperative not subject to regulation under the Act).

[9] 18 C.F.R. § 35.28(g)(1)(i)(A) (2017).

[10] Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64100, 64119, P 158 ("The term 'relevant electric retail regulatory authority' means the entity that establishes the retail electric prices and any retail competition policies for customers, such as the city council for a municipal utility, the governing board of a cooperative utility, or the state public utility commission."), *order on reh'g*, Order No. 719-A, 74 Fed. Reg. 37776 (July 29, 2009).

way, and deem a cooperative's governing board to be a "local regulatory authority" establishing "cost of service" rates for sales by a cooperative's generation resources, then the Proposed Rule would appear to exclude those resources from the definition of eligible resources. But the Proposed Rule does not discuss this issue, and in the end, is ambiguous.

A few cooperatives, however, may be fairly described as having resources that are "not subject to cost-of-service rate regulation by any state or local regulatory authority." This category consists of G&T cooperatives that are public utilities subject to the Commission's wholesale rate regulation under sections 205 and 206 of the Federal Power Act.[11] Section 201(f) of the Act[12] excludes an electric cooperative (and any corporation it wholly owns) from most provisions of the Act, including sections 205 and 206, if the cooperative has financing under the Rural Electrification Act[13] or sells less than 4 million megawatt-hours of electricity per year. But a few G&T cooperatives do not fit either description. For these G&T cooperatives, the cooperative's governing board sets its wholesale rates (either by tariff or contract), but these rates are subject to regulation by the Commission under sections 205 and 206 of the Act. Thus, if a generation resource of a Commission-jurisdictional G&T cooperative is only used to make wholesale sales, it would appear to be a potentially eligible resource under the plain language of the Proposed Rule. But once again, the Proposed Rule does not discuss this issue.

In any event, however, this peculiar resource-eligibility requirement in the Proposed Rule is unduly discriminatory and preferential. It would make eligibility for

[11] 16 U.S.C. §§ 824d, 824e.

[12] 16 U.S.C. § 824(f).

[13] 7 U.S.C. § 901 et seq.

compensation turn on state and local regulatory status, not on whether a resource provides grid reliability or resilience services under the Proposed Rule. Consumers that receive service from utilities with generation resources that are ineligible for compensation from the ISO or RTO—potentially including the member-consumers of electric cooperatives—may end up paying a disproportionate amount of the ISO or RTO's costs for grid reliability and resilience services. These consumers would bear the generation costs of their utility's ineligible resources that provide these grid services *plus* a share of the ISO or RTO's costs of compensating eligible resources for providing these same services. The Proposed Rule would result in one class of the ISO or RTO's customers subsidizing service to the entire ISO or RTO grid. Nothing in the Proposed Rule prevents this unduly discriminatory result. In NRECA's view, eligibility for compensation for providing grid reliability and resilience service to an ISO or RTO should be based on the technical ability to provide the service, not on the regulatory status of the resource under state or local law.[14]

B. Immediate implementation of the Proposed Rule poses risks of unintended distortions to wholesale markets and increased costs to consumers.

The existing rules governing price formation in ISO and RTO energy, ancillary services, and centralized forward capacity markets are intertwined with one another. Designing mechanisms for compensating resources for providing grid reliability and resilience services may require careful review of how this compensation would interact

[14] The Proposed Rule's discriminatory compensation-eligibility requirement departs without explanation from the Commission's previous rejection—for both efficiency and practical reasons—of state and local regulatory treatment as a reason for adjusting the compensation of supply and demand resources in centralized wholesale energy markets. *See* Demand Response Compensation in Organized Wholesale Energy Markets, Order No. 745, 76 Fed. Reg. 16658, 16668, PP 62–63 (Mar. 24, 2011), *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *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).

with the ISO or RTO's existing design of its centralized wholesale markets. For example, ISO-New England's "pay for performance" rules and PJM's "Capacity Performance" rules involved simultaneous amendments to both capacity and energy market rules.[15]

Compensating resources for grid reliability and resilience services also requires consideration of previous and ongoing efforts by the ISOs and RTOs and their stakeholders to improve resource performance and resilience and, in the ISOs and RTOs that operate forward capacity markets, to accommodate state resource policies. A final rule requiring implementation of the Proposed Rule in its current form would disrupt efforts already underway in these RTOs to address many of the same issues.

Pricing and compensation reforms are complex to implement within existing markets. Doing so on a short timetable is risky and may produce unintended consequences and the need for corrective measures. The Proposed Rule's short deadlines—for issuing a final rule by December 11, 2017; for the effective date of a final rule 30 days after its publication; for compliance filings by the RTOs and ISOs 15 days later; and for the effective dates for any tariff changes 15 days after that[16]—simply do not allow enough time for the Commission and the industry to address these complex market-design and implementation issues. A hurriedly adopted and implemented final rule could cause undue damage to these centralized wholesale markets.

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[15] *See PJM Interconnection, L.L.C.* 151 FERC ¶ 61,208 (2015), *order on reh'g*, 155 FERC ¶ 61,157 (2016), *aff'd sub nom. Advanced Energy Mgt. Alliance v. FERC*, 860 F.2d 656 (D.C. Cir. 2017); *ISO New England, Inc.*, 147 FERC ¶ 61,172 (2014), *reh'g denied*, 153 FERC ¶ 61,223 (2015), *pet. for review pending sub nom. New England Power Generators Ass'n v. FERC*, No. 16-1023 *et al.* (filed Jan. 19, 2016).

[16] Proposed Rule, 82 Fed. Reg. at 46945, 46946.

III. The Commission should promptly open an inquiry into compensation of generation resources for grid reliability and resilience services in ISO and RTO markets.

NRECA recommends that instead of adopting the Proposed Rule (or modifications to it) as a final rule by December 11, 2017, the Commission should promptly initiate further proceedings in this docket focused on the important grid reliability and resilience issues raised by the Proposed Rule.

These further proceedings would provide time to address the questions about the Proposed Rule and its implementation posed by the Commission staff in the October 4 notice in this docket. In NRECA's view, these proceedings should focus on three important, overriding issues:

- Defining the grid reliability and resilience services needed by a regional grid operator from the region's generation resources;
- Developing reasonable resource-eligibility criteria tied to the ability of the generation resources to provide these needed services; and
- Arriving at just and reasonable, and not unduly discriminatory or preferential, methods of providing appropriate compensation for providing these grid services.

This compensation mechanism should be designed so that it does not undermine the region's existing wholesale markets and so that the costs for these services are fairly allocated on a cost-causation basis.[17]

The Commission should allow each RTO, with its stakeholders, to determine the compensation mechanism to be used, rather than imposing a uniform compensation

[17] These proceedings should be focused on the discrete issues raised by the Proposed Rule, not broader market issues well beyond its scope, such as whether to implement a centralized forward capacity market where they do not now exist.

mechanism. Without limiting the universe of possible solutions, several possible mechanisms would appear to be available to provide such compensation:

- First, the ISO or RTO could enter into bilateral contracts with specific eligible resources (analogous to reliability-must-run contracts).
- Second, the ISO or RTO could establish a separate product category for grid reliability or resilience service from eligible resources (analogous to the reactive power ancillary service).
- Third, the ISO or RTO could develop a separate product for a separate capacity auction or use a two-stage auction to identify needed eligible grid reliability and resiliency resources.

Under any of these schemes, however, LSEs such as cooperatives should be allowed to self-supply grid reliability or resilience resources and receive compensation or credit against grid costs allocated to them.

Procedurally, NRECA recommends that the Commission initiate these further proceedings in this docket by issuing a notice of inquiry or advanced notice of proposed rulemaking and promptly hold a technical conference or workshop. After receiving public comments, the Commission will be in a position to determine what further action is warranted, including a formal rulemaking. The further proceedings in this docket can move in parallel with the pending Commission price-formation rulemakings addressing ISO and RTO energy and ancillary services markets.[18]

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[18] *See* Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. RM17-3-000, 81 Fed. Reg. 96391 (Dec. 30, 2016) (notice of proposed rulemaking); Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators, Docket No. RM17-2-000, 82 Fed. Reg. 9539 (Feb. 7, 2017) (notice of proposed rulemaking).

IV. If the Commission adopts a final rule in this proceeding, it should modify and clarify the Proposed Rule in several respects.

If the Commission moves forward with a final rule at this time, however, the Commission should clarify and modify several aspects of the Proposed Rule.

A. The final rule should eliminate the unduly discriminatory resource-eligibility requirement tied to state or local regulation.

For the reasons described earlier, the final rule should eliminate the unduly discriminatory requirement in proposed 18 C.F.R. § 35.28(g)(10)(i)(E) that limits eligible resources to those "not subject to cost of service rate regulation by any state or local regulatory authority." Eligibility for compensation should be based on the ability of a resource to provide grid reliability and resilience services, not its state or local regulatory status.

B. The final rule should clarify the definition of "essential energy and ancillary reliability services" that eligible resources must be able to provide.

Under the Proposed Rule, "eligible grid reliability and resiliency resources" must be "able to provide essential energy and ancillary reliability services, including but not limited to voltage support, frequency services, operating reserves, and reactive power." But the Proposed Rule does not define the term "essential energy and ancillary reliability services," and this term has no standard meaning in the industry. The Proposed Rule's open-ended list of ancillary services does not provide a clear definition. The Proposed Rule also does not define the term "resiliency," which again has no standard meaning in the industry. These key terms must be defined in any final rule.

C. The final rule should clarify the Proposed Rule's on-site fuel-supply requirements for eligible resources.

The Proposed Rule requires that an eligible resource have "a 90-day fuel supply on site, enabling it to operate during an emergency, extreme weather conditions, or a natural or man-made disaster." The final rule should clarify this resilience requirement.

The Proposed Rule does not explain the basis for the 90-day requirement. NRECA understands that most coal units do not carry that much coal today. Indeed, some coal units cannot hold that much coal under their permitting requirements. Without some technical analysis, and some weighing of the costs and benefits of this particular threshold, a 90-day fuel-supply requirement is an unreasonable cost for consumers to bear. Moreover, there is no reason to assume that the same duration is appropriate for all fuels. A sliding-scale fuel-security or fuel-availability requirement for different fuels or generation types may be reasonable.

The final rule also should clarify the additional requirement that this fuel supply be "on site" and should allow alternative ways of meeting this requirement. The requirement's purpose is "enabling [the resource] to operate during an emergency, extreme weather conditions, or a natural or man-made disaster." A resource may be able to operate in these conditions without the fuel being physically on site before the event occurs, so long as there is a secure path to fuel delivery on site. Thus, there may be cost-effective but secure alternatives to storing fuel on-site, or partial substitutes to having on-site fuel, such as having dual-fuel capability; having alternative fuel suppliers (e.g., more than one supplying pipeline); having nearby fuel storage (mine-mouth coal or nearby underground gas storage) accompanied by firm transportation to the generating resource.

The final rule should clarify the on-site requirement and provide reasonable flexibility to meet this requirement.

D. The final rule should eliminate the Proposed Rule's requirement that eligible resources be "compliant with all applicable federal, state, and local environmental laws, rules, and regulations."

The Proposed Rule requires that an eligible resource must be "compliant with all applicable federal, state, and local environmental laws, rules, and regulations." The Proposed Rule does not explain the basis for this requirement. The purpose of the requirement appears to be to clarify that deeming a resource to be eligible for compensation under the Proposed Rule would not override the need to comply with applicable environmental laws.

That is a useful clarification, but it does not belong in a list of eligibility requirements. Making environmental compliance an eligibility requirement could be interpreted as a zero-tolerance environmental-compliance standard. It also could be interpreted to authorize the Commission to impose civil penalties under the Federal Power Act[19] for such non-compliance, which is beyond FERC's authority.

The final rule should remove this language from the resource-eligibility requirements and instead replace it with a standard savings clause stating that the eligibility for compensation does not override or affect any environmental laws, rules, and regulations applicable to a resource.

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[19] *See* 16 U.S.C. § § 825*o*, 825*o*-1.

E. The final rule should require the costs of compensating resources for grid reliability and resilience services to be allocated on a cost-causation basis.

The Proposed Rule does not address how the compensation costs are to be allocated and recovered by the RTOs and ISOs. The final rule should require that the ISO or RTO allocate these compensation costs on a cost-causation basis in accordance with established Commission policy.

F. The final rule should provide flexibility for regional compliance.

For the reasons already discussed, the final rule should provide ISOs and RTOs with flexibility in developing compliance proposals in conjunction with their stakeholders.

G. The compliance deadlines in the Proposed Rule are unworkable; the final rule should adopt reasonable deadlines.

The final rule should adopt reasonable compliance deadlines for the RTOs and ISOs to enable them to receive stakeholder input on their compliance proposals. The Proposed Rule directs the Commission to make any final rule effective 30 days after it is published in the Federal Register.[20] The Proposed Rule also proposes that ISO and RTO compliance filings be due 15 days later, and that any tariff changes take effect 15 days after the compliance filings are due.[21]

These latter two compliance periods are simply unworkable. As noted, ISO and RTO market rules are extraordinarily complex and interrelated. Tariff changes usually take months, not weeks, to develop, and allowing stakeholder review and input is an

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[20] Proposed Rule, 82 Fed. Reg. at 46945.

[21] *Id.* at 46946.

important part of the process.[22] Because the Proposed Rule's compliance deadlines are far too short, the final rule should adopt reasonable compliance deadlines for the RTOs and ISOs to enable them to receive stakeholder input on their compliance proposals.

CONCLUSION

The Commission should initiate further proceedings as outlined above. If the Commission issues a final rule in this proceeding, it should modify and clarify the Proposed Rule as described above.

Respectfully submitted,

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[22] The final rules in Commission rulemakings governing ISOs and RTOs have allowed them much longer times to file their compliance filings, recognizing the complexity of the task and the need to work with their stakeholders. *See, e.g.*, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 Fed. Reg. 49842, 49957, P 792 (Aug. 11, 2011) (12 months for regional transmission planning and cost allocation); Credit Reforms in Organized Wholesale Electric Markets, Order No. 741, 75 Fed. Reg. 65942, 65946, P 32 (Oct. 27, 2010) (8 months); Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. at 64163, PP 578–79 (six months).