UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through	**)**	**Docket No. RM21-17-000**
Electric Regional Transmission	**)**	
Planning and Cost Allocation and	**)**	
Generator Interconnection	**)**	

INITIAL COMMENTS OF PJM INTERCONNECTION, L.L.C.

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On behalf of PJM Interconnection, L.L.C.

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INITIAL COMMENTS OF PJM INTERCONNECTION, L.L.C.

PJM Interconnection, L.L.C. ("PJM")[1] hereby submits the following initial comments ("Comments") in response to the Advance Notice of Proposed Rulemaking ("ANOPR") issued by the Federal Energy Regulatory ("Commission") on July 15, 2021 in the above-captioned docket.[2] PJM appreciates the opportunity to comment on the vast number of issues and questions raised in the ANOPR.

I. EXECUTIVE SUMMARY

These Comments identify the "Guiding Principles" that PJM believes should govern the Commission's and stakeholders' consideration of appropriate planning reforms included in any future rule in this docket. These Guiding Principles address the following four areas:

- ***Accommodating the Nation's Move Toward a More Decarbonized Future***: Planning processes should ensure a reliable and resilient transmission grid that incorporates and enables effective implementation of policy choices made by local, state and federal governments, as well as the desires of customers, for reduced carbon electricity. Accommodating states' goals by implementing policy choices while ensuring just, reasonable and nondiscriminatory outcomes need not be an "either/or" choice. By carefully crafting policy choices that do not favor one resource type over another, both goals can be achieved consistent with applicable law.

[1] PJM is an independent regional transmission organization ("RTO") that coordinates the movement of wholesale electricity for systems that serve approximately 65 million customers in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM's more than 1,040 members/customers include power generators, transmission owners, electricity distributors, power marketers and large consumers. PJM operates one of the world's largest centrally dispatched grid. PJM dispatches approximately 185,000 megawatts ("MW") of generating capacity over more than 85,000 miles of transmission lines.

[2] *Advance Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (July 15, 2021) ("ANOPR").

- ***Grid Resilience***: Resilience is far too important an issue to be excluded from any forward-looking holistic approach to proactively plan for transmission needs of the electricity grid of the future. To that end, PJM believes it is imperative for the Commission to put in place a common working definition of resilience, as well as resilience-based industry planning drivers to ensure the grid is prepared to withstand or quickly recover from events that pose operational risks, including but not limited to, climate change and extreme weather events, as well as threats of physical and cyberattacks.

- ***Protecting Consumers***: PJM's currently-effective rules create a balance in that interconnecting generators pay their "but for" costs to interconnect to the existing transmission system, while load thereafter bears the costs of ensuring continued deliverability of those generators once interconnected. Other pricing policy models can and should be considered, but any change to the Order No. 2003[3] pricing policy should account for a reasonable allocation of risk and reward to ensure that the change in policy choice does not result in an unreasonable shift of costs or risks to load.

- ***Equitable Treatment Between RTO/Independent System Operator ("ISO") and Non-RTO/ISO Regions***: Changes to the energy mix and customer demands are not limited to RTO/ISO regions. The Commission should ensure that its proposed reforms are implemented in a manner that does not create disincentives for transmission owner participation in RTOs/ISOs. Additionally, PJM identifies herein those areas where the roll out and implementation of any planning reforms should be consistent across the nation, and those areas where reforms would be more appropriately addressed by the respective regions.

With these Guiding Principles in mind, PJM organizes these Comments as follows:

- ***Addressing Key Facts that May Affect the Commission's Proposed Rule***: In Section III below, PJM addresses a number of key facts that the Commission should bear in mind as it begins to evaluate evolving conditions and consider whether changes in regional transmission planning, cost allocation and generator interconnection processes are warranted. Specifically, PJM seeks to correct or clarify the record on the following topics:

    - At least in the PJM Region, the overwhelming majority of new resources, including renewable resources, are not locating far from load centers;[4]

    - The concern that regional planning, interconnection and cost allocation processes may be inappropriately "siloed" from one another is both overly broad and inaccurate with respect to PJM's planning and generator interconnection processes. All Regional Transmission Expansion Plan ("RTEP") projects, whether they are initially driven by reliability, market efficiency or state public policy requirements, are analyzed, integrated and incorporated into a single annual RTEP. Projects are

[3] *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007) (collectively referred to as "Order No. 2003").

[4] *See* Section III.A, *infra*.

separately identified, however, based on their cost allocation, which differs based on the original driver for the project;[5]

- Contrary to the assumption set forth in the ANOPR, load cannot and should not be characterized as a "free rider" under a participant funding pricing policy;[6] and

- In deciding whether to require that transmission be built to accommodate future generators not yet in the interconnection queue, the Commission should be cognizant of the high level of generation that has entered PJM's interconnection queue over the years but has never moved forward to commercial operation.[7]

- ***PJM's Proposed Recommendations for Reform***: In these Comments, PJM sets forth a number of specific recommendations to be considered by both stakeholders and the Commission as this process moves forward to any future Notice of Proposed Rulemaking ("NOPR" or "Proposed Rule").[8] PJM has further divided its recommendations as between: (i) recommendations that are appropriate for inclusion in a national rule; (ii) recommendations that PJM will be undertaking with its stakeholders as potential initiatives to enhance its existing planning processes; (iii) areas where the Commission should avoid a national rule and instead defer to individual regions; and (iv) areas where PJM believes reforms are not necessary. PJM's proposed reforms can be summarized as follows:

    - ***Enhanced Tools are Needed to Ensure Reliability as the Grid Transitions to Increased Reliance on Renewable Resources***: PJM explains how any Proposed Rule should account for challenges associated with the increased penetration of renewable resources to ensure that the current level of system reliability is maintained or enhanced in order to preserve resource adequacy and system stability.[9] Any requirements or standards adopted to address the changing resource mix should apply on a nationwide basis.

    - ***Resilience***: PJM urges the Commission to adopt a common definition of resilience applicable to the industry, as well as a specific Commission-directed resilience planning driver of transmission upgrades applicable to all planning regions.[10]

    - ***Planning for Future Generation***: PJM outlines its recommendations for the development of enhanced long-term planning processes, which includes development

[5] *See* Section III.B, *infra*.

[6] *See* Section III.C, *infra*.

[7] *See* Section III.D, *infra*.

[8] PJM includes in Appendix A to these Comments proposed revisions to Attachment K of the *pro forma* Open Access Transmission Tariff ("OATT"). PJM's proposed revisions memorializes these proposed reforms specific to procedures and mechanisms providing for a Commission-directed resilience driver and common definition of that term, as detailed in Section IV.B, and revisions proposing procedures and mechanisms for incorporating long-term scenario planning, as detailed in Section IV.C.

[9] *See* Section IV.A, *infra*.

[10] *See* Section IV.B, *infra*.

of a 15-year forward "master plan" that includes surveying and documenting customer-identified needs, and consideration of probabilistic planning. PJM requests specific Commission guidance on those decision-making parameters that would drive the planning authority to direct the construction of new transmission consistent with those documented needs.[11]

- ***Ongoing Interconnection Queue Management Reforms***: PJM urges the Commission to make clear that the ANOPR is not intended to interfere with RTOs/ISOs moving forward on interconnection queue process reforms that would improve the management of their respective interconnection queues. Specifically, PJM recommends that the Commission allow ongoing regional interconnection process reforms to continue, and that the Commission address any resulting proposals on a region-specific basis;[12]

- ***Interconnection Pricing Policies and Cost Allocation***: PJM believes that if the Commission finds that a departure from the interconnection pricing policies set forth in Order No. 2003 is warranted, the fundamentals of the cost allocation should be addressed on a nationwide basis. PJM provides the Commission with six potential alternative interconnection cost responsibility options (the "Six Options")[13] that could substitute for the present "cost causer pays" rule of Order No. 2003. PJM developed these options in consultation with stakeholders through the PJM Interconnection Policy Workshops[14] and are presented, not as a PJM endorsement of any particular cost allocation principle, but as alternative options for the Commission's consideration;[15]

- ***Interregional Coordination versus Interregional Planning***: PJM explains why a move from "interregional coordination" to "interregional planning," despite its facial appeal, would not work given the disparate market models between regions;[16] and

- ***Independent Transmission Monitor***: PJM believes that if the Commission were to require an Independent Transmission Monitor, it would be far more appropriate to begin this initiative in areas where there is no structural independence as between the transmission planner and its generation affiliates. Additionally, PJM suggests that, rather than simply layering another level of independent oversight onto an already Commission-approved independent RTO/ISO, the oversight function over costs of transmission and the prudence of those investments not reviewed through the RTEP

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[11] *See* Section IV.C, *infra*.

[12] *See* Section IV.D.1, *infra*.

[13] https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210722-workshop-3/20210722-item-03-interconnection-policy-reforms-overview-presentation.ashx.

[14] *See* n. 22, *infra*.

[15] *See* Section IV.D.2, *infra*.

[16] *See* Section V.C, *infra*.

> process are best addressed by improving customers' ability to make their voices heard through the Commission's regulatory process.[17]

In addition to the above detailing of facts and specific recommendations, PJM also endeavors to answer a number of the Commission's questions raised in the ANOPR concerning the transmission planning process. For instance, PJM responds to the Commission's questions about grid-enhancing technologies[18] and probabilistic transmission planning approaches.[19]

The transmission planning process has continued to evolve since its inception in PJM. PJM is committed to continuous improvement to that process. As a result, PJM urges that this proceeding serve as a policy foundation to support reforms PJM is already undertaking with its states and stakeholders, while at the same time challenging the entire industry to ensure that effective transmission planning continues to meet the needs of customers.

Finally, it is important that the industry acknowledge the cost, time, local and environmental impacts and obstacles to siting new greenfield transmission in one state, and the even greater challenges of siting greenfield transmission across multiple states, each capable of delaying or halting decade-long siting processes. Optimizing existing transmission facilities and corridors will be equally essential to a quick, low-cost transition to clean energy. Thus, a thoughtful and surgical approach to planning a grid that will accommodate future needs will be the most cost effective and efficient solution to decarbonize the grid and meet both state and federal policies.

II. INTRODUCTION

PJM supports changes to transmission planning, cost allocation and interconnection processes where changes are necessary and are consistent with customer-identified needs. PJM believes, however, that it is critical that the Commission find the "sweet spot" between those issues

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[17] *See* Section V.D, *infra*.

[18] *See* Section V.A, *infra*.

[19] *See* Section V.B, *infra*.

that require a degree of standardization and consistency across both RTO/ISO and non-RTO/ISO regions through the development of a national rule versus those issues that are best left to individual regions.

Thus, any proposals contained in a future Proposed Rule should not undermine or slow regional planning activities that are currently underway in PJM and other regions aimed at proposing reforms to current interconnection processes. For example, since April 2021, PJM has been working with stakeholders through its Interconnection Process Reform Task Force ("IPRTF")[20] to address reforms to the interconnection study process and cost concerns in an effort to reduce current and future interconnection queue backlogs. The IPRTF is targeting the end of 2021 to complete its activities, with the intent of filing comprehensive tariff revisions with the Commission in the first quarter of 2022. Delaying that initiative would seriously impede PJM's ability to improve the efficiencies of its interconnection study process.[21]

In addition to the IPRTF, PJM has spent a great deal of time discussing and debating the issues in this ANOPR with its stakeholders. In this regard, before the ANOPR was even announced, PJM commenced a policy forum to discuss with stakeholders policy issues associated with planning, interconnection and cost allocation ("Interconnection Policy Workshop").[22] The Interconnection

[20] The IPRTF has focused on several key areas for discussion and potential reform that include: (i) opportunities to increase certainty for cost responsibility; (ii) reducing the overall time projects are in the interconnection queue by focusing on improvements to the study phases; (iii) exploring options on how to obtain interim service prior to completion of interconnection studies; (iv) investigating options to improve the drafting and execution of service agreements; and (v) investigating requirements for admission into the New Services Queue and requirements to proceed through subsequent study phases including modifications to New Service Requests. *See* https://pjm.com/-/media/committees-groups/task-forces/iprtf/postings/iprtf-problem-statement.ashx.

[21] In these Comments, PJM proposes a way to segment this issue so as to allow interconnection process improvements to move forward while the Commission considers whether or not to depart from the Order No. 2003 "cost causer pays" paradigm for network upgrades. *See* Section IV.D, *infra*.

[22] PJM's Interconnection Policy Workshop series commenced on May 18, 2021. The series aims to promote communication and dialogue among stakeholders on policy issues national in scope as well as policy issues that directly affect how PJM administers its interconnection queue today or how it might administer its RTEP process and queue in the future. The workshop format includes an educational component as well as panel discussions and stakeholder dialogue. To date, PJM has convened six sessions. The next session is scheduled for November 2, 2021.

Policy Workshop, which was launched with opening remarks from Chairman Glick,[23] was designed to complement, but not impede, the specific interconnection reforms underway through the IPRTF. In these Comments, PJM provides for the Commission's benefit some of the cost allocation alternatives to today's "cost causer pays" paradigm that were discussed among stakeholders in that workshop.[24]

On the other hand, should the Commission issue a NOPR in this docket, it is imperative that certain topics covered in this ANOPR (and as identified by PJM below) have equal application and corresponding obligations throughout the country (including in RTO/ISO and non-RTO/ISO regions). Those topics include issues, by way of example, that require coordination across regions so as to avoid some of the inconsistent roll-out and levels of compliance that accompanied implementation of Order No. 1000.[25]

That said, PJM offers the following key points the Commission should consider in striking the right balance between those issues that deserve standardization and consistency across both RTO/ISO and non-RTO/ISO regions through the development of a national rule versus those issues that are best left to individual regions:

- Existing regional process reforms, such as management of interconnection queues, should be encouraged, and supplemented, but not derailed as the result of a Final Rule. Specifically, reforms to the processing of queue requests can and should go forward through individual RTO/ISO filings while the Commission, through a nationally-applicable Final Rule, addresses potential alternatives to the strict "cost causer pays" rule of Order No. 2003. In short, the Commission can appropriately "slice" the interconnection issues so as to allow

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[23] May 18, 2021 Interconnection Policy Workshop – Session 1. *See* Session 1 Agenda, https://pjm.com/-/media/committees-groups/committees/pc/2021/20210518-workshop/20210518-agenda.ashx.

[24] *See* IV.D, *infra*.

[25] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (collectively referred to as Order No. 1000). This is not to imply that specific regional variations could not be accommodated. That said, the Commission should guard against imposing a rule that places new responsibilities on RTO/ISO regions and far less on non-RTO/ISO regions.

specific processing issues to continue to move forward on an RTO/ISO-specific basis while potentially considering alternative cost allocation processes via a national rulemaking;[26]

- Any Final Rule should help to define and establish a nationally-applicable transmission driver by which public utility transmission providers (referred to herein as "transmission providers") can address the need to enhance the resiliency of the grid. As the nation faces more extreme weather conditions, this is the time for the Commission to provide all transmission planners with clear authority and direction to address regional and subregional resilience issues, while still respecting the fact that specific asset management decisions remain the province of the asset owners consistent with Commission precedent;[27]

- Any Final Rule designed to expand the definition of project "benefits" should provide clear decision criteria on whether and when it is appropriate for all transmission planners to actually order construction of new transmission, through the competitive process or otherwise, for anticipated future generation not yet in the interconnection queue. Absent clear and nationally consistent direction from the Commission, the planning process would simply devolve into endless arguments of scenarios with no clear process to allow transmission planners, working with states and stakeholders, to actually land on one or more planning solutions in order to move forward; and

- Any Final Rule should impose consistent obligations on both RTO/ISO and non-RTO/ISO regions and ensure consistent implementation across the nation, particularly for those topics that require coordination across regions. The inconsistent rollout of Order No. 1000 compliance across RTO/ISO and non-RTO/ISO regions has done little to provide the industry with confidence in the durability of that Order. The Commission should avoid repeating that situation. Most importantly, the Commission should not create disincentives for participation by transmission owners in RTO/ISOs by requiring a host of compliance rules and obligations on those regions without a corresponding and equal obligation on non-RTO/ISO regions.

III. FACTS THAT MAY AFFECT THE COMMISSION'S PROPOSED RULE

The ANOPR seeks comments regarding whether transmission providers in each planning region should amend their respective regional transmission planning, generator interconnection, and cost allocation processes to plan for transmission needs of anticipated future generation to meet a changing resource mix, including generation that is not yet in the interconnection queue. As described below, there are several basic facts underlying the Commission's discussion in the

[26] *See* Section IV.D, *infra*.

[27] *See, e.g.*, *Southern Cal. Edison Co., et al.,* 164 FERC ¶ 61,160 (2018), *order on reh'g*, 168 FERC ¶ 61,170 (2019); *Cal. Pub. Util. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 (2018), *order on reh'g*, 168 FERC ¶ 61,171 (2019); *Appalachian Power Co.*, 170 FERC ¶ 61,196, *order on reh'g*, 173 FERC ¶ 61,157 (2020); *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242 (2020), *order on reh'g*, 176 FERC ¶ 61,053 (2021).

ANOPR that PJM wishes to clarify. PJM believes it is important that the Commission have an accurate factual record as it begins to evaluate evolving conditions and consider whether there should be changes in the regional transmission planning, cost allocation and generator interconnection processes.

A. In the PJM Region, Existing and Planned Resources – Including Renewable Resources – Are Located Close to Load Centers

In the ANOPR, the Commission cites to the rapidly changing generation mix "from largely centralized resources located close to population centers towards renewable resources located far from customers,"[28] which the Commission infers may necessitate new transmission infrastructure to meet the needs of the changing resource mix. As PJM demonstrates below, however, this is one of those scenarios where "not all regions are created equal." In considering any reforms, it is important that the Commission recognize the unique characteristics of each transmission planning region, and accord each region the flexibility needed to tailor processes to accommodate such regional differences rather than requiring wholesale changes to such processes.

In short, given the relative proximity of existing and planned renewable generation resources (at least in the PJM Region as illustrated below), the Commission should avoid assuming that new long transmission lines are necessarily the best nationwide solution for each RTO/ISO and non-RTO/ISO region, and avoid crafting regional and interregional planning policies based on this assumption. The majority of current in-service generation and queued, future generation projects in PJM (most of which are renewable resources) are geographically located 100 miles or less from load centers. By way of illustration, PJM includes the following data.

Table 1 and the accompanying map show that of the 691 renewable generation projects currently in-service, 613 generation projects (88.7%) are geographically located 100 miles or less

[28] ANOPR at P 160.

from load centers, 74 generation projects (10.7%) are geographically located between 101 miles to 200 miles from load centers, and only four generation projects (0.6%) are geographically located more than 200 miles from a load center.

TABLE 1: Current In-Service Generation (Geographical Distance)

In-Service Generating Facilities

Distance From Load Center	Count					MW				
	Renewable	Fossil	Nuclear	Other	**Total**	Renewable	Fossil	Nuclear	Other	**Total**
0 - 100 miles	236	270	17	90	**613**	20,242	124,617	30,838	1,007	**176,704**
101 - 200 miles	47	20	1	6	**74**	7,014	11,778	1,819	59	**20,670**
201 - 300 miles	1	3	0	0	**4**	250	1,846	0	0	**2,096**

Renewable: Solar, Wind, Hydro | **Fossil:** Natural Gas, Coal, Oil | **Other:** Biomass, Landfill, Battery, Flywheel

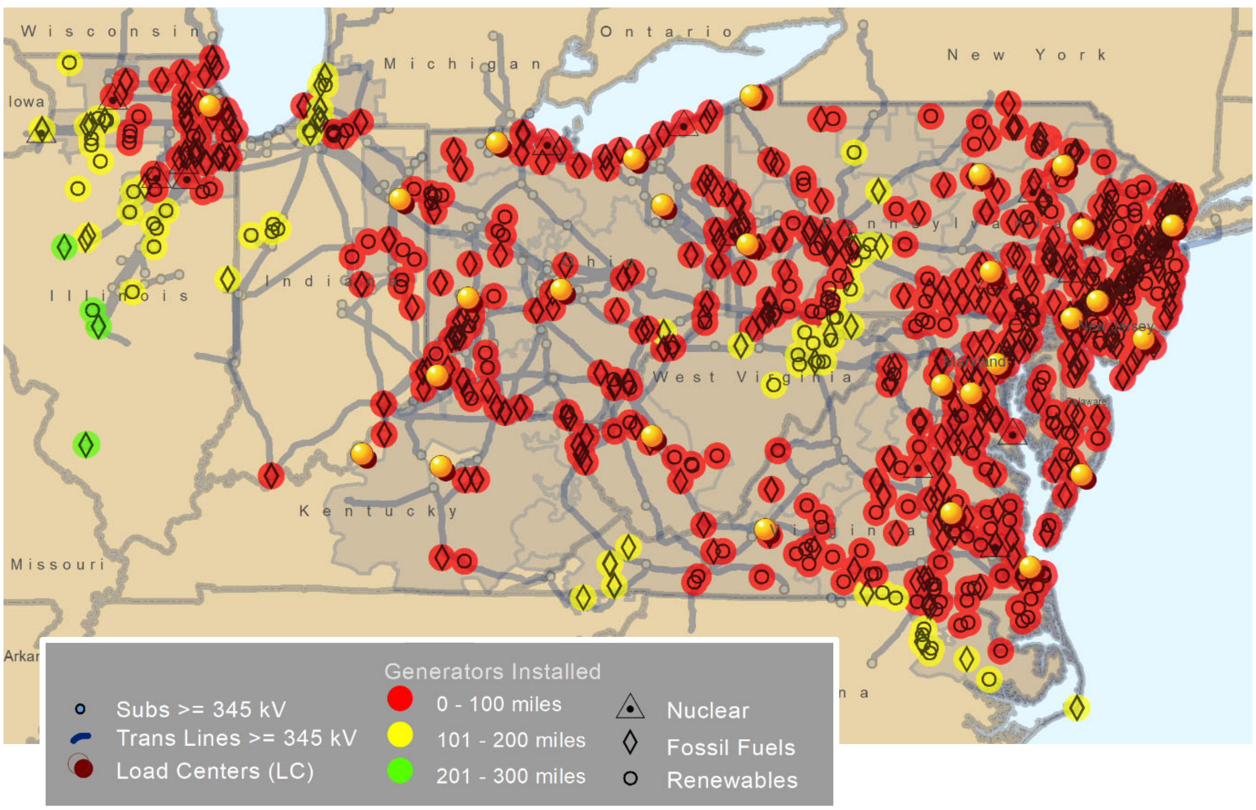


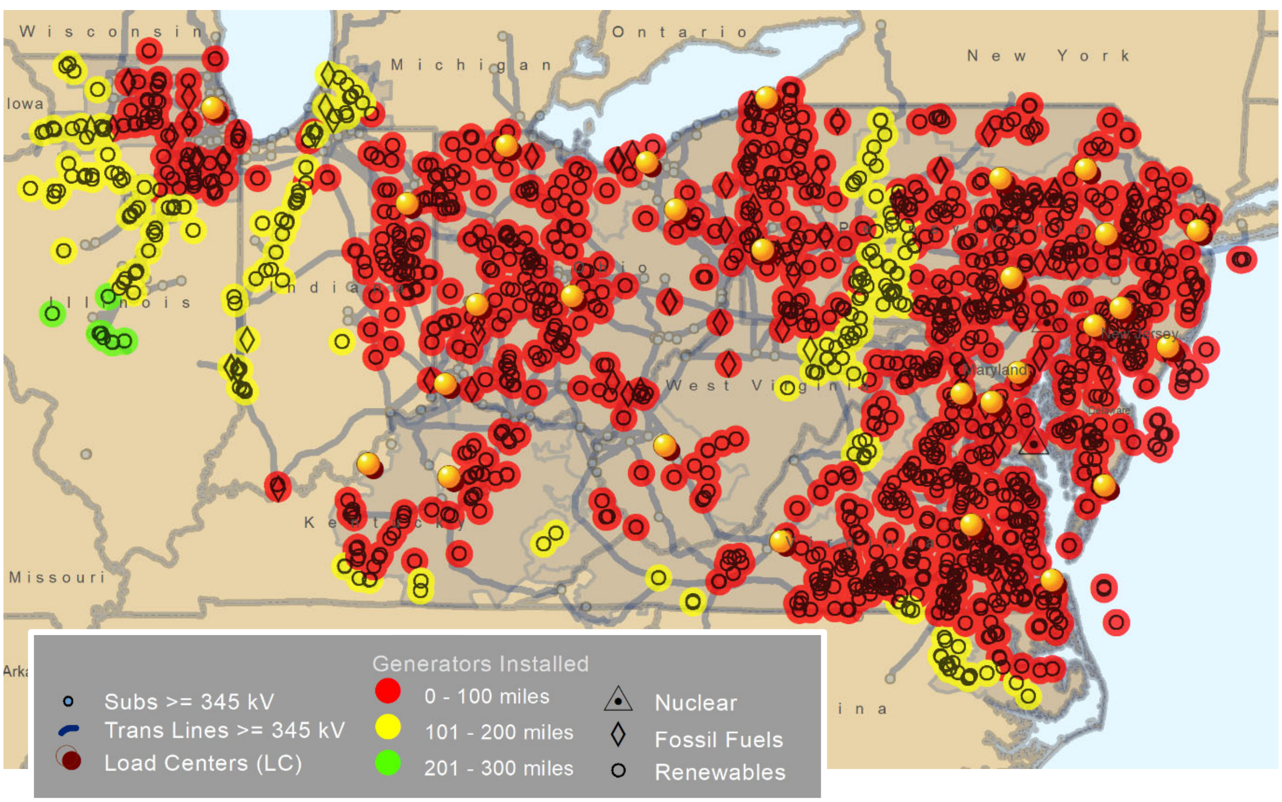
Table 2 and its accompanying map shows that of the 1,826 planned generation projects currently in the PJM interconnection queue, 1,560 planned generation (85.4%) projects are located geographically 100 miles or less from load centers, 254 planned generation projects (13.9%) are

geographically located between 101 miles to 200 miles from load centers, and only 12 planned generation projects (0.7%) are geographically located more than 200 miles from a load center. Thus, future interconnection queue generation will remain close to load centers in PJM, with only a marginal reduction in relative proximity.

TABLE 2: Future Interconnection Queue Projects (Geographical Distance)

Distance From Load Center	Future Projects: Count					Future Projects: MW				
	Renewable	Fossil	Nuclear	Other	**Total**	Renewable	Fossil	Nuclear	Other	**Total**
0 - 100 miles	1,212	98	6	244	**1,560**	108,435	17,552	190	19,055	**145,232**
101 - 200 miles	200	13	0	41	**254**	27,784	4,588	0	3,365	**35,737**
201 - 300 miles	8	0	0	4	**12**	1,008	0	0	186	**1,194**

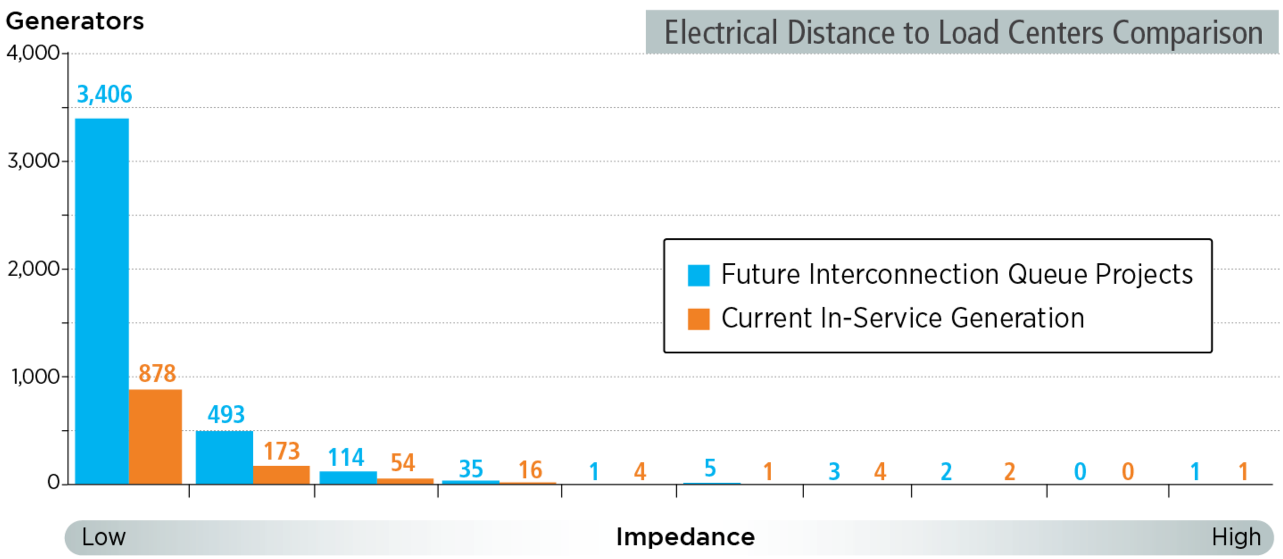
Renewable: Solar, Wind, Hydro | **Fossil:** Natural Gas, Coal, Oil | **Other:** Biomass, Landfill, Battery, Flywheel



The data shown above demonstrates PJM's unique regional structure. In PJM, geographically favorable locations for renewables are under 100 miles from its densely-populated and highly-networked major metropolitan areas, unlike other areas of the country – *e.g.,* Midcontinent Independent System Operator, Inc. ("MISO"), Southwest Power Pool ("SPP"), California Independent System Operator ("CAISO"), and Electric Reliability Council of Texas ("ERCOT") – where distances can exceed 100 miles.

PJM also performed an analysis to determine the electrical distance of generation to load centers. In order to perform this analysis, PJM utilized its Electrical Distance Test[29] to calculate the Thevenin equivalent impedance between current in-service generators and load centers and future interconnection queue projects and load centers. A summary of those results is presented in **Table 3** below.

Table 3: Electrical Distance Comparison



The Electrical Distance Test demonstrates that future interconnection queue projects (blue bars) are not more distant from load centers as compared to current in-service generators (orange

[29] PJM's Electrical Distance Test is one of the Commission-approved eligibility requirements that an external resource must satisfy in order to become a Pseudo-Tie within the PJM Region. This test is performed as follows: "Each external resource requesting to Pseudo-Tie into PJM will be evaluated by calculating the electrical distance, which is the equivalent Thevenin impedance from the highest connected voltage from the station the unit is inter-connected to a PJM border bus. *See* Dynamic Transfers: Electrical Distance Test, https://www.pjm.com/-/media/about-pjm/member-services/dynamic-transfers-electrical-distance-test.ashx?la=en. *See also Cube Yadkin Generation, L.L.C. v. PJM Interconnection, L.L.C.*, Response of PJM Interconnection, L.L.C. to Paper Hearing Order, Docket No. EL19-51-000 (filed Sept. 25, 2019) (describing PJM's Electrical Distance Test).

bars). In fact, they are electrically closer, as a larger portion of future interconnection queue projects have lower Thevenin equivalent values as compared to the current in-service generation.

In light of the information above, PJM cautions the Commission against assuming that every region faces the same planning input parameter assumptions for reaching sites where renewable generation is likely to seek interconnection. Rather, PJM advises the Commission to recognize that each transmission planning region is geographically unique. Any Proposed Rule arising out of this proceeding should give each region the flexibility needed to tailor its transmission planning, interconnection and cost allocation processes to accommodate such regional differences, rather than requiring wholesale changes to such processes. Additionally, any rules requiring RTOs/ISOs to establish a process to identify "geographic zones"[30] that have the potential for the development of large amounts of new generation (particularly renewable resources) should be tailored to what makes sense for each transmission planning region.

B. The Concern that Regional Transmission Planning and Cost Allocation Processes May Be Inappropriately "Siloed" from One Another Is Overly Broad and, as to PJM, is Inaccurate in Key Respects

The ANOPR and the separate concurring statement of Chairman Glick and Commissioner Clements very broadly charge that existing "regional transmission planning processes may be siloed, fragmented, and not sufficiently forward-looking."[31] Although there are certain improvements that can be made through a Proposed Rule as outlined below, the Commission should consider key facts that contradict some of the more sweeping statements made in the ANOPR. Specifically, PJM seeks to correct the following:

- The ANOPR erroneously posits that the interconnection queue processes and the baseline planning processes are not integrated and coordinated with each other.[32] As explained below, this is not correct with respect to PJM.

[30] *See* ANOPR at PP 54-60.

[31] *Id*. at P 85; Chairman Glick and Commission Clements concurring statement at P 8.

[32] *See id*. at PP 34-36.

- The ANOPR also posits that planning under the different transmission drivers (reliability, market efficiency and public policy) are not integrated.[33] The RTEP is based on a single model that results in a holistic plan that includes projects approved by the PJM Board of Managers ("PJM Board") to address each of these drivers.[34] Nonetheless, the cost allocation for each of these specific drivers is markedly different. The differences are driven by the ruling of the Seventh Circuit Court of Appeals that costs must be allocated "roughly commensurate with" benefits,[35] rather than PJM's administration of the planning process.

1. *Integration of Interconnection and Baseline Planning Processes*

PJM's planning and interconnection processes are consolidated to the extent possible while honoring cost causation principles. Certainly, if cost causation principles were to change, the two processes could be further integrated.

PJM implemented common process controls and assumption alignment for the interconnection queue and RTEP cases by leveraging a common system modeling approach to ensure consistent annual power flow base case use for baseline reliability and market efficiency analyses that is then updated for interconnection analysis. This integrated approach ensures (i) consideration of common load forecast assumptions (based on latest load forecast); (ii) inclusion of RTEP baseline and Supplemental Projects;[36] (iii) alignment of base case assumptions with the model of the Eastern Interconnection; (iv) inclusion of generation projects that have executed interconnection service agreements ("ISAs"); (v) recently deactivated generators; and (vi) accurate Capacity Interconnection Rights ("CIRs"). These modeling parameters ensure aligned internal PJM transmission topology and generator capability.

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[33] *Id*. at P 85.

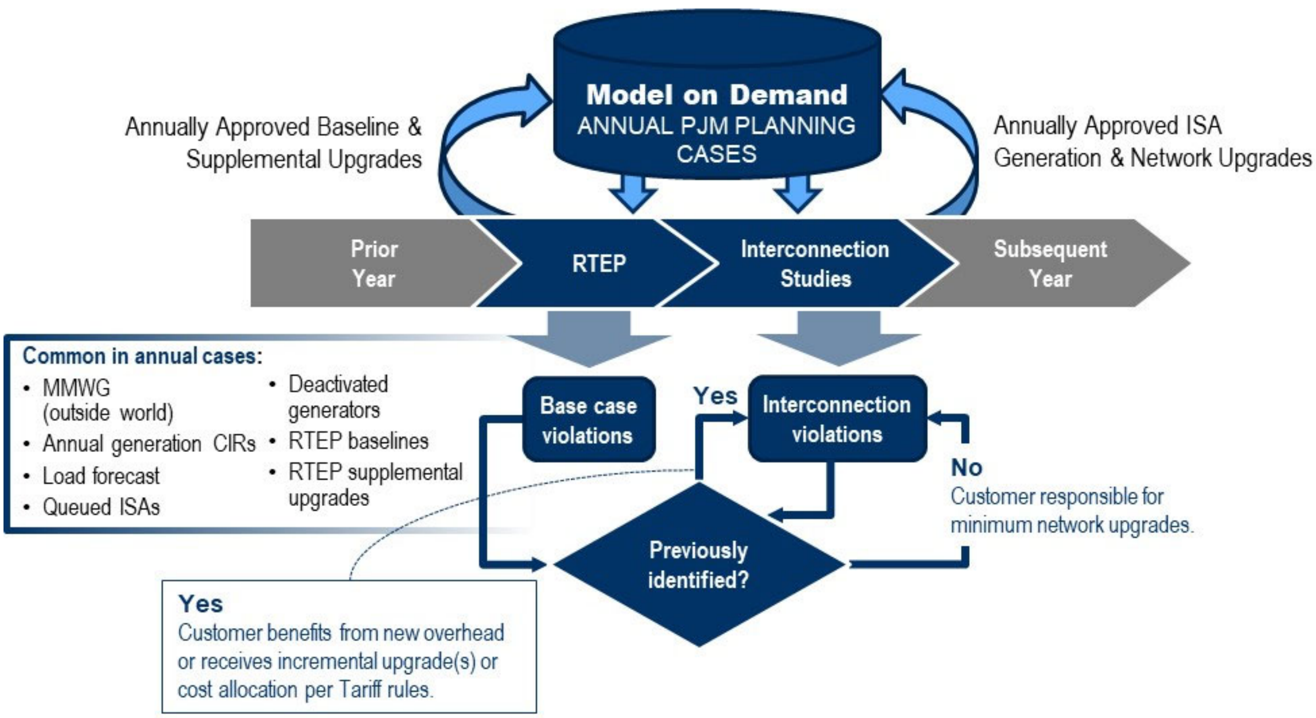
[34] Operating Agreement, Schedule 6, section 1.1.

[35] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) ("*ICC v. FERC*").

[36] A Supplemental Project is a transmission expansion or enhancement that is not required for compliance with the following PJM criteria: system reliability, operational performance or economic criteria, pursuant to a determination by the Office of the Interconnection and is not a state public policy project pursuant to Operating Agreement, Schedule 6, section 1.5.9(a)(ii). *See* Operating Agreement, section 1, Definitions S-T.

PJM's RTEP process incorporates procedures that require the baseline studies to be completed annually in order to "lock down" the annual base case prior to commencing interconnection studies. This process provides a New Services Customer with a complete system model by which to make informed business decisions based on new system capabilities using the most recent Board-approved RTEP grid enhancements. PJM provides **Table 4**, below, illustrating how the two processes are integrated for purposes of interconnection analyses.

Table 4: PJM Annual Model Build and Study Cycle



As shown in the "PJM Annual Model Build and Study Cycle" diagram above, PJM uses the most recent RTEP approved by the PJM Board to develop the base case without reliability criteria violations, which is to be used for analyzing generator interconnection requests and other New Services Customer requests, in queue order, and for identifying the need for network upgrades. Once PJM Board-approved baseline projects, together with Supplemental Projects, are included in the RTEP and reflected in power flow base case models, interconnection customers are able to take advantage of remaining system capability (*i.e.*, "headroom") available on the transmission system before the need for customer-funded network upgrades are identified.

2. *Coordination Among RTEP Planning Drivers*

PJM's forward-looking RTEP process integrates RTO-wide analyses of system reliability, market efficiency, operational performance, and public policy, as well as Supplemental Projects to address system needs.[37]

a. *Coordination between a reliability project and an identified market efficiency need*

PJM's RTEP process permits PJM to accelerate or modify an existing RTEP project to address economic needs. Specifically, the 24-month market efficiency process consists of two similar 12-month cycles ("near-term analysis") to identify approved RTEP projects that may be accelerated or modified and one 24-month planning cycle to provide sufficient time to identify and develop long lead-time transmission upgrades.[38] The scope of the near-term analysis is completed as part of the annual planning cycle. It includes a review of congestion in year 1 and year 5 and existing RTEP projects. This review permits PJM to identify RTEP projects that may be accelerated or modified and meet the market efficiency benefit/cost criteria.[39]

b. *Coordination among reliability violations, market efficiency needs and public policy considerations through the Multi-Driver Approach*

The PJM RTEP process also provides opportunities for PJM to plan for and select a multi-driver project that offers a more cost effective or efficient solution to address a combination of reliability, market efficiency and/or public policy drivers needs for inclusion in the RTEP.[40] Multi-

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[37] *See* PJM Manual 14B: PJM Region Transmission Planning Process, § 2 (rev. 49, June 23, 2021), https://www.pjm.com/-/media/documents/manuals/m14b.ashx. ("Manual 14B").

[38] Manual 14B, § 2.1.3.

[39] *Id.*

[40] Operating Agreement, Schedule 6, section 1.5.10.

driver project costs are allocated pursuant to the Tariff, Schedule 12, section (b)(xiv). The process was proposed to fit under the Commission-accepted Order No. 1000 RTEP process.[41] The multi-driver project approach is intended to give PJM the flexibility to identify the more efficient or cost effective solution using a combination of two or three of the existing drivers (reliability, economic and public policy).[42] The multi-driver project approach utilizes PJM's Commission-accepted RTEP process, including the Order No. 1000 competitive solicitation process.[43] In order to qualify as a multi-driver project, a project proposal submitted through a proposal window must either: (i) meet more than one of the posted needs and qualify as a multi-driver project or (ii) be identified by PJM as the more efficient or cost-effective solution consisting of a combination of two or more separate proposals. Additionally, PJM can also designate a multi-driver project that combines separate project proposals provided discrete elements of the combined project can be designated to respective entities that proposed them.[44]

c. PJM's RTEP processes allow PJM to achieve efficiencies across RTEP projects, Supplemental Projects and Customer-Funded Upgrades, as they arise

As part of its RTEP process, PJM leverages opportunities to develop more efficient solutions to RTEP baseline needs that can also solve needs driven by Supplemental Project and New Service Requests. PJM notes the following:

- ***Baseline Enhancements and Interconnection Network Upgrades***: When PJM identifies instances where increasing the capability of an RTEP project would obviate the need for a separate network upgrade driven by a generator interconnection request, the interconnection customer's incremental need(s) would be factored into the RTEP project and the customer

[41] *PJM Interconnection, L.L.C. and Baltimore Gas & Electric Co., et al.*, Joint Response to Deficiency Notice, Docket No. ER14-2864-000 and ER14-2867-000 (not consolidated) (filed Dec. 23, 2014) ("December 23 Deficiency Response").

[42] December 23 Deficiency Response at 2.

[43] Operating Agreement, Schedule 6, section 1.5.8.

[44] PJM acknowledges that it has not had the opportunity to select a multi-driver project for inclusion in the RTEP. PJM will continue to work to identify opportunities to select a multi-driver project and engage with PJM stakeholders to improve the existing framework to allow greater opportunities for identification and selection of multi-driver projects.

would be responsible to pay for the incremental portion of the project. This coordination across processes permits PJM to plan grid enhancements that benefit both load and interconnection customers.

- ***Baseline Enhancements, Supplemental Projects and Customer-Funded Upgrades***: PJM's RTEP process requires that PJM work with stakeholders to identify any upgrades or projects that interact electrically. By doing so, PJM is able to determine the proper classification of a project based on one or more types of drivers, as well as develop the more efficient or cost-effective solutions.[45] More specifically, PJM's planning process allows PJM to identify potential opportunities to achieve efficiencies (i) between a Supplemental Project during the Attachment M-3 Process,[46] (ii) after a Supplemental Project is included in the Local but not yet included in the RTEP base case[47] and (iii) after an RTEP project is included in the base case (in a prior RTEP cycle) and an identified Supplemental Project or Customer-Funded Upgrade interacts with the RTEP project.[48] In each instance, PJM's process provides PJM the opportunity to discuss the interaction with the relevant transmission owners and/or customer at the appropriate stakeholder committee meeting, *e.g.,* Transmission Expansion Advisory Committee ("TEAC") or Subregional RTEP Committee. After PJM has had an opportunity for stakeholder review and comment, PJM will determine the action to take depending upon which stage in the process the interaction is identified.

C. The Present Participant Funding Mechanism Was Based on a Design to Achieve Equitable Sharing of Costs as Between Network Upgrades Required to Interconnect a Generator to the Transmission System and Paid for by Generators Versus Baseline Upgrades Required to Ensure Continued Delivery of Those Interconnected Generators and Paid for by Customers

In evaluating the use of participant funding, the Commission questions whether allowing load to benefit from interconnection-related network upgrades without paying for a proportionate share of their costs is an example of the "free rider" problem that the Commission's "beneficiary pays" cost causation principle seeks to avoid.[49]

In that regard, it is important that the Commission not lose sight of the fact that a generator developer comes to the RTO/ISO seeking to interconnect its generation project to an existing transmission system that has already been built and paid for by both load and prior interconnection

[45] Manual 14B, § 1.4.2.

[46] *Id*., § 1.4.2.1.

[47] *Id*., § 1.4.2.2.

[48] *Id*., § 1.4.2.3.

[49] *See* ANOPR at PP 86, 112.

customers.[50] Moreover, future upgrades to ensure continuing deliverability of that generation to load is borne 100 percent by load. As a result, the present paradigm works to balance the burdens and costs of both interconnection-related network upgrades and future baseline upgrades as between load and interconnecting new generation projects. In an attempt to dispel a "free rider" problem, PJM provides the following facts.

First, generators fund all costs (*e.g.*, interconnection facilities, including transmission owner interconnection facilities and customer interconnection facilities, and network upgrades) to interconnect their projects but do not pay transmission costs in PJM once they are interconnected to the transmission system. Second, in return for funding network upgrades, interconnection customers receive CIRs that assure their continued deliverability 24 hours a day, 7 days a week, 365 days per year. Third, once a new generator is interconnected to the transmission system, load takes on the cost responsibility to upgrade the transmission system to ensure continued deliverability of the generation project. One can argue about alternative pricing paradigms, but the Commission should be careful not to simply conclude that a cost shift to ensure fairness and meet the needs of new generators versus load by eliminating participant funding is the only way to meet its goals.

Nonetheless, PJM has engaged stakeholders in considering alternatives, and with stakeholders' input, is including in Section IV.D.2 of these Comments, the Six Options, which are six alternative cost allocation paradigms for interconnection should the Commission feel compelled that a complete change from today's allocation of costs as between generators and load is no longer just and reasonable and must be fixed.

[50] To put things in perspective, most of the excess grid transmission capability today arises out of PJM Board-approved in-service RTEP baseline grid enhancements paid for by load and totaling approximately $24 billion through December 30, 2020. In contrast, queue-submitted, interconnection-related in-service network upgrades paid for by interconnection customers total approximately $1.5 billion. *See* PJM 2020 RTEP Report (Feb. 28, 2021), https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx.

D. In Deciding Whether to Require that Transmission Be Built for Future Generators Not Yet in the Interconnection Queue, the Commission Should Be Cognizant of the High Level of Generation that has Entered PJM's Interconnection Queue Over the Years But Has Never Moved Forward to Commercial Operation

In the ANOPR, the Commission expresses concern that today's generator interconnection process may not adequately consider whether it may be more efficient or cost-effective to consider the interconnection-related network upgrades needed for multiple *anticipated* future generators that are not yet in the interconnection queue in areas that are resource-rich with wind or solar attributes that could support multiple future generators.[51] Given this concern, the Commission seeks comment as to whether there may be a need for coordination between the regional transmission planning process and the generator interconnection process.[52]

While PJM appreciates that "co-optimizing" the two processes may create certain efficiencies, building transmission for estimated future generation would place a significant risk on load unless there are guardrails put in place.[53] Otherwise, load could be saddled with stranded costs associated with new transmission construction for generation that may never achieve commercial operation. To illustrate the risk, PJM performed a historical analysis of the generation capacity that has been studied through PJM's interconnection queue. Since PJM implemented its interconnection queue process in 2006, PJM has studied 213,097 MW of proposed generation. Of that 213,097 MW

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[51] ANOPR at P 35. As part of that discussion, the Commission notes that certain regions (*e.g*., MISO) have the ability to share costs of network upgrades with future generation but it is generally limited to the short term. In addition to MISO, PJM's interconnection process also provides for cost sharing with future generation. *See* Tariff, section 219, which provides in pertinent part:

> In the event that Transmission Provider determines that accommodating a New Service Customer's New Service Request would require, in whole or in part, any Local Upgrade or Network Upgrade that was previously determined to be necessary to accommodate, a New Service Request that was part of a previous New Services Queue, such New Service Customer may be responsible, subject to the terms of Sections 231.4, 233.5, and 234.5 below and in accordance with criteria prescribed by Transmission Provider in the PJM Manuals, for additional costs up to an amount equal to a proportional share of the costs of such previously-constructed facility or upgrade.

[52] *Id*. at P 36.

[53] PJM discusses potential solutions in Section IV.C, *infra*.

of proposed generation, 33,433 MW (or 16%) of generation capacity has achieved commercial operation.

Table 5 below illustrates that success rates (in terms of MW) increase as generation moves through the various study stages to an executed ISA. That is, the further a project progresses through the PJM interconnection study phases (*i.e.*, the various studies performed by PJM include Feasibility Studies, System Impact Studies and Facilities Study through the signing of an ISA), the more likely generation (in terms of MW) will achieve commercial operation.

Table 5

Queue Stage	MW Success Ratio	MW Capacity	Actual In-Service MW Capacity
Feasibility	16%	213,097	33,433
Impact	33%	102,421	33,433
Facilities	51%	64,923	33,433
ISA	71%	47,272	33,433

PJM also performed an analysis to determine the projected commercial probability rate of generation capacity that is currently in the interconnection queue. PJM analyzed the history of the interconnection queue since 2006, and looked at such factors as study phase in the queue or executed ISA, fuel type, MW size of the generation unit, whether the interconnection request is for a new generator or uprate, and geographic location. As shown in **Table 6**, based on statistical analysis, PJM determined that there is a commercial probability that approximately 35 percent of the CIRs associated with existing generation in the interconnection queue will ultimately achieve commercial operation. Again, the further along generation is in the interconnection queue process, the more likely the generation (in terms of MW) will achieve commercial operation.

Table 6

Queue Stage	Commercial Probability	MW Capacity	Expected In-Service MW Capacity
Feasibility	3%	41,174	1,180
Impact	9%	26,099	2,414
Facilities	58%	45,906	26,485
ISA	78%	22,409	17,373
Total	**35%**	**135,588**	**47,452**

The analysis set forth in **Tables 5 and 6** above illustrates that it is difficult to predict with certainty which generation in the queue will achieve commercial operation, particularly in relation to the study phase, let alone how much estimated future generation that is not yet in the queue will actually go into service. Building transmission for future generators not yet in the interconnection queue could result in significant risk to load, in that load will pay the costs of new transmission construction without predictability that such generation will actually materialize.

PJM has attempted to address this conundrum in these Comments at Section IV.C through its proposal for the development of a 15-year Enhanced Long-Term Planning Process. PJM proposes that, under the Enhanced Long-Term Planning Process, transmission providers be required to document, among other things, customer-identified needs into the future, so that any decision by the transmission provider to plan for and construct transmission paid for load is supported by clear documentation of customer-identified needs and state renewable goals, as developed (and documented) through surveys and other means.

IV. PJM'S PROPOSED REFORMS

A. The Commission Should Use the NOPR Process to Provide Regulatory Support for the Tools Needed to Ensure Reliability as the Grid Transitions to Increased Reliance on Renewable Resources

Today's resource profile in PJM is both reliable and diverse. PJM's resource mix includes a combination of natural gas, coal, nuclear energy, as well as renewables such as hydro, wind, solar, biomass and geothermal, demand response, and storage. However, with increasing public demand for cleaner energy resources, coupled with today's push by states to enact Clean Energy Standards[54] that include Renewable Portfolio Standards[55] as a part of their requirement, the resource mix is evolving quickly. This change in resource mix is evident within PJM's generation interconnection queue, which reflects a shift from proposed natural gas resources to proposed renewable resources such as solar, wind and storage.

1. The Commission Should Encourage Continued Development of Grid-Forming Inverter Technology

While the observed shift to renewables is certainly necessary to achieve a decarbonized grid of the future, neither PJM nor the Commission can ignore the need for new measures to ensure continued reliability and challenges that must be addressed. Most importantly, the challenges created by a rapid turnover of the generation fleet (*e.g.*, ensuring reliability and the need for new tools and authority to address them) must be fully recognized by the North American Electric Reliability Corporation ("NERC") in its standard setting initiatives and enforcement activities, as well as by policymakers at the state and federal level. Maintaining or increasing the level of NERC-defined

[54] Clean energy typically refers to sources of energy that have zero carbon emissions.

[55] Renewable Portfolio Standards require a specified percentage of the electricity sold by utilities to come from renewable resources. The difference between a Renewable Portfolio Standard and a Clean Energy Standard is generally determined by how a particular state defines what is a "renewable" versus a "clean" source of energy.

essential reliability services will be key to ensuring system reliability and overall resilience, particularly in the face of the increasing frequency of extreme weather events.[56]

That said, PJM submits the following recommendations. For starters, renewable resources may not be able to provide all of the NERC-defined essential reliability services necessary to ensure a reliable system[57] without a significant amount of inverter-based resources that are able to provide frequency response and voltage regulation capability. As inverter technology for transmission-connected renewables and batteries continues to advance, the Commission should periodically update interconnection requirements to mandate compliance with new standards (such as the in-progress Institute of Electrical and Electronics Engineers ("IEEE") Standard P2800[58]). Such improvements will be necessary to ensure stability under higher concentrations of inverter-based resources while avoiding the need for investment in dedicated equipment such as synchronous condensers and static compensators ("STATCOMs"). The Commission should encourage continued development of grid-forming inverter technology so that ultimately large areas of the grid can run stably with 100 percent inverter-based resources.

2. *Potential for Intermittency Impacts*

Further reliance on renewable resources brings with it challenges associated with the intermittency of these resources. While geographic diversity could reduce some of the impacts of weather conditions in individual localities (assuming there is sufficient transmission capability to

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[56] Recent reliability events, as witnessed across the United States, highlight the delicate balance of the BES amid an increasing penetration of renewable resources, retirements of dispatchable generation, reliance on power from neighboring regions and the impact of volatile weather conditions.

[57] A system composed primarily of renewable resources poses reliability challenges. While inverter-based resources must provide frequency response and voltage regulation capability, renewable resources operate differently and face reliability challenges such as decreased inertia and frequency response, ramping and balancing control, low short-circuit capability, reduced dynamic and voltage stability, reduction in black start generation and system restoration and fuel assurance.

[58] IEEE P2800 - IEEE Draft Standard for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems. *See* https://standards.ieee.org/project/2800.html.

transfer energy), the risks associated with the lack of energy assurance will rise as renewable penetration increases. This increase in renewable resources could result in increased dependency on non-renewable generators – particularly nuclear and flexible combined-cycle gas turbines with firm delivery contracts – necessary to produce power when sunlight and wind are limited.

Storage solutions, such as batteries, can alleviate some fuel assurance concerns and provide balancing across hourly and daily timescales. In particular, next-generation storage technology may be able to replace traditional fuel-assured resources. However, deployment of longer duration storage outside of existing hydro resources is still in its nascent stage. The challenges of energy assurance highlights the importance of adequate transmission transfer capability as discussed in these Comments in Section V.C.

Given this increase in renewable penetration and the associated challenges with maintaining system reliability during periods in which renewable resources are not able to fully meet system needs alone, PJM recently developed and implemented an Effective Load Carrying Capability ("ELCC") methodology to determine the capacity value of variable and limited duration resources. The ELCC methodology (i) measures the performance of each resource over all 8,760 hours of the year; (ii) properly recognizes the performance of the resource over the critical high load, high risk hours; and (iii) also recognizes the declining reliability value of wind, solar and storage resources as their penetration level increases.

PJM proposes that the Commission and NERC consider the usefulness of expanding the ELCC methodology on a nationwide basis. Specifically, PJM would support a Commission policy that encourages the adoption of an ELCC-based methodology for variable and limited duration resources, particularly in regions with a high penetration level of such resources. This approach would ensure that the capacity value of each resource is accurately measured so that load is reliably served over all hours of the year.

3. *The Commission Should Take Steps to Ensure that the Impact of Increased Penetration of Distributed Energy Resources ("DERs") Supports the Continued Reliability of the Grid*

The increase in the deployment of DERs can, if not done correctly, create additional reliability challenges. With the increasing penetration of DERs on the grid, the Commission must ensure that DERs are held to adequate reliability, performance, and cybersecurity standards so as to ensure that grid reliability can be maintained.

One way to address this issue may be to require the application of the IEEE Standard 1547-2018.[59] When the standard is implemented in concert with regional entities (as recommended in the standard), it ameliorates many of the reliability impacts that wide-scale deployment of DERs could pose to the transmission system. However, when distribution utilities or local regulators have declined to require this standard in regions that exhibit high deployment of DERs, those regions may experience the increased potential for transmission reliability issues. In areas with especially high DER deployment, it may be necessary for distribution utilities to enable robust grid functionality, such as very robust voltage ride through and frequency response with an appropriately narrow deadband. And, to the extent that DER communicates with utilities or other third parties, continued work is necessary to require that such communications are cyber-secure.

Due to existing authority and jurisdictional limitations, DER generation is not directly subject to Commission oversight or NERC Reliability Standards. Rather, the authority to regulate DERs

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[59] IEEE Standard 1547-2018 - Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, https://standards.ieee.org/standard/1547-2018.html, (as amended in standard IEEE 1547a-2020, https://standards.ieee.org/standard/1547a-2020.html) is a standard meant to provide a set of criteria and requirements for the interconnection of DER with electric power systems ("ESPs") and associated interfaces. The standard addresses the technical specifications for, and testing of, the interconnection and interoperability between utility EPSs and DERs. The standard provides for requirements relevant to the interconnection and interoperability performance, operation, and testing, and to safety, maintenance and security considerations. It also includes general requirements, response to abnormal conditions, power quality, islanding, and test specifications and requirements for design, production, installation evaluation, commissioning, and periodic tests. The stated requirements are universally needed for interconnection of DER, including synchronous machines, induction machines, or power inverters/converters and will be sufficient for most installations.

resides with the States. Since there has not always been consistent application of DER performance requirements at the State level, PJM recommends that the Commission work directly with the appropriate State regulating and enforcement agencies to ensure that the IEEE Standard 1547-2018 (or its equivalent) is applied and enforced for all DERs.[60] IEEE 1547 provides significant flexibility in implementation, and so the Commission should also consider requiring that transmission utilities communicate to the applicable Reliability Coordinator the default settings applied to DER by their distribution affiliates, along with any exceptions to the default. By having a known and consistently applied standard or set of standards, PJM and all grid Planners and Operators can correctly model the behavior of DERs in all reliability simulations and operating strategies.

B. It Is Essential that the Commission Consider Resilience Issues in This Rulemaking Proceeding

Resilience is far too important to the future reliability of the grid to be excluded from any forward-looking holistic approach that proactively plans for transmission needs. Any endeavor to tackle the transmission needs of the electricity grid of the future would be incomplete without factoring in resilience in any proposed reforms and revisions to electric regional transmission planning and cost allocation processes.

PJM has set forth the need to address resilience in a number of proceedings,[61] dating back to the Commission's now-closed resilience proceeding in Docket No. AD18-7-000 ("Resilience

[60] PJM suggests that this issue can be explored among the Commission and the National Association of Regulatory Utility Commissioners ("NARUC") via the recently-established Joint Federal-State Task Force on Electric Transmission ("Joint Task Force"). *See Joint Federal-State Task Force on Electric Transmission*, 175 FERC ¶ 61,224 (issued June 17, 2021).

[61] *See, e.g.*, *Grid Resilience in Regional Transmission Organizations and Independent System Operators,* Comments and Responses of PJM Interconnection, L.L.C., Docket No. AD18-7-000 (filed Mar. 9, 2018) ("2018 Resilience Comments"); *Climate Change, Extreme Weather, and Electric System Reliability*, Comments of PJM Interconnection, L.L.C., Docket No. AD21-13-000, at 3- 6 (filed Apr. 15, 2021) ("Initial Climate Change Comments"); *Climate Change, Extreme Weather, and Electric System Reliability*, Post-Technical Conference Comments of PJM Interconnection, L.L.C., Docket No. AD21-13-000 (filed Apr. 15, 2021) ("Post-Technical Conference Climate Change Comments"); *Reliability Technical Conference*, Statement of Christopher Pilong on behalf of PJM, Docket No. AD21-11-000 (filed Sept. 30, 2021).

Proceeding").[62] In its initial comments in Docket No. AD21-13-000, the ongoing proceeding addressing climate change and extreme weather events ("Climate Change Proceeding"), PJM outlined the steps that it and its stakeholders currently take under existing processes to prepare for, withstand and/or respond to extreme weather events.[63] Additionally, in its 2018 comments in the Resilience Proceeding,[64] as well as its post-technical conference comments in the Climate Change Proceeding,[65] PJM discussed areas where further direction from the Commission would be beneficial in helping grid operators prepare for, withstand and/or respond to extreme weather events, in and across the nation.

Although PJM has made some notable strides in these areas and is continuing to work through some of these issues in the stakeholder process and with natural gas pipelines,[66] the requested specific guidance requested in those dockets will allow PJM to make even further progress. PJM therefore renews its request that the Commission move forward expeditiously with clear concrete steps along the lines proposed by PJM in the Resilience Proceeding and in the Climate Change Proceeding, as outlined below.

1. Concrete Steps the Commission Should Take Now to Address Resilience

PJM urges the Commission to: (a) develop a working definition and common understanding of grid resilience; (b) propose a framework by which regions can develop resilience-based industry

[62] *Grid Resilience in Regional Transmission Organizations and Independent System Operators,* 174 FERC ¶ 61,111 (2021).

[63] Initial Climate Change Comments at 3-6.

[64] *See generally* 2018 Resilience Comments.

[65] *See* Post-Technical Conference Climate Change Comments at 2-23.

[66] In PJM's 2018 Resilience Comments, PJM highlighted the considerable progress it has made on coordination with the gas pipeline industry as to information sharing and communication protocols since the Polar Vortex of 2014. PJM detailed the memorandum of understanding and data sharing agreements it has with each of the major pipelines in its 2018 Resilience Comments. Since then, PJM has continued to collaborate with the pipeline industry to further work through issues that go beyond traditional notions of reliability and work towards ensuring resilient operations in a way that meets the needs of both the pipeline industry and PJM. PJM is grateful for the improved communication and coordination that has evolved over the last five years with the support of the pipeline industry.

planning drivers to advance resilience planning; (c) establish information sharing requirements among NERC, PJM and generators; and (d) consider a transmission planning driver to ensure planning for system restoration, such as fuel security for black start resources.

a. The Commission Should Establish a Working Definition and Common Understanding of Resilience

In its 2018 Resilience Comments, PJM offered detailed comments in response to the Commission's proposed definition for resilience. Specifically, PJM proposed the following definition for resilience:

> The ability to withstand or reduce the magnitude and/or duration of disruptive events, which includes the capability to identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or timely recover from such an event.

As PJM explained in its 2018 Resilience Comments, PJM's proposed definition varied modestly from the Commission's then-proposed definition[67] in order to ensure the definition is realistic and requirements on transmission planners are achievable.[68] With respect to PJM's proposed refinements to the Commission's previously proposed definition of resilience, PJM indicated the following:[69]

- Requiring the Bulk Electric System ("BES") to "withstand" a disruptive event, as the Commission's proposed definition suggested, is concerning because Transmission Planners should not be required to plan and design the BES to be invulnerable to a broad spectrum of hazards and corresponding impacts, regardless of the cost to do so or the incremental value that may be achieved in making such improvements. This is particularly true for a contingency that will rarely, if ever, occur. For that reason, PJM suggested the word "and" should be changed to "or" in PJM's proposed definition to allow transmission planners to make a rationale determination of the cost benefit of making certain system improvements.

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[67] PJM's proposed refinements to the Commission's definition were as follows:

> The ability to withstand ~~and~~ or reduce the magnitude and/or duration of disruptive events, which includes the capability to ~~anticipate~~ identify vulnerabilities and threats, and plan for, prepare for, mitigate, absorb, adapt to, and/or ~~rapidly~~ timely recover from such an event.

[68] 2018 Resilience Comments at 10.

[69] PJM also noted that it understood the terms "absorb" and "adapt" to mean the ability of asset owners and operators on the BES to manage incidents as they are unfolding to minimize the initial impact in a prudent manner – not the ability to absorb a threat unscathed. *See id*. at 11.

- The word "anticipate," as incorporated into the Commission's proposed definition, should not be included because transmission planning regions cannot perfectly anticipate all potential risks, vulnerabilities, or threats to the BES. Instead, it is more appropriate for regions, "to identify vulnerabilities and threats."

- Once such vulnerabilities and threats are identified, in addition to absorbing, adapting to and recovering from a disruptive event, transmission planners also need to plan for and prepare for such an event, and mitigate against the identified vulnerabilities and threats, in order to develop mechanisms to prevent the BES from being disrupted.

- The word "rapidly" in the Commission's proposed definition should be replaced with the word "timely" in because any recovery must be reasonably timely under the circumstances. The word "rapidly" could impose an unreasonable expectation depending on the circumstances or the event. Furthermore, including "rapidly" in a federal definition could engender unnecessary disputes and litigation after a successful timely restoration.

PJM believes that its proposed definition of resilience (i) has commonality of intent with the Commission's previously proposed definition; (ii) accurately reflects what transmission planners are capable of doing to protect the BES from vulnerabilities and threats; and (iii) does not subject transmission planners to additional liabilities, or unreasonable new duties or standards of care. PJM further believes that establishing a working definition of resilience, applicable to all regions, is the first step to position all regions across the country well to advance resilience efforts within their respective transmission planning processes.

b. The Commission Should Direct Transmission Planning Entities to Develop Resilience-Based Industry Planning Drivers

While a working definition of resilience will provide transmission planning entities, like PJM, a common understanding of the term and assist in identifying specific projects needed to mitigate resilience risks, more is required. Specifically, the industry needs the Commission to require all regions to develop resilience planning criteria that would trigger actionable grid expansion, *e.g.* NERC CIP-014,[70] extreme weather events, cyberattacks, physical attacks. The

[70] *See* n.75, *infra*.

impacts of extreme weather events, and other events such as cyberattacks and physical attacks, could cost utilities and their customers billions of dollars[71] and present a risk to the health and safety of our nation. Thus, the ability to address system vulnerabilities threatened by these types of events is essential, as is the ability to be able to plan the transmission system to ensure the grid is resilient.

PJM therefore believes it would be beneficial for the Commission to make clear its expectation that grid resilience should serve as a specific driver for enhancements and expansions of the transmission system for purposes of cost allocation. It would further be beneficial for the Commission to set specific resilience criteria for system performance and associated boundaries to ensure reasonableness. Resilience criteria would apply to both regional and local facilities. It is important to recognize the need for local resilience planning, such as storm hardening to protect substations against flooding, ensuring reliable service when customers need it the most.

PJM could then engage with each PJM transmission owner to publicize for stakeholder review specific resilience needs on the transmission owners' systems and present coordinated plans to incorporate resilience planning into the regional planning process and reduce the need for addressing resilience solely through Supplemental Projects.[72] Developing a clear Commission-directed planning driver would give transmission planning entities authority to move forward with resilience projects, thereby avoiding endless and unnecessary stakeholder debate and litigation.

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[71] *See* U.S. Government Accountability Office, *Electricity Grid Resilience: Climate Change Is Expected to Have Far-Reaching Effects and the DOE and FERC Should Take Actions* (Mar. 5, 2021), https://www.gao.gov/assets/gao-21-346.pdf.

[72] PJM's request to the Commission to adopt a specific resilience planning driver is not intended to change the balance of transmission owner asset management responsibility recently affirmed by the Commission in Docket No. ER20-2308-000. *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242 (2020), *reh'g*, 176 FERC ¶ 61,053 (2021) (addressing whether a transmission project needed to address end-of-life conditions involves expansion or enhancement of the regional transmission system). However, it would allow for a more integrated and coordinated approach where regional resilience needs could be addressed through the PJM planning process with local transmission owner needs addressed through the existing sub-regional processes.

PJM further believes the Commission should identify the level of the above-referenced events that RTOs/ISOs (and transmission providers in non-RTO/ISO regions) should study and mitigate. Again, with respect to extreme weather events, for instance, the Commission could direct the regional development of extreme weather design standards such as high and low temperature thresholds, wind speed levels for generation resources such as offshore wind, and flood levels for substation design for transmission and generation operating criteria. Although this could be done through the NERC standard-setting process, the recent experience in the development of NERC Reliability Standards EOP-011-2 (Emergency Preparedness and Operations), IRO-010-4 (Reliability Coordinator Data Specification and Collection), and TOP-003-5 (Operational Reliability Data) (collectively, the "Cold Weather Reliability Standards")[73] illustrates the difficulty of developing specific criteria through the NERC stakeholder process. Moreover, as some would argue that "resilience criteria" are beyond NERC's statutory mandate, the Commission may want to consider development of these criteria through its own authority over planning and system operations to meet the needs of customers. Specifically, PJM believes that Federal Power Act ("FPA") section 217[74] provides the Commission with ample authority to require planning for resilience given the section's directive that planning meet the long-term needs of load serving entities.

NERC developed reliability standard CIP-014-2 to identify and protect transmission stations and substations, and their associated primary control centers that, if rendered inoperable or damaged by physical attack, could result in instability, uncontrolled separation, or cascading ("CIP-014

[73] *North American Electric Reliability Corp.*, Petition of the North American Electric Reliability Corp., Docket No. RD21-5-000 (filed June 17, 2021) ("Cold Weather Reliability Standards Filing"). The Commission approved the Cold Weather Reliability Standards in an order issued August 24, 2021. *See North American Electric Reliability Corp.*, 176 FERC ¶ 61,119 (2021).

[74] Through section 1233 of EPAct 2005, Pub. L. No. 109-58, § 1233(b), 119 Stat. 594, 960 (2005), Congress added FPA section 217, 16 U.S.C. § 824q, entitled "Native Load Service Obligation," which addresses transmission rights held by load serving entities.

Facilities").[75] The standard requires transmission owners to conduct assessments to identify such critical facilities.[76] Currently, however, no industry standard or uniform planning driver exists by which transmission providers can plan the regional transmission system specifically in order to mitigate[77] CIP-014 Facilities. Transmission providers should be required to assess the impact of the loss of such critical facilities, including facilities that the transmission provider identifies as critical on a regional basis based upon reliability principles.

Due to the physical characteristics of the BES, resilience risk mitigation through planning is most effective when widely applied. PJM has initiated efforts as part of its Critical Infrastructure Stakeholder Oversight process to develop RTEP criteria to enhance grid resilience in order to avoid the creation of new, or eliminate future, CIP-014 Facilities, which requires analyzing extreme contingencies and the physical hardening of critical substations, with no requirements to mitigate. While PJM has initiated these efforts, the Commission should require all transmission providers to submit develop and file proposed tariff amendments to implement resilience planning criteria. Such criteria could include processes for the identification of vulnerabilities, threat assessment and mitigation, regional restoration planning, and other related processes or procedures needed to advance resilience planning.

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[75] NERC Standard CIP-014-2, Section A.3. *See also Physical Sec. Reliability Standard*, Order No. 802, 149 FERC ¶ 61,140 (2014), *reh'g denied*, 151 FERC ¶ 61,066 (2015) (approving Reliability Standard CIP-014-1); *N. Am. Elec. Reliability Corp.*, Docket No. RD15-4-000 (July 14, 2015) (delegated letter order approving Reliability Standard CIP-014-2, which removed the term "widespread" from the text of the standard in compliance with Order No. 802).

[76] The PJM transmission owners utilize planning procedures set forth in Tariff, Attachment M-4 that they apply to a limited subset of Supplemental Projects designed to mitigate the risk associated with critical transmission stations and substations identified pursuant to NERC reliability standard CIP-014-2. The PJM transmission owners sought to incorporate Tariff, Attachment M-4 to allow them to plan transmission projects for the purpose of mitigating risks associated with CIP-014-2 transmission stations and substations more effectively than physical security measures alone without disclosing highly sensitive information about those stations and substations that could threaten their security. *See Appalachian Power Co.*, Proposed Tariff Revisions to Add New Attachment M-4, Docket No. ER20-841-000, at 2 (filed Jan. 17, 2020). Tariff, Attachment M-4 provides that the maximum number of CIP-014 mitigation projects permitted is 20 and that it sunsets five years after the Commission approved Attachment M-4 for inclusion in the Tariff. *See* Tariff, Attachment M-4, sections (b)(2) and (d).

[77] As used in this section, the term "mitigate" or any variation thereof means an enhancement to the power system that results in declassifying a facility as a CIP-014 Facility.

Preparation and proactive planning of the transmission system is critical for both reliability and resiliency. PJM's perspective is that a Commission-directed planning driver for resilience is important in order for RTOs/ISOs (and transmission providers in non-RTO/ISO regions) to comprehensively assess and plan for these risks to the transmission system. This is particularly the case given the impact these events can simultaneously have on multiple regions (*e.g.*, like the February 2021 freeze in Texas and the Midwest (the "February 2021 Cold Snap") and its impact on the MISO, SPP, and ERCOT regions).

c. The Commission Should Consider a Transmission Driver to Address Planning for System Restoration, Including Optimal Cranking Paths, Location of Black Start Resource and Fuel Assurance

System restoration and black start plans are critical to maintaining a resilient grid during extreme weather-related events. Black start units are designated generators that are able to start and initiate system restoration without using an outside electricity supply in the unlikely event that power is lost throughout the entire PJM footprint. The main objective of system restoration is to restore power to the backbone BES, which can then facilitate restoration of the distribution system and end-use customer power supply. Once connected, black start units can supply start-up power — also called cranking power — to other generating units and help restore "critical load" in each transmission zone.

As the fuel mix continues to change, and penetration of renewable resources continues to increase, the transmission infrastructure will have to develop to accommodate the transition, and system restoration needs to be a major policy consideration in that transition.

Currently, system restoration and black start plans are developed at the Transmission Operator, Reliability Coordinator, and RTO/ISO region level based on changing system conditions. Going forward, PJM recommends that, as the Commission considers what planning drivers and policy changes are needed to accommodate these transition, the Commission incorporate system restoration and black start resources to reflect the increase in intermittent resources, DERs, new transmission builds and customer load growth or migration.

The winter events of 2021 and hurricanes of the 2021 summer demonstrated the impacts of extreme weather on the grid and on customers as a result of outages. System restoration and black start considerations need to be a major policy consideration moving forward. This policy should also reflect the potential for multiple threats to the system. The Commission should also foster an increased focus on restoration planning coordination between RTO/ISO and non-RTO/ISO regions and pipelines, as each entity has valuable information that can affect the other's timely restoration. For purposes of the next phase of this ANOPR process, PJM recommends that in developing a resilience planning driver, the Commission:

- Ensure that transmission planners have the authority and direction to look at all aspects of resilience and system restoration, including analyzing whether existing cranking paths are adequate to ensure timely system restoration, whether system restoration plans need to be modified to reflect a changing resource mix, whether new transmission development reduces the risk of system interruption beyond the requirements of today's NERC Standards, and whether new transmission development would assist in ensuring more timely and efficient system restoration in the event of an outage;

- Encourage enhanced communication and coordination of identified needs for pipeline expansion with the long-range identified needs and plans of transmission system planners and require a coordinated stress-tested resilience review of the interdependencies of both systems; and

- Develop a timeline for submission of coordinated transmission planner responses to add these features of resilience planning to their planning processes after working with states and stakeholders.

The need to study the issue before investing is equally important. New investments in black start capability will have to be paid for by ratepayers, and the impact of those costs cannot be ignored. In the end, the Commission and state regulatory commissions are charged with ensuring that rates are just and reasonable. Therefore, it is essential that before investments are made, analyses of a full range of scenarios are conducted, including what may appear to be extreme scenarios, in order for policymakers and regulators to understand the basis for the investments.[78]

Looking more broadly, the risk of power outages based on the interdependencies between natural gas and electric infrastructure is not new, but would also benefit from detailed analysis. The severe impact on power generation that could come from a loss of natural gas supplies has been raised within the past few years. It is important to understand that extreme scenarios can occur more often than we think. What are presently perceived as "fictional events" can later become very real. Thus, it is necessary to perform studies to understand possible ranges of outcomes, even those that may seem extreme.

The Department of Energy ("DOE"), working with the electric utility industry, other federal governmental agencies like the United States Department of Defense ("DOD") and Department of Homeland Security ("DHS"), and state regulatory agencies, should develop a holistic Design-Basis Threat policy and use it to assess black start requirements. This proposal is consistent with a 2018 recommendation from the National Infrastructure Advisory Council to develop a federal design basis and design criteria to recover from a catastrophic power outage.[79]

Even making all the investments to anticipate, absorb and adapt to a cyberattack, the possibility exists that a successful attack can occur with devastating consequences. That said, investments in equipment for rapid recovery and restoration will help mitigate against those consequences. Shortly after the February 2021 Cold Snap, ERCOT representatives speculated that if a full blackout had occurred, power could have been out for a vast majority of Texans for weeks,

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[78] *See, e.g.*, S. T. Naumann, *DOE Threat Assessment Needed to Guide "Blackstart" Plans*, The Energy Daily, Aug. 6, 2021, at 4.

[79] *See* National Infrastructure Advisory Council's 2018 Catastrophic Power Outage Study, https://www.cisa.gov/sites/default/files/publications/NIAC%20Catastrophic%20Power%20Outage%20Study_FINAL.pdf.

if not longer.[80] Fortunately, ERCOT avoided a full blackout, but from any objective point of view, a recovery taking weeks or longer is not acceptable.

2. *PJM Requests that the Commission Include in Any Proposed Rule PJM's Key Resilience Recommendations from the Resilience Proceeding*

Although the Commission declined to proceed with a generic rulemaking to address resilience concerns in its prior Resilience Proceeding,[81] PJM strongly encourages the Commission to reconsider that decision and provide in any Proposed Rule clear direction with respect to the recommendations PJM proposed in its 2018 Resilience Comments to enhance the resilience of the grid and interrelated systems that depend on the BES.[82] The interrelated nature of these systems cannot be ignored. For example, with a changing resource mix and a changing transmission system to accommodate it, a flexible natural gas infrastructure will be necessary to support the grid through this transition. Therefore, due to the importance of this topic, PJM restates some of the recommendations from its 2018 Resilience Comments as follows:

- Finalize a working definition and common understanding of grid resilience, clarifying that resilience resides within the Commission's existing authority with respect to the establishment of just and reasonable rates, terms and conditions of service under the FPA).[83]

- Establish a Commission threat verification process, either informally through one or more of the Commission's existing offices, or formally through a filing process, that would allow an RTO to receive verification as to the reasonableness of its assessments of vulnerabilities and threats, including Commission utilization of cyber or physical threat information that may be available to it, but not available to the RTO because of national security issues. Those assessments, once verified, could then form the basis for RTO actions under its planning or operations authority consistent with its tariffs. Simply put, in coordination with other federal agencies such as the United States DOD, DOE, DHS, as well as NERC, the Commission needs to provide intelligence and metrics to apply to resilience vulnerability and threat

[80] *See* R. Smith, The Texas Grid Came Close to an Even Bigger Disaster During February Freeze, Wall Street Journal, May 27, 2021.

[81] *Grid Resilience in Regional Transmission Organizations and Independent System Operators*, 174 FERC ¶ 61,111, at P 5 (Feb. 18, 2021) (terminating its rulemaking proceeding to evaluate the resilience of the BES in RTO/ISO regions finding that any generic action to address resilience concerns is not appropriate; instead, such concerns "are best addressed on a case-by-case and region-by-region basis."

[82] *See* n.61, *supra*.

[83] *See, e.g.*, FPA, section 215 (16 U.S.C. §824o).

analyses that can then guide and anchor subsequent RTO planning, market design, and/or operations directives.[84]

- Articulate that the regional planning responsibilities of RTOs currently mandated under 18 CFR § 35.34(k)(7), and the NERC TPL standards (which among other things require RTOs to plan to provide reliable transmission service and assess Extreme Events to the BES), includes an obligation to assess resilience. The Commission should, as part of this effort, after confirming that resilience is a component of such planning, authorize a planning driver to address system-wide resilience in light of reasonably foreseeable and verified physical and cybersecurity threats. As part of this effort, the Commission should reconcile its continued interest in transparency in planning processes under Order Nos. 890 and 1000 with the challenges of public disclosure of significant grid resilience vulnerabilities. Working with stakeholders, PJM has begun this process to include examining critical facilities like those identified in the NERC standard, and urges the Commission to provide assistance to ensure that the goals of transparency and information to end users do not become a means to disclose grid vulnerabilities that can be exploited by those with bad intent.[85]

- Require that all RTOs (and jurisdictional transmission providers in non-RTO regions) submit a subsequent compliance filing, including any necessary proposed tariff amendments, to implement resilience planning criteria, and develop processes for the identification of vulnerabilities, threat assessment and mitigation, restoration planning, and related process or procedures needed to advance resilience planning.

- Request that system operators submit a subsequent filing, including any necessary proposed tariff amendments, to permit non-market operations during emergencies, extended periods of degraded operations, or unanticipated restoration scenarios. Such filings could include provisions for cost-based compensation when the markets are not operational or when a wholesale supplier is directed to take certain emergency actions by PJM for which there is not an existing compensation mechanism.[86]

- Establish improved coordination and communication requirements between RTOs and Commission-jurisdictional natural gas pipelines to address resilience as it relates to natural gas-fired generation located in RTO footprints.

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[84] Through this process, PJM would be seeking verification that its vulnerability identification or threat assessment is consistent with information (including classified information not necessarily available to PJM) held by the federal government and thus should be used to guide future actions. The verification would be solely of the identified vulnerability or assessed threat and would not preclude challenges in the context of a rate proceeding or otherwise as to the cost efficiency of addressing the vulnerability or threat.

[85] *See Appalachian Power Company, et al.*, 173 FERC ¶ 61,157 (Nov. 19, 2020) (Chairman Glick dissenting in part, at PP 3 – 4, expressing sympathy for "the pickle that PJM and the Transmission Owners find themselves in" when trying to develop transmission projects under a planning process that requires openness, transparency and coordination among interested parties for facilities that must be kept non-public to avoid serious risks to the public interest. Chairman Glick further commented [w]hatever you think of competition . . . it seems like "a bad fit with projects designed to alleviate critical constraints whose identity [must] absolutely remain secret.")

[86] Any such RTO procedures would be limited, and would not interfere with DOE emergency actions under FPA sections 202(c) or 215A (16 U.S.C. §§ 824a(c), 824o-1).

- Implement additional efforts to encourage sharing of pipelines' prospective identification of vulnerabilities and threats on their systems and, sharing on a confidential basis in real-time, the pipeline's modeling of such contingencies and communication of recovery plans. This would ensure that the RTO has the best information in real time to make a determination whether to increase Operating Reserves or take other emergency actions in response to a pipeline break or other contingencies occurring on the pipeline system. Although a degree of effective coordination and communication with the pipelines serving the PJM Region has been achieved, more of a focus on real time coordination of modeling of contingencies and real-time communication of same would ensure greater consistency in coordination and information and can bring gas/electric coordination, to the next level to face the next generation of resilience issues. Accordingly, PJM recommended a more holistic regulatory framework for identifying and coordination of modeling of (i) pipeline contingencies in RTO planning and (ii) real-time impacts of adverse pipeline events on BES operations.

- Foster an increased focus on restoration planning coordination between RTOs and pipelines as each entity has valuable information that can affect the other's timely restoration.

- PJM believes that much can be done both in the Commission's exercise of jurisdiction over RTOs as well as interstate pipelines to improve generation interconnection coordination with pipelines in order to better align interconnection activities and timelines and minimize potential issues associated with generation facilities located in areas on pipeline systems where reliability or resilience benefits may be suboptimal.

- Act to support the harmonization of cyber and physical security standards between the electric sector and the natural gas pipeline system. PJM recognizes that this matter spans beyond the Commission and also involves the Transportation Security Administration and Pipeline and Hazardous Materials Safety Administration, but believes that through greater interagency coordination, a base level of resilience to physical and cyber-attacks can be achieved even while still respecting the different regulatory authorities of each agency.

- Require coordination across the nation of a consistent means to determine Critical Restoration Units and the development of criteria to assure fuel capability to such Critical Restoration Units.[87]

- Require RTOs, as part of their restoration role, to demonstrate steps they are taking to improve coordination with other critical interdependent infrastructure systems (*e.g.*,

[87] PJM noted in the Resilience Comments that, at the time, PJM was moving forward on requiring dual fuel capability at all black start units. PJM initiated a stakeholder process to focus on issues associated with such a requirement. PJM undertook to model the costs and benefits in response to input from the Organization of PJM States, Inc. ("OSPI"). OPSI ultimately informed PJM that OPSI states were unable to reach consensus on whether such an across-the-board tariff mandate to upgrade all units (new and existing) for dual fuel capability was cost-justified. While PJM will continue to work with OPSI and stakeholders on this matter, to date, PJM has chosen the route of providing added points to its RTO-wide request for proposal ("RFP") process that it administers every five years. *See* PJM, Manual 14D: Generator Operational Requirements (rev. 56, June 6, 2021), https://www.pjm.com/~/media/documents/manuals/m14d.ashx. PJM provides additional points toward an award for units that have dual fuel capability and/or firm fuel contracts. While the RFP process has been successful to date, PJM would benefit from further guidance from the Commission as to whether a reliability-based directive is warranted. PJM continues to view this as a critical issue and will continue to make modifications through some of the current stakeholder processes involving black start and capacity requirements.

telecommunications, water utilities) that (i) could be impacted through events of type discussed herein or (ii) are themselves vulnerabilities that could contribute to, or amplify the impact of such events. Coordination between the Commission, the Federal Communications Commission and DHS would provide additional federal support for such efforts.

While PJM requested the guidance described above in the context of the Commission's Resilience Proceeding, PJM believes that these recommendations are more relevant than ever in light of the dynamically changing profile of the generation fleet and the resilience challenges that the grid continues to face and therefore should be addressed in any Proposed Rule to avoid this issue becoming siloed.

Although PJM has made some good strides in these areas and is continuing to work through some of these issues in the stakeholder process, the requested guidance will allow PJM to make even further progress. PJM therefore recommends that the Commission consider these recommendations, as they relate to transmission planning, in this docket as well.

C. Grid Optimization (PJM's Proposed Enhanced Long-Term Planning Process)

Historically, the PJM 15-year long-term planning horizon sought to ensure a review of system conditions to provide sufficient transmission infrastructure to serve projected load growth, recognizing the necessary lead time required to build new greenfield transmission for higher voltage facilities. Energy efficiency, changes in the economy and growth in DER resulted in a reduction in load growth, thus decreasing the need for long lead-time transmission facilities. As environmental regulations and economic pressures resulted in the retirement of certain fossil fuel facilities, replacement generation, primarily combined cycle gas generation as a result of the Marcellus and Utica shale gas, moved closer to load centers. Consequently, mostly incremental transmission upgrades to existing transmission facilities were built to accommodate that replacement generation, as opposed to new long-lead greenfield transmission projects. As discussed above, PJM's analysis supports the continued trend that future interconnection queue generation will remain close to load centers, with only a marginal reduction in relative proximity.[88]

Moving forward, PJM recognizes there will be opportunities for more holistic system planning solutions. Although PJM currently prepares a 15-year forward-looking analysis today, PJM proposes to develop a plan to reform its current 15-year forward-look analysis into an Enhanced Long-Term Planning Process. This process would both:

- Include a detailed survey of customer and future needs of its states that would help to inform the development of future scenarios and the ultimate choice of one or more scenarios to guide future planning; and

- Empirically evaluate the 15-year planning horizon to allow transmission providers to account for trends in projected resource mix (interconnection queue and retirements) and load (demand response, energy efficiency, and impact of electrification), as well as leveraging probabilistic techniques where appropriate as part of the scenario development effort.

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[88] *See* Section III.A, *supra*.

1. Customer Input as Part of the Enhanced Long-Term Planning Process

Engagement by states and stakeholders is essential to further define the input assumptions to long-term planning scenarios. In implementing the Enhanced Long-Term Planning Process, PJM would utilize survey techniques and processes to create a record of future customer-identified needs so that the choice of scenarios and future planning decisions are based on a record of defined customer needs, as opposed to the RTOs mere prognostication of future needs. The customer intake process would include an analysis of state and federal goals regarding future portfolios, as well as legislation mandating generation retirements and their associated timelines. Other data collected would include the level of future interconnection queue resources and generation retirement as a part of traditional transmission planning reinforcement outside of the interconnection process.

2. Probabilistic Planning Component of the Enhanced Long-Term Planning Process

Probabilistic planning techniques may provide additional scope and insights. Probabilistic planning scenario development, along with leveraging a Monte Carlo-like approach to transmission expansion,[89] could provide an optimal hedge against probable scenarios (as opposed to trying to deterministically eliminate all violations in all scenarios). Such an approach may include analyzing the stochastic behavior of renewable resources, analyzing multiple generation output profiles, while also analyzing a future cascading path resilience criteria in order to identify potential transmission corridors to address both needs.[90]

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[89] A Monte Carlo-like approach to transmission expansion refers to a broad class of computational algorithms that rely on repeated random sampling to obtain numerical results. The underlying concept is to use randomness to solve problems that might be deterministic in principle.

[90] *See* Section V.B, *infra* (discussing how PJM currently uses a "Cascading Trees" methodology to incorporate probabilistic methods into its planning process to analyze High-Impact-Low-Frequency ("HILF") events and to identify areas of risk and potential resilience enhancements to the grid).

3. *Rationale for Potential Modification to the Planning Process*

The ANOPR seeks comments on whether the transmission system should be planned to ensure delivery of generation resources not yet in the interconnection queue. PJM believes the answer to that question is "yes," as long as sufficient guardrails are put in place. Specifically, as PJM explains above, building transmission for estimated future generation that has not yet entered the interconnection queue – let alone proceeded to an ISA – could subject load to high costs associated with the construction of new transmission facilities for generation that may never achieve commercial operation.[91] Therefore, PJM believes that it is important that, if the Commission requires transmission planners to build transmission for estimated future generation, the construction of such transmission should be informed by: (i) customer input based on surveys as described above, (ii) articulated state and federal clean energy goals, (iii) planned generation retirements; and (iv) to the extent possible, generation within the interconnection queue.

Moreover, PJM envisions a process whereby state policymakers and the Commission will support the proposal to construct such transmission based on long-range future generation forecasts before the directive to construct the transmission is actually issued. Having a record developed through the Enhanced Long-Term Planning Process, as described above, will help support the transmission planner's decision to build transmission for estimated future generation. However, affirmation by state policymakers for the proposed build (and its attendant cost) is appropriate to ensure that customer dollars are committed wisely and with full support of the policymaker.

As PJM has discussed with stakeholders, one option could be to build transmission for new interconnection projects in the existing queue based on observed large concentrations of generators in some subzones visualized with heat maps. Transmission enhancements could be developed for

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[91] *See* Section III.D, *supra*.

those facilities impacted by the injection of generators located in these generation-centric areas and further advance renewable energy projects to more efficiently meet state or federal policy goals.

Additionally, probabilistic methodologies could be explored as a way to assist in scenario development to protect against assumptions that may result in transmission overbuild and thereby protect consumer interests. PJM cautions, however, that such probabilistic methodologies should not be viewed as a "silver bullet," and will require more industry dialogue.

As part of the long-term planning process, neighboring systems would coordinate the exchange of upfront modeling information and discuss a summary of analysis results. Potential violations would be reviewed with neighboring systems to identify potential overlaps, which could be more effectively addressed as part of the interregional coordination process. These overlaps would then be re-analyzed and discussed as the long-term planning horizon approaches the short-term planning horizon. Existing stakeholder processes associated with ISO/RTO interregional coordinated planning initiatives would provide the appropriate forum to formulate such coordination including addressing identified overlaps.

4. *Role of the 15-Year Enhanced Long-Term Planning Process*

PJM believes that 15-year long-term planning studies will help highlight areas of the system that may experience increased transfers and transmission criteria violations, providing advanced situational awareness of potential need for required system reinforcements. The 15-year long-term analysis results will inform stakeholder discussions and set in motion the review of potential solutions as input assumptions become more certain as we approach the long-term 8-year analysis. For example, the identification of similar violations within a common electrical area multiple years in a row would allow transmission planners to identify more holistic solutions such as the conversion of multiple 138 kV aging facilities to 230 kV facilities.

5. *Interaction of the 15-Year Enhanced Long-Term Planning Process with Annual RTEP Development*

To ease in administering this process with the RTEP deadlines and associated compliance, PJM would maintain its current near-term analysis on a 5-year-out base case, reflecting any approved system upgrades as part of the 8-year base case. The near-term analysis on the 5-year out base case will continue to address retirements and interconnection queue generation with signed ISAs. The goal would be to allow for the development of a long-term plan while avoiding the time constraints associated with issuing an annual RTEP for the first five years of the planning horizon. Moreover, the annual RTEP process will provide a check on the process so as to ensure continued support by states and the Commission, as well as allowing for any needed course correction.

6. *PJM's Recommendation for Proposed Commission Action for the NOPR Regarding Enhanced Long-Term Planning*

Through the above sections (IV.C.1 through IV.C.5), PJM has outlined its conceptual thoughts on how it could expand its current planning processes to address additional forward planning as suggested in the ANOPR. PJM recognizes that the above changes require additional review and discussion, and eventually would need to be filed with the Commission either through a compliance filing or an FPA section 205 application.

By the same token, PJM believes that the Commission should incorporate a basic obligation on all transmission providers, both in RTO and non-RTO regions, to undertake a forward looking analysis that includes both building a record of future customer-identified needs and undertaking the probabilistic analysis described above.

In order to effectuate these changes, PJM asks the Commission to:

- Ensure consistency in the application of any future rule in this area by requiring all planning authorities to seek customer and policymaker input on regional needs as a key component of longer range (*e.g.*, beyond 5-years forward) planning. The Commission should also require documentation of those identified needs to inform future long range transmission planning. PJM has submitted proposed language for inclusion in a Proposed Rule to address this requirement;

- Provide clear guidance as to the appropriate drivers that planning authorities (whether in RTO/ISO regions or not) should use in determining whether and when to order new transmission based on long-range future generation forecasts. Speculative forecasts of future at-risk generation and future locations of generation beyond that already in PJM's interconnection queue could have the detrimental, unintended consequence of skewing power markets. Although the specific application of the policy can and should vary by region, it would not be helpful to allow a completely separate patchwork approach across the country of policy drivers and decision criteria that planning authorities should consider in deciding, out of the various scenarios tested, which should result in projects being selected. Moreover, because costs to customers can begin to accrue once an RTO/ISO approves a given transmission project, it is appropriate for the Commission, as the ratemaking agency, to provide guidance to planning authorities as to the drivers that planning authorities should use in determining whether to order construction of new transmission or forego from directing the construction of new transmission based on its forecast of future generation;[92]

- Provide clear guidance regarding the allocation of costs of new transmission resulting from projections of future unannounced generation retirements and interconnection queue generation without signed ISAs. The Commission could consider one of the Six Options for cost allocation that PJM developed with its stakeholders[93] or select an entirely different measure of beneficiaries as it sees fit; and

- Build into the Final Rule processes to ensure, from the time period that the project need is first identified to the actual authorization of construction, continued state policymaker support and Commission review of the commitment to construct major new transmission to meet estimated future generation and the attendant costs of that transmission. This would help to avoid projects later being second-guessed as policy preferences and administrations change.

D. Interconnection Initiative and Participant Funding

PJM understands the Commission's concerns regarding not only the need for reforms to existing interconnection processes generally, but also the potential need for reforms to interconnection funding policies. That said, PJM strongly believes that the Commission should take a far more surgical approach, and not derail the positive steps toward reform of the processing of

[92] This requirement is also captured in PJM's proposed revisions to Attachment K of the *pro forma* OATT, set forth in Appendix A.

[93] *See* Section IV.D.2, *infra*.

interconnection requests that are underway in PJM, and in other RTOs. PJM expects to be file proposed reforms with the Commission in the first quarter of 2022.

In particular, as PJM discusses below, it is actively engaged with its stakeholders to work towards implementing revised rules governing the management of its interconnection queue. PJM believes that such reforms are more appropriately addressed on a RTO- or region-specific basis.

On the other hand, PJM believes that the Commission *could* address potential alternatives to the strict "cost causer pays" rule of Order No. 2003 via a national rulemaking. The two issues are severable and, accordingly, should be sequenced to allow region-specific reforms on interconnection queue management to move forward, while the Commission undertakes a larger policy discussion as to whether it wishes to depart from the "cost causer pays" requirement of Order No. 2003.

PJM discusses below its ongoing interconnection queue reform stakeholder process, as well as the potential cost allocation alternatives being vetted through its stakeholder process.

1. The Commission Should Allow Ongoing Regional Interconnection Process Reforms to Continue and the Commission Should Address Proposed Revisions on an RTO- or Region-Specific Basis

a. PJM's Ongoing Interconnection Queue Management Reforms

While PJM's existing interconnection queue process[94] has been a useful tool in helping to achieve states' renewable targets, PJM recognizes that changes to its interconnection process may be warranted due to an increase in the number of New Service Requests received each year, leading to a record-high volume of projects under study.[95] This increase in New Service Requests directly

[94] PJM's existing interconnection process is designed to provide nondiscriminatory treatment for all interconnection customers, regardless of project type. The interconnection process promotes open access and competition through its "first come, first served" queue structure. *See Chesapeake Transmission, L.L.C. v. PJM Interconnection, L.L.C.,* 116 FERC ¶ 61,234, at P 38 (2006) ("[P]riority for the requests of interconnection customers and transmission delivery customers for service is established on a first come, first served basis" (citing *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, 106 FERC ¶ 61,220, at P 541 (2004))).

[95] The changing makeup of the project interconnection queue is being driven by increasing numbers of smaller generation resources – primarily renewable and storage – seeking to interconnect to the transmission system and participate in PJM's markets.

impacts, on a cascading basis, PJM's study process and timing.

In light of the backlog in the study segment of its New Services Queue, in October 2020, PJM launched a comprehensive set of workshops to explore and collaborate with developers, transmission owners and other stakeholders on ways to improve the interconnection process in step with PJM's rapidly growing New Services Queues and evolving grid. This four-workshop series[96] focused on: (i) the history and an overview of federal interconnection policy, (ii) PJM's long-standing processes, as well as stakeholders' feedback on PJM's interconnection process, (iii) challenges ahead posed by increasing renewable development, and (iv) suggestions for improvements. PJM and stakeholders addressed a number of issues during these workshops, including timing in the queue, flexibility of the current process, the difficulties of cost allocation and the first to cause construct, and issues surrounding project readiness.

Following the workshop series, PJM launched the Interconnection Process Reform Task Force, or IPRTF.[97] In consideration of the feedback received through the IPRTF, PJM has offered a proposal solution to its stakeholders that contemplates two fundamental changes to PJM's current interconnection process. First, PJM has proposed to transition from the current "first-come-first-served" process to a "first ready–first served" process. In order to demonstrate readiness, PJM has proposed that developers be required to meet more stringent site control milestones and submit at-risk readiness deposits to show their commitment towards moving forward.

Second, PJM has proposed to restructure its cost allocation process such that all projects in a particular cycle will share the costs of network upgrades. This is in contrast to PJM's current cost allocation process, pursuant to which the first project to cause the need for the network upgrades pays 100 percent of the cost with subsequent reimbursement.

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[96] *See* https://insidelines.pjm.com/pjm-to-explore-interconnection-process-reform/.

[97] *See* n.20, *supra*.

In addition to these two fundamental changes, PJM's solution proposes: (i) scheduled retools and project modifications (reductions, suspensions, withdrawals); (ii) cost certainty improvements by gating future project studies by completion of prior cycles first; and (iii) simplification of the application process and review windows.

The IPRTF is also currently considering four different solution proposals by stakeholders, which are variations of PJM's proposal. The current IPRTF schedule allows stakeholders to continue to refine the proposals through October 2021, and to vote on a solution package to move forward. The IPRTF is targeted to complete its activities by end of 2021 with the intent of filing comprehensive Tariff revisions with the Commission in the first quarter of 2022.

b. PJM's Recommendations Regarding Interconnection Process Reforms

As indicated above, the Commission has suggested a number of potential reforms to interconnection processes generally aimed at addressing queue delays and cost allocation uncertainties in RTO/ISO interconnection processes.[98] Specifically, the Commission has proposed mechanisms to discourage the practice of speculative interconnection requests;[99] fast-tracking the process for generators that have committed financially to new regional transmission facilities;[100] and fast-tracking requests that meet certain readiness criteria, such as a project with an executed power purchase agreement, or one sited at a previously developed point of interconnection.[101]

PJM and its stakeholders are currently exploring these very issues with its stakeholders through the IPRTF. The solutions arising out of this task force will specifically be tailored to the needs of PJM and its stakeholders. PJM strongly believes that existing regional process reforms,

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[98] ANOPR at PP 150-158.

[99] *Id*. at P 138.

[100] *Id*. at P 157.

[101] *Id.*

such as management of interconnection queues, should be encouraged, but not derailed, as the result of a Final Rule. PJM believes that reforms addressing the processing of queue requests can and should go forward through individual RTO/ISO filings versus prescriptive national rules. Each RTO/ISO already has interconnection process approaches in place that are tailored to its respective needs. Each RTO/ISO is at a different place with respect to the proposed ANOPR reforms governing current backlog, "fast-tracking," and financial commitments to demonstrate readiness. If the Commission should decide on national rules, existing RTOs/ISOs – unlike non-RTOs/ISOs – should be permitted to demonstrate why an independent entity variation in this area should be accepted by the Commission.

2. *If the Commission Wishes to Address Interconnection Pricing Policies More Broadly, It Should Do So on a National Basis and Sever Those Considerations From the Need for Interconnection Process Reforms on a Regional Basis*

The currently-effective, Commission-approved participant funding policy requires an interconnection customer to pay for interconnection facilities,[102] as well as interconnection-related network upgrades,[103] that would not otherwise be required "but for" the new or modified interconnection(s).[104] The Commission now posits, however, that "changing circumstances have cast doubt on whether it continues to be just and reasonable to provide RTOs/ISOs with the flexibility to adopt participant funding approaches for interconnection-related network upgrades."[105]

As an initial matter, for the reasons stated in Section III.C above, PJM believes that the Commission's concerns about participant funding[106] are premised on inaccurate assumptions.

[102] Tariff, Definitions I-J-K.

[103] Tariff, Definitions L-M-N.

[104] *See, e.g.*, Order No. 2003, 104 FERC ¶ 61,103, at P 679 (pursuant to a "policy of participant funding . . . those [that] benefit from a particular project pay for it").

[105] ANOPR at P 111.

[106] *Id*. at PP 123-130.

Nonetheless, PJM proposes that if the Commission determines that the current cost allocation process is no longer just and reasonable, rather than eliminating participant funding altogether, the participant funding policy should be amended in order to make the resulting cost allocation process more fair and efficient. PJM describes below the Six Options, which are alternative pricing options that have been developed and reviewed in the context of PJM's Interconnection Policy Task Force since before the issuance of the ANOPR.[107]

PJM believes that if the Commission finds that a departure from Order No. 2003's "cost causer pays" cost allocation for new interconnections is warranted, the fundamentals of the cost allocation should be addressed on a nationwide basis. Although the *application* of the policy can be addressed in individual regional compliance filings, the Commission should be reluctant to skew decisions on where generators choose to locate based on the level of cost responsibility they will bear in different regions. If the Commission wants to recognize the national scope of the drive toward renewables, then a nationwide set of guiding principles should apply.

PJM is cognizant of the flexibility the Commission provided through the independent entity variation built into Order No. 2003.[108] This has served the PJM Region well given the fact that generators in the PJM Region do not pay costs for transmission service and receive valuable CIRs that might not be available in other regions. However, any fundamental change to the overarching "cost causer pays" principles of Order No. 2003 must be made applicable on a national level to avoid

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[107] Chairman Glick served as the keynote speaker at the Interconnection Policy Forum Workshop's initial kick-off meeting. *See* https://insidelines.pjm.com/pjm-launches-interconnection-policy-workshop-series/.

[108] *See* ANOPR at P 110 (explaining that "each RTO/ISO sought an independent entity variation to adopt a participant funding approach rather than adopt the crediting policy"). *See also* PJM's Order No. 2003 compliance filing submitted on January 20, 2004 in Docket No. ER04-457-000, in which PJM sought to continue its participant funding model for generator interconnections. Specifically, PJM requested, and the Commission granted, an independent entity variation for PJM to depart from the default Order No. 2003 crediting policy in favor of the participant funding model that is often referred to as a "but for" funding mechanism for interconnections of new generation resources. PJM stated that this funding construct for Network Upgrades would send the appropriate price signals for siting new generation resources. *See* Answer of PJM to Comments and Protests, Docket No. ER04-457-000, at 4 (filed Feb. 25, 2004) ("PJM 2004 Answer").

skewing generator interconnection decisions among various RTOs or otherwise forcing load in different areas to bear very different allocations of the cost to interconnect.

a. Participant Funding in PJM

Currently, PJM uses a participant funding approach to allocate costs associated with generation interconnections.[109] That is, the generator pays all costs for upgrades (both attachment facilities and network upgrades) that are needed due to the generator's proposed interconnection.[110] PJM evaluates each generator that enters its queue and determines the "but for" system enhancements needed for the generator to interconnect to the transmission system (*i.e.*, those network upgrades that would otherwise not be needed "but for" the interconnection request). Generators that are the "first to cause" the need for a network upgrade must pay for 100 percent of the costs of the network upgrade. Thus, the generator, not load, bears the risk of its decisions, including whether the generation asset reaches in-service commercial operation, including the attendant transmission capability to deliver its power to the grid.

In return, the interconnecting generator has free use of the entire transmission system and its wide reach throughout the PJM Region, all of which was paid for by load or previous interconnecting customers. Moreover, load has the continued responsibility going forward to ensure the deliverability of each of the generators once they are interconnected to the system and in service. In this way, participant funding represented a "grand bargain" of sorts – an equitable sharing of the

[109] PJM adopted participant funding to encourage "smart" placement of new generation, and to send a price signal for inefficient placement relative to congestion on the system. *See PJM Interconnection, L.L.C.*, 87 FERC ¶ 61,299, at P 17 (1999) ("… generators will be required to pay the full cost of grid expansion …. this type of proposal forces the developer to consider the economic consequences of its siting decisions when evaluating its project options, and should lead to more efficient siting decisions."). In Order No. 2003, the Commission provided RTOs/ISOs with the flexibility to propose participant funding for interconnection-related network upgrades for a generator interconnection. *See* Order No. 2003 at PP 28, 694.

[110] *See* Tariff, section 217.3(a).

risks, rewards and costs of ensuring a reliable grid that is available both to new interconnecting generators and load serving entities.

As indicated, although generators initially pay for 100 percent of the costs of any network upgrades necessitated by their interconnection, generators do not pay the costs of transmission service in PJM once they are interconnected to the transmission system. Additionally, in return for funding network upgrades, interconnection customers receive CIRs that assure their continued deliverability 24 hours a day, 7 days a week, 365 days per year.[111] The CIRs that generators receive have real value in PJM markets. CIRs are used to monetize and offset interconnection costs in a way that generator owners cannot when they simply receive future transmission service credit, which itself can change in value and end once the cost of the network upgrades are reimbursed. CIRs grant full deliverability to the PJM markets without the need to procure transmission service as under a load-funded approach. Finally, once a new generator is interconnected to the transmission system, load takes on the cost responsibility to upgrade the system to ensure continued deliverability.

In short, participant funding has served each entity well over the years as it is grounded in an equitable allocation of risk and reward. Although, as noted below, PJM is open to other cost allocation approaches applied on a national basis, the Commission should keep in mind the fundamental rationale and policy that led to the development of participant funding in the PJM Region.

[111] Order No. 2003 at P 700. In addition, generators may be entitled to Firm Transmission Rights ("FTRs") in exchange for "but for" cost payments, as well as Incremental rights such as Incremental Auction Revenue Rights ("IARRs") and Incremental Capacity Transmission Rights ("ICTRs") for any incremental capacity if the generator's project creates incremental capability on the transmission system as defined under the Tariff.

b. PJM's Ongoing Stakeholder Discussions Regarding Interconnection Pricing Policies and Possible Alternative Interconnection Cost Responsibility Options

In recognition of the ongoing evolution of the grid, and in tandem with the IPRTF discussed above, PJM has commenced a series of Interconnection Policy Workshops.[112] Among other things, PJM initiated the Interconnection Policy Workshops to encourage stakeholder discussions about the currently-effective cost allocation methodologies, and particularly discussions about whether any changes or enhancements to the participant funding approach are warranted. Through the Interconnection Policy Workshops, PJM and its stakeholders have discussed the Six Options to explore whether there are more efficient and fairer ways to allocate interconnection-related costs.[113]

Each of Six Options provides a potential path to planning for future generation, including renewable resources, in a way that does not rely solely on the interconnection queue process. Rather, these options provide an approach that can address more than a single queue project and would allow for long-term planning for future generation that would be anticipated to meet state renewable goals. All of these options would impact the current cost allocation construct of participant funding for transmission upgrades in that load serving entities and ultimately their customers would assume some degree of cost responsibility.[114] It is for this reason that PJM presents these not to advocate one or the other, but instead to put into the record the thoughtful discussion that stakeholders have had in the PJM Region on each of these Six Options.

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[112] PJM initiated the Interconnection Policy Workshops in order to complement, but not delay, the specific interconnection reforms discussed in the IPRTF, by focusing on larger policy issues that affect interconnection.

[113] *See* Interconnection Policy Workshop: Session 3 Presentation of Six Options at https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210722-workshop-3/20210722-item-03-interconnection-policy-reforms-overview-presentation.ashx.

[114] PJM has also been meeting directly with state commissions to explore these options and discuss how these policy constructs could enable their public policy objectives and what concerns they might have. It is reasonable to expect that if a state would agree to fund new transmission to support the interconnection of its preferred resource types, whether it be one of the Six Options described above or the current State Agreement Approach process detailed in the Operating Agreement, that there would be a commensurate assurance that the transmission would be available for its preferred resource types.

Discussions regarding the Six Options remain ongoing, and implementation and cost allocation details have not yet been fully flushed out. Therefore, PJM provides a very high level review of the Six Options under consideration:

- ***Option 1: State Underwriting for Transmission to Particular Renewable-Rich Areas as Identified by Queue Requests***

    - Based on demand, as identified by the New Services Queue and state policies, states could voluntarily take responsibility for funding network upgrades based on their renewable portfolio goals. States that have high renewable portfolio standards ("RPS") standards and wish to develop a "backbone system" that could ensure the most delivery of these renewables to meet their aggressive goals may wish to consider this approach, obviously depending on the level of costs and the relative efficiencies of such a backbone system as opposed to individual upgrades in meeting their RPS targets.

    - Potential implementation methods may include the following:
        - Network upgrades that exceed a certain dollar threshold could be presented to states for their consideration as to whether they wish to underwrite these costs under the State Agreement Approach;[115]
        - Network upgrades with 10 or more interconnection projects impacting the same facility are provided to the state with an option for the state to support the funding of the facility through assessment to load; or
        - Generators that have impacts on the facility reimburse the state under the terms and conditions set forth in an agreement under the State Agreement Approach process.

- ***Option 2: Enhancing Baseline Upgrades for Transmission to Particular Renewable-Rich Areas as Identified by Queue Requests***

    - Under this approach, the interconnection queue and concentrations of new renewable generation in a particular location, as evidenced by their queue requests, could trigger PJM to undertake a review of whether a more robust solution than individual upgrades would be the most efficient and cost effective way to meet state RPS targets. Unlike the more blanket approach of Option One, the queue would still provide valuable information on what the market is indicating are the best locations for new generation so as to avoid states having to underwrite random project interconnections in locations where there are not concentrations of generation.

    - Potential implementation methods may include the following:
        - PJM would examine the queue requests and present to the affected states a potential more robust transmission upgrade solution for those areas where the market, as evidenced by generation in the queue that are expected to move to

[115] *See* Operating Agreement, Schedule 6, section 1.5.9.

the ISA stage, indicate an interest. Interconnections in other locations where there is not a critical mass of renewables or more efficient transmission solutions would still be subject to today's participant funding policy. This would have the benefit of incenting generators to locate in optimal renewable-rich locations and ensure the development of a more efficient future grid while still respecting the rights of generation owners to locate at other places on the grid.

  - Cost Allocation: Costs allocated consistent with existing rules.

- ***Option 3: Option for Transmission Owners to Treat Upgrades as Supplemental Projects***

  - Under Option Three, one would maintain the 'but for' responsibilities of the generation owner to fund network upgrades but make clear that transmission owners could elect, under clear guidelines and with load support, to expand the grid to renewable-rich areas as Supplemental Projects. This would maintain the existing drivers of baseline planning grounded in reliability or market efficiency needs and the SAA but would provide another vehicle for transmission owners to develop requested projects. Clear rules would need to be established to ensure both transparency and nondiscriminatory application of this new potential expansion of what constitutes Supplemental Projects and its interrelationship with upgrades developed through the interconnection process.

  - Potential implementation methods may include:
    - Transmission owners and/or interconnection customers can voluntarily agree to develop upgrades based on queue activity;
    - Project-related costs would still be subject to review by the Commission, but would not be subject to Order No. 1000's competitive bidding requirements.

  - Cost allocation: Costs assigned to a single Transmission Owner zone consistent with existing cost allocation rules for Supplemental Projects.[116]

- ***Option 4: Baseline Upgrades for DOE-Identified Transmission Corridors per the Energy Policy Act of 2005 (EPAct 2005")***[117]

  - EPAct 2005 established a role for the DOE to declare, based on a direct grant of authority from the Congress, that development of projects within a given transmission corridor is in the national interest. Specifically, EPAct 2005 directed the DOE to create "transmission corridors" in locations that would help to address congestion on the interstate electricity transmission grid. A designation that projects in a given corridor are determined to be in the national interest would inform the allocation of costs under the Seventh Circuit Court of Appeals' ruling that costs must be allocated

[116] *See* Operating Agreement, Schedule 6, section 1.6(a) (Supplemental Projects are integrated into the RTEP approved by the PJM Board, but are not included for cost allocation purposes).

[117] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

"roughly commensurate with" benefits,[118] as Congress and DOE would have declared that transmission developed in certain corridors benefits the national interest, potentially allowing for a broader allocation of costs.

- Potential implementation methods may include:
  - Corridor-designation could be expanded to include reduction in congestion to promote power flows from renewable-rich areas.

- ***Option 5: Enhanced Merchant Funding for New Transmission to Renewable-Rich Areas***

  - Merchant transmission would be the primary vehicle for development of longer-distance transmission facilities (especially HVDC lines) that otherwise would not be needed under today's planning drivers. Such an approach could place the risks and rewards associated with building new transmission and seeking "anchor tenants" on merchants rather than captive ratepayers. Merchant transmission facilities would still need to be studied in the interconnection queue as to the degree with which they will cause the need for system upgrades consistent with the analysis that is undertaken for them in the interconnection queue today.

  - Cost allocation: Contractual as between merchant and its customers, while complying with open access rules. Load would not be responsible for costs of interconnecting the merchant transmission facilities.

- ***Option 6: Subscription Option for Generators***

  - Based on analysis identifying multiple interconnection projects impacting the same electrical area as revealed through the interconnection queue and additional PJM analysis, PJM would assess the level of commercial interest, as evidenced by subscriptions, to use the capability of the new transmission line before developing a "multi interconnection network upgrade."

  - Potential implementation methods may include:
    - PJM studies determine whether there is an advantage to assuming large scale network upgrades in that electrical area and whether the thresholds are met for determining that a large scale deployment is advantageous;
    - PJM would post the identified areas of the system and upgrades on its website to seek subscriptions (*i.e.,* interconnection requests looking to use the line). At different levels of subscription an upgrade would advance in the planning process. Such a process could provide for a more appropriate sharing between customers and interconnecting generators of the potentially large costs of new interconnection.

[118] *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009) ("*ICC v. FERC*").

- Cost allocation: Costs associated with the upgrade will be paid for by subscribing projects commensurate with their subscription level. The transmission line would be fully subscribed, such that the cost and investment risk of the transmission is ultimately borne by subscribing generators, not by customers or partially subscribed with load in a given state or set of states willing to underwrite the balance if the transmission line would assist in the state meeting its policy goals.

3. Summary of PJM's Recommendation Regarding Interconnection Initiative and Participant Funding

PJM reiterates its request that the Commission segment its attempts to reform the processing of interconnection requests through this ANOPR, as opposed to addressing, on a national basis, the appropriate allocation of costs between generation developers and load. The former should be allowed to proceed on a regional basis through individual FPA section 205 filings that address particular issues relevant in each region that are resulting in backlogs and allow for region-specific solutions. Those reforms should not be stymied while waiting for a Final Rule in this docket.

By contrast, PJM believes that the Commission could address, once those process reforms are in place, potentially different cost allocation pricing policies that depart from the "cost causer pays" rule of Order No. 2003. That second question should be addressed through the development of a consistent national policy (as was Order No. 2003) in order to avoid distortions in generator interconnection decisions based on a patchwork of different cost allocation rules across the nation. Of course, flexibility can be provided through compliance filings to address the implementation of a Final Rule, but an overarching policy direction change from Order No. 2003's fundamentals requires, in PJM's view, a national approach.

V. COMMENTS ON THE ANOPR'S SPECIFIC PROPOSALS

This portion of PJM's Comments focuses on certain questions posed and proposals suggested by the Commission in its ANOPR.

A. Grid-Enhancing Technologies

In seeking comment on the development of longer-term scenarios for planning purposes, the Commission asks whether and how grid-enhancing technologies[119] should be accounted for in determining what transmission is needed.[120] PJM recognizes that there are many changes on the horizon in terms of decarbonization and planning the grid of the future. Optimizing existing transmission corridors and infrastructure with the application of new technology will assist the industry in achieving these goals while minimizing societal and environmental impacts.

PJM provides below (i) a brief summary of its current processes for evaluating proposals that would deploy grid-enhancing technologies; (ii) a discussion of some of the ways in which PJM has to date attempted to facilitate the deployment of such technologies within the PJM footprint; and (iii) a discussion of future challenges associated with integrating grid-enhancing technology.

1. PJM's Current Processes for Evaluating Proposals to Deploy Grid-Enhancing Technologies

As part of its RTEP process, PJM performs studies that identify, evaluate, and analyze potential transmission expansions and enhancements, demand response programs, and other

[119] The Commission explains in the ANOPR that "[g]rid-[e]nhancing [t]echnologies increase the capacity, efficiency, or reliability of transmission facilities," and states that such technologies "include, but are not limited to: (1) power flow control and transmission switching equipment; (2) storage technologies, and (3) advanced line rating management technologies." ANOPR at n.68 citing *Grid Enhancing Technologies*, Notice of Workshop, Docket No. AD19-9-000 (issued Sept. 9, 2019).

[120] *See id*. at P 48.

alternative technologies as required to maintain system reliability.[121] To the extent submitted as part of PJM's competitive proposal process set forth in Operating Agreement, Schedule 6, or as a State Agreement Approach project,[122] PJM evaluates qualifying grid-enhancing technologies proposals in a manner that is not materially different than the way it evaluates other project proposals.

Although PJM is technology-agnostic when it evaluates project proposals submitted as part of RTEP windows or when proposed by transmission owners as potential Supplemental Projects, PJM nonetheless evaluates the impact of a technology's characteristics on solving identified reliability and market efficiency issues efficiently or cost effectively. Further, PJM evaluates whether a proposal calling for the deployment of a grid-enhancing technology requires any changes to PJM's telemetry, modeling and other operating tools or protocols to support and accommodate integration from a markets and operations standpoint.

Importantly, PJM also conducts the PJM Advanced Technology Pilot Program ("Pilot Program") as a testing ground for new industry technologies[123] that require integration into PJM's operations and market systems. The Pilot Program can identify and study and implementation challenges prior to widespread deployment, minimizing system risk and identifying efficiencies to consider when facilitating broader implementation. Although a grid-enhancing technology is not required to proceed through the Pilot Program to be deployed on PJM's system, it allows PJM and

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[121] Operating Agreement, Schedule 6, sections 1.3(c) and 1.5.7(i)(vi). In addition, PJM's market efficiency planning process specifically considers non-transmission alternatives. *See* Operating Agreement, Schedule 6, section 1.5.8(b) ("Following identification of existing and projected limitations on the Transmission System's physical, economic and/or operational capability or performance in the enhancement and expansion analysis process described in this Operating Agreement, Schedule 6 and the PJM Manuals, and after consideration of non-transmission solutions, and prior to evaluating potential enhancements and expansions to the Transmission System, the Office of the Interconnection shall publicly post on the PJM website all transmission need information, including violations, system conditions, and economic constraints, and Public Policy Requirements[.]")

[122] Operating Agreement, Schedule 6, section 1.5.9.

[123] For context, the Pilot Program has existed for more than a decade to study the viability of integrating emerging technologies that enhance system reliability, operational and market efficiency, and resilience. To date, the Pilot Program has conducted around 30 different pilot projects.

stakeholders to develop an understanding and experience with a new technology's operational performance and limitations.[124]

2. *PJM's Efforts to Facilitate the Deployment of Grid-Enhancing Technologies to Date*

Each grid-enhancing technology possesses different capabilities that present opportunities to improve system reliability and resilience. PJM briefly describes below some of its experience to date:

- ***Dynamic Line Rating ("DLR") Sensors***: In October 2020, PJM and one of its transmission owners, PPL Electric Utilities Corporation ("PPL"), began to pilot the use of DLR sensors on two transmission lines. PJM and PPL sought to determine if the DLR devices could alleviate congestion and provide PJM with real-time information to optimize the performance and increase actual power flow (not just static ratings).[125] The results to date suggest that PPL's installation of DLR sensors are likely to mitigate significant congestion, warranting PJM's removal of a posted market efficiency driver from a competitive proposal window. Although work remains to be done, this is an example of a situation where a proposed transmission technology may have obviated the need for a new or rebuilt transmission line.

- ***Flexible AC Transmission Systems***: A Flexible AC Transmission System ("FACTS") is a power system device that takes more conventional power system components – capacitors and reactors – and integrates them in various configurations with intelligent power electronics, high-speed thyristor valve technology and voltage sourced converter ("VSC") technology. FACTS devices can directly support additional transmission line power flow with reactive power injections at their point of interconnection and can indirectly control power flow by modulating transmission line impedances.[126] PJM cautions against a rush to

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[124] Grid-enhancing technologies may also be tested in the field through other programs, such as through demonstration or pilot projects undertaken or administered by other grid operators, national laboratories, or the Electric Power Research Institute, among others. PJM would weigh the results of pilots administered by others in evaluating the deployment of grid-enhancing technologies in the PJM planning process. *See* Operating Agreement, Schedule 6, sections 1.5.8(a), 1.5.8(c)(2), and 1.5.8(f).

[125] As part of the ongoing pilot, PJM and PPL are performing a full impact analysis, evaluating the technical, market efficiency, and reliability benefits, integration requirements (such as communication, system, operating protocols and governing documents), and a functional area impact assessment (including analyses of markets, operations, and planning and risk management impacts). PJM is also continuing to assess necessary data requirements, associated data volume, rating methodologies, and reliability compliance associated with DLR implementation. PJM is further assessing the interplay between NERC Standards and DLR implementation, and the impact DLR might have on the standards for establishing, monitoring, and controlling system operating limits.

[126] The most common FACTS devices include static VAR compensators ("SVCs") and Static Compensators ("STATCOMs"). PJM's RTEP Planning model includes SVC devices totaling more than 6,100 MVAR. These devices provide system operators with additional operational flexibility to control voltages, particularly during high-voltage conditions overnight when transmission lines are lightly loaded. Additionally, the model includes over 800 MVAR of STATCOM technology. A STATCOM includes a unique design that incorporates voltage-sourced converters and thyristor valves to yield additional performance, in terms of speed and dynamic range, as compared to SVC devices.

judge that one or another emerging technology is a one-for-one replacement for new conventional transmission. The use of FACTS devices in PJM have proven themselves as a technologically sound and cost effective solution for a specifically identified high-voltage issue. PJM expects that transmission owners and other transmission developers will rightly consider FACTS technology when submitting proposals through PJM's competitive proposal windows to solve identified grid issues.

- ***Transmission Tower Configuration Technology***: Transmission towers continue to advance technologically. For example, AEP's Sorenson-Robison Park 345 kV/138 kV line – energized in November 2016 – employs a new tubular steel tower configuration that has yielded shorter tower heights and increased capacity within an existing 138 kV right-of-way. This design, coupled with low impedance bundled conductors, reduces line losses and significantly increases power delivery capability while avoiding the complexities and costs of series compensation. Overall, the design increases line capacity by 50 percent, reduces system losses and maximizes transmission efficiency. Similarly, lines made from composite core conductors can lower line losses by 25 percent to 40 percent compared to traditional aluminum conductor steel reinforced cable. PJM expects that it will continue to see more transmission tower technology innovations in the future. PJM expects that transmission owners and other transmission developers will rightly consider new transmission tower technological advances as part of the development of cost effective engineering solutions submitted through PJM's competitive proposal windows to solve identified reliability and market efficiency congestion issues.

3. Future Challenges Associated With Integrating Grid-Enhancing Technology

Fundamental challenges exist in terms of integrating each grid-enhancing technology. PJM recognizes that the dynamic nature of each grid-enhancing technology could introduce a number of different conditions. Grid-enhancing technologies need to be tested and developed in a manner that encourages these non-wires alternatives but does not simply shift technology risk or excess costs to customers. The use of pilot programs, like those described above, allow the industry to understand the efficacy and ability of each type of technology to operate reliably and as expected. Moreover, pilot programs offer experience and validation of operational performance to accelerate the adoption of grid-enhancing technologies. It can also highlight barriers and challenges for the integration of specific types of transmission technologies.

There remain issues associated with the deployment of grid-enhancing technologies by non-incumbents, particularly through the use of pilot programs, given the current rules under Order No. 1000. For example, the question is whether technology like advanced power flow controllers that are installed on existing transmission infrastructure, absent agreement from the Transmission Owner, non-incumbents and technology providers may be prevented from installing such grid-enhancing technologies. Additional guidance from the Commission may be needed to support how to support the advancement of such technology through pilot programs. For instance, PJM recommends that the Commission request the industry, via NERC and/or the DOE, to develop a technology application guide to provide guidance and recommendations on where, when and how to apply grid-enhancing technology. Such guidance would be informed based on both domestic and global industry experience for the optimization of existing substation and transmission facilities, including existing transmission corridors and rights of way to maximize transmission throughput and minimize environmental and economic impacts.

In addition, the Commission should require RTO/ISOs and non-RTO/ISO planning authorities to develop a robust process to account for the potential for grid-enhancing technologies to be integrated into the planning processes as part both near-term and long-range expansion options before requiring that new greenfield transmission be built.

While PJM encourages the Commission to facilitate pilot programs to test new grid-enhancing technologies, PJM cautions the Commission against setting mandates for minimum technology in light of broader considerations at play, including, for example: (i) implementation timelines; (ii) cyber-security concerns; and (iii) transferring technology and liability risk from grid-enhancing technology developers to transmission owners and customers.

B. Probabilistic Transmission Planning Approaches

In the ANOPR,[127] the Commission asks whether greater use of probabilistic transmission planning approaches may help assess the benefits of regional transmission facilities. The

[127] ANOPR at P 49.

Commission notes that transmission providers use various planning techniques ranging from a small number of future scenarios to more advanced stochastic methods. Accordingly, the Commission seeks comment on the benefits and drawbacks of the various techniques in regional transmission planning assessments, including whether these approaches may facilitate the co-optimization of generation siting and transmission development, whether such methods capture savings in generation capital costs and production expenses that can be realized from transmission additions, and whether such methods are required to render rates just and reasonable.

Since the implementation of the RTEP process in 1999, PJM has continued to add elements such as winter peak conditions, low load system conditions, and natural gas pipeline contingencies to the initial summer peak load planning conditions. While traditional transmission planning relies on a set of models, assumptions and scenarios and deterministic analytical tools, new scenarios and more powerful techniques can be used for longer-range scenario development to better understand the full range of possibilities for the grid of the future. This is particularly true given the added uncertainty of future grid expansion needs, complexity associated with renewable generation output profiles, and PJM's growing reliance on a variable fuel source.

Currently, PJM incorporates probabilistic methods into its planning process to analyze HILF events and to identify areas of risk and potential resilience enhancements to the grid. This methodology (called "Cascading Trees") consists of quantifying the probability of cascading outages and its associated impact after an *N-k* disturbance such as a multiple facility trip event, like the loss of an entire substation and all the lines emanating from the substation. At its most fundamental level, a Cascading Trees analysis evaluates an extreme event that encompasses a risk that may, after some number of additional cascading events, lead to system collapse (*i.e.*, blackout). Major blackouts are usually caused by HILF events. Since the attacks of 9/11, the power industry has taken a closer look at system contingencies not only driven by naturally occurring events but additional man-made threats as well, including: (i) cyber-attacks; (ii) loss of interdependent systems; (iii) earthquake; (iv) physical attack; (v) severe terrestrial weather; (vi) geomagnetic disturbance; and (vii) electromagnetic pulse.[128]

PJM uses the Cascading Tree analysis to assess the probability and consequence of cascading outages in electric systems. PJM is currently developing a metric of resilience to complement and enhance a planning process that traditionally has been focused on reliability and market efficiency. The Cascading Trees methodology could be used in decision-making and as a driver for new projects. For example, transmission corridors that appear frequently across multiple cascading paths are good candidates for system reinforcements. Transmission planning for resiliency should not be associated with "gold plating" the system. Rather, surgically addressing a couple of corridors can cut the probability of a severe cascading outage in half, which would align with just and reasonable rates.

A larger shift to stochastic models could become an effective transmission planning tool. One application could involve renewable generation output profiles. These techniques may require a shift away from a deterministic elimination of violations to the identification of an optimal hedge against probable scenarios. These models, however, raise a number of complex issues that will require further thought and resolution:

- how to assign a proper probability to a scenario;
- resolving disagreement over assigned probabilities;
- what constitutes an optimal hedge in all scenarios (*e.g.*, eliminate or minimize violations for 99 percent of cases); and
- compatibility with other analytical tools (*e.g.*, AC power flow, transient stability, electromagnetic transient, etc.).

[128] Any such initial precipitating event could cause one or more transmission line overloads (on common right-of-way), transformer overload, loss of substation, generator under-voltage, or load under-voltage conditions, among others. The high-voltage transmission network that crisscrosses the country was planned based on a set of reliability and efficiency criteria. These criteria generally ensure that the transmission system is capable of withstanding a significant outage to one, or a few, critical pieces of equipment. These planning criteria do not assess, however, what would happen to the system should a significant disruption of many pieces of equipment occur at once, or in quick succession, as might be triggered by an extreme weather event.

PJM believes that probabilistic methods can be a valuable planning tool but should not be viewed as the only solution. PJM will continue to study the application and effectiveness of probabilistic approaches.

C. Enhanced Interregional Coordination

In order to comply with Order No. 1000 requirements, neighboring regions were required to engage in joint evaluation of proposed interregional projects,[129] which included sharing of information regarding each region's respective needs and potential solutions to those needs,[130] as well as identification and evaluation of interregional transmission alternatives to regional needs of neighboring planning regions, data exchange and transparency.[131]

In compliance with Order No. 1000, PJM has interregional joint agreements with all regions adjacent to PJM, which include RTO/ISOs and non-RTO/ISO transmission providers. Specifically, PJM participates in coordinated interregional planning activities with all its neighboring regions: (i) the Northeast: New York Independent System Operator, Inc. ("NYISO")[132] and ISO New

[129] Order No. 1000 at P 435.

[130] *Id*. at P 398.

[131] *Id*. at P 454.

[132] In addition to the Northeastern Protocol, PJM and NYISO entered into the Joint Operating Agreement Among and Between NYISO and PJM ("PJM-NYISO JOA"). The PJM-NYISO JOA provides for the reliable operation of the two transmission systems, as well as the coordination of transmission planning activities, including the allocation of costs of approved interregional transmission projects.

England ("ISO-NE");[133] (ii) the West: MISO;[134] and (iii) the Southeast: Southeastern Regional Transmission Planning ("SERTP") region.[135] The level of engagement between PJM and its neighboring region varies from region to region.

Additionally, PJM participates in the Eastern Interconnection Planning Collaborative ("EIPC"). EIPC was initiated in 2009 by a coalition of regional planning authorities. Its members are entities listed on the NERC compliance registry as Planning Authorities, and represent the majority of the Eastern Interconnection. EIPC builds upon the regional expansion plans developed each year by regional stakeholders in collaboration with their respective NERC Planning Authorities by coordinating similar interconnection-wide analyses and harmonization of regional plans.

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[133] The Northeastern ISO/RTO Planning Coordination Protocol ("Northeastern Protocol" or "Protocol")[133] governs the processes and procedures through which PJM, NYISO and ISO-NE coordinate system planning and stakeholder activities. In addition, the Protocols are conducted in coordination with the Regional Reliability Councils of northeastern United States and eastern Canada. Under the Northeastern Protocol, the parties exchange data and information in support of the coordinating system planning activities, develop power system analysis models to perform analyses required to develop the Northeastern Coordinated System Plan ("NCSP"), and coordinate with the other parties to conduct studies required to determine the impact of a generator or merchant transmission interconnection request or a request for long term firm transmission service.

[134] The PJM Joint Operating Agreement between the MISO and PJM Interconnection, L.L.C. ("MISO-PJM JOA") provides, among other things, for the reliable operation of the neighboring regions and the coordinated planning and stakeholder activities between the two regions, including the allocation of costs of approved interregional transmission projects, data and information exchange, and the analysis of interconnection and long-term firm transmission service requests, incremental auction revenue rights requests and generator deactivations. Under the MISO-PJM JOA, the parties engage in the development of a Coordinated System Plan ("CSP") and CSP study process. The MISO-PJM JOA includes project criteria and cost allocation methodologies for Cross-Border Baseline Reliability Projects, Interregional Reliability Projects, Interregional Market Efficiency Projects, Interregional Public Policy Projects and Targeted Market Efficiency Projects.

[135] To comply with the interregional transmission coordination requirements of Order No. 1000, PJM submitted the Interregional Transmission Coordination Planning Procedures between PJM and the jurisdictional transmission providers of the SERTP as a new Schedule 6-A to the PJM Operating Agreement. The Jurisdictional SERTP Sponsors include the following public utilities: Duke Energy Progress, Inc. ("Duke Energy"), Louisville Gas and Electric Company and Kentucky Utilities Company, Ohio Valley Electric Corporation and Southern Company. The Jurisdictional SERTP Sponsors also filed separately the procedures as attachments to their respective open access transmission tariffs. The interregional transmission coordination procedures provide for coordinated planning between the two regions, including the allocation of costs of approved interregional transmission projects, data and information exchange, as well as posting procedures to allow for the coordination and joint evaluation on an open and transparent transmission planning forum so that transmission providers can engage with stakeholders regarding transmission plans across the regions.

1. The Track Record on Order No. 1000's Interregional Coordination

The Commission seeks comments on whether reforms to the current interregional transmission coordination process, including potentially requiring interregional transmission planning, are needed or appropriate to carry through the potential approaches discussed in the ANOPR.[136] The Commission should be careful to not simply reverse Order No. 1000's directive for "interregional coordination" by insisting on "interregional planning." Words matter, and the Commission's precedent in this area needs to be carefully considered before ordering such a significant shift.

This is not a new issue for the Commission. Order No. 1000, by design, enshrined a "bottom up" interregional planning process. The Commission did so after considering comments filed in its Order No. 1000 rulemaking docket from many regions and states arguing for the Commission to respect regional differences and avoid imposing a "top down" interregional planning regime given disparate regional models, processes and benefit metrics. The MISO-PJM JOA[137] has proven to be a model in interregional coordination.

Although some stakeholders dismiss the interregional coordination provisions of Order No. 1000 as a "failure," a more appropriate view would focus on the fact that coordination among regions (particularly as exemplified by the MISO-PJM JOA and its Coordinated System Plan[138]) has markedly improved since Order No. 1000. In particular, MISO and PJM developed the Coordinated System Plan in order to "ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, enhance the competitiveness of electricity markets or promote public policy."[139]

[136] ANOPR at P 62.

[137] *See* n.134, *supra*.

[138] MISO-PJM JOA, section 9.3.7.

[139] *Id*., section 9.3.

It is true that there have not been a significant number of new "mega-project" multi-mile transmission lines between regions. But, even a facial analysis would reveal the reasons why:

- First, the traditional drivers for large-scale new transmission lines between the regions have not justified such projects;
- Second, congestion has significantly declined in most regions as a result of more limited load growth and development of new generation within each region.[140] This has tended to leave many of the remaining congestion "pinch points" deep within each region rather than at the seams; and
- Third, entities such as the NYISO have been focused on developing renewable generation within the state of New York, rather than increasing exports from PJM.

PJM believes the answer to enhancing interregional coordination lies in avoiding sweeping accusations, and instead creating the analytical framework and transmission planning driver focused on improvements in *interregional transfer capability* to support increased reliability and resilience across the seams, as outlined in our specific recommendation below. Obviously, this would have the ancillary benefit of also encouraging renewable development while avoiding the planning process becoming embroiled in more parochial discussions (and related cost allocation disputes) about whether renewables should be developed in one's home state or imported from distant locations.

2. Accomplishing the Commission's Goals While Avoiding a "Standard Market Design" for Planning

In Order No. 1000, the Commission considered whether "top down" interregional transmission planning reforms were necessary, as opposed to a "bottom up" approach in order to promote cost-effective interregional transmission planning. By way of example, the Commission wrestled with the reality that each planning region had developed different planning processes and

[140] In PJM, total congestion declined from $2,052 million in 2008 to $529 million in 2020. Total congestion costs in 2020 were lower than total congestion costs in any year from 2008 through 2019. *See* PJM State of the Market Report 2020 at Table 11-11, https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-sec11.pdf.

models to analyze benefits for purposes of determining whether a given project met the 1.25 benefit/cost threshold. It was noted in comments to Order No. 1000 that such deference was appropriate[141] since, for example, some regions, such as PJM, can measure market efficiency benefits based on locational marginal price ("LMP") differentials, while neighboring regions such as Duke Energy Progress ("Duke") or Tennessee Valley Authority ("TVA") do not utilize LMPs. A "bottom up" approach allows each region to establish its own benefits calculation and use the interregional coordination process to determine if there are more efficient or cost-effective interregional solutions that would provide benefits not only to each region, individually, but across regions. By contrast, a "top down" approach would have the Commission define an overarching benefit metric that would guide "interregional planning," even if that metric were not consistent with each region's individual benefit metric.[142]

If, on the other hand, the Commission determines that it needs to depart from its Order No. 1000 precedent and drive a "top down" process, the Commission will need to define the explicit "top down" metric it wishes to impose on each region and provide a clear legally defensible directive as to how each region must plan to meet that metric. PJM does not recommend this approach. However, if the Commission is seeking to transform interregional coordination into true "top down" interregional planning, it must wrestle with the need to revisit its fundamental Order No. 1000 finding on this subject, as well as all of the challenges that caused the Commission to adopt a "bottom

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[141] Order No. 1000 at P 643.

[142] When confronted with a request in the Northern Indiana Public Service Company ("NIPSCO") complaint proceeding that PJM and MISO be required to establish singular models, the Commission declined to order interregional planning or singular models. *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator,* 155 FERC ¶ 61,058 (2016) ("NIPSCO Complaint Order"), *order on reh'g and compliance*, 158 FERC ¶ 61,049 (2017). As noted by PJM and MISO in their August 19, 2016 Informational Report filed in the NIPSCO Complaint docket, the revisions to the MISO-PJM JOA, particularly with regard to the Coordinated System Planning Study process, submitted in compliance with the NIPSCO Complaint Order ensure that the RTOs' regional planning processes, "although different from one another in some respects, are appropriately and effectively synchronized with the JOA planning processes." *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc., et al.,* Informational Report, Docket No. EL13-88-000, at 4 (filed Aug. 19, 2016) ("August 19 Informational Report").

up" approach at that time. Given the complexity of this approach, PJM urges the Commission to not rush to this conclusion or add more requirements on the planning regions to drive "interregional planning" without addressing all of the issues that gave rise to its Order No. 1000 decision on this issue.[143]

3. Improving Interregional Transfer Capability through the Development of an Interregional Transfer Capability Metric and Planning Driver

In these Comments, PJM recommends that the Commission, through this ANOPR docket or otherwise, work with stakeholders to develop an ***interregional transfer capability metric*** that can ensure that there is adequate transfer capability between regions so as to enhance both reliability and resilience as the nation faces more extreme weather and other related challenges. PJM believes that a common metric (and planning driver to support transmission expansions to meet that metric) would, in addition to enhancing reliability, have the ancillary benefit of allowing for increased import and export of renewable generation across the regions in other hours of the year without the Commission facing legal challenges that it is forcing development of new transmission to accommodate one particular type of generation.

In addition, PJM continues to work collaboratively with its neighbors to improve transfer capability along its seams. For example, under extreme weather conditions such as the February 2021 Cold Snap, PJM was able to export an unprecedented amount of electricity to its neighboring southwest regions.[144] Under similar conditions, *i.e.*, the 2014 Polar Vortex, PJM relied on the same strong ties to import peak energy of approximately 8,600 MW. *See* Table 6, below.

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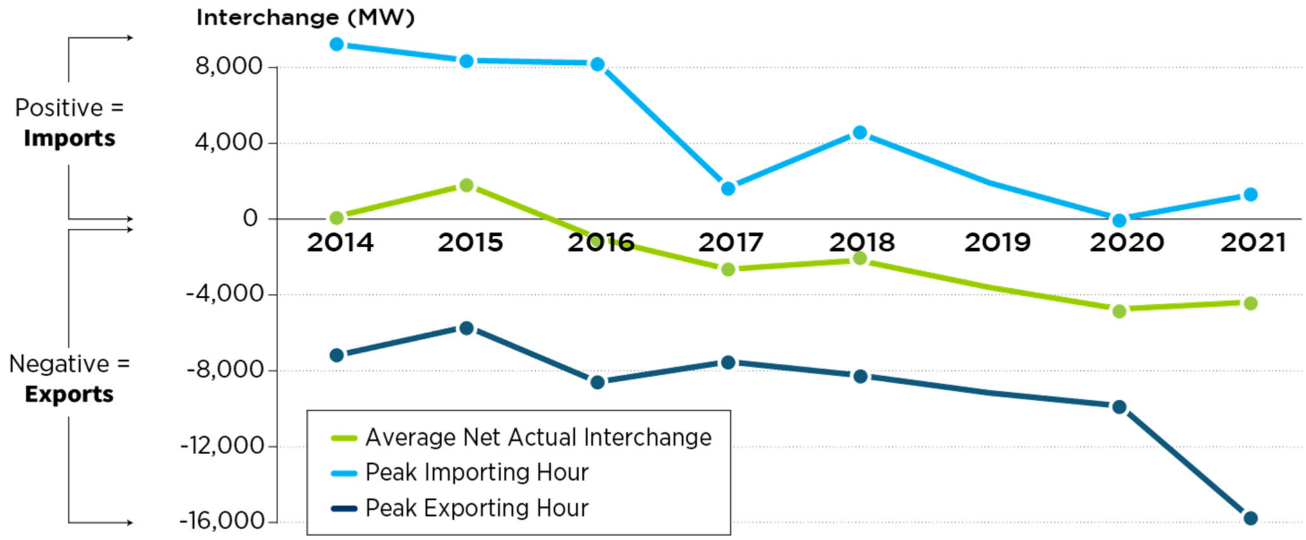
[143] In addition to having to revisit the "bottom up" finding of Order No. 1000, the Commission would need to reverse its ruling that one region can decline to pay for the costs of a project being planned in another region even if the "vetoing" region would realize benefits from that project. *See ISO New England Inc., et al.*, 151 FERC ¶ 61,133, at P 178 (2015).

[144] The February 2021 Cold Snap established a completely new top 10 list of peak winter interchange hours in PJM. During those peak hours, net exports were three times higher than the 2020/2021 winter average, with a high of over 15,700 MW on February 15, 2021. *See* PJM, *Winter Operations of the PJM Grid: December 1, 2020 – February 28, 2021*, at 26–30 (Apr. 8, 2021), https://pjm.com/-/media/committees-groups/committees/oc/2021/20210408/20210408-item-14-winter-operations-review.ashx.

Table 6



Under this ANOPR, the Commission questions whether neighboring regions need to improve transfer capability to access remote generation outside an RTO/ISO's region in order to meet a region's renewable needs. While RTO/ISO and non-RTO/ISO regions can work together to figure out how to plan transfer capability through power flow and engineering analyses, challenging the regions to develop an interregional transfer metric and decision analysis that is grounded in both reliability and resilience needs would help to move this effort along. Moreover, if the Commission were to embrace this approach, the value of enhanced interregional transfer capability must be recognized as a benefit across regions. Such a finding would help to guide, with Commission direction, a cost allocation approach that meets the standard that costs must be allocated "*roughly commensurate with*" benefits. All regions should then be allocated their fair share based on a consistently applied decision analysis and metric defined by the Commission and tied to enhancing the reliability and resilience of the grid.

By contrast, PJM posits that a focus on who is the importing versus the exporting region is not the best approach to this issue. Greater interregional transfer capability has a significant ***reliability benefit*** for both adjoining regions as demonstrated above by the February 2021 Cold Snap and the 2014 Polar Vortex. In short, the Commission should approach the issue of strengthening interregional ties as a broad reliability-based benefit. This would avoid regions arguing about the more parochial issue as to whether renewables sourced from RTO "X" or state "Y" are preferable to renewables from one's own state or RTO.

One approach to moving forward on development of this decision analysis and transfer metric could be for the Commission to work with the industry and stakeholders to explore the development of transfer metrics in an effort to evaluate an appropriate level of import/export capability by Balancing Authority (*i.e.*, X% of load).[145] Such study(ies) may result in a national standard or recommended planning driver for bi-directional transfer capability to enable delivery of power driven by multiple drivers (reliability, market efficiency, public policy and resilience) yielding criteria for which interregional coordination, with input from states on matters such as renewables penetration and siting, can be pursued.[146]

4. Affected System Coordination

While PJM does not recommend prescriptive interconnection-wide requirements for affected system coordination, PJM believes that policy-level Commission guidance would assist both RTO/ISO and non-RTO/ISO regions in better aligning affected systems coordination processes so that interconnection customers are equipped to make financial decisions about whether to move

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[145] For instance, the Commission could work with the DOE to initiate a National Labs Study to be performed with industry input.

[146] Through section 1233 of EPAct 2005, Pub. L. No. 109-58, § 1233(b), 119 Stat. 594, 960 (2005), Congress added FPA section 217, 16 U.S.C. § 824q, entitled "Native Load Service Obligation," which addresses transmission rights held by load serving entities.

forward with proposed projects.[147] Any proposals should allow the RTO/ISOs to leverage stakeholder processes evaluated in the stakeholder process to ensure it fits within the overall structure of each regions interconnection processes.

5. *Summary of PJM's Recommendation to the Commission on Interregional Coordination*

The Commission should embrace the development of a decision analysis and transmission planning driver that would recognize the value of interregional transfer capability to ensure a more reliable and resilient grid in the face of extreme weather and other challenges.[148] To provide the analytical framework to guide this effort, the Commission could work with the industry and stakeholders to explore the development of transfer metrics in an effort to evaluate an appropriate level of import/export capability by Balancing Authority (*i.e.*, X% of load). The transfer metric evaluation should consider resilience, in the form of extreme event planning, which may serve as input into the development of transfer metrics. Depending on the results, a national standard or recommended planning driver for bi-directional transfer capability to enable delivery of power driven by multiple drivers (reliability, market efficiency, public policy and resilience) could yield criteria for which interregional planning can be pursued. As with the resilience issue above, the Commission has ample legal authority to direct a planning driver around interregional capability pursuant to its authority under FPA section 217.

Additionally, the Commission should provide guidance on the issue of cost allocation for upgrades designed to increase transfer capability by defining such actions as a cognizable "benefit"

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[147] The Commission had sought comment on whether it should prescribe guidelines for affected systems analyses and coordination in its Notice of Proposed Rulemaking for Reform of Generator Interconnection Procedures and Agreements issued in Docket No. RM17-8-000. *Reform of Generator Interconnection Procedures and Agreements Notice of Proposed Rulemaking*, 157 FERC ¶ 61,212 (Dec. 15, 2016) ("December 15 NOPR"). The Commission determined to address the affected systems issue in Docket No. AD18-8-000, which docket was terminated by Order issued on September 19, 2019 (the Commission declined to initiate a generic proceeding on the broader affected systems coordination issues raised in the December 15 NOPR).

for purposes of applying the legal standard that costs must be allocated “roughly commensurate with” benefits. Each region would be expected to pay its fair share recognizing that transfers are bi-directional and that enhanced reliability and resilience between regions is a common good that benefits both regions. Such Commission direction could help to shape the resulting cost allocation determinations to follow.

D. The Commission Should Consider the Establishment of Independent Transmission Monitors, if at all, in Non-RTO/ISO Regions

In considering whether additional measures are necessary to ensure appropriate oversight over how new regional transmission facilities are identified and paid for, the Commission seeks comments on whether it would be appropriate to establish an independent entity to monitor the planning and cost of transmission facilities in RTO/ISO and non-RTO/ISO regions[149] or whether different or new transparency measures are needed with RTO/ISO and non-RTO/ISO regions.[150]

In Order No. 890, the Commission expressly declined to require the establishment of an independent third party coordinator as part of the RTO/ISO regions’ planning processes.[151] Despite arguments in favor of such a proposal, the Commission found no need for an independent evaluator in an RTO/ISO region, which already is a Commission-approved independent organization. While the Commission found that there may be benefits to be gained from independent third party oversight, transmission providers, customers and other stakeholders should determine for themselves in developing their regional planning process whether and, if so, how to utilize an independent third party.[152]

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[149] ANOPR at P 163.

[150] *Id*. at P 172.

[151] Order No. 890 at P 567.

[152] Order No. 890-A at P 258 (citing *to* Order No. 890 at P 567).

Additionally, the Commission stated that transmission planners could comply with the Order No. 890 principles without the use of an independent third party as long as a transmission provider could demonstrate in its compliance filing that its regional transmission planning process is open and transparent with a meaningful coordination and dispute resolution process. The Commission elaborated through an open and transparent planning process that included a meaningful dispute resolution process customers would have the opportunity to identify and raise meaningful concerns (i) if a plan did not appear to treat similarly-situated customers in a comparable manner, (ii) where planning appears to be conducted in a discriminatory manner, or (iii) in other instances where the independence of planning may be in question.[153] The Commission concluded that if a dispute should arise and cannot be resolved consensually, the Commission's dispute resolution service is available as well to encourage a consensual resolution or the matter could be resolved by the Commission if a complaint is filed.[154]

To that point, PJM's standing committees specific to planning include the Planning Committee and the TEAC.[155] The TEAC, in particular, offers stakeholders an open, transparent public forum to provide advice and recommendations throughout the development of the RTEP. PJM also conducts stakeholder meetings through three Subregional RTEP Committees (Mid-Atlantic, Western and Southern). These three Subregional RTEP Committees review proposed upgrades of more local concerns.[156]

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[153] Order No. 890 at P 568.

[154] *Id*.

[155] PJM's stakeholder processes were found by the Commission to satisfy its Order No. 890 and Order No. 1000 openness principles through PJM's open and transparent planning committees. *See PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,163, at P 28 (2008), *order on compliance*, 127 FERC ¶ 61,166 (2009), *order on reh'g*, 129 FERC ¶ 61,177 (2009) (Order No. 890 Compliance Orders) and *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 52 (2013) (PJM's 2013 Order No. 1000 Compliance Order).

[156] The Subregional RTEP Committees are open to all interested parties and meet regularly to review local transmission needs on below 230 kV facilities prior to finalizing the Local Plan that is integrated into the RTEP. *See* Operating Agreement, Schedule 6, section 1.3.

PJM conducts its tariffed regional planning process by first developing the study scope and assumptions to be used in identifying system needs.[157] Following identification of system needs, PJM reviews proposed solutions and vets the selection and recommendation of proposed solutions with the TEAC for review and comment before presenting the recommended plan to PJM's independent PJM Board of Managers for review and approval.[158] The TEAC is also involved in review of project modifications[159] and annual reevaluation of market-efficiency projects.[160]

Specific to input from state entities, PJM amended Schedule 6 of the Operating Agreement to include input from the Independent State Agencies Committee ("ISAC").[161] PJM facilitates periodic meetings with the ISAC to discuss: (i) the assumptions used in performing the evaluation and analysis of potential transmission needs; (ii) regulatory initiatives, if appropriate; (iii) the impact of regulatory actions and other trends in the industry; and (iv) alternative sensitivity studies, modeling assumption variations and scenario analyses proposed by the ISAC. At such meetings, PJM also discusses the status of the RTEP study process, including any input received from the TEAC and Subregional RTEP Committees. PJM also informs the TEAC and Subregional RTEP Committees of the input received from the ISAC. ISAC's input is considered in developing the range of assumptions to be used in the studies and scenario analyses of the potential enhancements and expansions to the RTEP. Although PJM had previously engaged with its state commissions, this amendment to its RTEP process memorialized PJM's commitment to meet regularly with state

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[157] Operating Agreement, Schedule 6, sections 1.5.2-1.5.4, 1.5.6(b), (d); 1.5.7(a), (c)(i)-(iii).

[158] *See id*., sections 1.5.7(c)(iii), 1.5.8(d) and 1.6.

[159] *Id*., section 1.5.8(k).

[160] *Id*., section 1.5.7(f).

[161] The ISAC was formed via unanimous resolution by the Organization of PJM States, Inc. ("OPSI"), which officially endorsed the formation of an Independent State Agencies Committee. *See* OPSI Charter at https://opsi.us/wp-content/uploads/2020/10/ISAC-Charter-10.1.20.pdf.

representatives (not limited to state commissions) in order to encourage greater input from the states and to better integrate individual state needs into the regional plans.

Consistent with the requirements of Order Nos. 890 and 1000, PJM has a coordinated open and transparent planning process, as well as meaningful dispute resolution processes for both planning[162] and generator interconnection projects.[163] Absent any evidence that an independent RTO, like PJM, is not implementing its regional transmission planning process in a just, reasonable and not unduly discriminatory or preferential manner, the Commission should follow its decision in Order No. 890 and allow independent RTOs, like PJM, to address this concern by continuing to demonstrate that they have a coordinated open and transparent planning process and meaningful dispute resolution processes. This would be far more efficient than simply creating another independent entity to review an independent entity.

The Commission asks whether the Independent Transmission Monitor would be helpful to address costs and prudence reviews of Supplemental Projects which, by definition, and as affirmed by the Commission,[164] are projects that are not subject to full independent review by PJM. Customer objections to Supplemental Projects have principally focused on the need for and choice of the projects (*i.e.*, its prudence) as well as its costs. Both of those issues are clearly the responsibility of the Commission to oversee and adjudicate through its responsibilities under the FPA. However, customers today arguably face significant litigation hurdles in mounting a challenge to a particular Supplemental Project if they believe it to be imprudent or too costly. The Commission may, as a

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[162] *See* Operating Agreement, Schedule 5, PJM Dispute Resolution Procedures.

[163] *See* Tariff, Part 1, section 12 (*Dispute Resolution Procedures Specific to Disputes between Transmission Customer or New Service Customer, an affected Transmission Owner or the Transmission Provider*) and Part IV (*Interconnection Procedures*), section 40 (*Non-binding Dispute Resolution Procedures*).

[164] *Monongahela Power Co.*, 164 FERC ¶ 61,217, at PP 13 - 14 (2018) ("Monongahela Power"); *see also Appalachian Power Co.*, 170 FERC ¶ 61,196, at PP 59 – 60 (issued Mar. 17, 2020) and *PJM Interconnection, L.L.C.*, 173 FERC ¶ 61,242, at PP 55 - 56 (Dec. 17, 2020) (affirming its decision in Monongahela Power that "[t]he PJM Transmission Owners have primary responsibility for planning Supplemental Projects . . . .").

more constructive first step than the creation of an Independent Transmission Monitor, examine its own processes so as to improve a customer's ability to meaningfully participate in the ratemaking process involving Supplemental Projects.

If, however, the Commission were to require an Independent Transmission Monitor, it would be far more appropriate to begin this initiative in areas where undoubtedly there is *no* structural independence of the transmission planner from its generation affiliates, all of which operate under a single corporate umbrella. That is Thus, rather than create more layers of oversight on independent RTO/ISO regions, the oversight function over cost of transmission and the prudence of those investments not reviewed through the RTEP process are best addressed by improving customers' ability to make their voices heard through the Commission's regulatory process.

VI. CONCLUSION

PJM respectfully requests that the Commission consider (i) the Comments set forth above and (ii) PJM's proposed revisions to Attachment K of the *pro forma* OATT, set forth in Appendix A herein. A thoughtful and surgical approach to planning a grid to accommodate future needs, as defined by the Commission, states and customers, will be the most cost effective and efficient solution to decarbonize the grid, and meet both state and federal policies.

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On behalf of PJM Interconnection, L.L.C.

Dated: October 12, 2021

APPENDIX A

ATTACHMENT K

Transmission Planning Process

Local Transmission Planning

The Transmission Provider shall establish a coordinated, open and transparent planning process with its Network and Firm Point-to-Point Transmission Customers and other interested parties to ensure that the Transmission System is planned to meet the needs of both the Transmission Provider and its Network and Firm Point-to-Point Transmission Customers on a comparable and not unduly discriminatory basis. The Transmission Provider's coordinated, open and transparent planning process shall be provided as an attachment to the Transmission Provider's Tariff.

The Transmission Provider's planning process shall satisfy the following nine principles, as defined in Order No. 890: coordination, openness, transparency, information exchange, comparability, dispute resolution, regional participation, economic planning studies, and cost allocation for new projects. The planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements consistent with Order No. 1000. The planning process also shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890.

Consistent with Order No. [XXX], the planning process shall include procedures and mechanisms to reinforce the resilience of the bulk electric system, which shall mean the ability to withstand or reduce the magnitude and/or duration of disruptive events, including the capability to identify vulnerabilities and threats and plan for, prepare for, mitigate, absorb, adapt to and/or timely recover from such an event.

The description of the Transmission Provider's planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for consulting with customers;

(ii) The notice procedures and anticipated frequency of meetings;

(iii) The methodology, criteria, and processes used to develop a transmission plan;

(iv) The method of disclosure of criteria, assumptions and data underlying a transmission plan;

(v) The obligations of and methods for Transmission Customers to submit data to the Transmission Provider;

(vi) The dispute resolution process;

(vii) The Transmission Provider's study procedures for economic upgrades to address congestion or the integration of new resources;

(viii) The Transmission Provider's procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; ~~and~~

(ix) The relevant cost allocation method or methods; and

(x) The Transmission Provider's procedures and mechanisms for considering transmission needs to reinforce grid resilience, which shall mean the ability to withstand or reduce the magnitude and/or duration of disruptive events, including the capability to identify vulnerabilities and threats and plan for, prepare for, mitigate, absorb, adapt to and/or timely recover from such an event, consistent with Order No. [XXX].

Regional Transmission Planning

The Transmission Provider shall participate in a regional transmission planning process through which transmission facilities and non-transmission alternatives may be proposed and evaluated. The regional transmission planning process also shall develop a regional transmission plan that identifies the transmission facilities necessary to meet the needs of transmission providers and transmission customers in the transmission planning region. The regional transmission planning process must be consistent with the provision of Commission-jurisdictional services at rates, terms and conditions that are just and reasonable and not unduly discriminatory or preferential, as described in Order No. 1000. The regional transmission planning process shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider's regional transmission planning process shall satisfy the following seven principles, as set out and explained in Order Nos. 890 and 1000: coordination, openness, transparency, information exchange, comparability, dispute resolution, and economic planning studies. The regional transmission planning process also shall include the procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000. The regional transmission planning process shall provide a mechanism for the recovery and allocation of planning costs consistent with Order No. 890. <u>Consistent with Order No. [XXX], the regional transmission planning process shall include the procedures and mechanisms to reinforce the resilience of the bulk electric system, which shall mean the ability to withstand or reduce the magnitude and/or duration of disruptive events, including the capability to identify vulnerabilities and threats and plan for, prepare for, mitigate, absorb, adapt to and/or timely recover from such an event.</u>

The regional transmission planning process also shall include the procedures and mechanisms for incorporating long-term scenario planning through surveying and documenting future customer-identified needs in a systematic manner and the use of probabilistic analysis to assist in determining future transmission needs consistent with Order No. [XXX].

The regional transmission planning process shall include a clear enrollment process for public and non-public utility transmission providers that make the choice to become part of a transmission planning region. The regional transmission planning process shall be clear that enrollment will subject enrollees to cost allocation if they are found to be beneficiaries of new transmission facilities selected in the regional transmission plan for purposes of cost allocation. Each Transmission Provider shall maintain a list of enrolled entities in the Transmission Provider's Tariff.

Nothing in the regional transmission planning process shall include an unduly discriminatory or preferential process for transmission project submission and selection.

The description of the regional transmission planning process must include sufficient detail to enable Transmission Customers to understand:

(i) The process for enrollment in the regional transmission planning process;

(ii) The process for consulting with customers;

(iii) The notice procedures and anticipated frequency of meetings;

(iv) The methodology, criteria, and processes used to develop a transmission plan;

(v) The method of disclosure of criteria, assumptions and data underlying transmission plan;

(vi) The obligations of and methods for transmission customers to submit data;

(vii) Process for submission of data by nonincumbent developers of transmission projects that wish to participate in the transmission planning process and seek regional cost allocation;

(viii) Process for submission of data by merchant transmission developers that wish to participate in the transmission planning process;

(ix) The dispute resolution process;

(x) The study procedures for economic upgrades to address congestion or the integration of new resources;

(xi) The procedures and mechanisms for considering transmission needs driven by Public Policy Requirements, consistent with Order No. 1000; ~~and~~

(xii) The relevant cost allocation method or methods. The regional transmission planning process must include a cost allocation method or methods that satisfy the six regional cost allocation principles set forth in Order No. 1000~~.~~;

(xiii) The procedures and mechanisms for considering transmission needs to reinforce grid resilience, which shall mean the ability to withstand or reduce the magnitude and/or duration of disruptive events, including the capability to identify vulnerabilities and threats and plan for, prepare for, mitigate, absorb, adapt to and/or timely recover from such an event, consistent with Order No. [XXX]; and

(xiv) The procedures and mechanisms for incorporating long-term scenario planning through surveying and documenting future customer-identified needs in a systemic manner and the use of probabilistic analysis to assist in determining future transmission needs consistent with Order No. [XXX].

Interregional Transmission Coordination

The Transmission Provider, through its regional transmission planning process, must coordinate with the public utility transmission providers in each neighboring transmission planning region within its interconnection to address transmission planning coordination issues related to interregional transmission facilities. The interregional transmission coordination procedures must include a detailed description of the process for coordination between public utility transmission providers in neighboring transmission planning regions (i) with respect to each interregional transmission facility that is proposed to be located in both transmission planning regions and (ii) to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities. The interregional transmission coordination procedures shall be described in an attachment to the Transmission Provider's Tariff.

The Transmission Provider must ensure that the following requirements are included in any applicable interregional transmission coordination procedures:

(1) A commitment to coordinate and share the results of each transmission planning region's regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than

separate regional transmission facilities, as well as a procedure for doing so;

(2) A formal procedure to identify and jointly evaluate transmission facilities that are proposed to be located in both transmission planning regions;

(3) An agreement to exchange, at least annually, planning data and information;

and (4) A commitment to maintain a website or e-mail list for the communication of information related to the coordinated planning process.

The Transmission Provider must work with transmission providers located in neighboring transmission planning regions to develop a mutually agreeable method or methods for allocating between the two transmission planning regions the costs of a new interregional transmission facility that is located within both transmission planning regions. Such cost allocation method or methods must satisfy the six interregional cost allocation principles set forth in Order No. 1000 and must be included in the Transmission Provider's Tariff.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document on those parties on the official Service List compiled by the Secretary in these proceedings.

Dated at Audubon, Pennsylvania this 12th day of October, 2021.

/s/ *Jessica M. Lynch*
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