UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection

Docket No. RM21-17-000

REPLY COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

Pursuant to the July 15, 2021 Advanced Notice of Proposed Rulemaking ("ANOPR")[1] the Solar Energy Industries Association ("SEIA") submits these reply comments on the Commission's potential reforms to improve the electric regional transmission planning and cost allocation and generator interconnection processes.

SEIA and other commenters support the Commission's inquiry and urge the Commission to enact sensible transmission planning and generator interconnection reforms that will help our nation realize the full potential of and benefit from our renewable energy resources. In doing so, the Commission should be mindful of and continue to build upon its prior successes in creating and maintaining a stable, open, nondiscriminatory, and investible framework for competitive power generation. These reply comments focus on three main areas where there is generally agreement among commenters. First, the Commission should implement specific changes to the transmission planning process including: a longer term planning horizon, consideration of reliable indicators of future transmission need and scenario planning, acceleration of clearly needed and beneficial projects, Independent Transmission Planning oversight in non-market areas, and inclusion of grid enhancing technologies ("GETs"). Second, the present approach to

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 176 FERC ¶ 61,024 (2021) (ANOPR).

cost allocation has resulted in transmission planning processes that fail to achieve needed and timely regional investment. Changes are needed to the definition of benefits in "beneficiary pays" to account for the beneficial aspects of resiliency, increased import capacity, and the congestion management contribution of storage, among other factors. Third, participant funding as it stands today is unjust and unreasonable and should quickly be replaced with a method that is consistent with cost allocation precedent and avoids imposing further burdens upon interconnection customers while providing a solution to the current iterative interconnection study process. These reply comments also include several near- and long-term principles the Commission should consider with respect to interconnection reforms, including suggested reforms to enhance the Order No. 845 interconnection reports. Finally, while many of these comments specifically apply to organized markets, some could also just as easily apply in vertically integrated regions. The Commission should not overlook the substantial overlap of issues across regions and should examine and compare the different approaches (and successes) in the various regions that could be implemented elsewhere.

I. COMMENTS

A. Regional Transmission Planning and Cost Allocation Processes – Planning for the Transmission Needs of Anticipated Future Generation

SEIA and several other commenters agree that a longer-term transmission planning horizon is necessary, with periodic review of the planning models used.[2] SEIA agrees with Exelon Corporation's ("Exelon") suggestion that transmission planners should use numerous future scenarios using probabilistic analysis to identify the infrastructure that is the most likely to

[2] *E.g.* Comments of Exelon Corp. at 12-14; Motion to Intervene and Comments of the Iowa Office of Consumer Advocate at 2; Comments of NextEra Energy, Inc. at 70-77.

be needed and ensure that it is built cost-effectively and timely.[3] The Organization of Midcontinent Independent System Operator, Inc. ("MISO") States offered the example of an improved approach to transmission planning as shown in the MISO Futures plans, based upon the flexible tool that MISO developed to address planning uncertainty by using multiple forward-looking scenarios ("Futures") to provide a range of future outlooks based upon a collection of assumptions.[4] The assumptions in the Futures scenarios establish different ranges of economic, policy, and technological possibilities—such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas price, and generation capital cost—over a twenty-year period. Consideration of such broad and flexible assumptions to bookend the potential fleet resource mix over a longer planning period, intended to be used for several years with minimal updates, can help to identify the infrastructure that is the most likely to be needed and ensure that it is built cost-effectively and timely. The status quo, which repeatedly delays investment until commercialized projects and load are more perfectly aligned, presents an unsolvable "chicken and egg" dilemma that stifles transmission expansion, which ultimately fails developers, investors, and consumers alike.

In addition, use of tools for identifying and analyzing high-value zones for renewable energy development, such as National Renewable Energy Laboratory's (NREL) Renewable Energy Potential model ("reV"), could significantly enhance the transmission planning process.[5]

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[3] Comments of Exelon Corp.at 13.

[4] *See* Comments of Organization of MISO States at 4 (discussing the *MISO Futures Report* (April 2021) https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf).

[5] *See* Comments of United States Department of Energy at 79 (Appendix B: National Laboratories' Supplemental Information to Comments of Department of Energy to Advance Notice of Proposed Rulemaking (ANOPR) with link to NREL, Geospatial Data Science, *reV: The Renewable Energy Potential Model*, available at https://www.nrel.gov/gis/renewable-energy-potential.html.

SEIA agrees with Exelon's proposal that an improved transmission planning approach involving multiple scenarios could result in a more efficient planning cycle that could occur every five to seven years with minimal updates.[6] SEIA urges the Commission to incorporate these improvements in the transmission planning process.

Informational uncertainty is a risk that underlies long-term planning studies. The PJM Independent Market Monitor ("IMM") and Potomac Economics raise concerns regarding the role of informational uncertainty and the consideration of lower probability actions. They also express reservations about any mandate for long-term planning studies that would involve transmission providers speculating as to lower probability factors.[7] However, they concede that improvements could be made in the planning process to identify and incorporate a broader array of near-term emerging trends.[8] SEIA recognizes such concerns regarding uncertainty but points to NextEra Energy, Inc.'s ("NextEra") comments addressing such concerns: "system planners can mitigate the risk of stranded costs by using *a range of realistic future scenarios* to identify the most efficient, least-regrets transmission solutions that address multiple system needs over a range of scenarios, including needs driven by expected changes in the generation resource mix."[9] SEIA urges the Commission to improve the transmission planning process by requiring consideration of numerous realistic future scenarios using probabilistic analysis. Such an approach combined with the use of newer planning tools like the MISO Futures plan and

[6] Comments of Exelon Corp. at 17.

[7] Comments of the Independent Market Monitor for PJM at 2-6; Comments of Potomac Economics, Ltd. at 3-4.

[8] Comments of the Independent Market Monitor for PJM at 6; Comments of Potomac Economics, Ltd. at 4.

[9] Comments of NextEra Energy, Inc. at 56 (emphasis added).

NREL's reV model could help to identify the infrastructure that is the most likely to be needed and ensure that it is built cost-effectively and timely.

SEIA also agrees with other commenters that the Commission should look for ways to accelerate clearly needed and beneficial projects. NewSun Energy LLC notes that there may be some transmission projects that are obviously needed, such as ones that have been identified in multiple studies and/or which provide critical backbone infrastructure to a wide array of beneficiaries.[10] Creating a process which will accelerate such projects could represent "low hanging fruit" for the Commission and transmission owners to encourage earlier movement towards alleviating transmission congestion and unlocking additional renewable resources.[11]

SEIA and other commenters also recommend that transmission providers include GETs in the transmission planning process and in the interconnection process. A review of the ANOPR comments shows that use of GETs is generally non-controversial. As noted by the Edison Electric Institute ("EEI"), GETs have demonstrated improvements in efficiency, capacity, reliability, and resiliency and going forward, GETs may play an important role in increasing efficient use of the system.[12] However, EEI, and others have also expressed reservations, stating that it is not appropriate to require that GETs be incorporated into the long-term planning processes contemplated by the Commission in the ANOPR. EEI believes that at present most GETs—such as power flow control and transmission switching equipment, storage technologies, and advanced line rating management technologies—currently provide operational flexibility to

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[10] Motion to Intervene and Comments of NewSun Energy LLC at 23.

[11] *Id.*

[12] Initial Comments of the Edison Electric Institute at 7, 38-39.

system operators in the short-term.[13] MISO's concern over GETs seems to be one of resource allocation and "bang for the buck"—given the transformation in generation resources evident in MISO, enabling a substantial jump in bulk delivery capability through new transmission appears to be a more pressing need in MISO's view in order to meet the evolving generation fleet. However, PPL concedes that while GETs may currently have limited applications, it expects that they may be adopted more broadly once the costs come down or the benefits of GETs increase. PPL also believes that to the extent the Commission wishes to encourage additional GETs innovation, it should consider the use of transmission incentives. Potomac Economics does not share these concerns. It believes that GETs should be incorporated into transmission planning processes to the extent that the transmission operator has the ability to integrate GETs into operations.[14] Potomac Economics believes that GETs will likely serve both the planning process in the short-term by enabling interim solutions during construction of transmission projects and other transmission outages and in the longer-term as alternatives or complements to traditional projects.

SEIA appreciates Potomac Economics' more balanced view. SEIA believes that GETs should not be limited to short-term operational control and should be considered in both long-term transmission planning and as part of the generator interconnection process. As explained by Pine Gate Renewables, LLC ("Pine Gate"), GETs should be considered in the interconnection process as a means of reducing the need for costly network upgrades. Moreover, GETs can bridge the gap in time between relatively quickly constructed renewable energy resources and

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[13] *Id*. *See also* Comments of Midcontinent Independent System Operator, Inc. at 45-46; Comments of PPL Electric Utilities Corp. at 13-14.

[14] Comments of Potomac Economics, Ltd. at 8-9.

the slower process for constructing transmission. GETs could enable large amounts of renewable resources to interconnect to the transmission system relatively quickly.[15] SEIA supports Pine Gate's innovative suggestion that the Commission could require that GETs be considered in the generator interconnection process upon the request of the interconnection customer. Pine Gate proposes that the Commission adopt a framework that is substantially similar to what is outlined in the Efficient Grid Interconnection Act of 2021.[16] Under that proposal, the interconnection customer would have the ability to consult with the transmission owner and, if applicable, the RTO/ISO to request the consideration and study of the deployment of GETs in addition, or as a substitution to, carrying out a traditional transmission upgrade or addition. The transmission owner would then determine whether to deploy the GETs. If the transmission owner elects not to deploy the GETs, the interconnection customer would then have the right to appeal that determination to the Commission. This proposed framework strikes a reasonable balance that will enable the interconnection customer to request the deployment of GETs in the interconnection process, but still provides the RTO/ISO and transmission owner with a reasonable level of discretion regarding what technologies are utilized on the transmission system. The Commission should consider issuing a policy statement, similar to its April 2021 carbon pricing policy statement, addressing the use of GETs for both transmission planning and generator interconnection.

[15] Comments of Pine Gate Renewables, LLC at 10-13.

[16] Efficient Grid Interconnection Act of 2021, H.R. 4027, 117th Cong. § 4 (2021) ("Efficient Grid Interconnection Act").

B. Cost Allocation for Transmission Facilities Planned through the Regional Transmission Planning Process

SEIA and other commenters believe that the present approach to cost allocation has resulted in transmission planning processes that fail to build needed regional investment. A significant factor in this failure is how "benefits" are defined and how the principle "beneficiary pays" is implemented. The Commission should establish transmission planning approaches that quantify the full range of transmission expansion benefits including reliability and resource adequacy, generation capacity cost savings, energy cost savings, environmental benefits, public policy benefits, and employment and economic stimulus benefits—based on a multi-value analysis and a portfolio-based approach.[17] Benefits may need to vary depending upon regional needs and unique regional characteristics. Including consideration of the beneficial aspects of resiliency, increased import capacity, and the congestion management contribution of storage, among other factors, should also be incorporated in an updated definition of "benefits."

The Commission should define "resiliency" and incorporate it in the definition of benefits through a policy statement, while maintaining flexibility for each region to further define the term in a way that best suits that region.[18]

Additional terms that need to be incorporated in the definition of benefits include import capacity benefits and the congestion management benefits of adding storage. The Kansas Corporation Commission ("KCC") provides an insightful perspective on the value of import capacity benefits. The KCC's position on interregional cost allocation had previously been that the costs of interregional facilities that are built to transport low-cost renewable power should

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[17] Initial Comments of American Electric Power Service Corp. at 12-16.

[18] Comments of the California Independent System Operator Corp. at 9-10, 85-86.

flow with the user of energy. However, the KCC's experience with Winter Storm Uri caused it to reconsider that view. The KCC now has "an acute appreciation for the substantial reliability and resiliency benefits that can be provided by robust import capabilities among regions. While benefits will mostly flow to large load centers and consumers of renewable energy resources, the KCC now believes cost allocation should consider the inherent reliability benefits to all regions of enhancing import-export capabilities during capacity shortfall events."[19] Potomac Economics has identified that the characteristics of future generation can be as important as its location, which can provide a significant benefit. For example, installing battery storage at, or near, new renewable facilities to allow them to charge the batteries when congestion limits the quantities that can be delivered to load can substantially change the value of upgrading the transmission network.[20]

When the Commission addresses expanding the factors that are included in the definition of benefits, it should broadly socialize these resiliency, import capacity, and congestion management benefits to all beneficiaries. The New York University Institute for Policy Integrity articulated why the Commission should use postage stamp allocation for costs associated with societal benefits and public goods like emissions reductions and resilience and how, in keeping with the "beneficiary pays" principle, the costs incurred to garner these broadly distributed benefits should be allocated as broadly as possible.[21] The Commission should also use the social cost of carbon, per President Biden's January 20, 2021 Executive Order,[22] as a metric for

[19] Comments of Kansas Corporation Commission at 11.

[20] Comments of Potomac Economics, Ltd. at 3.

[21] Comments of Institute for Policy Integrity at New York University School of Law at 49-58.

[22] *See Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis,* Executive Order No. 13990 (January 20, 2021).

calculating the societal benefits of transmission solutions that result in decarbonization. By expanding the definition of benefits and reexamining the breadth of beneficiaries that should share in the allocation of costs, the Commission can improve the transmission planning processes to spur needed regional investment.

C. Participant Funding and Crediting Policy for Funding Interconnection-Related Network Upgrades

1. The Participant Funding Model is no longer just and reasonable.

The participant funding model, as it exists today, no longer serves the needs of the transmission system. The comments in response to the Commission's inquiry regarding transmission planning varied widely in exactly how the Commission should address participant funding. However, while a small few commentors seek to keep participant funding as-is,[23] far more commentors saw the current participant funding mechanism for what it is: A mechanism that no longer suits the needs of the grid.

As American Electric Power Service Corp. notes in its comments, the "circumstances have changed significantly" since Order No. 2003.[24] The costs to integrate new resources, not just renewable projects, have significantly increased.[25] But, since the Commission issued Order No. 1000, the "total regionally planned transmission investment in RTOs decreased by 50

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[23] Comments of the Large Public Power Council at 4, 28; Comments of the Public Utilities Commission of Ohio at 14; Initial Comments of Ameren Services Co. at 14; Comments of the Louisiana Public Service Commission at 20-21.

[24] Initial Comments of American Electric Power Service Corp. at 39.

[25] Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 21 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.

percent."[26] As Tenaska, Inc. notes, much of the network upgrade process has been occurring outside of the regional planning process, shifting the burden of identifying and planning for system upgrades onto the interconnection process.[27]

The interconnection process is a poor stand-in for transmission planning. As the State Agencies note, transmission development is very "lumpy."[28] Multiple developers may be able to interconnect with little expense, but eventually, system capacity gets used up and a new project will trigger a costly network upgrade.[29] And these network upgrades affect the economics of the entire project.[30]

2. The original justifications for Participant Funding are not consistent with the needs of the evolving transmission grid.

Several commentors argue that the Commission should keep participant funding because it encourages efficient project siting.[31] The siting concerns that justified the adoption of participant funding in Order No. 2003 have become increasingly complex, requiring a closer look at this justification.[32]

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[26] Tenaska Comments at 5 (citing Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 21 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.).

[27] Comments of Tenaska, Inc. at 5-6.

[28] Comments of the State Agencies at 38.

[29] Comments of the State Agencies at 38; *see also* Comments of Tenaska, Inc. at 7 (discussing how the Tenaska Clear Creek Project were subject to approximately $66 million in network upgrade costs, despite evidence that the facilities at issue were already overloaded in the base case scenarios).

[30] R Street Comments at 12.

[31] Entergy Comments at 20; Dayton Power & Light Comments at 8; Public Utilities Commission of Ohio at 14.

[32] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, P 695 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005), *aff'd sub nom. Nat'l Ass'n of Regul. Util. Comm'rs v. FERC,* 475 F.3d 1277 (D.C. Cir. 2007).

Siting concerns address the optimization of generation output and the use of existing transmission lines. However, siting can include other issues such as local laws, which may encourage the placement of solar facilities through local tax credits, or prohibit the placement of solar facilities on certain land. Additionally, the affected system planning process affects siting decisions. The North Carolinas Utilities Commission ("NCUC") gives the example of its rejection of a certificate of public convenience and necessity for the Friesian Project as an example of why participant funding is still necessary.[33] The NCUC explains that the project, located in the Duke Energy Progress ("DEP") footprint, would sell output into the PJM markets. The NCUC argues that under the Order No. 2003 paradigm, the costs of that project would be allocated to customers in North Carolina. What the NCUC fails to recognize is that the limited transmission capacity between DEP and PJM is the result of a failure of the interregional planning process and the inability to adequately plan for affected systems upgrades.[34] Had there been meaningful, proactive interregional transmission planning in place between PJM and DEP, the network upgrade costs associated with the Friesian Project would likely be far lower.

Another justification that several commentors relied on to support participant funding is that participant funding protects load from paying for generators to interconnect to the transmission system.[35] The Commission addressed this concern in Order No. 2003, but contrary to what the commentors argue, this protection for load was not absolute. In setting forth the

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[33] Comments of North Carolina Utilities Commission at 19-20.

[34] *See* Complaint of the Carolina Clean Energy Business Association to Fix the Affected System Coordination Process, Docket No. EL21-92 (July 30, 2021) (outlining the repeated failures of DEP and PJM to plan for affected system upgrades). The Complaint was withdrawn to allow the parties to consider the issues raised in the complaint through settlement and to file any resulting amendments to PJM and DEP's joint operating agreement. *See* Notice of Withdrawal re Carolinas Clean Energy Business Association v. PJM Interconnection, L.L.C, Docket No. EL21-92 (Sept. 3, 2021).

[35] Comments of the Louisiana Public Service Commission at 20-21; Comments of Dayton Power & Light at 8; Initial Comments of Ameren Services Co. at 14.

transmission crediting mechanism in Order No. 2003, the Commission found that establishing a five year period for the transmission provider to either reimburse the interconnection customer for the network upgrade costs or provide transmission credits equal to the cost of the network upgrades would help "to ensure that other Transmission Customers, including the Transmission Provider's native load, will not have to bear the cost of the Network Upgrades *if the Interconnection Customer ceases operation of the Generating Facility prematurely*."[36] The Commission did not intend to permanently protect native load customers. These customers were protected only in instances where the generator went out of operation before the return on the network upgrades could be realized. This limited protection does not change the Commission's finding that though the interconnection customer caused the Network Upgrades, once constructed, it is the entire transmission system that benefits from those upgrades.[37]

Further, arguments that interconnection customers are free riding on the existing system built and paid for by the load serving entities,[38] ignores the fact that an increasingly larger share of network upgrades, upgrades which benefit the entire transmission system,[39] are paid for by interconnection customers, without repayment by load.[40] These arguments are also undercut by

[36] Order No. 2003, 104 FERC ¶ 61,103 at P 616 (emphasis added).

[37] Order No. 2003-A, 106 FERC ¶ 61,220, P 584.

[38] Comments of the Northern Virginia Electric Cooperative at 14-15.

[39] Order No. 2003-A, 106 FERC ¶ 61,220, P 584.

[40] Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 13-16 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.

the allocations to interconnection customers of network upgrade costs that are nowhere near the point of interconnection.[41]

Arguments in favor of maintaining the current participant funding model also implicitly assume that load is not bearing the ultimate cost of these facilities.[42] These costs are ultimately incorporated into the bid price of energy, which the customer will pay.[43] No matter whether the costs of network upgrades are subject to a participant funding construct or not, load will ultimately pay for the cost of the network upgrades. However, a participant funding mechanism, as it exists now, creates perverse incentives with respect to transmission planning and building that will result in higher costs to load.

3. The Commission should begin near- and long-term reforms to the Participant Funding Mechanism.

As SEIA stated in its initial comments, participant funding was created by the independent entity variations the Commission granted from the original requirements of Order No. 2003.[44] While they may have worked then, those variations are no longer just and reasonable. Interconnection customers cannot wait until the Commission initiates a rulemaking, and accepts compliance filings, for the just and reasonable replacement rate. The Commission should, as an interim measure, initiate an investigation as to whether the RTOs/ISOs that received variations from Order No. 2003's crediting mechanism should remain entitled to those

[41] *See* Comments of Enel North America, Attachment, Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning, Appendix B (discussing an example in which the interconnection customer was a share of the network upgrade costs for transmission facilities that were 450 miles from the project).

[42] *See* Initial Comments of Ameren Services Co. at 15 ("Spreading the costs will create a new set of problems; it mutes the true cost of delivered power…").

[43] Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 13-16 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.

[44] Order No. 2003, 104 FERC ¶ 61,103, P 584.

variations. If interconnection customers provide the upfront funding for network upgrades that benefit the entire transmission system, then those customers should be compensated for providing that funding through transmission credits.

The California Independent System Operator, Corp.'s ("CAISO's") participant *financing* serves as the template for how Order No. 2003's original participant funding mechanism, which was paired with a crediting mechanism, could be implemented today.[45] In CAISO, interconnection customers provide the initial financing to construct their interconnection facilities and network upgrades. Upon the commercial operation of the generating facility and the network upgrades, the transmission owner reimburses the interconnection customer in cash within five years. The transmission owner then includes the costs in its transmission revenue requirement.[46]

In the long-term though, the transmission crediting mechanism or participant financing will not work for the grid of the future. Interconnection queues across the country are changing and growing, not *because* of the current participant funding mechanism,[47] but *despite* it.[48] The demand for clean energy will continue to grow. States will continue to set clean energy goals. Large, sophisticated customers will continue to demand clean energy.[49] The question that the

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[45] *See* Comments of the California Independent System Operator Corp. 90-100.

[46] Comments of the California Independent System Operator Corp. at 92.

[47] *See* Comments of Midcontinent Independent System Operator, Inc. at 90 ("The Commission should note that MISO's implementation of participant funding has not caused a lack of Interconnection Requests in MISO.").

[48] Comments of the Pennsylvania Public Utilities Commission at 14 ("While the PAPUC supports the participant funding model, it is cognizant that the implementation of that principle in PJM has resulted in a significant backlog of renewable generation attempting to interconnect to the grid.").

[49] *See* Amazon, Renewable Energy, https://sustainability.aboutamazon.com/ (establishing a goal of 100% renewable energy by 2025); Walmart, Setting Records, Walmart Continues Moving Toward Becoming a Totally Renewable Business, https://corporate.walmart.com/ (establishing a goal of 100% renewable energy by 2035); Apple, Apple powers ahead in new renewable energy solutions with over 110 suppliers, https://www.apple.com/newsroom/2021/03/apple-powers-ahead-in-new-renewable-energy-solutions-with-over-110-

Commission must grapple with is whether participant funding is currently sending the correct market signals to ensure that the supply of energy can reach the load demanding that energy.

If the Commission decides not to eliminate participant funding in the long-term, there are multiple participant funding reforms proposed in this proceeding that the Commission should consider.[50] However, before the Commission embarks on long-term participant funding reforms, it must reevaluate and redefine its transmission planning policies so that participant funding is not used as a poorly affixed band-aid for that process. The current method of network upgrade funding is inefficient and inhibits needed transmission expansion.[51] Further, the Commission must also redefine beneficiary, so that any network upgrades remaining after a new and fulsome transmission planning process are allocated properly. It is only after the Commission addresses these fundamental issues that it should then turn to participant funding and interconnection reform.

D. Near- and Long-term Guiding Principles for Interconnection Reform

Interconnection reforms are underway across the country. On October 29, 2021, Southwest Power Pool filed reforms to its interconnection process to help mitigate its interconnection queue backlog.[52] In April 2021, PJM formed its Interconnection Process Reform Task Force to discuss challenges related to the interconnection process and look for opportunities

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suppliers/ (establishing a goal of a carbon neutral supply chain by 2030); *see also* Rich Glick, Matthew Christiansen, FERC and Climate Change, 40 Energy L.J. 1, 8 (2019).

[50] *See* Comments of Enel North America, Attachment, Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning; Comments of American Clean Power Association and U.S. Energy Storage Association at 5-10; Comments of the American Council on Renewable Energy at 1-5; Comments of NextEra Energy, Inc. at 47-53.

[51] *See* Comments of Northwest & Intermountain Power Producers Coalition at 33.

[52] *See* Southwest Power Pool, Inc., Revisions to Modify Generator Interconnection Procedures to Mitigate Backlog, Docket No. ER22-253 (Oct. 29, 2021).

to improve the process.[53] MISO is currently working on reforms that would shorten the timeline to provide new resources with the information they need to move their projects forward.[54] While SEIA appreciates the need for independent entity variations to account for differing operating characteristics of different RTOs/ ISOs, the need for transparency must govern interconnection reform regardless of location.

In Order No. 845, the Commission instituted interconnection study metrics reporting.[55] The purpose of this requirement was to provide interconnection customers with information necessary to assess whether a transmission provider is using "reasonable efforts" to complete interconnection studies.[56] The reports are quick to identify queue withdrawals and cascading restudies as the source of delays.[57] However, the reports still lack the information necessary to identify the source of the withdrawals.

In order to provide the transparency necessary to show the source of the queue withdrawals and subsequent interconnection delays, the Commission should expand the reporting requirement set forth in Order No. 845 to include the following information:

- The cost of the network upgrades associated with the delayed or withdrawn projects;

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[53] *See* PJM Interconnection, L.L.C., Interconnection Process Reform Task Force, https://www.pjm.com/committees-and-groups/task-forces/iprtf.

[54] *See* Midcontinent Indep. Sys. Op., Inc., Interconnection Process Working Group, https://www.misoenergy.org/stakeholder-engagement/committees/interconnection-process-working-group/.

[55] *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043, P 305 (2018), *errata notice*, 167 FERC ¶ 61,123, *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137, *errata notice*, 167 FERC ¶ 61,124, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019)

[56] Order No. 845, 163 FERC ¶ 61,043, P 306. Currently, under the *pro forma* LGIP, the requirement that transmission providers complete interconnection studies on a timely basis is based on a "reasonable efforts" standard.

[57] MISO, Informational Report, FERC Order 845 Study Delays, Docket No. ER19-1960, at 8 (Nov. 15, 2021); PJM, Informational Report on Interconnection Study Performance Metrics, Docket No. ER19-1958, at 10 (Aug. 16, 2021).

- The capacity value of the project at the time it either executes its interconnection service agreement or withdraws from the queue; and
- A breakdown of the interconnection delays by transmission zone, to determine whether there is a particular transmission owner associated with the interconnection delays.

To provide transparency, the Commission must commit itself to uncovering the sources of interconnection delays.

In the ANOPR the Commission seeks comments specifically on "how the regional transmission planning and cost allocation and generator interconnection processes could be better coordinated or integrated."[58] SEIA believes there are opportunities to align the generator interconnection process with the regional planning process to ensure that the upgrades needed to connect generation projects that have significantly progressed through the interconnection process and have a high certainty of being constructed are an input into the planning process. We encourage the Commission to further explore these opportunities and propose in this rulemaking to require transmission providers to align and integrate their regional transmission planning and generator interconnection processes to ensure that transmission needs driven by needed new generation development, and the benefits that transmission will provide, are accounted for in regional plans.

One option is to consolidate the generator interconnection process into the regional transmission planning process in RTOs/ISOs. Taking this step would help resolve the cost allocation and market entry barrier problems created by participant funding, because it would charge the planning process with finding the more efficient or cost-effective transmission solutions to facilitate interconnections of new generation and meet other identified transmission

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[58] ANOPR, 176 FERC ¶ 61,024 P 66.

needs. While transmission planning processes incorporate future scenarios today—and should include more of them to address additional transmission needs as explained above—they operate independently and on different timelines from the generator interconnection process. This results in missed opportunities to identify more efficient or cost-effective solutions to transmission needs, and to assess the benefits and fairly allocate the costs of transmission projects that both facilitate interconnection of new generation and provide benefits to customers more broadly.

This approach could also help unburden constrained and backlogged interconnection queues that are creating barriers to entry and the risk of unjust and unreasonable rates and undue discrimination by removing a central barrier to projects that are otherwise ready to move to construction. Specifically, better aligning the interconnection process with the regional planning process by providing a window during which the transmission needs of generation projects that have met certain milestones demonstrating their readiness can be inputted into the regional planning process would remove those projects from the existing serial process of determining needed upgrades project-by-project in a vacuum, which creates uncertainty and delay in the interconnection process.[59] The purpose of this would be to accelerate transmission upgrades that have broad applicability and are clearly identified as something that will benefit the region and should be included in the regional planning process. It should not undermine or delay interconnection queue positions or the ability of interconnection customers to rely on and invest in that stable open access framework the Commission has worked so hard to establish and preserve.

[59] *See* Comments of Enel North America, Inc., Enel Working Paper.

In the long-term though, the Commission should consider interconnection reforms that will align the incentives and price signals between the transmission planning process and interconnection queues. Future Commission interconnection reforms must explore the question of whether a cost saving measure will truly result in consumer savings, or will just obfuscate the true costs of a project and the system. While it is certainly not an easy task, the Commission must start expanding its analysis to consider the long-term costs of its reforms.

II. CONCLUSIONS

SEIA respectfully request that the Commission accept its reply comments and recommendations regarding the Commission's potential reforms to improve the electric regional transmission planning and cost allocation and generator interconnection processes.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned certifies that a copy of this pleading has been served this day upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 30th day of November 2021.

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