June 19, 2018

Chairman Fred Upton
Subcommittee on Energy
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, DC 20515

VIA ELECTRONIC DELIVERY

Dear Subcommittee Chairman Upton,

It was a pleasure to testify before the Energy Subcommittee on Thursday, May 10, 2018, at the hearing entitled "Examining the State of Electric Transmission Infrastructure: Investment, Planning, Construction and Alternatives"

In response to your request dated June 5, 2018, for additional information for the record, I respectfully submit the attached response to the questions posed by you and other members of the Committee.

Thank you for your continued interest in the electric markets and the work the subcommittee is undertaking in the Powering America series. The electric sector is undergoing a period of significant change and Congressional oversight is appropriate at this time.

Sincerely,

John Twitty

Attachment: "TAPS Response to House E and C QFR"

Responses to Additional Questions for the Record

The Honorable Fred Upton

1. In 2012, the Commission issued a policy statement encouraging transmission developers seeking rate incentives to participate in joint ownership arrangements (JOAs). FERC found that such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks. From your perspective have transmission developers been willing to partner with your utilities [as encouraged by] FERC's policy statement in 2012?

Response:

Although the Commission's 2012 Incentive Policy Statement correctly recognized the benefits of joint ownership arrangements and sought to encourage them, this encouragement has proven insufficient to induce large transmission owners and other developers to enable small embedded load-serving entities to invest in their share of the grid. As a result, the answer to your question is generally no—developers have generally been unwilling to partner with transmission-dependent load-serving entities. Incumbent utilities have been even less willing to do so.

GridLiance, a non-incumbent transmission developer focused on partnering with public power entities and cooperatives,[1] is a limited exception to that general statement. However, although a number of Transmission Access Policy Study Group ("TAPS") members have engaged with GridLiance in proposing projects, there has been little tangible progress. In part that has been due to the failings of the Order 1000 planning process, as currently implemented. FERC Staff's own analysis shows that in 2016, no proposals submitted by nonincumbent transmission developers were selected by any of the transmission planning regions that had competitive proposal windows[2]—a strong indication that the Commission's effort to foster more efficient and cost-effective transmission development through competition is significantly flawed.

2. Your testimony suggested that FERC must do more to make sure that grid planning encompasses all entities that use the grid for delivery of electric energy to consumers. What suggestions would you have for Congress to encourage FERC to assure that planning is more inclusive?

Response:

Congress should exercise oversight authority to inform FERC that this is a priority for the Committee, and urge FERC to do more to encourage joint ownership arrangements. There is much that FERC can do to achieve this important objective.

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[1] http://www.gridliance.com/.

[2] FERC, *2017 Transmission Metrics Staff Report* at 4 (2017), available at https://www.ferc.gov/legal/staff-reports/2017/transmission-investment-metrics.pdf.

For example, FERC can use its authority under Section 219 of the Federal Power Act ("FPA"), which provides for incentive-based transmission rates, to more directly link incentives to willingness to enter into joint ownership arrangements. Specifically, those seeking transmission rate incentives, particularly incentive equity returns, should not be permitted to turn away load-serving entities in the footprint seeking to make their load-ratio investment in the grid. Instead, a showing that the applicant has offered such investment opportunities on reasonable terms should be a prerequisite for incentives. Similarly, Congress could urge FERC to also explore using its other authority to encourage joint transmission ownership. For example, the willingness to offer load-serving entities in the footprint an opportunity to make their load-ratio investment in the grid on reasonable terms could be a consideration when evaluating whether a proposed merger is in the public interest.

In addition, FERC's Order 1000 transmission planning process can be a more effective vehicle for fostering inclusive transmission investments. As described in my May 10, 2018 written testimony at pages 5-6, Order 1000 also recognized the value of and encouraged joint ownership arrangements, but more can be done to achieve that objective. Non-incumbent transmission developers, especially those (like GridLiance) that accommodate participation by small load-serving entities, should have a fair opportunity to compete to develop needed new transmission. Indeed, a developer's inclusiveness of small load-serving entities would merit positive consideration in the selection process. Unfortunately, despite Order 1000's efforts to promote a competitive transmission development process and vigorous competition for those projects that have been open to competition, positive results have been limited, as FERC's own analysis confirms (as noted above). As discussed on pages 13-14 of my written testimony, Congress should encourage the Commission to revisit and reinvigorate the Order 1000 competitive transmission development process in a manner that will promote joint transmission ownership, as well as use competitive discipline to curb rising transmission costs.

FERC's exercise of the full range of its FPA authority to promote joint ownership, as urged above, would fulfill Congress' directive in FPA Section 217 by enabling load-serving entities to directly participate in ensuring that their reasonable needs are satisfied, and would allow them to offset the increasing cost of transmission, benefiting consumers and businesses.

3. In the ***Powering America*** hearing series, the Committee has heard concerns that the RTOs may not be functioning as originally intended. Your members have assets and serve customers in virtually all of the RTOs. Can you tell me the biggest problems your members face in the RTOs and what can be done to better address the concerns?

Response:

As you correctly note, TAPS members serve customers in virtually all the RTOs. In fact, even though they are relatively small, a number of TAPS members have loads and diverse resources in multiple RTOs due to the RTO-membership decisions of large transmission owners. Large transmission owner changes in their RTO membership can significantly impact the ability of our members to continue to use their long-term resources to serve their loads. As discussed in my written testimony at pages 10-11, such changes can create an RTO seam that disrupts the long-term power supply arrangements of embedded load-serving entities that have loads and/or resources on the larger transmission owners, significantly increasing the costs and risks to which the smaller utility and its customers are exposed. Nevertheless, FERC generally offers little or no protection to such embedded utilities when such RTO membership changes occur. Indeed, rather than fulfill its FPA Section 217 obligations to preserve and honor the load-serving entity's long-term rights to firm delivery of its capacity resources to it load, the Commission has accepted new RTO resource adequacy requirements that aggravate the adverse impacts.

Capacity markets are a significant concern to TAPS members. TAPS members in the eastern RTO face mandatory capacity "markets," which are administrative constructs that include features that undermine the members' traditional, obligation-to-serve business model. For example, the ISO New England and PJM tariffs include minimum offer pricing rules ("MOPRs"). TAPS members in those regions undertake long-term power supply commitments to fulfill their load-serving resource adequacy obligations. Under the MOPRs, however, they may have to purchase capacity a second time if the minimum offer price imputed by the RTO to those long-term capacity resources causes them not to clear in the capacity "market." Continuously changing rules and performance requirements also can disqualify their long-term resources from being counted for resource adequacy. Such restrictions undermine the ability of public power entities to make the long-term power supply commitments that Congress sought to protect through FPA Section 217, and which have a proven track record of supporting reliability, adequacy, and resilience. Nevertheless, in a recent decision, a divided FERC indicated receptivity to expanding MOPRs.[3]

So far, FERC has rejected efforts by Midcontinent Independent System Operator ("MISO") and certain generators to import aspects of the mandatory eastern market capacity constructs into the MISO region, in which more than 90% of the load is subject to traditional state cost-of-service regulation. However, various generators continue to press for such changes in order to increase prices. Costs to consumers are also threatened by the Commission's refusal to apply FPA Section 217's directives to ensure delivery of the capacity associated with load-serving entity's power supply arrangements, as I explain at pages 9-10 of my written testimony.

As my comments above highlight, minimizing cost to American consumers and businesses, who rely on electricity for economic and social well-being, is not the central focus of RTOs. Indeed, nearly a decade ago, FERC declined to mandate specific statements in RTO mission statements requiring RTOs to provide cost reductions and net benefits to the ultimate consumers they serve, and rejected other proposals to make RTOs more accountable.[4] Particularly given the recent GAO findings that FERC lacks the data to assess RTO performance,[5] Congress should exercise oversight to ensure that the FPA's overarching consumer protection mandate is not forgotten.[6]

[3] *ISO New England, Inc.*, 162 FERC ¶ 61,205 (2018), *reh'g pending*.

[4] *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719-A, 74 Fed. Reg. 37,776, 37,799, 37,801 (July 29, 2009), FERC Stats. & Regs. ¶ 31,292, PP 178-180, 193, *reh'g on other points*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[5] *Electricity Markets: Four Regions Use Capacity Markets to Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their Performance*, U.S. General Accounting Office (Dec. 7, 2017), https://www.gao.gov/products/GAO-18-131?utm_medium=email&utm_source=govdelivery.

[6] *See, e.g., FERC v. EPSA*, 136 S. Ct. 760, 781-82 (2016) (finding FERC has statutory duty to hold down prices and the FPA "aims to protect 'against excessive prices'"); *Atl. Ref. Co. v. Pub. Serv. Comm'n of N.Y.*, 360 U.S. 378, 388

The Honorable H. Morgan Griffith

1. You stated in your testimony that the Joint Ownership transmission model has many benefits. What are some of the benefits over our current model and what steps can we do to increase joint ownership opportunities for transmission?

Response:

The joint ownership model provides numerous benefits. They include the following:

1. *Inclusive joint ownership makes joint planning real*. Although FERC has issued rules to promote open, inclusive, and transparent planning they have fallen short of accomplishing the goals. There is a big practical difference in how planning is accomplished when all load-serving entities are at the table as owners. Aligning the ownership structure of the grid with the reality of the way the network operates results in better planning. When diverse parties are owners, openness, transparency, and more balanced decision making flow automatically. The end result is more efficient grid investment and a more robust and resilient grid.

2. *Inclusive joint ownership results in a better and more efficient transmission system planned to meet multiple needs*. This has been the experience of TAPS members in Wisconsin, where combining five systems into one jointly owned transco (the American Transmission Company or "ATC") has certainly led to a more rationally developed system than had balkanized planning and construction.[7] We also see it in CapX2020, a joint initiative of 11 transmission-owning utilities in Minnesota, North Dakota, South Dakota, and Wisconsin formed to upgrade and expand the electric transmission grid to ensure continued reliable and affordable service. The 800 mile, nearly $2 billion investment includes four 345-kilovolt transmission lines and a 230-kilovolt line. It is the largest development of new transmission in the upper Midwest in 40 years.[8]

3. *The diverse support that joint ownership provides is very important in siting*. By meeting the needs of multiple utilities, a joint project is able to demonstrate multiple benefits. Although participation by municipals and cooperatives may be relatively small percentage-wise, these utilities bring a wealth of political support to the state approval process. This support can make all the difference in speeding up permitting and addressing local concerns. FERC explicitly recognized this benefit in its 2012 Incentive Policy Statement.

4. *Inclusive joint ownership arrangements provide the critical alignment of interests that makes it easier for state regulators to approve proposed transmission projects*. When state commissions are presented with projects that are least-cost because they meet multiple needs, when they see unity among the utilities on need, and when they are faced with a broad base

(1959) (requiring natural gas be sold "at the lowest possible reasonable rate consistent with the maintenance of adequate service in the public interest").

[7] https://www.atcllc.com/.

[8] http://www.capx2020.com/.

of support from diverse stakeholders, it is far easier for them to grant requested authorizations.

5. *Inclusive joint ownership makes the cost allocation issue easier to resolve, although it still remains a thorny issue*. For instance, while ATC's transmission rates have been increasing because of ATC's construction efforts, municipal and cooperative owners, through their ownership in ATC, have been able to offset about 20% of those costs. This has made it easier for them to support needed ATC build-out. Similarly, investor-owned utilities that are able to participate in projects have an earnings opportunity, rather than simply an opportunity to pay.

6. *Inclusive joint ownership spreads the risk of major projects broadly and provides a variety of sources of capital for projects*. In a post-financial crisis world of tightened credit and tougher credit-worthiness standards, the financial diversity and strength achieved through joint ownership arrangements should be increasingly valuable. FERC explicitly recognized this advantage of joint transmission ownership as a risk reducing in its 2012 Incentive Policy Statement.

7. *The broad base of support achieved through joint ownership arrangements can be essential to securing state legislative action required to better align retail rate recovery with the need for supporting major transmission investment*, as has occurred in Minnesota with the full support of the CapX group.

8. *Inclusive joint ownership arrangements reduce the need for FERC to referee rate and other disputes*.

9. *Inclusive joint ownership arrangements benefit consumers.* The benefits listed above work together to produce transmission better designed to meet all needs, and that can be sited and built more quickly. As a result, inclusive joint ownership arrangements benefit consumers and reduce costs.

As to what steps that can be taken to increase joint ownership, step one would be to exercise oversight authority to inform FERC that this is a priority for the Committee, and urge FERC to do more to encourage joint ownership arrangements. There is much that FERC can do to achieve this important objective. Please see my response to the second question from Chairman Upton.

2. How will we know when we've achieved a cost-effective, appropriate level of resilience?

    a. Do you think we have the data in place to measure resilience currently?

<u>Response</u>:

In comments filed with FERC in its ongoing Grid Resilience proceeding,[9] TAPS urged against a one-size-fits-all approach to identifying and addressing resilience challenges. Each region faces different resilience challenges, based on its particular resource and load mix, location, scope, market design, the retail regulatory systems of the states in its footprint, and regional differences in the pace and direction of the changes transforming the electric industry. Establishing priorities and metrics—a crucial first step toward any resilience program—will also require local knowledge and assessment of the costs and benefits of potential actions to improve resilience. The key question as to the level of resilience to be achieved can best be answered by balancing the interests of multiple stakeholder groups, with particular attention to state and local regulators, consistent with FPA Section 217(b)(4)'s directive to the Commission to facilitate planning for the reasonable needs of load-serving entities. TAPS urged FERC to allow RTO stakeholder processes time to build consensus on these complex issues.

As noted, the crucial question is: "what is resilient enough?" "Resilience" should not become a license for RTOs to gold-plate the system by taking unilateral actions that unduly drive up the costs to consumers, including transmission costs—an outcome fundamentally inconsistent with FPA Section 217(b)(4)'s directive to the Commission to facilitate planning for the *reasonable* needs of load-serving entities. It is always possible to build more redundancy into the grid or require ever higher levels of reserves, spare equipment, and personnel standing by. Therefore, to make "resilience" a useful and meaningful concept for evaluating and planning the grid, we have to decide: What are the scenarios that we want the system to be able to withstand? What are the specific restoration targets that we want to achieve? And at what cost?

The North American Electric Reliability Corporation's ("NERC") definition[10] of "Adequate Level of Reliability"[11] is instructive: it distinguishes (at 1) between predetermined Disturbances ("the more probable Disturbances to which the power system is planned, designed, and operated") and "low probability Disturbances," and recognizes that it may be appropriate to treat them differently. NERC states (at 4) that

> [Bulk Electric System ("BES")] owners and operators may not be able to apply any economically justifiable or practical measures to prevent or mitigate [the] Adverse Reliability Impact on the BES [of low probability Disturbances], despite the fact that these events can result in Cascading, uncontrolled separation or voltage collapse. For this reason, these events generally fall outside of the design and operating criteria for BES owners and operators.

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[9] *See* Comments of Transmission Access Policy Study Group, Docket No. AD18-7-000 (May 9, 2018), available at https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14913057.

[10] N. Am. Elec. Reliability Corp., Informational Filing on the Definition of "Adequate Level of Reliability," Docket No. RR06-1-000 (May 10, 2013), available at https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=13257018.

[11] A criterion for being certified by FERC as the Electric Reliability Organization is "the ability to develop and enforce . . . reliability standards that provide for an adequate level of reliability of the bulk-power system." FPA § 215(c)(1), 16 U.S.C. § 824*o*(c)(1).

NERC's "Adequate Level of Reliability" definition thus recognizes (as Congress implicitly did by including the word "adequate" in the statute) that a requirement of "zero blackouts" is neither economically justifiable nor practically feasible.

Decisions about the degree of resilience and regional priorities necessarily entail judgments as to the risks and costs that consumers should bear. There must also be a requirement that the benefits of resilience measures outweigh their costs. Implementing this standard will not be easy: assessing the risks and benefits associated with mitigating high impact/low frequency events is difficult, particularly where investments may rapidly become obsolete as the electric industry continues to rapidly evolve. Moreover, they will have ramifications for matters outside the Commission's jurisdiction (e.g., retail service reliability and local distribution facilities); and the strategies available to achieve resilience may well require close collaboration with distribution utilities and relevant electric retail regulatory authorities. For these reasons, TAPS urged that determinations as to resilience priorities and measures should be addressed on a regional basis through the stakeholder process, with appropriate deference to state and local regulators. Moreover, the decision-making process to undertake resilience measures must be transparent, and the measures must be just, reasonable, not unduly discriminatory, cost-effective, and subject to FERC approval.

The Honorable Richard Hudson

On April 19, FERC issued a new rule (Order No. 845) concerning revisions to the interconnection process for large generators which are over 20 MWs. The intent of this rule is to reduce the backlog of interconnection queue requests, however, these new regulations put the onus on the transmission provider to develop new procedures to accommodate additional flexibility for interconnecting generators. The interconnection process is already quite complicated with several studies often required to determine the impact of the new generation on the transmission grid with various deadlines for each specific step in the process. This was manageable when there were only a handful of interconnection requests in a year. However, these queues have grown more recently due to the significant increase in the number of smaller-sized interconnection requests for wind and solar generation. Developers typically put in several requests at one time, knowing that many of them will not get built. In some cases, there is more proposed generation in the queue than the total customer load in a particular area.

1. Do you believe that this new interconnection rule will alleviate these backlogs?

2. How would modifications made by interconnection customers affect the interconnection studies of later-queued requests?

Response:

TAPS recognizes the challenges associated with the interconnection queue and backlogs. TAPS filed comments in the rulemaking proceeding leading up to Order 845 that generally supported the proposed reforms, which were drawn from lessons learned in RTO areas and reasonably balance the needs of interconnection customers with the needs of load and transmission providers.[12] While TAPS is hopeful that the reforms will be helpful, we are unable to assess the specific impacts about which the questions inquire.

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[12] Comments of Transmission Access Policy Study Group, Docket No. RM17-8-000 (Apr. 13, 2017), available at https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=14558960.