UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through	**)**	**Docket No. RM21-17-___**
Electric Regional Transmission	**)**	
Planning and Cost Allocation	**)**	
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REQUEST FOR REHEARING AND CLARIFICATION OF PJM INTERCONNECTION, L.L.C.

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TABLE OF CONTENTS

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Pursuant to section 313 of the Federal Power Act ("FPA"), 16 U.S.C. § 825*l*(a), and Rules 212 and 713 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission" or "FERC"), 18 C.F.R. §§ 385.212 and 385.713, PJM Interconnection, L.L.C. ("PJM")[1] respectfully submits this Request for Rehearing and Clarification of Order No. 1920.[2]

I. EXECUTIVE SUMMARY

PJM strongly agrees with the Commission's goal to encourage long-term, forward-looking, regional transmission planning, including scenario-based planning. Indeed, prior to the issuance of the Final Rule, PJM was at the cusp of finalizing with states and stakeholders an enhanced long-term planning process pursuant to which PJM could choose from an array of future scenarios—developed with state and stakeholder input—to identify, evaluate, and select regional transmission

[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 grids. PJM dispatches approximately 185,000 megawatts ("MW") of generating capacity over more than 88,000 miles of transmission lines.

[2] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 (2024) ("Order No. 1920" or "Final Rule"). All capitalized terms that are not otherwise defined herein have the meaning as set forth in the Final Rule, or as defined in the PJM Open Access Transmission Tariff ("Tariff"), Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), or Reliability Assurance Agreement ("RAA") among Load Serving Entities in the PJM Region. The Tariff, Operating Agreement and RAA are collectively referred to in this filing as the "Governing Documents."

facilities to address long-term needs based on evolving reliability concerns, changes in the resource mix, and changes in demand.[3]

Importantly, the PJM LTRTP Process was designed in such a way as to recognize the unique makeup of the PJM Region—comprised of 14 jurisdictions that have public policy initiatives that are simultaneously overlapping and conflicting[4]—while also taking into consideration the challenges the PJM Region is facing as a result of the accelerating energy transition.[5] PJM's number one responsibility is maintaining system reliability notwithstanding these competing policies and identified challenges. To that end, PJM developed its LTRTP Process with the primary goal of identifying potential factors that will have an impact on long-term reliability that could be developed as reliability projects, while also considering state public policy requirements and goals that could affect long-term needs that could be developed as public policy projects with input from the states whose public policy drive the need for the transmission facility.[6]

PJM appreciates the Commission's confirmation that the Final Rule is not intended to interfere with transmission provider's ongoing efforts to address transmission planning and cost

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[3] As discussed further below, beginning in 2022, PJM has held a series of workshops during which PJM transparently engaged with its states and stakeholders to develop manual language that outlines the framework pursuant to which PJM proposed to engage in long-term, scenario-based, regional transmission planning (referred to herein as "PJM LTRTP Process" or "PJM's LTRTP Process"). The PJM LTRTP Process is described briefly in Section II.C, and more fully in Attachment A. Most recently, PJM transparently engaged with its states and stakeholders to develop manual language the LTRTP Process framework, and planned to bring the manual language to a vote before the Markets and Reliability Committee on April 25, 2024. However, in light of the Commission's April 18, 2024 announcement that it would issue the Final Rule on May 13, 2024, PJM stakeholders voted to defer consideration of the manual language until June 2024. PJM has further deferred consideration of the proposed manual language until such time as PJM has had the opportunity to fully review the requirements of the Final Rule.

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

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

[6] *See* Attachment A. As discussed more fully in Attachment A, under the PJM LTRTP Process, PJM would (i) develop three Long-Term Scenarios, including a base reliability scenario, a medium public policy scenario and a high public policy scenario; (ii) identify long-term reliability and public policy needs over a 15-year planning horizon; (iii) measure the economic benefits associated with facilities that could solve those needs; and (iv) evaluate and decide whether to select any facilities to address any of those identified needs.

allocation,[7] and the Commission's encouragement to transmission providers to "continue to innovate to improve their transmission planning and cost allocation processes."[8] PJM also appreciates the Commission's acknowledgement throughout Order No. 1920 that transmission providers will need significant flexibility to implement the requirements of the Final Rule in their respective planning regions.[9]

However, PJM is concerned that the Final Rule is overly prescriptive in several areas, and that, combined with both (i) the Commission's statement that it will "reject requests for flexibility that exceeds [the flexibility] provided in this final rule"[10] and (ii) its rejection of requests that the Commission apply the "independent entity variation" standard for proposed deviations from the requirements in the Final Rule on compliance,[11] the Commission has diminished the flexibility it promises in these critical areas.[12] In particular:

- ***<u>Development of Scenarios, Including No Discounting of Factors Related to Public Policy Requirements</u>***: The Commission requires transmission providers to develop three distinct "plausible and diverse" Long-Term Scenarios,[13] each of which, at a minimum, must incorporate seven specific categories of factors,[14] where transmission planners must assume that individual factors within the first three categories are fully met.[15] PJM fully

[7] Order No. 1920 at P 13.

[8] *Id*.

[9] *See, e.g.*, *id*. at PP 231, 237, 238, 925, 967.

[10] *Id*. at P 237.

[11] The Commission rejected requests that transmission providers be able to justify, on compliance, any deviations from the Final Rule under the more lenient "independent entity variation" standard, rather than the more rigid "consistent with or superior to" standard. *See id.* at P 1772.

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

[13] *See* Order No. 1920 at PP 575, 599.

[14] *See id*. at PP 409, 411, 415, 599. The seven specific categories of factors include: (1) Federal, federally-recognized Tribal, state and local laws affecting the resource mix and demand; (2) Federal, federally-recognized Tribal, state and local laws on decarbonization and electrification; (3) state-approved integrated resource plans and expected supply obligations for load-serving entities; (4) trends in fuel costs and in the cost, performance and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and Federal, federally-recognized Tribal, state and local policy goals that affect Long-Term Needs. *Id*. at P 409.

[15] *Id*. at P 417.

appreciates the rationale for requiring a Long-Term Scenario that incorporates these factors, and includes in its LTRTP Process a scenario that is consistent with that requirement. As described more fully in Attachment A, PJM's LTRTP Process is premised on identifying long-term reliability needs (including reliability needs driven by certain public policies) and long-term public policy needs (including needs driven by, for instance, the incentivization of specific resource types). It is important for PJM to be able to identify transmission needs this way (*i.e.*, distinguishing between reliability vs. public policy driven-needs) due to the fact that there are 14 jurisdictions within the PJM Region that have disparate public policy goals and requirements. In order to maintain the progress already underway as part of the PJM LTRTP Process, PJM seeks flexibility with respect to the Final Rule's requirements related to scenario development, and specifically with respect to how the Final Rule would require PJM to consider factors in Categories 1-3 without flexibility.[16] Additionally, PJM seeks clarification that it is not obligated to select facilities under any of the scenarios it develops.

- ***Development of Ex Ante Cost Allocation Methodologies Applicable to Long-Term Regional Transmission Facilities***: The Commission specifies that transmission providers "may *not* establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may *not* establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types."[17] Given the long and litigious history of cost allocation in the PJM Region,[18] the PJM Transmission Owners[19] should be permitted to continue to use existing cost allocation methodologies unless and until there is a Commission-accepted Long-Term Regional Transmission Cost Allocation Methodology that takes into consideration the views of the 14 jurisdictions within the PJM Region.[20] Furthermore, an overly stringent cost allocation methodology may impede the selection of facilities to address Long-Term Regional Transmission Needs.

- ***Use of Seven Required Benefits to Identify Long-Term Regional Transmission Needs***: The Commission appears to require transmission providers to use the specific set of seven required benefits "to help to inform their identification of Long-Term Transmission Needs."[21] PJM does not currently use benefits to identify needs as part of its Regional Transmission Expansion Plan ("RTEP") sponsorship model. Other than one specific limited example related to one specific benefit, the Commission does not explain how

[16] *See infra*, Section III.A.2.

[17] Order No. 1920 at P 1474 (emphasis added).

[18] *See infra*, Section III.A.3.

[19] The PJM Transmission Owners have exclusive authority and responsibility to submit filings under FPA section 205 "in or relating to . . . the transmission rate design under the PJM Tariff." *See* Tariff, section 9.1 and Consolidated Transmission Owners' Agreement ("CTOA") §§ 7.1 and 7.3. *See also Atl. City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).

[20] *See infra*, Section III.A.3.

[21] Order No. 1920 at P 301; *see also id.* at P 719 ("[A]s discussed in the Development of Long-Term Scenarios section, these same benefits should help to inform transmission providers' identification of Long-Term Transmission Needs.").

benefits could be used to help inform the identification of needs. PJM therefore requests that the Commission allow for greater flexibility while PJM explores whether and how to incorporate these seven specific benefits into its LTRTP Process.[22]

- ***Requirement to Use Seven Specific Required Benefits***: The Final Rule appears to be a departure from the Commission's commitment in the Notice of Proposed Rulemaking[23] to regional flexibility with respect to the use of any specific benefits. Instead, the Commission requires transmission providers to measure, at a minimum, a set of seven required benefits and then use those seven specific required benefits to evaluate Long-Term Regional Transmission Facilities for selection.[24] PJM developed an evaluation framework based on reliability-first approach coupled with a comprehensive list of broadly-defined benefits which are designed to sum up to system cost impacts. That framework would provide PJM, states and stakeholders with the flexibility needed to innovate and identify the projects that are most beneficial to the PJM Region, while also meeting the reliability needs of the system.[25] PJM therefore requests that the Commission allow for greater flexibility to measure the specific benefits that are most relevant to the PJM Region.

PJM recognizes that the PJM LTRTP Process does not strictly comply with all of the requirements of the Final Rule, and that some implementation details differ in some way from those the Final Rule prescribes.[26] However, PJM believes that the PJM LTRTP Process is directionally consistent with the Commission's long-term planning goals and, importantly, the process recognizes PJM's unique needs and circumstances. PJM therefore urges the Commission to grant rehearing and permit flexibility with respect to the issues identified above (and discussed more fully below) to allow PJM to use the PJM LTRTP Process as the foundation for a long-term planning process that achieves the objectives of the Final Rule. To be clear, PJM does not seek

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

[23] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028, at PP 183-225 (2022) ("LTRTP NOPR" or "NOPR").

[24] Order No. 1920 at PP 719, 721. The seven required benefits are: "(1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme weather events and unexpected system conditions; and (7) capacity cost benefits from reduced peak energy losses." *Id*. at P 720.

[25] *See infra*, Section III.A.5.

[26] PJM intends to modify several aspects of the PJM LTRTP Process on compliance with the Final Rule, including, by way of example, PJM will propose to use a 20-year planning horizon to comply with the Final Rule.

regional flexibility to be able to opt out of any of the fundamental aspects of the Final Rule. Rather, PJM seeks flexibility to implement the requirements of the Final Rule in a less prescriptive way such that PJM can tailor its approach to reflect its unique circumstances and its regional needs.

In addition to the above, PJM seeks rehearing and/or clarification of two additional aspects of the Final Rule:

- ***<u>Greater Coordination Between Existing Order No. 1000[27] Regional Transmission Planning Processes and Generator Interconnection Process</u>***: The Commission's mandate to require greater coordination between regional transmission planning and generator interconnection processes[28] is arbitrary and capricious in its application to PJM, because it ignores contrary evidence presented by PJM, invites gaming opportunities that would undermine PJM's newly-implemented generation interconnection reforms, lead to unduly discriminatory treatment of interconnection customers, and inappropriately shift costs from generation to load.[29]

- ***<u>The Start Date of the Long-Term Planning Horizon</u>***: The Final Rule specifies that (i) the transmission planning horizon starts at the beginning of the Long-Term Regional Transmission Planning cycle and ends 20 years from that date,[30] and (ii) transmission providers must plan for the entire duration of the 20-year transmission planning horizon and to assess Long-Term Needs starting in year one of the 20-year planning horizon.[31] The Final Rule does not fully address to what extent it modifies NERC's definition of "long-term planning horizon," adopted by the Commission in the LTRTP NOPR, which clarifies that the start date of the long-term transmission planning horizon is year six.[32] In the NOPR, the Commission was clear that it proposed to establish the new Long-Term Regional Transmission Planning process as an add-on, supplemental process, that is not intended to

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[27] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g & clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g & 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).

[28] Order No. 1920 at P 1107.

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

[30] *See* Order No. 1920 at P 347.

[31] *See id*. at P 346 ("We clarify that transmission providers ***must plan for the entire duration of the 20-year transmission planning horizon***. Specifically, transmission providers must, among other requirements established in this final rule, develop and use Long-Term Scenarios to identify Long-Term Transmission Needs ***occurring in any period of the 20-year transmission planning horizon and to evaluate potential transmission solutions to those needs.***" (emphasis added)); *id*. at P 347 ("We specify that the ***transmission planning horizon starts at the beginning of the Long-Term Regional Transmission Planning cycle and ends 20 years from that date.***" (emphasis added)).

[32] In the LTRTP NOPR, the Commission defined the long-term planning horizon as the "[t]ransmission planning period that ***covers years six through ten or beyond*** when required to accommodate any known longer lead time projects that may take longer than ten years to complete." LTRTP NOPR at P 94 n.160 (emphasis added and citation omitted).

modify existing short-term reliability and market efficiency processes.[33] The Final Rule lacks this needed clarity and infuses confusion by requiring transmission providers to propose on compliance "a date, no later than one year from the date on which initial filings to comply with this final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle (unless additional time is needed to align the first Long-Term Regional Transmission Planning cycle with existing transmission planning cycles)."[34]

PJM respectfully requests that the Commission grant rehearing and clarification on these issues as further described below.

II. BACKGROUND REGARDING THE IMPACT OF THE ENERGY TRANSITION ON THE PJM REGION AND PJM'S LONG-TERM REGIONAL TRANSMISSION PLANNING PROCESS REFORM EFFORTS

A. PJM State Public Policy Trends Related to the Energy Transition

The PJM Region encompasses all or parts of 13 states and Washington, D.C., which collectively have a diverse set of public policy goals and requirements. As with the entire U.S. electric grid, PJM is experiencing an accelerating transition toward intermittent renewable generation. State and federal policies, economics and consumer choices are shifting the grid away from dispatchable, carbon-emitting, generation resources toward intermittent generation with little-to-no carbon emissions. The pace of retirements is being driven in large part by state laws and federal environmental initiatives that create a clear near-term, date-certain requirement for generation to comply or retire. Ten states in the PJM footprint, plus the District of Columbia, have enacted renewable portfolio standard ("RPS") mandates. These state RPS targets require that a certain percentage of a state's load be served by qualified renewable energy resources.

[33] *See* LTRTP NOPR at P 72 ("With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change Order No. 1000's requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region's reliability and economic requirements.").

[34] Order No. 1920 at P 1768. *See infra,* Section III.B.

Since 2018, Delaware, the District of Columbia, Illinois, Maryland, Michigan, New Jersey and Virginia have all established new RPS targets. On the other hand, PJM also serves states with public policies that move in the opposite direction such as embracing the preservation of existing coal generation in the name of reliability and economic development in their state.

B. The Effects of Policy and Other Impacts on the PJM Region

PJM is facing potential future reliability challenges due to anticipated impacts that the energy transition will have on the PJM Region.[35] First, the growth rate of electricity demand is likely to continue to increase due to electrification coupled with the proliferation of high-demand data centers in the PJM Region.[36] Second, thermal generators are retiring at a rapid pace due to the policies described above, as well as due to private sector policies and for other economic reasons.[37] Third, resource retirements in PJM are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain issues, whose long-term impacts are not fully known.[38] Finally, in response to the policies described above, PJM's interconnection queue is composed primarily of intermittent and limited-duration resources,[39] and

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[35] *See, e.g.*, *Energy Transition in PJM: Resource Retirements, Replacements and Risks*, PJM Interconnection, L.L.C., (Feb. 24, 2023), https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx ("PJM 4R Report").

[36] *See* PJM Resource Adequacy Planning Department, *PJM Load Forecast Report*, PJM Interconnection, L.L.C. (Feb. 1, 2024), https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx. In addition to the retirements, PJM's long-term load forecast shows summer peak demand growth of 1.6% per year for the PJM footprint over the next 10 years and winter peak demand growth of 1.9% per year for PJM over the next 10 years. Due to the expansion of highly concentrated clusters of data centers, combined with overall electrification, certain individual zones exhibit more significant demand growth—as high as 5.5% for Dominion's summer peak 10-year growth rate. PJM 4R Report at 2.

[37] *See* PJM 4R Report at 2. PJM's analysis shows that 40 GW of existing generation are at risk of retirement by 2030. This figure is composed of: 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity. *Id*.

[38] *See* PJM 4R Report at 1.

[39] PJM's New Services Queue consists primarily of renewables (94%) and gas (6%). Despite the sizable nameplate capacity of renewables in the interconnection queue (290 GW), the historical rate of completion for renewable projects has been approximately 5%. *See* PJM 4R Report at 1.

projections show that the current pace of new entry is unlikely to keep up with expected retirements and demand growth.

C. PJM's Proposed Long-Term Regional Transmission Planning Process

The PJM Region's varying state public policy targets, in combination with the trends discussed above, led PJM to engage with states and stakeholders to develop a long-term regional transmission planning process[40] in order to address the identified overlapping grid challenges in a reliable and affordable manner in a way that addresses PJM's unique needs.[41]

Specifically, as described more fully in Attachment A, PJM developed a process pursuant to which it would maintain existing Order No. 1000-compliant near-term (*i.e.*, five-year out) reliability and market efficiency planning processes, and replace its existing long-term reliability planning process with the PJM LTRTP Process as an enhancement to those existing processes. Consistent with the Long-Term Regional Transmission Planning Process outlined in Order No. 1920, PJM's LTRTP Process would also seek to identify the impact of multiple transmission needs scenarios that include the impact of, among other things, traditional factors that PJM considers when identifying reliability needs, load growth associated with electrification and new technologies, the evolution of the generation resource mix to meet public policy and customer demands for lower carbon emissions, and an increase in renewable resources driven by the state public policies identified above.

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[40] As discussed further below, beginning in 2022, PJM has held a series of workshops during which PJM transparently engaged with its states and stakeholders to develop manual language that outlines the framework pursuant to which PJM proposed to engage in long-term, scenario-based, regional transmission planning (referred to herein as "PJM LTRTP Process" or "PJM's LTRTP Process"). The PJM LTRTP Process is described briefly in Section II.C, and more fully in Attachment A.

[41] PJM has always utilized a 15-year forward planning horizon. Nevertheless, reliability violations which occurred during the first five years could not be ignored although the particular remedies ordered by the PJM Board of Managers were designed with an analysis of the longer term needs over the 15-year planning horizon.

Whereas the Order No. 1920 Long-Term Regional Transmission Planning Process would require transmission planners to consider all of these factors in each of three scenarios to identify Long-Term Transmission Needs, PJM's LTRTP process would spread these factors across three distinct scenarios that are designed in such a way as to identify long-term reliability and public policy needs. PJM's LTRTP Process was designed to allow PJM to identify holistic transmission solutions to address the long-term challenges it has identified, while maintaining system reliability and adhering to its current cost allocation methodology. PJM would also calculate multiple benefits for the transmission solutions developed pursuant to the process.

III. REQUEST FOR REHEARING

A. The Commission Should Grant Rehearing and or Clarification and Confirm that Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") Have Flexibility to Tailor Their Long-Term Planning Processes to Accommodate Regional Differences

Throughout Order No. 1920, the Commission acknowledges that transmission providers will need significant flexibility to implement the requirements of the Final Rule in their respective planning regions,[42] and states that the Final Rule allows for such flexibility.[43] The Commission also: (i) recognizes that "transmission providers have ongoing efforts to address transmission planning and cost allocation,"[44] (ii) states that the Final Rule "is not intended to interfere with the potential progress represented by those efforts,"[45] and (iii) "encourage[s] transmission providers to continue to innovate to improve their transmission planning and cost allocation processes."[46] However, as discussed below, there are several critical components of the Final Rule where the

[42] *See, e.g.*, Order No. 1920 at PP 237, 238, 925, 967.

[43] *See, e.g.*, *id*. at PP 231, 967.

[44] *Id.* at P 13.

[45] *Id*.

[46] *Id*.

Commission appears to require strict compliance,[47] and indicates that it will "reject requests for flexibility that exceeds that provided in this final rule."[48]

The Commission's firm position on these specific requirements,[49] paired with its statement that it will reject requests for flexibility not specifically provided for in the Final Rule,[50] is at odds with other statements in the Final Rule recognizing that transmission providers will need significant flexibility to implement the requirements of the Final Rule in their respective planning regions.[51] Such inconsistency renders this aspect of the Final Rule arbitrary and capricious.[52] Moreover, the Commission failed to sufficiently consider substantial evidence offered by nearly every RTO and ISO regarding the need for genuine flexibility on these specific issues in a way

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[47] Specifically, as discussed further below, the Commission appears to require strict compliance with the Final Rule with respect to: (i) the development of three Long-Term Scenarios, each of which must consider seven specific categories of factors, including three categories where the transmission provider has no discretion to weigh individual factors within that category (*see, e.g.*, Order No. 1920 at PP 409, 417, 440, 447); (ii) the development of at least one extreme weather-related sensitivity applied to each Long-Term Scenario (*see* Order No. 1920 at P 593); (iii) the measurement of a defined set of seven required benefits in each Long-Term Scenario (*see* Order No. 1920 at P 409); (iv) the use of the seven required benefits to help to inform the identification of Long-Term Needs (*see* Order No. 1920 at PP 719, 721); and (v) the development of new *ex ante* cost allocation methodologies that cannot account for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve public policy, and that existing cost allocation methodologies cannot be the default until such time as agreement on new methodologies is reached (*see* Order No. 1920 at PP 1291, 1474).

[48] Order No. 1920 at P 237. The Commission further limits flexibility by requiring transmission providers, on compliance, to justify any deviations from the Final Rule under the more rigid "consistent with or superior to" standard, as opposed to the "independent entity variation" standard. *See id.* at P 1772, *cf Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 827 (2003) ("With respect to an RTO or ISO . . . we will allow it to seek 'independent entity variations' from the Final Rule . . . . This is a balanced approach that recognizes that an RTO or ISO has different operating characteristics depending on its size and location and is less likely to act in an unduly discriminatory manner than a Transmission Provider that is a market participant."), *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), *cert. denied*, 552 U.S. 1230 (2008); *Improvements to Generator Interconnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054, at P 1764, *limited order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g & clarification*, Order No. 2023-A, 186 FERC ¶ 61,199 (2024), *appeals pending*, Petition for Review, *Advanced Energy United v. FERC*, Nos. 23-1282, et al. (D.C. Cir. Oct. 6, 2023).

[49] *See supra* n.47.

[50] Order No. 1920 at P 237.

[51] *See, e.g.*, *id*. at PP 231, 237, 238, 925, 967.

[52] *See* 5 U.S.C. § 706(2)(A); *ANR Storage Co. v. FERC*, 904 F.3d 1020, 1024 (D.C. Cir. 2018) (an internally inconsistent agency order is arbitrary and capricious); *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983).

that accommodates regional differences in their respective planning regions,[53] further rendering this aspect of the Final Rule arbitrary and capricious.[54]

PJM therefore respectfully requests that the Commission grant rehearing as further described below. Granting rehearing and permitting flexibility with respect to the issues identified below would allow PJM to use the PJM LTRTP Process[55] as the foundation for a long-term planning process that achieves the objectives of the Final Rule, even though implementation details may differ in some way from those the Final Rule prescribes.

1. The Final Rule Is Arbitrary and Capricious Because the Commission Failed to Consider Evidence Offered by RTOs and ISOs Demonstrating the Need for Flexibility that Accommodates Regional Differences

Nearly every RTO and ISO, individually and/or collectively,[56] requested that the Commission afford flexibility to the RTO/ISO to establish tailored long-term planning approaches and implementation details that meet the stated principles and objectives of the LTRTP NOPR.[57]

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[53] *See supra*, Section III.A.1.

[54] *See* 5 U.S.C. § 706(2)(A); *id.* at § 706(2)(E) (requiring agency findings to be supported by substantial evidence); *see also Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43 (an agency must examine the relevant data and articulate a satisfactory explanation for its action including a "rational connection between the facts found and the choice made" (citation omitted)); *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1313 (D.C. Cir. 1991) ("An agency's unsupported assertion does not amount to substantial evidence" and its decisions must be based on at least some explanation or analysis); *Power Auth. of State of N.Y. v. FERC*, 743 F.2d 93, 110-11 (2d Cir. 1984) (an agency's decisions must be supported by substantial evidence contained within the record); *Ass'n of Data Processing Serv. Orgs. Inc. v. Bd. of Governors of the Fed. Reserve Sys.*, 745 F.2d 677, 684 (D.C. Cir. 1984) (same).

[55] *See supra*, Section II.C. *See also* Attachment A.

[56] In addition to filing individual comments on the LTRTP NOPR, a number of ISO/RTOs joined comments submitted by the ISO/RTO Council, including PJM, California Independent System Operator ("CAISO"); ISO New England Inc. ("ISO-NE"); Midcontinent Independent System Operator, Inc. ("MISO"); New York Independent System Operator, Inc. ("NYISO"); and Southwest Power Pool, Inc. ("SPP"). *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Initial Comments of the ISO/RTO Council, Docket No. RM21-17-000 (Aug. 17, 2022) ("IRC NOPR Comments").

[57] *See, e.g.*, IRC NOPR Comments at 1-9; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Initial Comments of PJM Interconnection, L.L.C., Docket No. RM21-17-000, at 67, 72-73, 94 (Aug. 17, 2022) ("PJM Initial NOPR Comments"); *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Initial Comments of ISO New England Inc., Docket No. RM21-17-000, at 12-15, 20, 29 (Aug. 17, 2022) ("ISO-NE Initial NOPR Comments"); *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and*

The ISO/RTO Council explained that many ISOs and RTOs already engage in long-term planning processes or have ongoing initiatives to develop long-term planning procedures to be responsive to the needs of their respective regions.[58]

Notwithstanding the Commission's recognition regarding the need for regional flexibility, the Final Rule contains numerous prescriptive requirements which do not seem to allow for the recognition of regional differences.[59] The Commission also made compliance with the Final Rule more onerous by rejecting, without adequate explanation, requests that the Commission apply the "independent entity variation" standard, rather than the "consistent with or superior to" standard, for proposed deviations from the requirements in the Final Rule on compliance.[60]

Generator Interconnection, Comments of the Midcontinent Independent System Operator, Inc., Docket No. RM21-17-000, at 21-22 (Aug. 17, 2022) ("MISO Initial NOPR Comments").

[58] *See* IRC NOPR Comments at 1-3. The ISO/RTO Council further identified some of the NOPR requirements that ISO/RTOs found to be overly prescriptive given each individual ISO/RTO's particular circumstances, and expressed concern that preventing ISO/RTOs from being permitted to customize long-term planning procedures would undermine prior achievements and disrupt ongoing initiatives. *See* IRC NOPR Comments at 6-8 (providing specific examples of where overly prescriptive requirements in Order No. 1000 have prevented states from identifying any state or federal policies as driving transmission needs for the ISO's consider, and identifying concerns that the NOPR proposals could undermine collaborative efforts between RTO/ISOs and their states and stakeholders). PJM similarly described in its comments certain areas where the Commission should allow for flexibility in order to accommodate each region's unique circumstances. *See* PJM Initial NOPR Comments at 67, 72-73, 94.

[59] Specifically, as discussed further below, the Commission appears to require strict compliance with the Final Rule with respect to: (i) the development of three Long-Term Scenarios, each of which must consider seven specific categories of factors, including three categories where the transmission provider has no discretion to weigh individual factors within that category (*see, e.g.,* Order No. 1920 at PP 409, 417, 440, 447); (ii) the development of at least one extreme weather-related sensitivity applied to each long-term scenario (*see* Order No. 1920 at P 593); (iii) the measurement of a defined set of seven required benefits in each Long-Term Scenario (*see* Order No. 1920 at P 409); (iv) the use of the seven required benefits to help to inform the identification of Long-Term Needs (*see* Order No. 1920 at PP 719, 721); and (v) the development of new *ex ante* cost allocation methodologies that cannot account for different types of Long-Term Regional Transmission Facilities, such as those needed for reliability, congestion relief, or to achieve public policy, and that existing cost allocation methodologies cannot be the default until such time as agreement on new methodologies is reached (*see* Order No. 1920 at PP 1291, 1474). PJM explains in the following sections the specific prescriptive requirements in the Final Rule where it believes flexibility is necessary and why.

[60] Order No. 1920 at P 1772. PJM recognizes that the Commission has previously applied the "independent entity variation" standard in relation to interconnection rules and the "consistent with or superior to" standard in relation to regional planning rules. However, the Commission's rationale for allowing RTO/ISOs to seek the independent entity variation—*i.e.*, that "an RTO or ISO is independent and is less likely to act in an unduly discriminatory manner than is a Transmission Provider that is a market participant"—applies equally to transmission rules as it does to interconnection rules. Order No. 2003-A at PP 756, 759; Order No. 2023 at P 1764. The Commission did not adequately explain why the independent entity variation should not apply to RTO/ISOs that seek proposed deviations

For the reasons described below, the Final Rule limits the ability of ISO/RTOs to implement Long-Term Regional Transmission Planning in a way that allows them to retain their best practices and to properly reflect long-standing regional differences.[61] The Final Rule's specific and detailed requirements, if strictly imposed, would substantially disrupt PJM's efforts under the PJM LTRTP Process,[62] notwithstanding the fact that the PJM LTRTP Process would allow PJM to engage in regional transmission planning on a sufficiently long-term, forward-looking, and comprehensive basis, such that PJM would be able to identify, evaluate, and select more efficient or cost-effective regional transmission facilities to address Long-Term Transmission Needs[63] relevant to the PJM Region.

Thus, PJM urges the Commission to grant rehearing and confirm that it will consider requests for flexibility to accommodate regional differences.

2. To the Extent RTOs Do Not Have Flexibility to Develop Scenarios and Conduct Sensitivity Analyses in a Way that Recognizes Regional Differences, the Commission Should Grant Rehearing

For each planning cycle, the Commission requires transmission providers to develop three distinct "plausible and diverse" Long-Term Scenarios[64] each of which, at a minimum, must

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from the requirements in the Final Rule on compliance. *See* 5 U.S.C. § 706(2)(A); *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009).

[61] The Commission ignored evidence from ISO/RTOs that they need to be able to customize their Long-Term Regional Transmission Planning processes based on regional differences. *See Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (citing 5 U.S.C. § 706(2)(A)); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43 (The Commission must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."); *Wis. Gas Co. v. FERC*, 770 F.2d 1144, 1156 (D.C. Cir. 1985) (When applied to rulemaking proceedings, the substantial evidence test "is identical to the familiar arbitrary and capricious standard," which "requires the Commission to specify the evidence on which it relied and to explain how that evidence supports the conclusion it reached.").

[62] *See supra*, Section II.C. *See also* Attachment A.

[63] *See* Order No. 1920 at P 237. The Commission defines "Long-Term Transmission Needs" as "transmission needs identified through Long-Term Regional Transmission Planning by, among other things …, running scenarios and considering the enumerated categories of factors," where the seven required factors include by way of example, federal and state public policies, generator retirements, queue requests, and corporate commitments. *Id*. at P 299.

[64] *See* Order No. 1920 at P 575.

incorporate seven specific categories of factors[65] that include individual factors that the transmission provider has determined are likely to affect Long-Term Transmission Needs.[66] Although the Final Rule gives transmission providers some discretion regarding which specific factors to account for within each category of factors,[67] transmission providers are required to "assume that the laws, regulations, state-approved integrated resource plans, and expected supply obligations for load-serving entities identified in the first three categories of factors—that transmission providers have determined are likely to affect Long-Term Transmission Needs—are ***fully met***."[68] The Final Rule also requires transmission providers to develop at least one sensitivity, "applied to ***each*** Long-Term Scenario, to account for uncertain operational outcomes that determine the benefits of and/or need for transmission facilities during multiple concurrent and sustained generation and/or transmission outages due to an extreme weather event across a wide area."[69]

PJM agrees that developing distinct scenarios based on a wide variety of factors will lead to the identification of Long-Term Transmission Needs and potential solutions to address those needs. PJM also agrees that sensitivity analyses to account for the "uncertain operational

[65] *See id.* at PP 409, 411, 415, 599. The seven specific categories of factors include: (1) Federal, federally-recognized Tribal, state, and local laws affecting the resource mix and demand; (2) Federal, federally-recognized Tribal, state, and local laws on decarbonization and electrification; (3) state-approved integrated resource plans and expected supply obligations for load-serving entities; (4) trends in fuel costs and in the cost, performance and availability of generation, electric storage resources, and building and transportation electrification technologies; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and Federal, federally-recognized Tribal, state and local policy goals that affect Long-Term Needs. *Id*. at P 409.

[66] *See id*. at P 415.

[67] *See id*. at P 417 ("Transmission providers have discretion to determine whether specific factors must be accounted for within each category (*i.e.*, if the specific factor will likely affect Long-Term Transmission Needs), how to account for specific factors in the development of Long-Term Scenarios (*e.g.*, the method and data used to forecast resource retirements), and how to vary the treatment of each category of factors across Long-Term Scenarios (*e.g.*, assume all forecasted resource retirements materialize in some but not all Long-Term Scenarios)").

[68] *Id.* at P 417 (emphasis added).

[69] *Id.* at P 593 (emphasis added); *see id*. at P 594.

outcomes," including outages related to extreme weather, provide valuable information. However, the Final Rule's process by which transmission providers are required to develop the three scenarios is overly prescriptive and would complicate PJM-specific efforts to promote more efficient or cost-effective regional transmission planning and development. Moreover, the requirement to conduct sensitivity analyses for each Long-Term Scenario is overly burdensome.

As described above, the PJM Region covers all or parts of 13 states and Washington D.C., and these 14 jurisdictions have varying state public policies that have different requirements or goals with respect to decarbonization efforts and/or the incentivization of specific resource types.[70] The PJM Region is also facing significant challenges arising out of the accelerating energy transition.[71] PJM's number one responsibility is maintaining system reliability notwithstanding these challenges. To that end, PJM has developed its LTRTP Process with the primary goal of identifying potential factors that will have an impact on long-term reliability, while also facilitating state public policy requirements and goals that could affect long-term needs.

Specifically, as described in Attachment A, PJM would develop three distinct scenarios (base reliability, medium and high) which would generally account for the seven factors set forth in the Final Rule,[72] albeit not precisely in the manner prescribed in the Final Rule. Under PJM's LTRTP Process, PJM would develop a base reliability scenario, as well as additional scenarios that demonstrate a wider range of possible transmission needs as follows:

- ***Base Reliability Scenario***: PJM would construct a base reliability scenario and associated base cases to identify future transmission needs and solutions required to maintain the reliability of the system (the "base reliability scenario").[73] The primary categories of factors

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[70] *See supra,* Section II.A.

[71] *See supra,* Section II.B.

[72] Order No. 1920 at P 417.

[73] *See* Transmission Planning Department, *March 20, 2024 MRC Draft Manual 14B Proposed Revisions to Implement LTRTP*, PJM Interconnection, L.L.C., Attachment C, Section C.4.1, https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240425/20240425-item-02---4-ltrtp-manual-14b-revisions---clean.ashx.

to be included in the base reliability scenario would include: (i) the PJM Load Forecast Report;[74] (ii) announced retirements and anticipated retirements based on Public Policy Requirements[75] and company commitments;[76] (iii) in-service generation and generation not yet in-service but with an executed service agreement or State Agreement Approach ("SAA") "reservation; and (iv) replacement generation taken mainly from the PJM New Service Request process needed to maintain the 1-in-10 reliability standard, *i.e.*, to ensure resource adequacy.

- ***Medium Public Policy Scenario***: To develop the medium public policy scenario (the "medium scenario"), PJM would start with the base reliability scenario and model additional Public Policy Requirements including, by way of example, states' renewable portfolio standards. PJM anticipates that the only additional Public Policy Requirements that would be modeled in this scenario would be those traditionally brought by a state to PJM as part of the SAA[77] process[78] (recognizing now that there could be an *ex ante* cost allocation framework in place or an agreement contemplated by the SAA process for a state or states to share the costs). Upon the conclusion of this analysis, interested states would request that PJM develop transmission solutions for their consideration. PJM could also

[74] The PJM Load Forecast Report is an annual, independent load forecast prepared by PJM staff. The report includes long-term forecasts of peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area ("LDA"), and the total PJM Region. *See, e.g.*, PJM Resource Adequacy Planning Department, *PJM Load Forecast Report*, PJM Interconnection, L.L.C. (Feb. 1, 2024), https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx.

[75] Public Policy Requirements are defined as "policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government, where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity." Operating Agreement, Definitions O-P. Deactivations driven by Public Policy Requirements that PJM would include in the base reliability scenario include, by way of example, anticipated retirements to comply with the requirements of the Illinois Climate & Equitable Jobs Act, which mandates the scheduled phase-out of coal and natural gas generation by specified target dates. Climate and Equitable Jobs Act, 415 Ill. Comp. Stat. 5/9.15 (2022).

[76] Company commitments include environmental, social, and governance commitments brought to PJM's attention, where such commitments are per legal consent degree or other public statement such as press release, financial plan, or state-approved Integrated Resource Plans.

[77] *See* Operating Agreement, Schedule 6, section 1.5.9. The SAA process is a means by which PJM's Regional Transmission Expansion Plan ("RTEP") process is responsive to requests from a state (or group of states) that PJM develop transmission that would assist in implementing state Public Policy Requirements, including but not limited to, state renewable portfolio standards. The SAA process requires that should a state (or states) select a state public policy project, the state(s) also must agree that 100% of the costs of such project will be allocated to the zones within such state(s).

[78] An example of a SAA request that could be considered as part of the medium scenario is the state of New Jersey's request to use the SAA process to solicit proposals to improve and/or expand the PJM Transmission System to provide for the deliverability of up to 7,500 MW of offshore wind generation by 2035. *In the Matter of Declaring Transmission to Support Offshore a Public Policy of the State of New Jersey*, Order, NJBPU Docket No. QO20100630, at 7 (Nov. 18, 2020); *see also PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 142 (2013), *order on reh'g*, 147 FERC ¶ 61,128, at P 87 (2014).

combine reliability solutions developed pursuant to the base reliability scenario with a SAA project from this medium scenario to create a Multi-Driver Project.[79]

- ***High Public Policy Scenario***: To develop the high public policy scenario (the "high scenario"), PJM would start with the medium scenario (which, again, has its foundation the base reliability scenario), and model higher loads assumptions, incorporating for example more ambitious electrification, or renewable generation, reflecting for example carbon neutrality objectives. Specifically, this scenario would model Public Policy Objectives[80] brought to PJM by states to help inform their decisions related to the medium scenario, or to inform future Public Policy Requirements.

PJM, working with stakeholders, could determine the need for additional scenarios and sensitivities, for example, on economic retirements or extreme weather. PJM would use each of these scenarios and sensitivities to inform its near-term reliability analyses. Additionally, through the scenarios described above, PJM would be able to identify more efficient or cost-effective transmission solutions to address the long-term challenges it has identified, while maintaining system reliability.

In short, PJM believes the prescriptive requirements regarding the development of factors—*i.e.*, that PJM must develop three Long-Term Scenarios, each of which must incorporate seven categories of factors, where PJM cannot discount or weigh differently the individual factors included in Categories 1-3—would complicate PJM's region-specific efforts to promote more efficient or cost-effective regional transmission planning and development. Multi-state RTOs, like PJM, need regional flexibility to: (i) develop consistent regional methods to determine which factor input data makes the most sense to their respective regional planning processes, and

[79] A Multi-Driver Project is "a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives." Operating Agreement, Definitions M-N.

[80] Public Policy Objectives are defined as "Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations." Operating Agreement, Definitions O-P.

(ii) determine the degree to which each factor is incorporated into each Long-Term Scenario power flow model.

PJM believes that employing multiple Long-Term Scenarios, including one that includes a base case reliability scenario, as well as additional scenarios that demonstrate a wider range of possible transmission needs, is a prudent way to ensure transmission providers properly account for long-term needs without overbuilding the transmission system. Further, given the diversity among regions, PJM believes it is appropriate to allow transmission planners to work with states and stakeholders within their respective regions to determine the appropriate number of and specific scenarios to be used in the Long-Term Regional Transmission Planning process, as well as giving the transmission provider flexibility to determine how to weigh specific factors used to develop the assumptions upon which Long-Term Scenarios are based.

Thus, PJM urges the Commission to grant rehearing and confirm that it will consider requests for flexibility to develop Long-Term Scenarios and conduct sensitivity analyses in such a way as to accommodate regional differences. Additionally, PJM seeks clarification that it is not obligated to select facilities under any of the scenarios it develops.

3. To the Extent that RTOs Cannot Use Existing Cost Allocation Methodologies to Allocate Costs of Long-Term Regional Transmission Facilities Pending the Development and Acceptance of a New Cost Allocation Methodology(ies), PJM Seeks Rehearing

In Order No. 1920, the Commission creates a new category of transmission facilities, called "Long-Term Regional Transmission Facilities."[81] The Commission requires transmission providers to file at least one *ex ante* cost allocation methodology to assign costs associated with selected Long-Term Regional Transmission Facilities, and permits transmission providers to

[81] Order No. 1920 at P 41; *see id.* at PP 1469, 1474.

include a State Agreement Process pursuant to which states can agree to a cost allocation methodology for such facilities.[82] In contrast to Order No. 1000, the Commission states that "transmission providers may *not* establish reliability, economic, or public policy transmission facility types as part of Long-Term Regional Transmission Planning and, therefore, may *not* establish Long-Term Regional Transmission Cost Allocation Methods based on reliability, economic, or public policy transmission facility types."[83] However, the Commission states that if a transmission provider wants to use existing Order No. 1000 cost allocation methodologies as part of their Long-Term Regional Transmission Planning process, the transmission provider must demonstrate on compliance that existing methodologies, as applied to Long-Term Regional Transmission Facilities, are compliant with the Final Rule.[84]

No justification has been provided as to why the Commission would categorically prohibit existing cost allocation methodologies from remaining in place, even as a default, until an alternative has been approved by the Commission.[85] PJM is concerned that requiring the PJM Transmission Owners[86] to re-justify cost allocation methodologies that have already been subject

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[82] *Id.* at P 1291. The *ex ante* methodology must be the default methodology, since the Commission clarifies that the State Agreement Process cannot be the sole method filed for cost allocation for Long-Term Regional Transmission Facilities. *See id.* at P 1292.

[83] *Id.* at P 1474 (emphasis added).

[84] *Id.* at P 1302.

[85] This aspect of the Final Rule is arbitrary and capricious because the Commission ignored evidence from PJM describing why it was appropriate to allow existing cost allocation methodologies to remain in place. *See* PJM Initial NOPR Comments at 110-18; *see also Midwest ISO Transmission Owners*, 373 F.3d at 1368 (citing 5 U.S.C. § 706(2)(A)); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43 (The Commission must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."); *Wis. Gas Co.*, 770 F.2d at 1156 (When applied to rulemaking proceedings, the substantial evidence test "is identical to the familiar arbitrary and capricious standard," which "requires the Commission to specify the evidence on which it relied and to explain how that evidence supports the conclusion it reached.").

[86] The PJM Transmission Owners have exclusive authority and responsibility to submit filings under FPA section 205 "in or relating to . . . the transmission rate design under the PJM Tariff." Tariff, section 9.1; Consolidated Transmission Owners' Agreement, sections 7.1 & 7.3; *see Atl. City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002); Order No. 1920 at P 1430.

to years of protracted litigation will set back PJM's efforts to implement the PJM LTRTP Process successfully, and will undermine needed certainty regarding the development of the transmission facilities that PJM ultimately selects to be built. PJM agrees with the fundamental premise that knowing how costs of transmission facilities will be allocated is "critical . . . in the development of new transmission infrastructure."[87] However, the Final Rule undercuts this longstanding, widely-accepted notion by requiring renegotiation of all cost allocation without accounting for regional differences that would underscore the need for regional flexibility with respect to cost allocation. PJM urges the Commission to not simply throw out established cost allocation methodologies that were the result of collaboration with states and other stakeholders and have worked well in PJM.

By way of background, PJM's cost allocation methodology for reliability-based regional transmission facilities resulted from extensive settlement discussions before the Commission in Docket No. EL05-121.[88] The states in the PJM Region were actively involved in those discussions and, in fact, many were listed as either settling parties or non-opposing parties to the settlement agreement.[89] By the same token, PJM's supplemental cost allocation methodology for state public

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[87] Order No. 1920 at P 124.

[88] *See PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,233 (2014) (establishing hearing and settlement judge procedures regarding the cost allocation methodology for certain transmission facilities that operate at 500 kV and above in the PJM Region); *PJM Interconnection, L.L.C.*, Order of Chief Judge Designating Settlement Judge and Scheduling Settlement Conference, Docket No. EL05-121-009 (Jan. 5, 2015); *PJM Interconnection, L.L.C.*, Status Report, Docket No. EL05-121-009 (May 31, 2016) (listing settlement conferences held on May 5, 2016, December 16, 2015, August 6, 2015, June 9, 2015, April 17, 2015, March 5, 2015, February 11,2015 and January 14, 2015).

[89] *See PJM Interconnection, L.L.C.*, Offer of Settlement, Docket No. EL05-121-009 (June 15, 2016). The following state commission in the PJM Region actively participated in the settlement negotiations: (i) Settling Parties included Illinois Commerce Commission, Indiana Utility Regulatory Commission, Michigan Public Service Commission, Pennsylvania Public Utility Commission, Public Service Commission of West Virginia, and Public Utilities Commission of Ohio; and (ii) Non-Opposing Parties included Delaware Public Service Commission, New Jersey Board of Public Utilities, Public Service Commission of the District of Columbia and Virginia State Corporation Commission.

policy-driven transmission projects is embodied in its SAA.[90] This methodology was developed jointly with the Organization of PJM States, Inc. ("OPSI"), and was supported by an OPSI Resolution dated January 5, 2012.[91] By being so categorical in the Final Rule, the Commission has effectively wiped out years of work in developing and implementing accepted cost allocation methodologies that were the subject of extensive litigation before the Commission. The Commission should grant rehearing and indicate it would be open on compliance to allowing the existing cost allocations to remain in effect for long-term planning projects unless and until a filing is made to change them.[92]

PJM explains above that its LTRTP Process is focused on identifying potential factors that will have an impact on long-term reliability, while also facilitating state public policy requirements and goals that could affect long-term needs.[93] PJM underscores that it already has specific cost

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[90] *See* Operating Agreement, Schedule 6, section 1.5.9; *see also* PJM Tariff, Schedule 12, section (b)(xii).

[91] OPSI *Resolution # OPSI-2012-1*, Organization of PJM States, Inc. (Jan. 5, 2012), https://opsi.us/wp-content/uploads/2018/08/OPSI-2012-1.pdf; *see PJM Interconnection, L.L.C.*, Motion to Intervene and Comments of the Organization of PJM States, Inc., Docket No. ER13-198-000, at 1 (Dec. 10, 2012). The SAA process was supported by individual PJM states. For instance, the Delaware Public Service Commission stated that the approach represented an "important (and some would argue, the most important) culmination of the process states will utilize to identify and evaluate, review and consider, and, ultimately, approve for payment those projects satisfying transmission needs driven by public policy requirements." *PJM Interconnection, L.L.C.*, Comments of the Delaware Public Service Commission, Docket No. ER13-198-000, at 4 (Dec. 10, 2012); The New Jersey Board of Public Utilities viewed the SAA as the "cornerstone of [PJM's] Compliance Filing" that "correctly balances the desire to develop transmission assets to meet public policy goals with the need of states like New Jersey to ensure their elected officials retain ownership over associated costs." *PJM Interconnection, L.L.C.*, Motion to Intervene and Comments of the New Jersey Board of Public Utilities, Docket No. ER13-198-000, at 2-4 (Dec. 12, 2012). The Public Utilities Commission of Ohio urged the Commission to approve the SAA process. *PJM Interconnection, L.L.C.*, Comments Submitted on Behalf of the Public Utilities Commission of Ohio, Docket No. ER13-198-000, at 7 (Dec. 10, 2012). The Illinois Commerce Commission found that the SAA process is a method by which projects that states determine are necessary to develop in order to achieve a state's public policy requirements are included in PJM's RTEP. *PJM Interconnection, L.L.C.*, Notice of Intervention and Comments of the Illinois Commerce Commission, Docket No. ER13-198-000, at 5 (Dec. 10, 2012).

[92] PJM recognizes that the Commission has left undisturbed the existing cost allocation for PJM's existing short-term Order No. 1000 planning process. *See* Order No. 1920 at P 1300. But, at the same time, the Commission has indicated its strong desire for RTOs to concurrently engage in long-term planning and timely consider projects coming out of that process. The Commission's categorical requirements that the existing cost allocations "cannot" serve, even as an interim default, is not justified and will work to frustrate PJM's earnest desire to move forward with long-term planning.

[93] *See supra*, Sections II.C & Attachment A.

allocations for (i) reliability-based projects;[94] (ii) market efficiency projects;[95] (iii) public policy projects addressing state-identified needs;[96] and (iv) multi-driver projects.[97] Each of those cost allocation methodologies was developed through close consultation and extensive work with the states in the PJM Region. PJM intended to apply existing cost allocation methodologies to facilities selected to address long-term reliability and public policy pursuant to reliability cost allocation rules and cost allocation methodologies developed under the SAA process, respectively.[98]

Although PJM would support the development of additional cost allocation methodologies to apply to facilities selected to address Long-Term Transmission Needs, PJM strongly believes that existing cost allocation methodologies should remain in place unless and until those methodologies are replaced or until agreement on an alternate State Agreement Process is reached.

PJM thus urges the Commission to grant rehearing and confirm that it will consider requests for flexibility to maintain existing cost allocations on compliance unless and until an alternative is filed.

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[94] Tariff, Schedule 12, section (b).

[95] *Id.*, section (b)(v).

[96] *Id.*, section (b)(xii).

[97] Operating Agreement, Schedule 6, section 1.5.10. Multi-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. *PJM Interconnection, L.L.C. & Baltimore Gas & Electric Co.*, Joint Response to Deficiency Notice and Amendment to Filings, Docket Nos. ER14-2864-000 & ER14-2867-000 (not consolidated) (Dec. 23, 2014).

[98] *See* Attachment A.

4. PJM Seeks Clarification that the Commission Did Not Intend to Require RTOs to Use the Seven Required Benefits to Help to Inform Their Identification of Long-Term Transmission Needs. Alternatively, PJM Requests that the Commission Grant Rehearing of this Requirement

The Final Rule suggests that transmission providers will be required to use the specific set of seven required benefits described below[99] "to help to inform their identification of Long-Term Transmission Needs."[100] However, the only discussion about how benefits could inform Long-Term Transmission Needs is contained in the following statement from the section of Order No. 1920 where the Commission discusses the development of Long-Term Scenarios:

> As discussed in the Requirement for Transmission Providers to Use a Set of Seven Required Benefits section of this final rule, we require transmission providers to measure and use a set of seven required benefits in Long-Term Regional Transmission Planning. ***Transmission providers <u>must</u> use this same set of benefits to help to inform their identification of Long-Term Transmission Needs.*** For example, in this final rule we require transmission providers to measure and use production cost savings in Long-Term Regional Transmission Planning. As such, when transmission providers are working to identify Long-Term Transmission Needs, areas of significant congestion on the transmission system—where Long-Term Regional Transmission Facilities could reduce congestion and in turn facilitate production cost savings—***may*** indicate a Long-Term Transmission Need.[101]

Given that there is no other substantive discussion in the Final Rule about how benefits would help to inform Long-Term Transmission Needs, PJM questions whether the Commission meant to prescriptively require transmission providers to incorporate the seven required benefits into the analyses they use to identify transmission *needs*. PJM therefore seeks that the Commission

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[99] *See infra,* n.107.

[100] Order No. 1920 at P 301; *see also id.* at P 719 ("[A]s discussed in the Development of Long-Term Scenarios section, these same benefits should help to inform transmission providers' identification of Long-Term Transmission Needs.").

[101] *Id.* at P 301 (emphasis added).

clarify that it did not intend to require transmission providers to use any benefits, let alone all seven required benefits, to help to inform the identification of Long-Term Transmission Needs.

If the Commission did intend to require transmission providers to use the set of seven required benefits to help identify Long-Term Transmission Needs, PJM seeks that the Commission grant rehearing and confirm that transmission providers have flexibility to determine whether to use all or any benefits to help to inform the identification of Long-Term Regional Transmission Needs. In the Final Rule, the Commission only offers a hypothetical example of how *one* of the seven required benefits *might* help to inform the identification of Long-Term Transmission Needs. It does not provide any evidence—let alone substantial evidence—to demonstrate why transmission providers should be required to consider a mandatory set of seven required benefits when seeking to determine Long-Term Transmission Needs.[102] The Commission should grant rehearing of the requirement to use the required seven benefits *to help inform Long-Term Transmission Needs* on this basis alone.[103]

Additionally, using ***all*** of the Final Rule's seven required benefits to help to inform the identification of Long-Term Transmission Needs is incompatible with a sponsorship model like PJM's. For example, measuring the "Reduced Loss of Load Probability" or "Reduced Transmission Energy Losses" benefits requires contrasting model runs with and without a transmission solution (or plan or portfolio) to identify Long-Term Needs. But in a sponsorship

[102] *See Midwest ISO Transmission Owners*, 373 F.3d at 1368 (citing 5 U.S.C. § 706(2)(A)); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43 (The Commission must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."); *Wis. Gas Co.*, 770 F.2d at 1156 (When applied to rulemaking proceedings, the substantial evidence test "is identical to the familiar arbitrary and capricious standard," which "requires the Commission to specify the evidence on which it relied and to explain how that evidence supports the conclusion it reached.").

[103] PJM cannot find any statements in the LTRTP NOPR suggesting that the Commission proposed to require transmission providers to use any benefits, let alone a prescribed set of specific benefits, to help to inform Long-Term Transmission Needs. Thus, PJM did not have any notice of this requirement nor the opportunity to provide comments regarding why the requirement is inappropriate for the PJM Region.

model the solution is proposed after and in response to the identification of needs. This circularity can be resolved for the "Production Cost Saving" benefit by setting a congestion threshold to identify needs related to specific limiting transmission facilities. But for other benefits required in the Final Rule, like the two mentioned above this circularity is problematic.

PJM urges the Commission to clarify that it did not intend to require transmission providers to use any benefits, let alone all seven required benefits, to help to inform the identification of Long-Term Transmission Needs. Alternatively, PJM respectfully requests that the Commission: (i) grant rehearing of the requirement that transmission providers must use benefits to help to inform their identification of Long-Term Transmission Needs or (ii) grant rehearing and confirm that it will consider requests for flexibility to use the seven required benefits to help to inform their identification of Long-Term Transmission Needs so as to accommodate regional differences.

5. To the Extent the Commission Requires RTOs to Measure Each of the Seven Required Benefits Under Each Scenario, the Commission Should Grant Rehearing to Allow RTOs to Measure and Evaluate the Subset of Benefits that Are Relevant to their Specific Regions

In the LTRTP NOPR, the Commission recognized the benefit of allowing regional flexibility with respect to the calculation of benefits, declining to prescribe any particular definition of "benefits" or "beneficiaries," nor requiring the use of any specific benefits.[104] Instead, the Commission proposed to give transmission providers flexibility to propose what benefits to use as part of their Long-Term Regional Transmission Planning based on what made the most sense for

[104] LTRTP NOPR at P 183. Rather than adopting a particular definition of "benefits" or "beneficiaries," the Commission proposed a list of 12 benefits in the LTRTP NOPR to consider, including: (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity. *See id*. at PP 183-225.

their respective regions.[105] Without citing any evidence for its about-face,[106] the Final Rule diverges from the commitment to regional flexibility and instead requires transmission providers to measure, at a minimum, a set of seven required benefits and then use those seven specific required benefits to inform the identification of Needs, evaluate Long-Term Regional Transmission Facilities for selection, and allocate costs.[107] The Commission does not seem to allow for any flexibility for transmission providers to deviate from measuring and using the specific list of seven required benefits (although it does allow transmission providers to measure and use additional benefits beyond the seven required benefits[108]).

PJM agrees that assessing a broader set of benefits as part of a Long-Term Regional Transmission Planning process could demonstrate the greater value that regional, more holistic transmission development could provide. PJM therefore would support a requirement that transmission providers must consider an expanded set of benefits when evaluating transmission facilities to address Long-Term Needs. However, for the reasons the Commission set forth in the

[105] *Id.* at PP 183-84.

[106] The Commission merely states in a conclusory fashion, without any supporting citations, that "[t]he record in this proceeding shows that, in order to ensure just and reasonable Commission-jurisdictional rates, it is necessary to require transmission providers to measure and use in Long-Term Transmission Planning a set of particular benefits so that they may identify, evaluate and select regional transmission facilities that are more efficient or cost-effective transmission solutions to Long-Term Regional Transmission Needs." Order No. 1920 at P 722. This statement is insufficient to support a finding that the requirement to use seven specific benefits is based on substantial evidence. *See Midwest ISO Transmission Owners*, 373 F.3d at 1368 (citing 5 U.S.C. § 706(2)(A)); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43 (The Commission must "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made."); *Wis. Gas Co.*, 770 F.2d at 1156 (When applied to rulemaking proceedings, the substantial evidence test "is identical to the familiar arbitrary and capricious standard," which "requires the Commission to specify the evidence on which it relied and to explain how that evidence supports the conclusion it reached.").

[107] Order No. 1920 at PP 719, 721. The seven required benefits are: "(1) avoided or deferred reliability transmission facilities and aging infrastructure replacement; (2) a benefit that can be characterized and measured as either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme weather events and unexpected system conditions; and (7) capacity cost benefits from reduced peak energy losses." *Id.* at P 720.

[108] *See id.* at PP 729, 737.

NOPR[109] and as explained by numerous parties in comments,[110] transmission providers should have flexibility to propose which benefits make sense to consider in their own regions.

As discussed in Attachment A, under the PJM LTRTP Process, PJM would calculate multiple benefits for the transmission solutions developed pursuant to the process, which benefits were modeled off of those enumerated in LTRTP NOPR.[111] Specifically, PJM would measure the following benefits of proposed solutions to the Long-Term Transmission Needs identified through the PJM LTRTP Process:

- ***Reduced Loss of Load***: For this category, PJM would consider whether the proposed Long-Term Regional Transmission Facility would reduce the frequency and severity of load shed events by providing additional pathways for connecting generation resources with load in regions affected by extreme weather or other systemic events.[112]

- ***Avoided Generation Investments***: For this category, PJM would consider deferred generation capacity investments.[113] PJM would consider whether the proposed Long-Term Regional Transmission Facility would reduce or delay the cost of needed generation investments by increasing transfer capabilities between non-coincidental peak areas or by tapping into areas with higher renewable potentials.

- ***Expanded Production Cost Savings***: As part of this category, PJM would consider whether investment in a proposed Long-Term Regional Transmission Facility would result in a reduction of production costs.[114] This category extends beyond adjusted production cost savings commonly used in market efficiency analysis and can include the Final Rule's Benefits Three to Five and part of Six (the remainder of Benefit Six being measured as part of the reduced loss of load expectation benefit above).

- ***Avoided Cost of Transmission Replacement***: This category would consider reduced costs of avoided or delayed transmission investment otherwise required to address reliability needs or replace aging transmission facilities.[115] Specifically, when certain transmission projects are proposed to address changes in the resource mix and demand, transmission

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[109] *See* LTRTP NOPR at P 184.

[110] *See, e.g.*, PJM Initial NOPR Comments at 92-96; MISO Initial NOPR Comments at 21-22; ISO-NE Initial NOPR Comments at 12-15.

[111] *See* LTRTP NOPR at PP 183-225, 227-30, 233-35.

[112] This benefit category aligns with required benefit # 3. *See* Order No. 1920 at P 755-756.

[113] This benefit category aligns with the LTRTP NOPR proposed benefit # 9. *See* LTRTP NOPR at P 185.

[114] This benefit category aligns with required benefit # 3. *See* Order No. 1920 at PP 767-69.

[115] This benefit category aligns with required benefit # 1. *See* Order No. 1920 at P 745.

> upgrades that would otherwise have to be made to address reliability needs or replace aging facilities may be avoided or could be deferred for a number of years. These avoided or deferred reliability upgrades effectively reduce the incremental cost of the Long-Term Regional Transmission Facility.

As described, the benefits that PJM would measure under the PJM LTRTP Process encompass all required seven benefits, and possibly other benefits of transmission, in a way designed to sum up to system cost impacts (a proxy for welfare changes). This conceptual framework provides PJM with the flexibility needed to innovate and identify projects that are most beneficial, while meeting the reliability needs of the system.

Although PJM could measure and use all seven benefits, it believes that requiring the measurement and use of all seven required benefits is overly prescriptive. PJM agrees that Benefits 1-3 should be mandatory. However, Benefits 4 and 5 are additional benefits that RTOs could add as they gain experience and if quantitatively important. Benefit 6 has three different subcomponents and could be very cumbersome to measure if each one of them must be quantified. PJM therefore urges the Commission to grant rehearing and confirm that it will consider requests for flexibility regarding the requirement that PJM must measure and use all seven required benefits associated with Long-Term Regional Transmission Facilities so as to accommodate regional differences

B. The Commission Erred by Mandating Greater Coordination Between Existing Order No. 1000 Regional Transmission Planning and Generator Interconnection Processes

The Commission's mandate to require greater coordination between regional transmission planning and generator interconnection processes[116] is arbitrary and capricious in its application to PJM, because it ignores contrary evidence presented by PJM, invites gaming opportunities that

[116] Order No. 1920 at P 1106.

would undermine PJM's newly implemented generation interconnection reforms, leads to unduly discriminatory treatment of interconnection customers, and inappropriately shifts costs from generation to load.[117]

The Final Rule requires transmission providers to evaluate for selection regional transmission facilities that address qualifying interconnection-related transmission needs[118] associated with related network upgrades originally identified in the generator interconnection process. In contrast to the LTRTP NOPR's proposal to require coordination between interconnection processes and Long-Term Regional Transmission Planning Processes,[119] the Final rule requires transmission providers to consider for selection such regional transmission facilities as part of their *existing Order No. 1000* regional transmission planning and cost allocation processes.[120]

[117] *See* 5 U.S.C. § 706(2); 16 U.S.C. § 825*l*(b); *S.C. Pub. Serv. Auth.*, 762 F.3d at 66-67; *Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667, 687 (D.C. Cir. 2000); *Env't Def. Fund v. FERC*, 2 F.4th 953 (D.C. Cir. 2021).

[118] Qualifying interconnection-related network upgrades arise when: (i) the network upgrades have been identified in interconnection studies in at least two interconnection queue cycles during the preceding five years; (ii) the network upgrades have a voltage of at least 200 kV and an estimated cost of at least $30 million; (iii) the network upgrades have not been developed and are not currently planned to be developed; and (iv) the transmission provider has not identified another network upgrade to address the interconnection-related transmission need in an executed Generation Interconnection Agreement ("GIA") or an unexecuted GIA requested to be filed with the Commission. *See* Order No. 1920 at P 1145.

[119] *See* LTRTP NOPR at PP 166-74.

[120] *See* Order No. 1920 at PP 1106-07, 1121. The Final Rule's requirement that transmission providers evaluate for selection regional transmission facilities to address certain identified interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes, rather than in Long-Term Regional Transmission Planning, is arbitrary and capricious because it is not based on substantial evidence, and because parties were not given notice of or an opportunity to provide comments on this requirement. In doing so, the Commission also erred by reopening the accepted cost allocation methodologies for these projects in existing Order Nos. 1000 and 2023, both of which were built on the premise that the cost causer pays for the interconnection costs. *Midwest ISO Transmission Owners*, 373 F.3d at 1368 (citing 5 U.S.C. § 706(2)(A)); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Wis. Gas Co.*, 770 F.2d at 1156.

1. The Commission Ignored Record Evidence Presented by PJM Disproving the Commission's Assumptions Underlying the Need for Reform in the PJM Region

The Commission failed to provide substantial evidence for its conclusion that, nationwide, the "deciding factor" for interconnection customers' withdrawal from the interconnection queue is the "sticker shock" at their assigned network upgrades costs.[121] The Commission used this unsupported conclusion to impose a broad and sweeping reform on all regional transmission planning regions despite contrary evidence presented by PJM.

In its initial comments, PJM provided an analysis of more than 700 generator interconnection request in one transmission zone over a six-year period.[122] The analysis demonstrated that of the 700 interconnection requests, only 14—*or 2%*—would have likely met the voltage and cost thresholds in the Commission's proposal now part of the Final Rule. Furthermore, nine of the 14 interconnection requests withdrew before a Feasibility Study was issued, which would have provided the initial potential requirements for any upgrades and costs, thus disproving the premise that the unknown network upgrade cost would have been the decisive factor for the withdrawal. Of the remaining five interconnection requests, two were ultimately responsible for network upgrades of less than $30 million, thus leaving only three interconnection requests—*or less than one half percent of the total 700 requests—potentially* withdrawing due to the cost of the network upgrades. A withdrawal rate of less than one half percent in a large sample of interconnection requests over an extended period of time is within a statistical standard margin of error and indicates insignificant correlation between network upgrade costs, voltage level, and business decisions to withdraw.

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[121] *See* Order No. 1920 at P 1101.

[122] *See* PJM Initial NOPR Comments at 88.

On the other hand, PJM provided additional evidence that, over the past six years, several dozen projects that had executed Interconnection Service Agreements ("ISAs") and had associated network upgrades of less than $5 million nonetheless terminated their ISAs and did not reach commercial operation.[123] As PJM explained, common reasons for generator delay or failure to advance in the interconnection process are not connected to "sticker shock" concerns but to land and permitting issues, public policy and regulatory changes, as well as siting, industry, fuel, economics, and any combined impact of those factors on project financing.[124]

The Commission disregarded PJM's evidence and instead relied on studies of the MISO and SPP regions to justify a "one-size-fits-all" requirement on a national scale.[125] The Final Rule entirely omits discussion or consideration of PJM's contrary evidence with respect to its region, including evidence that (i) generators without significant network upgrade needs never reached commercial operation; (ii) network upgrades of over $30 million are rare in the PJM Region; and (iii) the majority of generators studied within a large sample of interconnection requests withdrew prior to receiving cost information, thereby disproving the Commission-advanced correlation between size and cost of network upgrades as justification for the need for reform. Consequently, the Commission's decision to rely on anecdotal evidence to justify a reform in the PJM Region, while ignoring specific and PJM contradicting data, is arbitrary and capricious.[126]

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[123] *See id*. at 87. This trend continues today, and, as of April 2024, PJM has cleared nearly 40,000 MW of generation projects through its interconnection process that are not moving to construction, despite having executed interconnection agreements with modest network upgrade costs. The reasons behind the business decisions to pause the process appear to be based on continued challenges with supply chain, financing, and local siting issues. *See* Paul McGlynn, *Interconnection Reform Is Working, but Will New Generation Actually Get Built?,* PJM Interconnection, L.L.C. (Apr. 23, 2024), https://insidelines.pjm.com/interconnection-reform-is-working-but-will-new-generation-actually-get-built/.

[124] *See* PJM Initial NOPR Comments at 87-89.

[125] *See* Order No. 1920 at PP 1101-02.

[126] *See* 5 U.S.C. § 706(2); 16 U.S.C. § 825*l*(b); *S.C. Pub. Serv. Auth.*, 762 F.3d at 66-67; *Transmission Access Policy Study Grp.*, 225 F.3d at 687; *Env't Def. Fund*, 2 F.4th 953.

2. The Final Rule is Arbitrary and Capricious Because it Creates Perverse Incentives for Generation Developers to Game the PJM Interconnection Process and Shift Costs in an Unduly Discriminatory Manner

The Commission erred in simply discounting PJM's concerns that the Final Rule would create perverse incentives for generation developers to game the interconnection process to their advantage by submitting and withdrawing multiple requests, thereby resulting in RTEP upgrades and shifting cost responsibility to load.[127] The Commission's reasoning that the stringent financial commitments in Order No. 2023 would prevent gaming[128] is arbitrary and capricious and not supported by substantial evidence, as applied to the PJM Region.

While PJM has recently adopted an interconnection cluster process[129] with stricter financial commitments for its three different generator interconnection Phases, such financial commitments pale in comparison to the financial windfall of a potential socialization of network upgrades exceeding $30 million. For example, study deposits are based on project size and vary between $75,000 and $400,000 per project.[130] Similarly, readiness deposits are calculated based on the MW values of the project, the interconnection Phase and the cost of required network upgrades, as shown below:

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[127] *See* Order No. 1920 at P 1119; PJM Initial NOPR Comments at 89.

[128] *See* Order No. 1920 at P 1120.

[129] PJM's new interconnection process was accepted by the Commission after PJM's Initial Comments in this matter. *PJM Interconnection, L.L.C.*, 181 FERC ¶ 61,162 (2022), *order on reh'g*, 184 FERC ¶ 61,006 (2023), *appeal pending*, Petition for Review, *Hecate Energy LLC v. FERC*, No. 23-1089 (D.C. Cir. Mar. 31, 2023). Consequently, the Commission should consider on rehearing PJM's evidence that was not available or proper for submission at the time in PJM's Initial Comments.

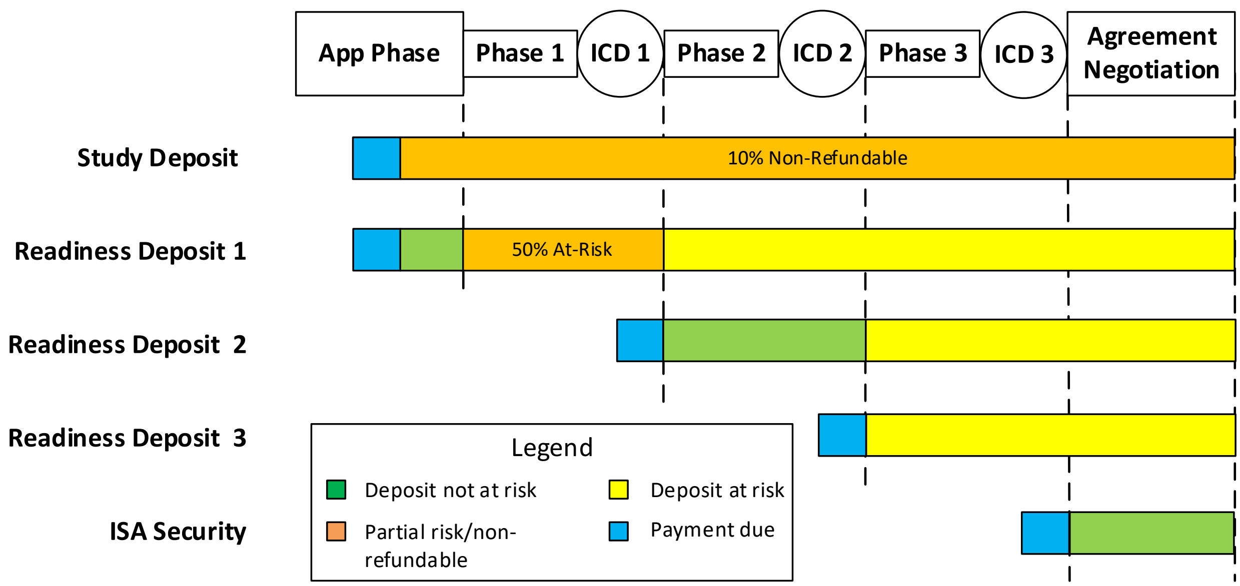
[130] *See New Service Request Deposits*, PJM Interconnection, L.L.C., https://www.pjm.com/planning/service-requests/application-and-forms/deposit-calc (last visited June 10, 2024); Interconnection Projects Department, *PJM Manual 14H: New Service Requests Cycle Process*, PJM Interconnection, L.L.C., Section 6 (July 26, 2023), https://www.pjm.com/-/media/documents/manuals/m14h.ashx.

Readiness Deposit Calculations

- RD1 = $4,000 per MW (50% at-risk once Phase 1 commences)
- RD2 = (10% of cost allocation towards required Network Upgrades) – RD1(RD1 is 100% at-risk once Phase 2 commences)
- RD3 = (20% of cost allocation towards required Network Upgrades) – RD1 – RD2 (RD3 is 100% at-risk once Phase 3 commences)

As Table 1 illustrates below, the maximum at risk amount of the readiness deposit interconnection agreement negotiation phase is 20% of their required cost responsibility for network upgrades. However, a generation developer would be assigned its network upgrade cost responsibility in Phase 2, thereby putting at risk only the initial readiness deposit (RD1) prior to learning its assigned network upgrade cost responsibility. In fact, the generation developer's readiness deposit related to cost responsibility for network upgrades will not be at risk until Phase 3 begins.

Table 1: Readiness and Study Deposit Timing Diagram[131]

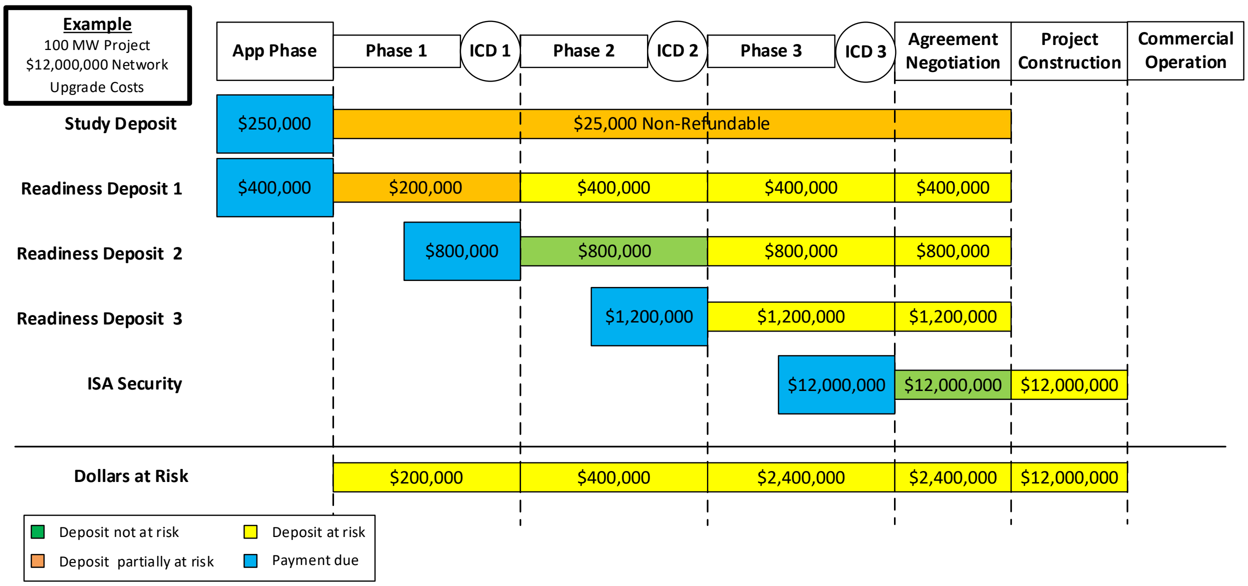


To put this in perspective, Table 2 below provides an example of a hypothetical 100 MW project requiring network upgrades of $12 million. In that example, the generation developer

[131] *See* Jack Thomas, *Interconnection Process Reform*, PJM Interconnection, L.L.C., 37 (Apr. 27, 2022), 20220427-item-02a-interconnection-process-reform-presentation.ashx (pjm.com).

would have at risk only $400,000 prior to learning its assigned network upgrade cost responsibility and posting an additional readiness deposit.

Table 2: Separate Treatment of Readiness Deposit and Security[132]



Applying the same formula to a hypothetical 300 MW project with network upgrades of $30 million, thereby triggering the dollar threshold in the Final Rule, the interconnection customer would risk only its readiness deposit of $1,200,000 (RD1 calculated as $4,000 * 300MW) prior to withdrawing and having to post an additional deposit. Armed with this information, sophisticated developers can flood the PJM interconnection process with speculative and larger than necessary interconnection requests that are withdrawn shortly after the required network upgrade costs are identified, and forcing PJM to consider RTEP upgrades that would incorporate the needed network upgrades and assign cost responsibility to load rather than the generation developers.

The Final Rule discounts these concerns, in part, by asserting that an interconnection customer would face several risks, including that the risk that the regional transmission solution

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132 *Id*. at 43.

would not be selected and that the newly created interconnection or transmission capacity would be allocated to a different interconnection or transmission customer.[133] Regarding these arguments, as PJM has demonstrated, the risk-to-benefit ratio heavily favors the submission of speculative interconnection requests for a relatively low at risk deposit, thereby justifying the risk of non-selection in the RTEP. Furthermore, a well-funded and sophisticated generation developer can leverage the low risk and enhance its chances of RTEP selection with well-informed and strategically positioned, but specious, interconnection requests. Finally, the Commission's requirement is arbitrary and capricious because it reopens the accepted cost allocation methodologies for these projects in existing Order Nos. 1000 and 2023, both of which were built on the premise that the cost causer pays for the interconnection costs.[134]

3. The Final Rule Is Arbitrary and Capricious Because it Undermines PJM's Extensive Interconnection Reforms that the Commission Approved Over the Last Two Years

In addition to facilitating gaming of the interconnection process, as explained above, the rule would work orthogonally with the recently implemented interconnection reforms that have transitioned PJM from a serial interconnection study process to a cluster one. The purpose of the transition to cluster studies is to adopt a "first-ready-first-serve" approach that allows for cost sharing of network upgrades by generation developers within the same cluster, i.e., those generation developers that are ready to move to construction and bring generation online. Thus, interconnection requests that jointly contribute to much needed—and frequently identified—network upgrades, already have a working process that allows for needed transmission solutions

[133] *See* Order No. 1920 at P 1119.

[134] *See Midwest ISO Transmission Owners*, 373 F.3d at 1368 (citing 5 U.S.C. § 706(2)(A)); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Wis. Gas Co.*, 770 F.2d at 1156.

to be built, as long as the generation developers can demonstrate their legal and financial commitment to proceed by signing an interconnection agreement.

As PJM has explained, common reasons for generator delay or failure to advance in the interconnection process are not connected to the cost of the network upgrades but to land and permitting issues, public policy and regulatory changes, as well as siting, industry, fuel, economics, and any combined impact of those factors on project financing.[135] By incentivizing the submission of speculative interconnection requests that would need to be studied and would needlessly strain limited PJM resources, the Final Rule works orthogonally with PJM's interconnection reforms that aim to speed up the review process and accelerate the interconnection queue during a period of significant generation transition. Finally, this specific interconnection requirement in the Final Rule is unnecessary, because Transmission Providers must already account for generation interconnection requests and withdraws as one of the seven factors in their Long-Term Scenario planning.[136]

4. The Final Rule is Arbitrary and Capricious Because it Requires Changes to PJM's Existing Order No. 1000 Regional Planning Processes Without Providing Substantial Evidence to Justify the Need for Reform

The Final Rule is arbitrary and capricious because it would insert an unjustified level of uncertainty in PJM's existing near-term regional planning process under Order No. 1000 by requiring the consideration of withdrawn and speculative interconnection requests as potential inputs or drivers of regional transmission needs. PJM's main RTEP drivers include reliability, operational performance, and market efficiency, which may consider public policies and

[135] *See* PJM's Initial NOPR Comments at 89.

[136] *See* Order No. 1920 at P 472.

incorporate the same in certain circumstances.[137] Generator interconnection requests are not factored in as RTEP drivers, but are already accounted for in the RTEP planning, which incorporates committed interconnection requests, as evidenced by executed ISAs or GIAs.

The Final Rule arbitrarily and capriciously requires the consideration of certain withdrawn interconnection requests in the near-term RTEP and provides them unduly preferential treatment over interconnection requests that have taken all required steps to obtain site control, permits, regulatory approvals, and pay required deposits. The undue discrimination is evidenced by the Final Rule's openness to (i) exempt certain network upgrades from subsequent Phases and commitments of PJM's interconnection process that the Commission has recently accepted, and (ii) allow the shifting of network upgrade costs from generation developers to load. In this way, the Final Rule unduly discriminates against interconnection customers that have followed to completeness PJM's interconnection processes and customers that will be paying for the network upgrades in favor of developers who manage to exercise financial and regulatory arbitrage by gaming the interconnection and RTEP processes.

Additionally, the Final Rule unjustifiably separates the RTEP and interconnection processes apart by injecting needs into the RTEP. In turn, the RTEP process provides its output for use in the interconnection process and, under the Final Rule, such output would be inflated by the addition of questionable transmission upgrades. As a result, the two processes, which are meant to be complementary and work in tandem, would become unnecessarily separated and infused with dubious inputs and drivers.

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[137] *See* Transmission Planning Department, *PJM Manual 14B: PJM Region Transmission Planning Process*, PJM Interconnection, L.L.C., Sections 1.3 and 2.1 (Dec. 20, 2023), https://www.pjm.com/-/media/documents/manuals/m14b.ashx.

C. The Commission Should Grant Rehearing or, in the Alternative, Clarification Regarding the Start Date of the Long-Term Planning Horizon and Allow Flexibility for Transmission Providers to Minimize Overlap Between Order Nos. 1000 and 1920 that may Result in Reliability Concerns

The Final Rule specifies that the transmission planning horizon starts at the beginning of the Long-Term Regional Transmission Planning cycle and ends 20 years from that date.[138] Additionally, transmission providers must plan for the entire duration of the 20-year transmission planning horizon and to assess Long-Term Needs starting in year one of the 20-year planning horizon.[139] The Final Rule also instructs that the transmission planning horizon is not tied to the in-service date of any identified transmission solution.[140]

Importantly, the Final Rule does not fully address to what extent it modifies the Commission's NOPR that defined the start date of the long-term transmission planning horizon as year six.[141] In the NOPR, the Commission was clear that it proposed to establish the new Long-Term Regional Transmission Planning process as an add-on, supplemental process that is not intended to modify existing short-term reliability and market efficiency processes.[142] The Final Rule lacks this needed clarity and infuses confusion by requiring transmission providers to propose

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[138] *See* Order No. 1920 at P 347.

[139] *See* Order No. 1920 at P 346 ("We clarify that transmission providers ***must plan for the entire duration of the 20-year transmission planning horizon***. Specifically, transmission providers must, among other requirements established in this final rule, develop and use Long-Term Scenarios to identify Long-Term Transmission Needs ***occurring in any period of the 20-year transmission planning horizon and to evaluate potential transmission solutions to those needs.***" (emphasis added)); *id*. at P 347 ("We specify that the ***transmission planning horizon starts at the beginning of the Long-Term Regional Transmission Planning cycle and ends 20 years from that date.***" (emphasis added)).

[140] Order No. 1920 at P 347.

[141] In the LTRTP NOPR, the Commission defined the long-term planning horizon as the "[t]ransmission planning period that ***covers years six through ten or beyond*** when required to accommodate any known longer lead time projects that may take longer than ten years to complete." LTRTP NOPR at P 94 n.160 (emphasis added and citation omitted).

[142] *See* LTRTP NOPR at P 72 ("With respect to transmission needs associated either with maintaining reliability or for addressing economic considerations and their associated cost allocation, we do not propose in this NOPR to change Order No. 1000's requirements for public utility transmission providers to create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region's reliability and economic requirements.").

on compliance "a date, no later than one year from the date on which initial filings to comply with this final rule are due, on which they will commence the first Long-Term Regional Transmission Planning cycle (unless additional time is needed to align the first Long-Term Regional Transmission Planning cycle with existing transmission planning cycles)."[143]

The Commission should grant rehearing of the requirement that transmission providers seek to identify Long-Term Needs starting in year one of the planning horizon in a way that overlaps with existing reliability and market efficiency planning pursuant to Order No. 1000. In the alternative, the Commission should clarify that the Long-Term Regional Transmission Planning horizon can start on year six, as proposed in the NOPR. Such rehearing or clarification is consistent with the transmission providers' ongoing obligation to maintain existing Order No. 1000 planning processes.

The Final Rule recognizes that Order No. 1000 planning processes are still needed to maintain reliable operations and solve market efficiency needs,[144] even though transmission providers will be required to engage in long-term, scenario-based planning. The Commission also makes clear that it does not require transmission providers to combine existing Order No. 1000 processes and the Long-Term Regional Transmission Planning process into one combined process.[145] Yet, the overlap in the planning horizons of the two rules and the lack of clarity as to when the 20-year long-term planning horizon starts create significant implementation challenges

[143] Order No. 1920 at P 1768.

[144] *See, e.g.*, Order No. 1920 at P 234 ("Long-Term Regional Transmission Planning—in addition to existing Order No. 1000 regional transmission planning and cost allocation requirements—is needed to support the reliable operation of transmission systems, given these changes."); *see also* P 241 ("Transmission providers may continue to rely on their existing regional transmission planning and cost allocation processes to comply with Order No. 1000's requirements related to transmission needs driven by reliability concerns or economic considerations.").

[145] *See id*. at P 245 ("[W]e do not require in this final rule that transmission providers plan for all reliability and economic transmission needs and Long-Term Transmission Needs through a single regional transmission planning process.").

for transmission providers. PJM still needs to be able to identify projects that are needed to maintain system reliability and for market efficiency reasons in the near-term, including planning for immediate need reliability projects.

PJM recognizes that the long-term planning horizon can and will certainly *inform* Order No. 1000 processes, but it is imperative that these two processed can function effectively together, and that PJM is able to respond to short-term needs quickly and nimbly. To that end, PJM would support modifying or replacing its existing Order No. 1000 "intermediate-term planning" (*i.e.*, its current six- to 15-year analysis to consider the aggregate effects of system trends) to better align with the Long-Term Regional Transmission Planning process outlined in Order No. 1920, subject to the clarification and rehearing requested herein. Accordingly, PJM requests flexibility in designing its long-term transmission planning process in a way that would minimize harmful interaction from the overlap of the two rules and would allow for the efficient use of PJM's resources.

IV. STATEMENT OF ISSUES AND SPECIFICATION OF ERRORS

The Final Rule is arbitrary and capricious, does not reflect reasoned decision-making and is not supported by substantial evidence. Pursuant to Rules 713(c)(1) and (c)(2),[146] PJM respectfully submits the following statement of issues and specification of errors, including citations to representative Commission and judicial precedent:

1. The Final Rule is arbitrary and capricious because it is contradictory and internally inconsistent in promising regional flexibility while mandating certain prescriptive and inflexible requirements that are unjustifiably being imposed without record support. *See* 5 U.S.C. § 706(2)(A); *Motor Vehicle Mfrs. Ass'n of the U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983); *ANR Storage Co. v. FERC*, 904 F.3d 1020, 1024, 1028 (D.C. Cir. 2018).

[146] 18 C.F.R. § 385.713.

2. The Final Rule is arbitrary and capricious because it fails to sufficiently consider substantial evidence offered by nearly every RTO and ISO regarding the need for genuine flexibility in a way that accommodates regional differences in their respective planning regions. *See* 5 U.S.C. § 706(2)(A); *id.* at § 706(2)(E); *see also Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1313 (D.C. Cir. 1991); *Power Auth. of State of N.Y. v. FERC*, 743 F.2d 93, 110-11 (2d Cir. 1984); *Wis. Gas Co. v. FERC*, 770 F.2d 1144, 1156 (D.C. Cir. 1985); *Ass'n of Data Processing Serv. Orgs. Inc. v. Bd. of Governors of the Fed. Reserve Sys.*, 745 F.2d 677, 684 (D.C. Cir. 1984).

3. The Final Rule is arbitrary and capricious because it fails to sufficiently consider substantial evidence regarding the need to maintain existing cost allocation methodologies applicable to transmission facilities unless and until a new cost allocation methodology or methodologies are developed. *See* 5 U.S.C. § 706(2)(A); *id.* at § 706(2)(E); *see also Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1313 (D.C. Cir. 1991); *Power Auth. of State of N.Y.*, 743 F.2d at 110-11; *Wis. Gas Co.*, 770 F.2d at 1156; *Ass'n of Data Processing Serv. Orgs.*, 745 F.2d at 684; *Atl. City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).

4. To the extent the Commission intended to require transmission providers to use the set of seven required benefits to help to inform their identification of Long-Term Transmission Needs, the Final Rule is arbitrary and capricious because such requirement is not based on substantial evidence. *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (citing 5 U.S.C. § 706(2)(A)); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Wis. Gas Co.*, 770 F.2d at 1156.

5. The Final Rule is arbitrary and capricious because it fails to explain its departure from the LTRTP NOPR which recognized the value of allowing regional flexibility with respect to benefits, and to instead require transmission providers to measure, at a minimum, a set of seven required benefits and then use those seven specific required benefits to inform the identification of Long-Term Regional Transmission Needs, evaluate Long-Term Regional Transmission Facilities for selection, and allocate costs. *Midwest ISO Transmission Owners*, 373 F.3d at 1368 (citing 5 U.S.C. § 706(2)(A)); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Wis. Gas Co.*, 770 F.2d at 1156.

6. The requirement in the Final Rule mandating greater coordination between existing Order No. 1000 regional transmission planning and generator interconnection processes is arbitrary and capricious in its application to PJM, because it ignores contrary evidence presented by PJM, and the Commission did not adequately consider, address, or explain its responses to arguments and evidence in the record. Furthermore, the Final Order is not the product of reasoned decision making, because it invites gaming opportunities that would undermine PJM's newly implemented generation interconnection reforms, lead to unduly discriminatory treatment of interconnection customers, and inappropriately shift costs from generation to load. *See* 5 U.S.C. § 706(2); 16 U.S.C. § 825*l*(b); *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 66-67 (D.C. Cir. 2014); *Transmission Access Policy Study Grp. v. FERC*, 225 F.3d 667, 687 (D.C. Cir. 2000); *Env't Def. Fund v. FERC*, 2 F.4th 953 (D.C. Cir. 2021); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *PSEG Energy Res. & Trade*

LLC v. FERC, 665 F.3d 203, 207-10 (D.C. Cir. 2011); *Am. Gas Ass'n v. FERC*, 593 F.3d 14, 19 (D.C. Cir. 2010); *PPL Wallingford Energy LLC v. FERC*, 419 F.3d 1194, 1198 (D.C. Cir. 2005); *Canadian Ass'n of Petroleum Producers v. FERC*, 254 F.3d 289, 299 (D.C. Cir. 2001).

7. The Final Rule's requirement that transmission providers evaluate for selection regional transmission facilities to address certain identified interconnection-related transmission needs in their existing Order No. 1000 regional transmission planning and cost allocation processes, rather than in Long-Term Regional Transmission Planning, is arbitrary and capricious because it is not based on substantial evidence, and because parties were not given notice of or an opportunity to provide comments on this requirement. In doing so, the Commission also erred by reopening the accepted cost allocation methodologies for these projects in existing Order Nos. 1000 and 2023, both of which were built on the premise that the cost causer pays for the interconnection costs. *Midwest ISO Transmission Owners*, 373 F.3d at 1368 (citing 5 U.S.C. § 706(2)(A)); *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Wis. Gas Co.*, 770 F.2d at 1156.

8. The Final Rule is arbitrary and capricious and not the product of reasoned decision making, because it provides contradictory statements regarding the start date of the long-term planning horizon and, therefore, fails to specify a meaningful and actionable compliance obligation for transmission providers. The Commission should reverse its holding on rehearing to avoid mandating an overlap with existing reliability and market efficiency planning pursuant to Order No. 1000. In the alternative, the Commission should clarify that the long-term regional transmission planning horizon can start on year six, as proposed in the NOPR, and provide implementation flexibility to transmission planners. *See* 5 U.S.C. § 706(2); 16 U.S.C. § 825*l*(b); *S.C. Pub. Serv. Auth.*, 762 F.3d at 66-67; *Transmission Access Policy Study Grp.*, 225 F.3d at 687; *Env't Def. Fund*, 2 F.4th 953; *Motor Vehicle Mfrs. Ass'n*, 463 U.S. at 43; *Assoc. Gas Distribs. v. FERC*, 824 F.2d 981, 1019 (D.C. Cir. 1987); *Wis. Gas. Co.*, 770 F.2d at 1151, 1168.

9. The Final Rule is arbitrary and capricious because the Commission did not adequately explain why the independent entity variation should not apply to RTO/ISOs that seek proposed deviations from the requirements in the Final Rule on compliance. *See* 5 U.S.C. § 706(2)(A); *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009).

V. CONCLUSION

For the reasons set forth above, PJM respectfully requests that the Commission grant the requests for rehearing and clarification set forth herein.

Respectfully submitted,

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

Dated: June 12, 2024

Attachment A

Summary of PJM-Developed Long-Term Regional Transmission Planning Process

For the past several years, PJM has been discussing with states and stakeholders a process pursuant to which PJM could use scenario-based planning to proactively identify long-term transmission needs and potential solutions to those needs.[1] Most significantly, throughout 2022 and 2023, PJM held workshops that were focused on PJM's proposed framework for scenario analysis to identify and address long-term reliability and public policy needs.[2] Following the conclusion of the Workshop process in December 2023, PJM transparently engaged with its states and stakeholders to develop manual language[3] that outlines the framework pursuant to which PJM proposed to engage in long-term, scenario-based, regional transmission planning (referred to herein as "PJM LTRTP Process" or "PJM's LTRTP Process").

Because PJM was aware of the then-pending Notice of Proposed Rulemaking[4] issued in this docket as it conducted its workshops, PJM designed the PJM LTRTP Process in such a way

[1] For instance, in May 2022, PJM released its "Enhanced 15-Year Long-Term (Master Plan) White Paper," outlining how best to work with states and other stakeholders to identify, from among an array of future scenarios, those scenarios which transmission planners could utilize to justify moving forward with directives to build new transmission to support customer needs and policy goals. *Enhanced 15-Year Long-Term (Master Plan) White Paper*, PJM Interconnection, L.L.C. (May 10, 2022), https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220525-long-term/enhanced-long-term-planning-discussion-document.ashx ("Master Plan White Paper").

[2] *Long-Term Regional Transmission Planning Workshop*, PJM Interconnection, L.L.C., (last visited June 10, 2024); Planning Committee, PJM Interconnection, L.L.C., https://pjm.com/committees-and-groups/committees/pc (last visited June 10, 2024).

[3] PJM planned to bring the manual language to a vote before the Markets and Reliability Committee on April 25, 2024. *See* Markets & Reliability Committee, *Meeting Details*, PJM Interconnection, L.L.C. (Apr. 25, 2024), https://www.pjm.com/forms/registration/Meeting%20Registration.aspx?ID=%7b86C346C5-0F46-4A74-93F0-8719F69163FE%7d (Agenda Item 02). However, in light of the Commission's April 18, 2024 announcement that it would issue the Final Rule on May 13, 2024, PJM stakeholders voted to defer consideration of the manual language until June 2024. PJM has further deferred consideration of the proposed manual language until such time as PJM has had the opportunity to fully review the requirements of the Final Rule.

[4] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022) ("LTRTP NOPR").

as to capture the spirit of the LTRTP NOPR, *i.e.*, to proactively plan for changes in the resource mix, while also recognizing the unique needs of and challenges facing the PJM Region as described above. Specifically, PJM proposed to maintain its existing Order No. 1000-compliant near-term (*i.e.*, five-year out) reliability and market efficiency planning processes, and replace its existing long-term reliability planning process with the PJM LTRTP Process as an enhancement to those existing processes. Pursuant to the PJM LTRTP Process, PJM proposed to implement a three-year, long-term reliability planning cycle, during which PJM would (i) develop three long-term scenarios as described further below; (ii) identify long-term reliability and public policy needs over a 15-year planning horizon; (iii) measure the economic benefits associated with facilities that could solve those needs; and (iv) evaluate and decide whether to select any facilities to address any of those identified needs.

PJM proposed to work with states and stakeholders through existing stakeholder processes (*i.e.*, the Independent State Agencies Committee and the Transmission Expansion Advisory Committee) to determine the assumptions to be used to develop three diverse long-term scenarios as part of the PJM LTRTP Process. Specifically, PJM would develop a base reliability scenario, as well as additional scenarios that demonstrate a wider range of possible transmission needs as follows:

- ***Base Reliability Scenario***: PJM would construct a base reliability scenario and associated base cases to identify future transmission needs and solutions required to maintain the reliability of the system (the "base reliability scenario").[5] The primary categories of factors to be included in the base reliability scenario would include: (i) the PJM Load Forecast Report;[6] (ii) announced retirements and anticipated retirements based on Public Policy

[5] *See* Transmission Planning Department, *March 20, 2024 MRC Draft Manual 14B Proposed Revisions to Implement LTRTP*, PJM Interconnection, L.L.C., Attachment C, Section C.4.1, https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240425/20240425-item-02---4-ltrtp-manual-14b-revisions---clean.ashx.

[6] The PJM Load Forecast Report is an annual, independent load forecast prepared by PJM staff. The report includes long-term forecasts of peak loads, net energy, load management, distributed solar generation, plug-in electric vehicles, and battery storage for each PJM zone, region, locational deliverability area ("LDA"), and the total PJM Region. *See*,

Requirements[7] and company commitments;[8] (iii) in-service generation and generation not yet in-service but with an executed service agreement or State Agreement Approach ("SAA") reservation; and (iv) replacement generation taken mainly from the PJM New Service Request process needed to maintain the 1-in-10 reliability standard, *i.e.*, to ensure resource adequacy.

- ***Medium Public Policy Scenario***: To develop the medium public policy scenario (the "medium scenario"), PJM would start with the base reliability scenario and model additional Public Policy Requirements including, by way of example, states' renewable portfolio standards. PJM anticipates that the only additional Public Policy Requirements that would be modeled in this scenario would be those traditionally brought by a state to PJM as part of the SAA[9] process[10] (recognizing now that there could be an *ex ante* cost allocation framework in place or an agreement contemplated by the SAA process for a state or states to share the costs). Upon the conclusion of this analysis, interested states would request that PJM develop transmission solutions for their consideration. PJM could also combine reliability solutions developed pursuant to the base reliability scenario with a SAA project from this medium scenario to create a Multi-Driver Project.[11]

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e.g., PJM Resource Adequacy Planning Department, *PJM Load Forecast Report*, PJM Interconnection, L.L.C. (Feb. 1, 2024), https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx.

[7] Public Policy Requirements are defined as "policies pursued by: (a) state or federal entities, where such policies are reflected in duly enacted statutes or regulations, including but not limited to, state renewable portfolio standards and requirements under Environmental Protection Agency regulations; and (b) local governmental entities such as a municipal or county government, where such policies are reflected in duly enacted laws or regulations passed by the local governmental entity." Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement"), Definitions O-P. Deactivations driven by Public Policy Requirements that PJM would include in the base reliability scenario include, by way of example, anticipated retirements to comply with the requirements of the Illinois Climate & Equitable Jobs Act ("CEJA"), which mandates the scheduled phase-out of coal and natural gas generation by specified target dates. Climate and Equitable Jobs Act, 415 Ill. Comp. Stat. 5/9.15 (2022).

[8] Company commitments include environmental, social, and governance commitments brought to PJM's attention, where such commitments are per legal consent degree or other public statement such as press release, financial plan, or state-approved Integrated Resource Plans.

[9] *See* Operating Agreement, Schedule 6, section 1.5.9. The SAA process is a means by which PJM's Regional Transmission Expansion Plan ("RTEP") process is responsive to requests from a state (or group of states) that PJM develop transmission that would assist in implementing state Public Policy Requirements, including but not limited to, state renewable portfolio standards. The SAA process requires that should a state (or states) select a state public policy project, the state(s) also must agree that 100% of the costs of such project will be allocated to the zones within such state(s).

[10] An example of a SAA request that could be considered as part of the medium scenario is the state of New Jersey's request to use the SAA process to solicit proposals to improve and/or expand the PJM Transmission System to provide for the deliverability of up to 7,500 MW of offshore wind generation by 2035. *In the Matter of Declaring Transmission to Support Offshore a Public Policy of the State of New Jersey*, Order, NJBPU Docket No. QO20100630, at 7 (Nov. 18, 2020); *see also PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 142 (2013), *order on reh'g*, 147 FERC ¶ 61,128, at P 87 (2014).

[11] A Multi-Driver Project is "a transmission enhancement or expansion that addresses more than one of the following: reliability violations, economic constraints or State Agreement Approach initiatives." Operating Agreement, Definitions M-N.

- ***High Public Policy Scenario***: To develop the high public policy scenario (the "high scenario"), PJM would start with the medium scenario (which, again, has its foundation the base reliability scenario), and model higher loads assumptions, incorporating for example more ambitious electrification, or renewable generation reflecting for example carbon neutrality objectives. Specifically, this scenario would model Public Policy Objectives[12] brought to PJM by states to help inform their decisions related to the medium scenario, or to inform future Public Policy Requirements.

Furthermore, PJM, working with stakeholders, could determine the need for additional scenarios and sensitivities, for example, on economic retirements or extreme weather. PJM would use each of these scenarios and sensitivities to inform its near-term reliability analyses. Additionally, through the scenarios described above, PJM would be able to identify more efficient or cost-effective transmission solutions to address the long-term challenges it has identified, while maintaining system reliability and adhering to its current cost allocation methodology as discussed below.

PJM would also calculate multiple benefits for the transmission solutions developed pursuant to the process, which benefits were modeled off of those enumerated in LTRTP NOPR.[13] Specifically, PJM would measure the following benefits of proposed solutions to the long-term transmission needs identified through the PJM LTRTP Process: (i) reduced loss of load expectation or planning reserve margin; (ii) extended production cost savings (including Benefits 4 and 5 identified by the Federal Energy Regulatory Commission ("Commission") in Order No. 1920); (iii) avoided cost of transmission replacement and (iv) avoided cost of generation. The four benefits that PJM would measure under the PJM LTRTP Process are designed to sum up to system cost impacts (a proxy for welfare changes) and provide PJM, states and stakeholders with the

[12] Public Policy Objectives are defined as "Public Policy Requirements, as well as public policy initiatives of state or federal entities that have not been codified into law or regulation but which nonetheless may have important impacts on long term planning considerations." Operating Agreement, Definitions O-P.

[13] *See* LTRTP NOPR at PP 183-225, 227-30, 233-35.

flexibility needed to innovate and identify projects that are most beneficial, while meeting the reliability needs of the system.

Finally, consistent with prior Commission precedent,[14] PJM would allocate the costs associated with projects developed through the PJM LTRTP Process and ultimately incorporated into the RTEP for purposes of cost allocation pursuant to existing cost allocation methodologies in the PJM Region for reliability projects (identified through the base reliability scenario) and public policy projects (identified through the medium and high scenarios).[15]

[14] *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at PP 441-42 (2013), *order on reh'g*, 147 FERC ¶ 61,128, at PP 389-394 (2014).

[15] *See Consideration of Federal and State Public Policy Initiatives Through PJM's Long-Term Regional Transmission Planning Process*, PJM Interconnection, L.L.C. (Dec. 15, 2023), https://www.pjm.com/-/media/committees-groups/committees/pc/2024/20240109/20240109-item-06h---position-paper---consideration-of-federal-and-state-public-policy-initiatives-through-pjm-ltrtp-process.ashx.

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 June, 2024.

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