UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Improvements to Generator Interconnection Procedures and Agreements	**Docket No.**	**RM22-14-000**

COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

Pursuant to the June 16, 2022 Notice of Proposed Rulemaking,[1] the Solar Energy Industries Association ("SEIA") submits these comments on the Commission's proposed reforms to address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies.

SEIA represents independent power producers both in and outside of organized markets. Since the Commission issued Order No. 2003,[2] SEIA and SEIA members have been active participants in interconnection proceedings before the Commission.[3] Along with member companies, SEIA also worked in stakeholder processes across the country to help address some of the major issues within interconnection queues. The comments and recommendations below represent the experiences of a wide range of member companies who faced, and continue to face,

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[1] *Improvements to Generator Interconnection Procedures and Agreements*, 179 FERC ¶ 61,194 (2022) ("NOPR").

[2] *Standardization of Generator Interconnection Agreements & Proc.*, Order No. 2003, 68 FR 49845 (Aug. 19, 2003), 104 FERC ¶ 61,103 (2003), *order on reh'g*, Order No. 2003-A, 69 FR 15932 (Mar. 5, 2004), 106 FERC ¶ 61,220, *order on reh'g*, Order No. 2003-B, 70 FR 265 (Jan. 19, 2005), 109 FERC ¶ 61,287 (2004), *order on reh'g*, Order No. 2003-C, 70 FR 37661 (July 18, 2005), 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) (*NARUC v. FERC*).

[3] *See* Comments of the Solar Energy Industries Association, Docket No. ER22-2110 (July 14, 2022) (PJM Interconnection Reform Filing); Joint Supplemental Comments of the American Clean Power Association, Advanced Energy Economy, the Solar Energy Industries Association, and the American Council on Renewable Energy on Generation Interconnection Queue Processing and Cost Allocation Reforms, Docket Nos. AD21-15 and RM21-17 (Feb. 14, 2022); Protest of Solar Energy Industries Association, Docket No. ER20-294 (July 17, 2020) (PacifiCorp Queue Reform); Comment of Solar Energy Industries Association, Docket No. RM17-8 (April 13, 2017) (Order No. 845 proceeding).

interconnection queue backlogs. SEIA represents an industry that needs to address these issues and an industry that is willing to do what it takes to solve them.

SEIA strongly supports many of the reforms in this proposal. Providing better information to interconnection customers earlier in the interconnection process will lead to better siting decisions and reduce network upgrade costs. Further, reforms such as moving to a cluster study process, sharing network upgrade costs, eliminating the "reasonable efforts" standard, standardizing affected system studies, and incorporating advanced technologies into the interconnection process, will provide more certainty in the process, leading to fewer withdrawals. SEIA also supports several of the reforms that would increase the requirements to enter the queue, such as higher study deposits and site control requirements, as these may help identify the more viable projects earlier in the process.

However, several aspects of the NOPR impose requirements on interconnection customers that are unduly burdensome and may be infeasible for certain solar developers. The proposed rule proposes that interconnection customers provide either (1) demonstration of firm contractual obligations for the sale of the generating facility's energy, capacity, or ancillary services, or the sale of the constructed generating facility itself; or (2) a commercial readiness deposit based on the interconnection customer's place within the cluster study process, which is returned if the interconnection customer demonstrates commercial readiness later on. SEIA supports allowing projects to demonstrate commercial readiness through means other than having finalized power sale contracts. Independent power producers would be challenged to enter into binding contractual sale obligations without having any reasonable certainty into their final interconnection costs. To that end, SEIA believes the final rule should allow developers to demonstrate commercial readiness through means other than firm contractual sale contracts or financial deposits. Commercial readiness should be evaluated based on the totality of circumstances, and should be required later in the process, so to avoid injecting uncertainty into the interconnection process.

SEIA urges the Commission to swiftly issue a final rulemaking in this proceeding that will implement efficient reforms to the interconnection process, while also leveling a playing field that is inherently unfair to interconnection customers. Reforms that provide for more transparency and certainty in the process will lower interconnection costs and ultimately reduce costs for consumers.

I. COMMENTS

A. Reforms to implement a first-ready, first-served cluster study process

1. The proposed informational interconnection study will provide information of limited value to interconnection customers while draining limited RTO resources.

SEIA supports reforms that will introduce more transparency into the interconnection process. A more transparent process will lead to better decisions by the interconnection customer and create more certainty and stability in the process. While SEIA appreciates that the Commission recognizes the lack of information available to interconnection customers at the time they enter the queue, SEIA does not support the proposal to require transmission providers to conduct informational studies for prospective interconnection customers. Such studies would be a drain on limited transmission provider resources, would not produce useful information for interconnection customers, and are redundant of the due diligence already required interconnection customers.

These studies would overburden limited transmission provider resources. In the transmission NOPR proceedings, several transmission providers noted that they have limited staff resources.[4] These comments have been echoed during stakeholder proceedings and other filings.[5] SEIA understands these concerns, and our members have experienced the effects of these staffing issues. By using limited transmission provider staffing resources, these studies could result in a longer interconnection queue process, as it ties up resources for conducting actual interconnection studies. SEIA sees no need to require transmission providers who are not already conducting these studies to expend their limited resources doing so, especially given the limited value of the studies.

These studies are of limited value to the interconnection customer. Under the proposed reform, the informational studies would provide (1) circuit breaker short circuit capability; (2) voltage overloads; and (3) "estimated network upgrade costs related to the identified overloads and violations."[6] Network upgrade costs are not a function of a single project: They are a function of *all* the projects within a cluster. Because the studies are designed to help *prospective* interconnection customers, they do not necessarily represent the interconnection customers that will ultimately be in the studied cluster, nor the network upgrades the interconnection customers in the cluster would be responsible for. The intent of this proposed reform is to provide cost estimates for the transmission provider's interconnection facilities and network upgrade costs.[7]

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[4] Comments of the Midcontinent Independent System Operator, Inc., at 15, Docket No. RM21-17 (Aug. 17, 2022) (noting that "limited staff resources" may hinder compliance with a new transmission planning rule); Initial Comments of PJM Interconnection, L.L.C. at 12829, Docket No. RM21-17 (Aug. 17, 2022) (explaining how PJM is in the process of expanding its staff in order to address long-term planning).

[5] *Cal. Indep. Sys. Operator Corp.*, 176 FERC ¶ 61,207, P 21 (2021).

[6] NOPR P 46.

[7] *See* NOPR P 42.

But without knowing what other projects will be in the same cluster as the studied project, the studies will not result in an accurate representation of the network upgrade costs for which an interconnection customer may be responsible.

In doing their due diligence, interconnection customers routinely assess Available Transmission Capacity and conduct various studies to guide them in project siting decisions and in determining whether to submit an interconnection request in the first place. These studies produce useful information, but they can be better, and better due diligence models will result in more efficient siting decisions and ultimately lower network upgrade costs. To make these models better, SEIA requests that the Commission, instead of requiring transmission providers to conduct pre-request studies, require transmission providers to provide previous cluster studies and models to interconnection customers, subject to a confidentiality agreement. Preparation and due diligence lead to viable interconnection requests. Providing the information to better perform that due diligence will help ensure the viability of the projects entering the interconnection queues.

2. Publicly posted information about bus-level interconnection capacity will be useful in helping independent power producers in making siting decisions.

SEIA supports requiring transmission providers to publicly post information about bus-level interconnection capacity constraints. Understanding where constraints are, and where network upgrades will likely be necessary, helps interconnection customers make more efficient siting decision, and ameliorate the incentive to submit multiple exploratory requests.[8]

[8] NOPR P 49; *see also* Order No. 2003, 104 FERC ¶ 61,103, P 695.

Unlike the proposed informational study requirement, requiring transmission providers to give information about transmission capacity does not impose a significant additional burden on transmission providers. As the Commission stated in the NOPR, the Midcontinent Independent System Operator, Inc. (MISO) already provides an interactive heatmap of expected congestion.[9] The PJM Interconnection L.L.C. (PJM) is currently in the process of developing and implementing its *Queue Scope* screening tool, which "screens potential points of interconnection (POI) on the PJM system by assessing grid impacts based on the amount of MW injection or withdrawal at a given POI."[10] These are tools that help interconnection customers make better siting decisions in the first place, and SEIA urges the Commission to adopt this reform in the final rule, with the following modifications:

- Allow the transmission providers flexibility in the way the information is presented. Whether the final product is a visual representation, like MISO's heatmap, or some other product, is not as relevant as the information provided by the product.
- Require transmission providers to use both the most recently available study models in creating the results, as well as the model used in the most recently completed system impact study.
- Require transmission providers to include more information regarding the hosting capacity, circuit strength, and harmonics of transmission system elements. If any such information is considered Critical Energy Infrastructure Information, then the transmission provider should make it available subject to any necessary confidentiality agreements.

As the Commission recognizes, there is a lack of information available to interconnection customers.[11] The information produced through this proposed requirement would resolve some of the information asymmetry interconnection customers face today.

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[9] NOPR P 50, n.105.

[10] *See* Interconnection Screening Tool Overview, "Queue Scope," (Sept. 28, 2022), https://pjm.com/-/media/committees-groups/subcommittees/ips/2022/20220928/item-05---overview-of-queue-scope.ashx.

[11] *See* NOPR P 42.

3. Moving to a cluster study approach can result in a more queue processing, if coupled with a holistic interconnection reform.

SEIA supports the Commission's proposal to make cluster studies the required interconnection study method.[12] A transmission to a cluster study process with higher deposit requirements will help address several issues that lead to cascading withdrawals.

The Commission has long preferred clustering for conducting interconnection studies,[13] finding that it allows "for more efficient prioritization of interconnection requests while still providing protection from undue discrimination by transmission providers."[14] Clustering studies not only leads to efficient queue management, but it also reduces the likelihood that a project will withdraw from the queue because of high network costs. First-come, first-served processes shift the costs of network upgrades to the first project that triggers the upgrade.[15] SEIA members have often seen network upgrade costs double the initial estimated interconnection costs, resulting in a previously viable project becoming uneconomic. In a serial queue process, the network upgrade costs continue to shift to the next customer in the queue until they reach a customer that can pay.[16] A cluster process, however, allocates the costs of interconnection network upgrades among multiple projects, which would alleviate the financial burden of those upgrades on any one interconnection customer, which should lead to less project withdrawals.

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[12] *See* NOPR P 64.

[13] Order No. 2003, 104 FERC ¶ 61,103 at P 155; Order No. 2006, 111 FERC ¶ 61,220 at P 181.

[14] NOPR P 64; *see also Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 18 (2008).

[15] Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 8 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.) ("Often one project would be assigned a high cost to upgrade the network, but then subsequent projects could utilize the capacity that project created, such that the subsequent project would be assigned a lower cost. When one project drops out, costs are typically shifted onto others, causing a domino effect of cancellations.").

[16] *See* PJM Interconnection Reform Filing, Connell Aff. at P 12.

To make the cluster study process more efficient, SEIA recommends that the Commission direct transmission providers to provide cost estimates at each stage of the interconnection process to allow interconnection customers to make more informed decisions earlier in the process. To further limit delays in the process, SEIA requests that the Commission add further certainty to the cluster study process by limiting the number of restudies the transmission provider may make for each cluster, with each restudy being limited to a 30-day period.[17]

In addition to these reforms, SEIA requests that the Commission specifically clarify that both project-specific and cluster Scoping Meetings must provide the option for Interconnection Customers to attend via teleconference, which is currently unavailable in all regions.[18] Already it can be difficult to coordinate in-person Scoping Meetings with just a single Interconnection Customer and transmission provider. Expanding this group with additional interconnection customers representing additional projects will compound this difficulty further. Greater certainty regarding the study timeline is critical because land use option rights, which are critical to maintaining queue position and to demonstrate commercial readiness, often expire if not exercised. Developers are particularly challenged when they are provided notice of study delay on the day before a completed study was expected in accordance with published interconnection procedures or study guidelines. To the extent project developers will be expected to adhere to

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[17] *See* NOPR P 78.

[18] *See* NVEnergy, OATT, Attach. N, Sec. 1, Definitions ("**Application Meeting** shall mean the *in person* meeting held between the Transmission Provider and the Interconnection Customer during the Application Process in order to process the Application Request, to discuss any potential siting impediments or timelines associated with an Interconnection Customer's Application Request, and to create a Preliminary Plan of Development (if necessary) for the Interconnection Customer's Application Request.") (emphasis added).

higher standards of commercial viability, transmission providers also must be held accountable for excessive delays in completing interconnection studies.

4. To deter the submission of exploratory interconnection requests, the shared costs of the cluster studies should be 50% pro rata based on MWs and 50% per capita based on number of interconnection requests in cluster.

SEIA generally supports the Commission's proposal to allocate the shared costs of cluster studies based on the size of the projects in the cluster and the number of requests in a cluster.[19] As the Commission finds, it has accepted a variety of cost allocation approaches, from allocating entirely on a pro rata basis to entirely on a per capita basis.[20] In response to a large influx of new interconnection requests, the California Independent System Operator, Inc. (CAISO) proposed, and the Commission accepted,[21] a methodology that allocates all study costs equally based on the number of interconnection requests within the cluster.[22] Unlike CAISO, MISO allocates all study costs based on the number of MWs requested.[23] MISO proposed significant interconnection reforms in 2015 to address the growing number of projects in its queue,[24] but its study cost allocation methodology was in place several year before that.[25]

The Commission bases its 90% pro rata, 10% per capita proposal on cost causation principles, finding that "the MW size of a cluster has a dramatic impact on the cost of studying

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[19] NOPR P 82.

[20] NOPR P 81.

[21] *California Independent System Operator, Inc.*, 140 FERC ¶ 61,070, P 4 (2012).

[22] CAISO, CAISO eTariff, OATT, app. DD, section 3 (14.0.0), section 3.5.1.2.

[23] MISO, FERC Electric Tariff, OATT, attach. X, (155.0.0) section 3.3.1.

[24] *See* MISO 2015 Queue Reform Filing, at 2, Docket No. ER16-675-000 (filed Dec. 31, 2015).

[25] *See* MISO filing Regarding Attachment X of its Tariff, Docket No. ER11-3583 (filed May 17, 2011) (showing the current per MW cost allocation methodology as tariff language already in place.)

the cluster, while also recognizing that the number of interconnection requests included in the cluster also impacts the cost of studying the cluster, but to a lesser degree."[26] The MW size of a cluster does impact the costs of studying the cluster, and the MW size of that cluster will be impacted by the number of requests in the queue. The MW size of the cluster may be artificially inflated when certain interconnection customers submit multiple exploratory requests.

SEIA recommends that the Commission set the default allocation of cluster study costs as follows: 50% of the applicable study costs to interconnection customers on a pro rata basis based on requested MWs included in the applicable cluster, and 50% of the applicable study costs to interconnection customers on a per capita basis based on the number of interconnection requests included in the applicable cluster. However, the Commission should allow transmission providers to propose other cost allocation methodologies that may be more suitable to their regions. Throughout the NOPR, the Commission consistently recognizes that there are many non-viable projects in the queue,[27] and transmission providers need to provide incentives to stop those projects from entering the queue in the first place, similar to the reasoning behind CAISO's study cost allocation methodology.[28] The Commission should maintain that approach here, and structure the cost allocation so that its customers with multiple projects are responsible for a greater share of the study costs. Increasing study costs for interconnection customers with more requests in a single cluster will reduce the incentive to submit non-viable requests.

[26] NOPR P 82.

[27] NOPR PP 26, 30, 40, 49.

[28] *California Independent System Operator, Inc.*, 140 FERC ¶ 61,070, P 4 (2012).

5. A Proportional Impact Method of cluster network upgrade cost allocation should be coupled with a Commission-set minimum distribution factor level.

SEIA generally supports the proposal to allocate network costs within a cluster based on proportional impact.[29] As explained above, first-come, first-served processes shift the entire costs of network upgrades to the first project that triggers the upgrade.[30] Many times these network upgrades can double the initial estimated interconnection costs, resulting in a previously viable project becoming uneconomic. High costs coupled with uncertainty contribute to once-viable projects needing to withdraw from the queue, triggering restudies and further cost shifting. This has become known as the "cascading withdrawals" problem. Cascading withdrawals and restudies are consistently flagged as the cause of interconnection queue delays.[31] Reducing network upgrade costs for any one customer by allocating those costs among several customers will reduce the number of cascading withdrawals and re-studies caused by those withdrawals. SEIA recommends that the Commission set a minimum distribution factor, for Energy Resource Interconnection Service (ERIS) and Network Resource Integration Service (NRIS) studies, to assess network upgrade costs, to network upgrade costs are just and reasonable.

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[29] NOPR P 88.

[30] Jay Caspary, et al., Disconnected: The Need for a New Generator Interconnection Policy at 8 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf).

[31] 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).

6. The Commission should ensure that costs allocated between clusters are not significantly impacted by the withdrawal of earlier clustered projects.

SEIA generally supports the proposal to allocate costs between clusters. An inter-cluster cost allocation methodology recognizes that interconnection customers may benefit from earlier-in-time network upgrades. It would be consistent with the Commission's cost-causation principles to require those customers to pay for those benefits.[32] Such an allocation methodology would also alleviate the burden on the earlier-in-time interconnection customer by providing an opportunity to recover some of the network upgrade costs that are likely to benefit later-in-time interconnection customers.

While this proposal accounts for the benefits for a later-in-time interconnection customer, and the appropriate compensation for the earlier-in-time interconnection customer, it does not protect that later-in-time customer from any negative impacts of the actions of the earlier-in-time customer. Specifically, a later-in-time customer may be identified as an entity that benefits from an earlier-identified network upgrade. However, at the time the benefit is identified, it may not be the case that the network upgrade has been *constructed*. Nor would it necessarily be the case that the earlier projects have entered into commercial operation. If the earlier queued projects withdraw from the queue, this could cause the need to reallocate the costs of the network upgrade. Since projects depend on network upgrades from earlier queued resources, projects withdrawals from earlier queued resources may create significant financial burden on later

[32] *See Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043, P 518 (2018), *errata notice*, 167 FERC ¶ 61,123, *order on reh'g*, Order No. 845-A, 166 FERC ¶ 61,137, P78, *errata notice*, 167 FERC ¶ 61,124, *order on reh'g*, Order No. 845-B, 168 FERC ¶ 61,092 (2019) ("The principle of cost causation generally requires that costs 'are to be allocated to those [that] cause the costs to be incurred and reap the resulting benefits.'") (citing *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 87 (D.C. Cir. 2014)) (quoting *NARUC v. FERC*, 475 F.3d at 1285).

queued projects. While the Commission proposes that "to require that the interconnection customer in the later study cluster not be required to pay for its share of the cost of the shared network upgrade until that shared network upgrade is in service,"[33] it is unclear whether it is possible for those network upgrade costs to increase. SEIA requests that the Commission implement protections for later-in-time customers from impacts of earlier queue withdrawals.

7. Increased study deposits can help better identify viable projects.

SEIA generally supports the proposal to increase study deposits and to implement those increased deposits in a tiered manner.[34] The Commission has recognized, both within RTOs and outside of them, that increased study deposits better identify viable projects and reduce the number of multiple interconnection requests made by the same customer for the purpose of evaluating the costs of different project sites.[35] Further, increased study deposits more accurately reflects the costs of the study and recognizes that larger projects likely carry a greater risk.[36]

However, these increased deposits must be paired with reforms to ensure reliable information on transmission capacity. As the Commission stated in the 2008 Order on Technical Conference regarding interconnection queue practices, "the more stringent the requirements, the more important it is to ensure that customers have access to alternative sources of reliable information about available transmission capacity to help them tailor their interconnection requests more narrowly toward a single acceptable interconnection configuration."[37] Without

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[33] NOPR P 99.

[34] NOPR P 106.

[35] *Sw. Power Pool, Inc.*, 178 FERC ¶ 61,015, at P 45 (2022); *Pub. Serv. Co. of New Mexico*, 136 FERC ¶ 61,231, P 80 (2011); *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 16 (2008)

[36] *Pub. Serv. Co. of New Mexico*, 136 FERC ¶ 61,231, P 80 (2011); *see also Sw. Power Pool, Inc.*, 128 FERC ¶ 61,114, P 61 (2011).

[37] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 16 (2008).

reliable information on where there are transmission constraints, developers will be unable to make efficient siting decisions and the incentive to submit multiple exploratory results will still exist.

8. Requiring interconnection customers to demonstrate 100% site control at the time of the interconnection request may be unreasonable.

SEIA generally supports the Commission's proposal to require interconnection customers to demonstrate site control and exclusive land rights over the site.[38] More stringent site control requirements "may help to reduce the number of speculative, duplicative, and non-ready projects."[39] The lack of stringent site control requirements has proven to be an issue in PJM, where projects with inadequate site control were not ready to move forward in the interconnection process.[40] SEIA has consistently supported imposing more stringent site control requirements, because doing so helps to eliminate some speculative projects from the queue.[41]

However, it is not necessarily always possible to acquire 100% site control, especially in instances where the interconnection studies produce results that would require a reconfiguration of a project or other additional site needs. When an interconnection customer enters the queue, there is generally some certainty in the size of facility and the acreage necessary to support that

[38] NOPR P 116.

[39] *Midcontinent Indep. Sys. Operator, Inc.*, 169 FERC ¶ 61,173, P 45 (2019).

[40] PJM Interconnection Reform Filing, n.144.

[41] Comments of the Solar Energy Industries Association, Docket No. ER22-2110 (July 14, 2022); Joint Supplemental Comments of the American Clean Power Association, Advanced Energy Economy, the Solar Energy Industries Association, and the American Council on Renewable Energy on Generation Interconnection Queue Processing and Cost Allocation Reforms, Docket Nos. AD21-15 and RM21-17 (Feb. 14, 2022); Dave Gahl et al., Lessons from the Front Line: Principles and Recommendations for Large-scale and Distributed Energy Interconnection Reform (June 14, 2022), https://seia.org/sites/default/files/2022-06/SEIA%20Interconnection%20Paper%206-14-22%20FINAL.pdf.

facility.[42] What an interconnection customer generally does not know, though, is the Transmission Provider's Interconnection Facilities for which they will be responsible.[43] This information is not even finalized until after the transmission provider produces the facilities study report.

SEIA recommends setting a site control requirement of 75%, for the generating site only, at the time of the interconnection request to allow for flexibility to interconnection customers to adjust their projects as necessary to address the results of the interconnection studies or other regulatory changes that can affect the size of a project. Further, SEIA requests that the Commission require transmission providers to allow interconnection customers to shift site boundaries or reduce the size of the project, subject to review of any associated changes to collection system or other electrical parameters under the applicable Permissible Technological Advancement or Material Modification review processes, so long as the project does not change its point of interconnection, in order to accommodate any needed changes to the project layout resulting from the interconnection studies or other regulatory changes.

SEIA supports a deposit in lieu of site control requirement.[44] SEIA recognizes that there are certain regulatory limitations when it comes to obtaining site control, especially when a project is sited on public land. It can take projects siting on public lands up to seven years to

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[42] Although, acreage needs are not always certain. For example, in March 2022, the Virginia Department of Environmental Quality issued a memo that would effectively consider solar panels an unconnected impervious surface, which would increase the amount of land necessary for a project to comply with state environmental concerns, and would apply to any project that did not have a stormwater management plan in place. *See* Virginia Department of Environmental Quality, Post-development Stormwater Management at Solar Projects (March 29, 2022), https://www.deq.virginia.gov/home/showpublisheddocument/13985/637842474433400000.

[43] The *pro forma* LGIA defines "Transmission Provider's Interconnection Facilities" as "all facilities and equipment owned, controlled or operated by the Transmission Provider from the Point of Change of Ownership to the Point of Interconnection as identified in Appendix A to the Standard Large Generator Interconnection Agreement." Not every region uses this term.

[44] NOPR P 118.

receive permitting and site control. Requiring those projects to obtain full site control before submitting its interconnection request would be burdensome and potentially prohibitive.

9. The commercial readiness requirements are commercially infeasible, impose unnecessary uncertainty in the interconnection process, and raise costs to consumers.

SEIA strongly opposes the proposal to include a commercial readiness framework. The commercial readiness framework proposed in the NOPR is inconsistent with the project development cycle and will impose significantly higher costs on the few companies that could make such showings, increase costs to consumers, and introduce needless uncertainty to interconnection queues.

a. The commercial readiness demonstration options to enter the queue sets a near impossible standard for independent power producers to meet.

The Commission proposes to provide the following options for a project to demonstrate commercial readiness in order to even enter the queue:[45]

- Executed term sheet (or comparable evidence) related to a contract, binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale is not less than five years;
- Reasonable evidence that the project has been selected in a resource plan or resource solicitation process by or for a load serving entity, is being developed by a load-serving entity (LSE), or is being developed for purposes of a sale to a commercial, industrial, or other large end-use customer; or
- Provisional LGIA which has been filed at the Commission (executed or unexecuted), which is not suspended and includes a commitment to construct the generating facility.

It is nearly impossible for an independent power producer to demonstrate any of these options.

[45] NOPR P 129

First, an independent power producer cannot enter into a contract for the sale of the resource or any output from the resource before having any reasonable certainty as to what the costs of the network upgrades associated with its request will be. In order to price a contract associated with a resource, whether it is for the sale of the resource or a Power Purchase Agreement (PPA), an independent power producer must know, or at least have reasonable certainty as to what its final costs will be.[46] An interconnection customer does not receive an estimate of those costs until after the transmission provider produces the system impact study report. If independent power producers are forced to enter into these contracts before these costs were certain, then they would need to incorporate that uncertainty into the PPA offer, which would drive up the costs of these contracts, resulting in higher consumer costs. In the event the independent power producer does not reflect the costs of the network upgrades in its PPA price, either the independent power producer or the consumer may attempt to break the contract, which will lead to increased contractual litigation. The third contractual option, a contract for provision of ancillary services, is almost entirely foreclosed to many inverter-based resource developers, as nearly every transmission provider bars inverter-based resources from providing ancillary services, either explicitly[47] or through operating requirements.[48]

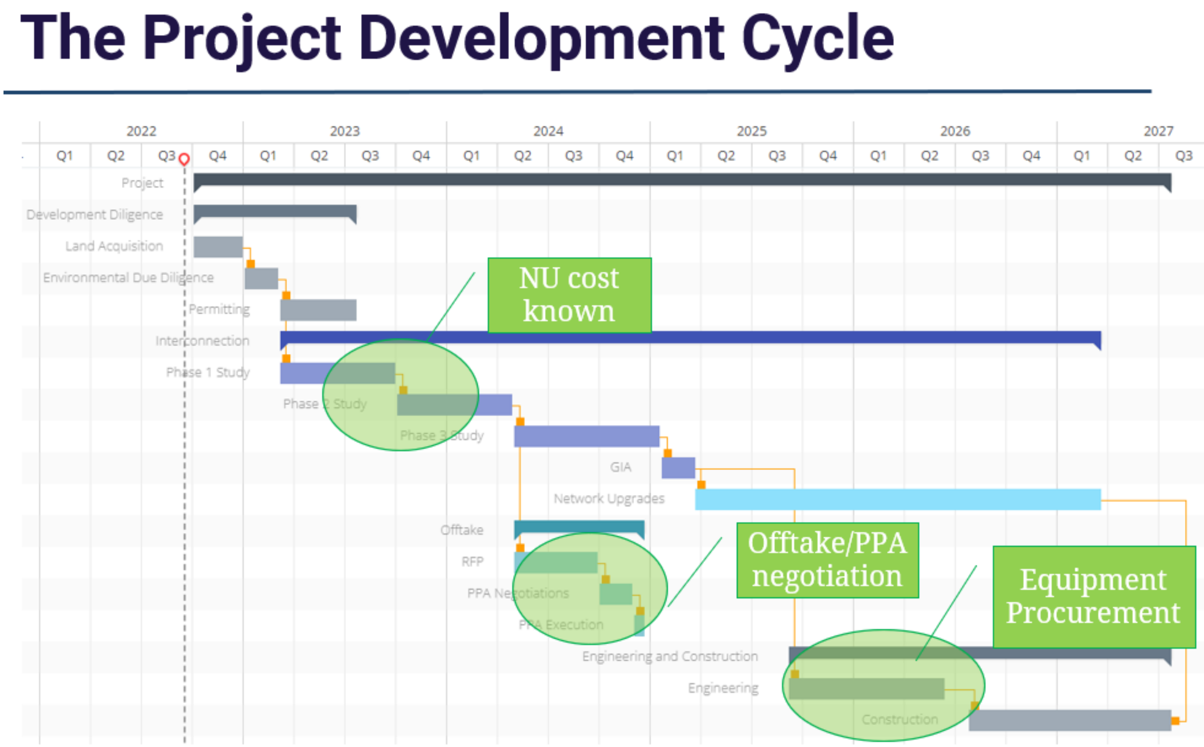
The table below shows the development cycle of a typical project, including when the developer begins contract negotiations and procurement. It also shows an estimate of how long

[46] *See* May Joint Task Force Tr. 74:9-21 (Andrew French) ("an essential element of being able to sell a product is to know what your inputs are so you can market it").

[47] *See* MISO Tariff, Section 39.2.1.B ("Resource Requirements for Operating Reserves" ("Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market will be limited to (i) committed Generation Resources that are not Dispatchable Intermittent Resources . . .")).

[48] Fredrich Kahrl, et al., Variable Renewable Energy Participation in U.S. Ancillary Services Markets, at 22-23 (Oct. 2021), https://eta-publications.lbl.gov/sites/default/files/vre_as_full_report_release.pdf.

each contract negotiation may take. Note that this is a "best-case" representation, assuming that the open bid windows for offtake opportunities align well with the interconnection cycle; often, this may not be the case.



Second, requiring an independent power producer to show evidence that the project has been selected in resource plan or other resource solicitation is premature at best. Many state resource plan proceedings require a resource to have made progress through the interconnection process in order to even be considered for the solicitation.[49] Further, this requirement coupled

[49] 2022 EAL Renewables RFP, at 10 (June 14, 2022), https://cdn.entergy-arkansas.com/userfiles/rfp/2022/2022_EAL_Renewables_RFP_Bidders_Conference.pdf?_ga=2.261475407.316220787.1665503441-1210047111.1665503441 (Requiring solar resources looking to participate in the Entergy Arkansas RFP process to have an "executed GIA with MISO or be included in the 2019, 2020 or 2021 MISO DPP Queue."); Dominion Energy Virginia RFP For Development Asset Acquisitions & Power Purchase Agreements Frequently Asked Questions, at 1, https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/renewable-projects/rfp/2022-solar-rfp/bidder-faq-document.pdf?la=en&rev=a81a0db46cd9472c94c9870e1fe72daa&hash=6852077C207CCF784CF7E4B49276F760 ("Our preference is to consider projects that have advanced to the point of having a fully executed PJM System Impact Study Agreement.").

with the proposal to allow Load Serving Entities (LSEs) to request an "Optional Resource Solicitation Study" presents numerous opportunities for a utility to discriminate against independent power producers in favor of that utility's own generation, or amongst independent power producers to favor their preferred counterparty. Under the "Optional Solicitation Study" proposal, an LSE could request an optional resource solicitation study from the transmission provider. As part of that request, the LSE is responsible for identifying the valid interconnection requests associated with the solicitation process. The transmission provider conducts the study, and the LSE can then make integrated resource plan decisions based on that study.[50] Under this paradigm, an LSE will be incentivized to use the study to select generation owned by its associated generation subsidiary, allowing those projects to meet the integrated resource plan demonstration of commercial readiness. In the NOPR, the Commission recognizes this potential for utility self-dealing, especially in non-RTO regions, and uses it as a basis in proposing the deposit in lieu of commercial readiness demonstration.[51] However, as explained below, allowing for the deposit in lieu of commercial to address potentially discriminatory treatment of independent power producers and then subjecting those independent power producers that use that option to higher withdrawal penalties, does not remedy the discriminatory treatment—it compounds that discriminatory treatment.[52]

Even if the project is not part of the solicitation, and is instead being developed for an end-use customer, as with the concern with the PPA pricing, it is nearly impossible for the

[50] *See* NOPR PP 223-224.

[51] *See* NOPR P 132 ("We note that, outside of RTOs/ISOs, transmission providers may be able to provide certain contractual arrangements to their own projects or other preferred interconnection customers, such as the term sheet option discussed above, which could lead to unduly discriminatory behavior.").

[52] *See* section I.A.9.c. *infra*.

independent power producer to price a sales contract without having reasonable certainty in its final costs. And in RTOs that have capacity auctions, such as PJM, ISO-NE, NYISO, and MISO, requiring a resource to be part of a resource solicitation, or to have a PPA in place, ignores the very nature of a capacity market, which is to allow independent power producers to sell capacity into a market.

Third, the option for an independent power producer to make a showing of commercial readiness with a Provisional LGIA is inconsistent with the independent power producer business model. Independent power producers try to minimize risk in development as much as possible. A Provisional LGIA is inconsistent with that business model, as it would require an independent power producer to assume almost all the risk of the costs of network upgrades without knowing what these costs are.

b. The commercial readiness demonstration options to enter the facilities study are commercially impracticable.

The Commission proposes the following options for a project to demonstrate commercial readiness in order to enter the facilities study:[53]

- Executed contract (as opposed to term sheet), binding upon the parties to the contract, for sale of (1) the constructed generating facility, (2) the generating facility's energy or capacity, or (3) the generating facility's ancillary services; where the term of sale is not less than five years;
- Reasonable evidence that the project has been selected in a resource plan or resource solicitation process by or for a load serving entity, is being developed by an LSE, or is being developed for purposes of a sale to a commercial, industrial, or other large end-use customer; or
- Provisional LGIA accepted for filing by the Commission, which is not suspended, with reasonable evidence that the generating facility and interconnection facilities have commenced design and engineering.

[53] NOPR P 130. We note that if the Commission imposes the commercial readiness requirement proposed in paragraph 129 of the NOPR, there are very few independent power producers that would be able to enter the queue in the first place and reach the facilities study.

Although an independent power producer has some level of cost certainty following the system impact study that precedes the facilities study, requiring an independent power producer to meet any of these commercial readiness demonstrations in order to enter the facilities study would be commercially impracticable.

As stated above, an independent power producer does not have any reasonable certainty as to what its final costs will be until after the transmission provider completes the system impact study report, in which network upgrades are identified. In most regions, there is a relatively short window of time between when the independent power producer receives an estimate of its network upgrade costs in the system impact study report and when it is required to execute a facilities study agreement. In PJM, there are 30 days between receiving the system impact study report and the facilities study execution.[54] In MISO, there are just 15 business days between when the interconnection customer receives the Revised System Impact Study results, which includes cost estimates for upgrades, and Decision Point II.[55] This is not nearly enough time for an independent power provider to negotiate and execute an agreement that generally takes months to complete.

Nor is it reasonable to expect an independent power producer to demonstrate commercial readiness by showing that the project has been selected in a resource plan or resource solicitation

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[54] PJM Tariff Sec 206.2 ("For a New Service Request to retain its assigned Queue Position pursuant to Section 201, *within 30 days of issuing the System Impact Study*, the Transmission Provider must be in receipt of (i) all past due amounts of the actual System Impact Study costs exceeding the System Impact Study deposits contained in Section 204.3A, if any, (ii) the executed Facilities Study Agreement and, (iii) the deposit required under this Section 206. If a participating New Service Customer fails to remit past due amounts, execute the Facilities Study Agreement or to pay the deposit required under this Section 206, its New Service Request shall be deemed terminated and withdrawn.") (emphasis added).

[55] MISO Tariff, Attach. X, definition of Interconnection Customer Decision Point II ("Interconnection Customer Decision Point II shall mean the time period beginning when the Interconnection Customer is provided the Revised System Impact Study results including cost estimates for upgrades and the Affected Systems analysis results including cost estimates for upgrades on the Affected System and *concludes after fifteen (15) Business Days*.") (emphasis added).

process. As stated above, many state resource plan proceedings require a resource to have made progress through the interconnection process in order to even be considered for the solicitation.[56] It may not be the case that the windows for the resource solicitation line up with the limited window in which an independent power producer has to execute the facilities study agreement.

Finally, again the option for an independent power producer to make a showing of commercial readiness with a Provisional LGIA is inconsistent with the independent power producer business model. Under a Provisional LGIA, the independent power producer must assume almost all the risk of the costs of network upgrades without knowing their costs. Given the 60-day timeline for the Commission to accept orders under section 205 of the Federal Power Act, an independent power producer must request that a transmission provider execute and file an LGIA with the Commission *before* receiving its network upgrade cost estimates. The independent power producer would be forced to assume unknown costs.

c. The Commercial Readiness Deposit in lieu option is discriminatory towards independent power producers.

The Commission also proposes a framework to allow interconnection customers to provide a commercial readiness deposit in lieu of meeting the commercial readiness requirements.[57] The Commercial Readiness Deposit would be tied to the study deposit amount, with the amount increasing throughout the interconnection process.[58] If an interconnection customer that uses the deposit in lieu option withdraws from the queue, the deposit will be applied toward any withdrawal penalties.[59] These withdrawal penalties are higher for the

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[56] *See* n.49 *supra*.

[57] NOPR P 133.

[58] NOPR P 133.

[59] NOPR P 134.

interconnection customers that made a deposit in lieu of a demonstration of commercial readiness.[60]

The Commission proposes this deposit as a protection against undue discrimination in the interconnection process.[61] However, the proposal for the deposit itself results in undue discrimination against independent power producers. As shown above, it is nearly impossible for an independent power producer to make any of the commercial readiness demonstrations as they are currently proposed in the NOPR. The deposit in lieu of meeting the commercial readiness requirements would not be an "option" for independent power producers: It would be the *only* path forward in the interconnection process.

An independent power producer looking to enter the interconnection process would be forced to agree to pay higher costs, which then increase over the process. These costs are not representative of the cost of the associated network upgrades for the interconnection requests, which would form the basis of any demonstration of commercial readiness. Under this commercial readiness demonstration deposit paradigm, when an independent power producer is weighing the risks of a project, it must be so based on costs that are unrelated to its final costs. While the Commission provides that the deposit would be refundable upon making a demonstration of commercial readiness,[62] in instances of participation in wholesale markets, or even in non-RTO region resource adequacy constructs, it may be the case that an independent power producer never makes one of the proposed commercial readiness demonstrations. Under the proposed rule, as it is currently written, such deposits would not be refunded, and it would

[60] NOPR P 134; NOPR P 144.

[61] NOPR P 132.

[62] NOPR P 134.

increase the costs of the energy and capacity associated with that independent power producer's resource.

The commercial readiness deposit in lieu is an opportunity to discriminate against independent power producers. As the Commission itself recognized, "transmission providers may be able to provide certain contractual arrangements to their own projects or other preferred interconnection customers, such as the term sheet option discussed above, which could lead to unduly discriminatory behavior."[63] A transmission provider or a transmission owner, especially in non-RTO areas, could favor its own projects, and then subject unaffiliated projects to higher costs, making those projects less competitive in the markets or in an IRP proceeding. And the discrimination that the Commission seeks to prevent would remain in the interconnection process.

d. Proposed alternatives to the commercial readiness demonstration.

SEIA proposes that the Commission eliminate the commercial readiness demonstration requirement from the final rule. Making such a demonstration would be nearly impossible for independent power producers, and those that do make that demonstration incur significant contractual risks. Allowing for a Commercial Readiness Deposit is also not a feasible option for independent power producers, as it subjects a class of developers to higher costs and provides an opportunity for undue discrimination. Such a proposal is unjust and unreasonable, and unduly discriminatory, resulting in needlessly higher rates to ratepayers.

If the Commission does not eliminate the commercial readiness demonstration, SEIA urges the Commission to modify the requirement as follows:

[63] NOPR P 132.

- Make the commercial readiness demonstration a requirement to enter into a generator interconnection agreement. A later-stage commercial readiness demonstration will allow independent power producers to make rational business decisions based on reasonably certain network upgrade costs.
- Allow interconnection customers to make a commercial readiness demonstration by providing an affidavit that it will sell energy, capacity, and/or ancillary services, as a wholesale merchant generator. Not only should this demonstration be available to developers within an RTO, but it should also be available to generators outside of one to allow developers to sell capacity to meet resource adequacy needs.
- Allow interconnection customers to make a commercial readiness demonstration by providing documentation of developer due diligence, including Available Transmission Capacity and modeling.
- Maintain the deposit in lieu of meeting commercial readiness option but set the value of the deposit as a percentage of the estimated network upgrade costs, which should be capped at $2,000,000. Additionally, the withdrawal penalties for interconnection customers that utilize this option should not be any different than the withdrawal penalties other interconnection customers face.

SEIA understands the need to increase the requirements imposed on interconnection customers as a means to reduce the number of non-viable in the queue. However, in setting forth a commercial readiness demonstration requirement that is nearly impossible to meet, the Commission would be incorrectly implying that projects developed by independent power producers are inherently not commercially viable to begin with. Independent power producers play a critical role in bringing robust competition to the markets. They drive innovation and decrease the cost of providing power.[64] "The public interest requires policies that do not harm the development of vibrant, fully competitive generation markets."[65]

10. Excessive withdrawal penalties incentivize non-viable projects to stay in the interconnection queue.

SEIA does not support the Commission's proposal to require transmission providers to assess increasingly higher withdrawal penalties to interconnection customers that withdraw from

[64] *AmerenUE*, Opinion No. 473, 108 FERC ¶ 61,081, P 61 (2004).

[65] *Id.*, P 59.

the interconnection process.[66] Increasing the amount of money at stake for an interconnection customer, and not providing off-ramps from the interconnection process does not incentivize projects to exit the queue. As a project progresses through the interconnection process, its penalty will be higher. When network upgrades are assessed, it becomes a game of who blinks first: A project may not really be able to afford its share of the network upgrade but knows that if it stays in the queue long enough, other projects will withdraw, and the penalty *those* projects pay will eventually be distributed to the remaining projects in the cluster.[67] Although the proposal exempts interconnection customers from the withdrawal penalty if there is no impact to other generating facilities in the same cluster,[68] it has been SEIA's members' experience that withdrawals almost always impact other generating facilities in the cluster. It is very likely that withdrawal penalties would be unavoidable.

Higher withdrawal penalties will not "encourage interconnection customers to make every effort to ensure their proposed projects are viable."[69] Better project development decisions come from better information, and more transparency into capacity constraints will allow interconnection customers to make siting decisions that will reduce the likelihood of prohibitively high network upgrade costs.[70] Further, as the Commission has recognized "the

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[66] NOPR PP 141-144.

[67] *See* Proposed LGIP Section 3.7.1.2 ("Withdrawal Penalty revenues associated with Section 3.7.1.1(c) of this LGIP shall not be distributed to the remaining Interconnection Customers in that Cluster until all Interconnection Customers in that Cluster have reached Commercial Operation and thereafter shall be distributed as described above.").

[68] NOPR P 141.

[69] NOPR P 140.

[70] *See* Section I.A.2. *supra*.

business of developing generation is very dynamic and requires the coordination of a whole host of factors beyond interconnection, *many of which are outside the full control of the developer*."[71]

A better solution would be for the Commission to direct transmission providers to implement processes like the MISO interconnection and off-ramp process. Under the MISO interconnection process, an interconnection customer makes an initial deposit that is tied to the size of the project.[72] Subsequent milestone payments are then tied to the cost of the network upgrades.[73] Throughout the process, interconnection customers have several decision points, or off-ramps, at which point they risk losing part or all of their escalating deposit amounts and at later phases, a portion of payment for network facilities. While there is still a loss of money for late-stage withdrawals, those amounts would be based on actual upgrade costs.[74] This process creates more certainty for the dollar amounts customers have at risk when they deliberate proceeding through the interconnection process milestones, and they can make better cost-based decisions at those milestone points with regard to taking an off-ramp.

Under a process like MISO's, projects would be incentivized to withdraw from the queue earlier in the process, instead of facing the choice between a steep withdrawal penalty or waiting for other projects to withdraw. Additionally, the Commission should direct transmission providers to implement a process like MISO's pre-DPP Screening Analysis.[75] Under this model, transmission providers would be required to perform an indicative non-binding screening analysis to identify potential thermal and voltage constraints for customers entering the cluster.

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[71] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 14 (2008).

[72] MISO Tariff, Attachment X, 3.3.1.

[73] MISO Tariff, Attachment X, 7.3.1.4.1 and 7.3.2.4.1.

[74] *Midcontinent Indep. Sys. Operator, Inc.*, 158 FERC ¶ 61,003, P 43 (2017).

[75] *See* MISO Tariff, Attachment X, Section 7.1.1.

Following the results of that Screening Analysis, interconnection customers would be able to determine whether they should proceed through the process, or withdraw, penalty-free, before making significant financial investments. This process would provide information necessary to make efficient project viability decisions while also recognizing that, despite a developer's best efforts, there are some factors that affect the development process that are beyond their control.

11. The commercial readiness requirements in the transition proposal will effectively bar many late-stage projects from the transitional study process.

SEIA generally supports the Commission's proposal to implement a transitional serial study.[76] However, SEIA opposes the requirement for the interconnection customer to make a commercial readiness demonstration and the deposit requirement to enter into the transitional serial study.

Under the Commission's proposal, interconnection customers that have executed a facilities study agreement at the time of the transition would have 60 days to provide evidence of exclusive site control for the entire generating facility and demonstrate commercial readiness.[77] To demonstrate commercial readiness, an interconnection customer would need to show:

- an executed term sheet (or comparable evidence) related to a contract for the sale of the generating facility or its energy/ancillary services;
- reasonable evidence that the generating facility is included in a resource planning entity's resource plan, has received a contract via a resource solicitation process, or is being developed for a large end-use customer; or
- a provisional LGIA that is not suspended and includes a commitment to build the generating facility.

[76] NOPR P 158-159.

[77] NOPR P 159.

These would be the same commercial readiness demonstrations an interconnection customer would need to make to enter the queue under the Commission's proposed new rule.[78]

In addition to the commercial readiness demonstration, an interconnection customer would need to provide a deposit equal to 100% of the interconnection facility and network upgrade costs allocated to the interconnection customer in the system impact study report.[79] If the interconnection customer were to withdraw from the transitional cluster, then the withdrawal penalty would be nine times the study cost.[80]

SEIA opposes the commercial readiness demonstration in the transition proposal for the same reasons it opposes the commercial readiness demonstration under a new interconnection process: The demonstration sets a near impossible standard for independent power producers to meet and ignores the very nature of a capacity market, which is to allow independent power producers to sell capacity into a market.

Rather than requiring interconnection customers to make a demonstration of commercial readiness to enter into the transitional study, SEIA recommends that the Commission require interconnection customers to provide a readiness deposit and evidence of site control. In order to protect the projects in the transitional cluster from the effects of withdrawal, the withdrawal penalty should be capped at the withdrawing project's allocation of network upgrade costs.

B. Reforms to increase the speed of Interconnection

Interconnection reform must be a matter of compromise. Interconnection customers, transmission providers, and transmission owners, must each do their part to address the issue.

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[78] *See* NOPR P 129.

[79] NOPR P 158.

[80] NOPR P 158.

Under the current interconnection paradigm, though, only interconnection customers bear the burden of compliance. If an interconnection customer does not meet any of the requirements it faces, it loses its queue position, and much of the investment it made in its project. Meanwhile, if a transmission provider or transmission owner fails to meet a tariff deadline, it does not face any penalties.[81] Processing interconnection requests in a timely manner "is critical to maintaining just and reasonable rates."[82] And yet, as the Commission notes, "nearly all transmission providers across the country regularly fail to meet interconnection study deadlines."[83] The backlog in the interconnection queues that result from these delays cause significant harm. They "not only deprive generation developers of needed business certainty, they also undermine other important public goals."[84] SEIA strongly urges the Commission to enact the reforms proposed in Sections II.B.1 and II.B.2 of the NOPR, which would level the playing field between interconnection customers and transmission providers and ensure a more efficient and equitable interconnection process.

1. Eliminating the "reasonable efforts" standard will incentivize the transmission providers to complete interconnection studies in a reasonable amount of time.

SEIA strongly supports the Commission's proposal to eliminate the reasonable efforts standard for transmission providers completing interconnection studies, and instead impose firm study deadlines and establish penalties that would apply when transmission providers fail to meet these deadlines.[85] Currently, transmission providers are required to use "reasonable efforts" to

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[81] NOPR P 166.

[82] NOPR P 167.

[83] NOPR P 166.

[84] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 5 (2008).

[85] NOPR P 168.

meet their tariff defined study deadlines. Order No. 2003 defined “reasonable efforts” as “actions that are timely and consistent with Good Utility Practice and are substantially equivalent to those a Party would use to protect its own interests.”[86] Following Order No. 2003, it does not appear that the Commission has ever found delays in the interconnection process that amounted to a violation of the standard.[87]

Transmission providers across the country “regularly fail to meet interconnection study deadlines.”[88] The reasons cited for these delays include “the high volume of interconnection requests” and “re-studies caused by withdrawal of higher-queued interconnection requests.”[89] This is only part of the story. First, the high volume of interconnection requests is a response by developers to meet federal, state, local, and corporate decarbonization goals. The number of interconnection requests have increased because demand for energy is shifting in response to the climate crisis. As electrification of transportation and buildings increases to meet these goals,[90] the amount of clean energy needed to meet the increase energy demand will need to increase as well. While the transmission system was originally planned to accommodate the operational characteristics of mostly thermal generation resources, clean energy sources have markedly different characteristics and pose different transmission demands. These resources are generally smaller with respect to output and require more of them to meet the same energy demands. This

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[86] Order No. 2003, P 65, 67.

[87] *See, e.g. Hecate Energy Greene County 3 LLC v. Cent. Hudson Gas & Elec. Corp.*, 176 FERC ¶ 61,023, at P 44 n.103 (2021); *EDF Renewable Energy, Inc. v. Midcontinent Indep. Sys. Operator, Inc.*, 165 FERC ¶ 61,071, at P 12 (2018); *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,050, at P 45 (2013).

[88] NOPR P 166.

[89] NOPR P 165, nn. 239-240.

[90] *See e.g.* Fiona Wissell, Brittany Speetles, Matt Townley, Deb Harris, and Stacy Noblet, The Impact of Electric Vehicles on Climate Change, at 4-5, https://www.icf.com/insights/energy/impact-electric-vehicles-climate-change (showing that electric vehicle sales doubled between 2020 and 2021).

has resulted in more interconnection requests needed to meet the same amount of energy demanded. Allowing backlogs to continue will undermine "important public goals."[91] It is incumbent on transmission providers to take concrete steps to improve the timeliness and accuracy of its interconnection studies in order to help meet these critical public goals.[92]

The other part to the interconnection delay story is that interconnection withdrawals and subsequent restudies are two problems caught in a vicious negative feedback loop. Queues across the country have been backlogged for some time, and with more incentives for clean energy resources to enter the market, the backlogs will continue. The backlogs "deprive generation developers of needed business certainty" and with more business uncertainty, projects face issues such as losing site control rights and financing, which would make once-viable projects no longer so.[93] Withdrawals have become the natural consequence of backlogs, which themselves leads to further withdrawals.

Restudies triggered by project withdrawals could be mitigated by the reforms proposed by the Commission in this proceeding. Providing more upfront information to interconnection customers will allow them to make efficient siting decisions and reduce the need to submit exploratory interconnection requests.[94] Moving to a cluster study approach will lessen the financial burden of those upgrades on any one interconnection customer, which should lead to

[91] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 5 (2008).

[92] *See Southwest Power Pool, Inc.*, 178 FERC ¶ 61,015, P 49 (2022) ("With regard to commenters' concerns about SPP lacking the resources and staffing necessary to implement its proposal, we expect SPP to continue to take concrete steps to improve the timeliness and accuracy of its interconnection studies. Such steps are particularly critical in light of recent errors and missteps in SPP's implementation of its study process. We note SPP's commitments to significantly increase its budget for outside consultants, hire and retain staff, enhance its modeling methodology, and work with transmission owners to ensure study deadlines are met. We expect SPP to fulfill these commitments, all of which appear to be both critical and necessary for SPP to mitigate its extensive backlog. We further expect that SPP will devote all necessary resources to its backlog mitigation effort.").

[93] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 5 (2008).

[94] *See* Section I.A.2 *infra*.

fewer project withdrawals.[95] And if the Commission amends its proposal on withdrawal penalties,[96] projects will be incentivized to exit the queue earlier in the process, reducing the impact on the remaining projects in the queue. However, these reforms will not completely resolve interconnection backlogs, and without an incentive for transmission providers to fulfill their requirements to complete the interconnection studies on time, there is no guarantee that the reforms will be effective. The lax definition of reasonable efforts in effect right now does not incentivize transmission providers to devote sufficient resources to completing accurate interconnection studies on time.[97] Removing the reasonable efforts standard, and imposing consequences for transmission providers that do not meet tariff deadlines, will help bring certainty to the interconnection process, turning the vicious circle of delays, withdrawals, and further delays into a virtuous one, in which projects have certainty in timelines and financing, leading to more finalized projects.

To the extent that transmission providers lack the resources to complete the studies, the Commission should make clear in the final rule that interconnection customers can use third-party consultants to produce required studies in accordance with transmission provider standards and criteria. Allowing interconnection customers to use third-party consultants will conserve transmission provider resources and provide a path forward through the process for interconnection customers.

Transmission provider delays are just part of the problem, though. Transmission owners are also responsible for completing parts of the interconnection studies. The Commission's

[95] *See* Section I.A.4 *infra*.

[96] *See* Section I.A.10 *infra*.

[97] Transcript 63:17-20 (Clements), Docket No. AD21-15 (May 6, 2022); Transcript 73:12-17 (Glick), Docket No. AD21-15 (May 6, 2022).

proposed rule, as written, only imposes the requirement on the transmission provider. SEIA requests that the Commission ensure that transmission owners are also financially responsible for these delays by either: (1) allowing transmission providers to recover the costs of transmission owner delays from the transmission owner; or (2) directly impose fines on the transmission owner. In order to protect consumers, transmission owners must not be allowed to recover those costs through their rates. Further, SEIA recommends that the Commission set the fine at $500 per day *per customer* and remove the cap on penalties.[98] Higher penalties are not punitive—they are compensatory. Delays in the interconnection process have significant impacts on interconnection customers as well as end-use customers. Higher penalties reflect the damage delays cause to all stakeholders.

2. Implementing an Affected System Study Process, along with *pro forma* Affected System Agreements and standardized study assumptions, will alleviate a significant barrier to an efficient interconnection process.

SEIA supports the proposal to standardize the Affected System Study process and implement a *pro forma* Affected Systems Study Agreement.[99] The Affected System process is a major barrier to interconnection. Although each region has an obligation to consider Affected Systems in its generator interconnection studies when it is the host region and to undertake Affected System analysis as the neighboring region,[100] there is no documented process for how the Affected Systems coordination occurs. The lack of transparency and certainty in this process has resulted in significant harm to interconnection customers, as their ability to make decisions

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[98] *See* NOPR P 170.

[99] NOPR PP 183, 197.

[100] Order No. 2003, P 118.

regarding entering or remaining in the interconnection queue is impacted by the uncertainty in the Affected System process.[101] Standardizing the process and providing more information to interconnection customers about the relative impacts of their projects, would provide greater certainty. Requiring firm deadlines and penalties associated with that process would enforce that certainty.

SEIA further supports the Commission's proposal to allocate network upgrade costs using a proportional impact method,[102] for the same reason we support the Commission's proposal to allocate intra-cluster network upgrade costs: High costs coupled with uncertainty contribute to once-viable projects needing to withdraw from the queue, triggering restudies and further shifting costs—better known as the "cascading withdrawals" problem. Cascading withdrawals and restudies have been consistently flagged as the cause of interconnection queue delays.[103] Reducing network upgrade costs for any one customer by allocating those costs among several customers will reduce the number of cascading withdrawals and re-studies caused by those withdrawals. SEIA recommends that the Commission set a minimum distribution factor for ERIS and NRIS studies to assess network upgrade costs, to provide equity across seams and ensure that affected systems network upgrade costs are just and reasonable.

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[101] *EDF Renewable Energy, Inc. v. Midcontinent Independent System Operator, Inc.*, 168 FERC ¶ 61,173, P 20 (2019).

[102] NOPR P 189.

[103] 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).

3. The Optional Resource Solicitation Study will provide opportunities to discriminate against independent power producers.

SEIA strongly opposes the Commission's proposal to require transmission providers to allow a resource planning entity to initiate an optional resource solicitation study. An optional resource solicitation study in situations where there is a commercial readiness requirement presents numerous opportunities for a utility to discriminate against independent power producers in favor of that utility's own generation. Under the "Optional Solicitation Study" proposal, an LSE could request an optional resource solicitation study from the transmission provider. As part of that request, the LSE is responsible for identifying the valid interconnection requests associated with the solicitation process. The transmission provider conducts the study, and the LSE can then make integrated resource plan decisions based on that study.[104] Under this paradigm, an LSE will be incentivized to use the study to select generation owned by its associated generation subsidiary, allowing those projects to meet the integrated resource plan demonstration of commercial readiness. The Commission recognizes this exact outcome, stating that the study helps "interconnection customers receive evidence of selection in a resource plan in a more timely manner by providing the resource planning entity with needed information."[105]

Further, as stated above, transmission providers have consistently stated that they have limited staff resources.[106] Instituting an additional study, especially one that can lead to discrimination against a class of developers, will put another strain on those limited staff resources.

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[104] *See* NOPR PP 223-224.

[105] NOPR P 225.

[106] Comments of the Midcontinent Independent System Operator, Inc., at 15, Docket No. RM21-17 (Aug. 17, 2022) (noting that "limited staff resources" may hinder compliance with a new transmission planning rule); Initial Comments of PJM Interconnection, L.L.C. at 12829, Docket No. RM21-17 (Aug. 17, 2022) (explaining how PJM is in the process of expanding its staff in order to address long-term planning).

C. Reforms to incorporate technological advancements into the interconnection process

1. The proposed reforms to increase the flexibility in the interconnection process will allow developers to add complementary generation resources to existing projects, which will provide capacity and reliability to the grid.

The Commission proposes four reforms that would allow interconnection customers to add complementary generation resources to existing interconnection requests or projects already in service. SEIA supports each of these proposals. First, the Commission proposes to require transmission providers to allow more than one resource to co-locate on a shared site behind a single point of interconnection and share a single interconnection request.[107] Second, the Commission proposes to require transmission providers to evaluate the proposed addition of a generating facility to an interconnection request as long as the interconnection customer does not request a change to the originally requested interconnection service level, without automatically considering the request to be a material modification.[108] Third, the Commission proposes to require transmission providers to allow interconnection customers to access the surplus interconnection service process once the original interconnection customer has an LGIA in place.[109] Finally, the Commission proposes to require transmission providers to use operating assumptions for interconnection studies that reflect the proposed operation of the resource.[110]

Allowing multiple resources to co-locate behind a single point of interconnection while sharing a single interconnection request will allow for significant efficiencies through the interconnection process. It would reduce the number of interconnection requests, by allowing

[107] NOPR P 242.

[108] NOPR P 255.

[109] NOPR P 264.

[110] NOPR P 280.

two, co-located resources, to be studied as a single request.[111] These studies would also be more accurate, as they would reflect the actual electrical impact when connected to the transmission system.[112] SEIA requests clarification on the terminology used in this proposal. In January 2021, in its order directing reports on information related to hybrid resources, the Commission used two distinct terms to identify hybrid resource market participation. "Co-located hybrid resources" are defined as two separate resources sharing a single point of interconnection that are modeled and dispatched separately.[113] "Integrated hybrid resources" are defined as sets of resources that share a single point of interconnection and are modeled and dispatched as a single resource.[114] There are benefits to each model of participation. Interconnection customers can best weigh the advantages and disadvantages of an integrated hybrid resource versus a co-located hybrid resource. As such, SEIA requests that the Commission adopt these terms in its final rule and clarify that interconnection customers retain the choice of how to structure their interconnection requests to best suit their needs and the needs of their customers.

Amending the material modification process to create a rebuttable presumption that the addition of storage to an existing interconnection request is not a material modification will add certainty to the current material modification process. The pro forma LGIA defines material modifications as "those modifications that have a material impact on the cost or timing of any Interconnection Request with a later queue priority date."[115] Yet, in several RTOs, adding storage to an existing interconnection request may result in a project losing its valuable queue

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[111] NOPR P 244.

[112] NOPR P 244.

[113] *Hybrid Resources*, 174 FERC ¶ 61,034, P 4 (2021).

[114] *Id*.

[115] *Pro forma* LGIP Art. 1.

position.[116] Adding a second resource without increasing the interconnection service level should not increase the costs to later interconnection requests, as it generally would not require additional network upgrades to accommodate the resource. Nor should the request delay later queued projects, as there would be no additional service to be studied. To the extent that transmission providers require specific types of control technologies to add an additional resource, they should make this transparent. The addition of storage results in better electrical performance. It increases reliability. It improves frequency response. There is no reason to deem such a change to be a material modification, especially when it is in the grid's best interest to add more storage.

Allowing interconnection customers to use the surplus interconnection process to add storage resources can provide significant benefits to the grid quickly, and with a high degree of control and transparency. As the Commission found in Order No. 845, the use of surplus service can:

> reduce costs for interconnection customers by increasing the utilization of existing interconnection facilities and network upgrades rather than requiring new ones, improve wholesale market competition by enabling more entities to compete through the more efficient use of surplus existing interconnection capacity, and remove economic barriers to the development of complementary technologies such as electric storage resources.[117]

Leaving storage resources to languish in backed-up interconnection queues, and denying customers of the benefits these resources provide, will ultimately hurt the markets and hinder grid reliability.

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[116] Rob Gramlich, Michael Goggin, and Jason Berwen, "Enabling Versatility: Allowing Hybrid Resources to Deliver Their Full Value to Customers," *available at* https://gridprogress.files.wordpress.com/2019/09/enabling-versatility-allowing-hybrid-resources-to-deliver-their-full-value-to-customers.pdf (Sept. 2019), at 12.

[117] Order No. 845, P 467.

Finally, requiring transmission providers to use study assumptions that reflect the proposed operation of an electric storage resource will result in just and reasonable rates for interconnection customers and consumers. Assuming that a storage resource will charge from the grid during peak periods improperly treats storage as a load during the highest peak periods, unnecessarily increases interconnection and upgrade costs. If the interconnection customer agrees to implement the necessary controls to avoid such charging during peak periods, then the transmission provider should take that into account when determining interconnection and upgrade costs.

2. Evaluating alternative transmission solutions during the cluster study will reduce network upgrade costs.

SEIA supports the Commission's proposal to require transmission providers, upon request of the interconnection customer, to evaluate alternative transmission solutions.[118] Many commenters in the ANOPR proceeding noted how alternative transmission solutions bring improvements in efficiency, capacity, reliability, and resiliency to the system, as well as increases efficient use of the system.[119] Alternative transmission technologies are and ideal medium-term solution to transmission building that bridges the gap in timing between building generation (around five years) and building transmission (around 10 years) by expanding capacity on existing transmission lines enough to allow new generation to come online without significant network upgrades. Decreasing the costs of network upgrades will reduce the number of withdrawals from the interconnection queues, creating a more stable and efficient interconnection process. Decreasing these costs will also reduce the project costs for developers,

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[118] NOPR P 297.

[119] *See* NOPR P 290.

who are then able to reflect those savings in power purchase agreements or integrated resource plan submissions.

SEIA generally supports the proposal to require transmission providers to provide information detailing how advanced technologies were considered in interconnection requests.[120] SEIA requests that the Commission provide flexibility to transmission providers in how to provide this information, whether it be in a report to the Commission or regular postings to its OASIS page.

3. Requiring interconnection customers to provide validated models when they submit their interconnection requests is premature and will not result in useful modeling data for the transmission provider.

SEIA opposes the Commission's proposal to require interconnection customers with non-synchronous resources to submit a generic library RMS positive sequence dynamics model, including a model block diagram of the inverter control system and plant control system, and a validated EMT model, if the transmission provider performs an EMT study as part of the interconnection study process.[121] Providing such models with the interconnection request is overly burdensome to interconnection customers and does not produce useful modeling data for transmission providers.

As an initial matter, some of these models are difficult to provide. Currently in the US, EMT models are not yet industry standard models. There is a limited talent pool of engineers that are able to conduct the studies. EMT models also require significant processing power compared

[120] NOPR P 302.

[121] NOPR P 329.

to RMS models.[122] An EMT model is not necessarily more accurate either. Different models have different uses and no one model fits all situations.[123]

What matters in modeling are the parameters used in each model. Requiring interconnection customers to use generic models, rather than user-defined models, could fail to identify the reliability impacts of a specific plant.[124]

Providing these studies at the interconnection request phase will not provide useful information as there are changes in inverters, network upgrades, and assumptions between when the request is submitted and when the project comes online. Even if there are no changes to the model between the interconnection request and commercial operation of the resource, there is no guarantee that the information in the interconnection customer produced models will be correct, as they rely on grid system information from the transmission providers. There is no corresponding requirement in this NOPR that would obligate the transmission provider to share that information.

SEIA requests that the Commission modify this requirement as follows:

- Require interconnection customers to provide all operating models within one year before the commercial operation date of the resource, in order to reflect the most accurate operating information in the models.
- Require transmission providers to make available to interconnection customers the necessary system data needed to create the models, to ensure that the models more accurately represent system operation.
- Require transmission providers to provide clear modeling requirements and validation guidelines and procedure.[125] If there is a need to change the modeling

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[122] Summary of the Joint Generator Interconnection Workshop, 28 (Aug. 9-11, 2022), https://www.esig.energy/wp-content/uploads/2022/10/Joint-Generator-Workshop-Summary-1.pdf ("Generator Interconnection Workshop Summary").

[123] *Id*. at 23.

[124] *Id.* at 24.

[125] *See e.g.* California ISO, Electromagnetic Transient Modeling Requirements (April 14, 2021), http://www.caiso.com/Documents/CaliforniaISOElectromagneticTransientModelingRequirements.pdf.

requirements, then transmission providers should engage stakeholders before making such changes.

- Allow interconnection customers to use user-defined RMS models, which will better reflect the actual technology used by the resource.

4. The Commission should use IEEE 2800 and 1547 as the ride-through standard reference.

SEIA requests that the Commission amend its proposal to modify article 9.7.3 of the *pro forma* LGIA and article 1.5.7 of the *pro forma* SGIA, so that the reference standard is IEEE 2800 or successor standards for large generators and IEEE 1547 for small generators.[126] Inverter-based resources are currently capable of providing ride-through. Many inverter-based resources have implemented such controls following the release of the consensus-based standards.

The IEEE 2800 standard establishes the required interconnection capability and performance criteria for inverter-based resources interconnected with transmission and sub-transmission systems for reliable integration into the bulk power system, including:

> voltage and frequency ride-through, active and reactive power control, dynamic active power support under abnormal frequency conditions, dynamic voltage support under abnormal voltage conditions, power quality, negative sequence current injection, and system protection.[127]

IEEE 2800 was developed by 175 industry experts over two years and was approved in April 2022 with a 94% approval rate.[128] The goal of the standard is to have harmonized interconnection requirements across different regions and jurisdictions.[129] The standard is still voluntary though. Incorporation into the LGIA would make it mandatory. And in making this standard mandatory, the Commission would bring some certainty in project design, as the

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[126] Generator Interconnection Workshop Summary at 20.

[127] IEEE 2800-2022, https://standards.ieee.org/ieee/2800/10453/.

[128] Generator Interconnection Workshop Summary at 32.

[129] *Id*.

reliability requirements for each project would be known at the time of the interconnection request.[130]

SEIA recommends that the Commission amend the proposed revisions to LGIP Article 9.7.3 to remove the following:

> *Interconnection Customer shall also implement under-voltage and over-voltage relay set points, or equivalent electronic controls, to ensure voltage "ride through" capability of the Transmission System.*

The language should be replaced with the following:

> *Interconnection Customer shall also implement the capability and performance criteria for inverter-based resources set forth for inverter-based resources in IEEE standard 2800, or any successor standard.*

II. CONCLUSIONS

Interconnection reforms alone will not resolve the issues plaguing interconnection queues across the country. In its 2008 Order on Technical Conference, the Commission stated that it believed that "the improved transmission planning required under Order No. 890 will address some of the causes of the current interconnection queue problems."[131] But improved transmission planning has not resulted in new transmission being built.[132] Without new transmission capacity for new resources,[133] the reforms in this NOPR will serve merely as a Band-Aid to a broken interconnection process. SEIA urges the Commission to issue a final rule in this proceeding, as well as the in transmission planning proceeding in Docket No. RM21-17,

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[130] *Id.* at 18.

[131] *Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 8 (2008).

[132] *See* 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.) ("The total regionally planned transmission investment in [regional transmission organizations] decreased by 50 percent.").

[133] *See Interconnection Queuing Pracs.*, 122 FERC ¶ 61,252, P 15 (2008).

to resolve the full scope of issue facing the interconnection and transmission planning processes and ensure that the grid is prepared for the changes we must make in response to the climate emergency.

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 13th day of October 2022.

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