APRIL 25, 2024

GAME CHANGING INTERCONNECTION REFORM:
RESHAPING TRANSMISSION PLANNING AND REALIGNING INCENTIVES

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EXECUTIVE SUMMARY

The process for connecting large-scale renewable energy projects to the grid has become a major impediment to reaching federal and state clean energy goals. Interconnection queues have grown, wait times to connect projects have increased, and the costs associated with interconnecting projects to an aging grid have skyrocketed. Now, regulators, grid operators, researchers, developers, and clean energy advocates are looking for ways to streamline interconnection requirements.

There are many process improvements that could be adopted by grid operators that would modestly decrease project wait times, increase cost certainty for interconnecting customers, and lower costs for firms seeking to connect.[1] But process improvements can only go so far. The underlying cause for the interconnection delays must be addressed. This paper focuses on two major underlying issues that are breaking the interconnection process. Grid operators and regulators must realign the incentive structures that govern interconnection policy today and reshape transmission planning to create a grid that is capable of connecting many more clean energy projects and meet significant growth in electricity load.

After describing the context behind why interconnection reform is critical, and explaining the urgent need for additional interconnection reform, we describe our two-part solution to addressing these key underlying problems.

1 A forthcoming paper will address a number of these process improvements.

INTRODUCTION

In 2022, Congress passed, and the President signed the most meaningful piece of legislation to address climate change in U.S. history: the Inflation Reduction Act ("IRA"). The IRA establishes tax policy changes, incentives, and other provisions to encourage the development of renewable energy projects and to replace the aging fleet of fossil fuel-fired power plants across the U.S.[2] In many places renewable energy projects such as solar power are already the cheapest source for adding new electric generation to the grid and the IRA has accelerated the drive to build clean energy projects to decarbonize our economy.

As we will show, however, a process not well-understood outside of utility and energy circles has become a major bottleneck for bringing large-scale renewable energy power plants online. Grid operators, such as regional transmission organizations ("RTOs"), independent system operators ("ISOs"), and transmission providers outside of regional markets have established detailed, step-by-step procedures for analyzing the impact of new projects on their systems and connecting power projects to the grid itself. For the sake of simplicity, we refer to these entities as "grid operators" throughout this paper.

Carefully debated in grid operator stakeholder working groups, and then approved by the Federal Energy Regulatory Commission ("FERC" or the "Commission"), the nation's "interconnection policies" have been designed to allow potential market participants to connect their projects to the grid, as well as ensure the safe and reliable operation of the grid itself.

As the result of skyrocketing interest from the electric industry and the power project development community, new federal legislation encouraging renewable energy development, and renewable energy mandates from state-level policymakers, grid operators have become inundated with interconnection applications.

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2 Public Law 117-169, 117th Congress. August 16, 2022.

Increasingly expensive transmission system improvements to the grid are now needed to allow new energy projects to interconnect.

The time it now takes to connect projects to the grid is at a twenty-year high[3] and the costs associated with interconnecting projects are also rising, resulting in many more projects withdrawing from the interconnection process.[4]

Furthermore, large-scale solar projects are interconnecting to an aging transmission system that was built specifically to support fossil fuel-fired power plants. But to replace these plants and their equivalent electric generation, more large-scale solar plants must be sited over a wider area than is currently served by the existing transmission system network. As a result, new transmission lines are needed to connect these projects.

Although the U.S. has made major investments in transmission capacity as the electric system has grown and when new economically competitive electric generation technologies have come online, the rate of transmission build-out has *slowed* during the past decade.[5] Between 2011 and 2015, on average, an additional 560 circuit miles of transmission capacity were installed each year. But from 2016-2020, average transmission capacity installations decreased to a negative 79 circuit miles per year, meaning lines were going out of service faster than new lines were being built.[6] Not only are interconnection processes complex, but as the result of this disinvestment, increasingly expensive transmission system improvements to the grid are now needed to allow new energy projects to interconnect.

FERC has made some progress towards improving these issues. It issued Order No. 2023 to reform interconnection processes across the country. Additionally, many transmission providers have instituted their own reforms to address queue backlogs.[7] FERC's approach made modest improvements to grid operator processes. But in many instances, grid operators had already either implemented or piloted approaches such as reviewing interconnection applications in batches or clusters, meaning FERC's reforms simply codified some elements of existing practice.

Despite the progress over the past few years, additional interconnection reforms should be considered by FERC

[3] Rand, Manderlink, Gorman et al., *Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023*, Lawrence Berkeley National Laboratory, (April 2024).

[4] Seel, Kemp et al., *Generator Interconnection Costs to the Transmission System*, Lawrence Berkeley National Laboratory, (June 2023).

[5] U.S. Department of Energy, *National Transmission Needs Study*, (October 2023).

[6] *Id.* P 21.

[7] See for example PJM interconnection reforms (2021) and SPP reforms (2022).

to speed up the process. While there are many kinds of reforms that could be considered by FERC and grid operators, including study enhancements, alternative service options, and increased use of alternative transmission technologies, this paper focuses on game-changing solutions that would help ensure the right incentives are in place for grid operators to build out the electricity grid to meet the supply and demand needs of the future in an efficient manner.

This paper begins by explaining the scope of the interconnection problem, and the reasons the current interconnection policies are inadequate. We then explain two distinct, but related reforms, that have the potential to unblock the congested queues. The first reform involves developing comprehensive regional transmission planning processes that integrate the interconnection queue into planning for the full range of transmission projects. The second reform then proposes charging interconnecting customers only for the costs for upgrading the immediate infrastructure needed to connect their project, instead of the cost of major transmission improvements across the grid operator's territory or other adjacent grid operators' territories.

This paper focuses on game-changing solutions that would help ensure the right incentives are in place for grid operators to build out the electricity grid to meet the supply and demand needs of the future in an efficient manner.

THE PROBLEM: INTERCONNECTION PROCESSES ARE NOT EQUIPPED TO DEAL WITH CURRENT DEMAND

INTERCONNECTION QUEUES ARE LONG AND WAIT TIMES ARE INCREASING.

Interconnection related delays have become a major stumbling block on the road to reaching federal and state clean energy goals. Although all sources of solar power now account for approximately six percent of the nation's electric generation mix—a significant increase from just a few years ago—the current rate of solar deployment is not on pace to reach the Biden Administration's goal of obtaining 100 percent of the nation's electricity from clean resources by 2035,[8] or state goals such as New York's goal of achieving 70 percent renewably resourced electricity by 2030 and a zero-emission electric gid 2040.[9]

Through the end of 2023, the volume of projects awaiting review, study, and approval in the interconnection queue has grown to more than 2,600 gigawatts of total electric generation and storage capacity.

Furthermore, if we hope to nearly phase out fossil fuels from the economy in what are typically called "deep decarbonization" goals, enough renewable energy resources must come online to meet electric demand that is more than 70 percent higher than it is today.[10] Policy makers must speed up interconnection processes to reach these targets. And yet recent data shows U.S. interconnection queues are already long and growing rapidly as new interconnection applications far outpace the rate of project interconnections.

Data collected annually by Lawrence Berkeley National Laboratory ("LBNL") and presented in Figure 1 show the size of the interconnection queue by resource type. Through the end of 2023, the volume of projects awaiting review, study, and approval in the interconnection queue has grown to more than 2,600 gigawatts of total electric generation and storage capacity.[11] Nearly 42 percent of the capacity stuck in these queues is from solar energy projects, with an additional 40 percent coming from storage projects.

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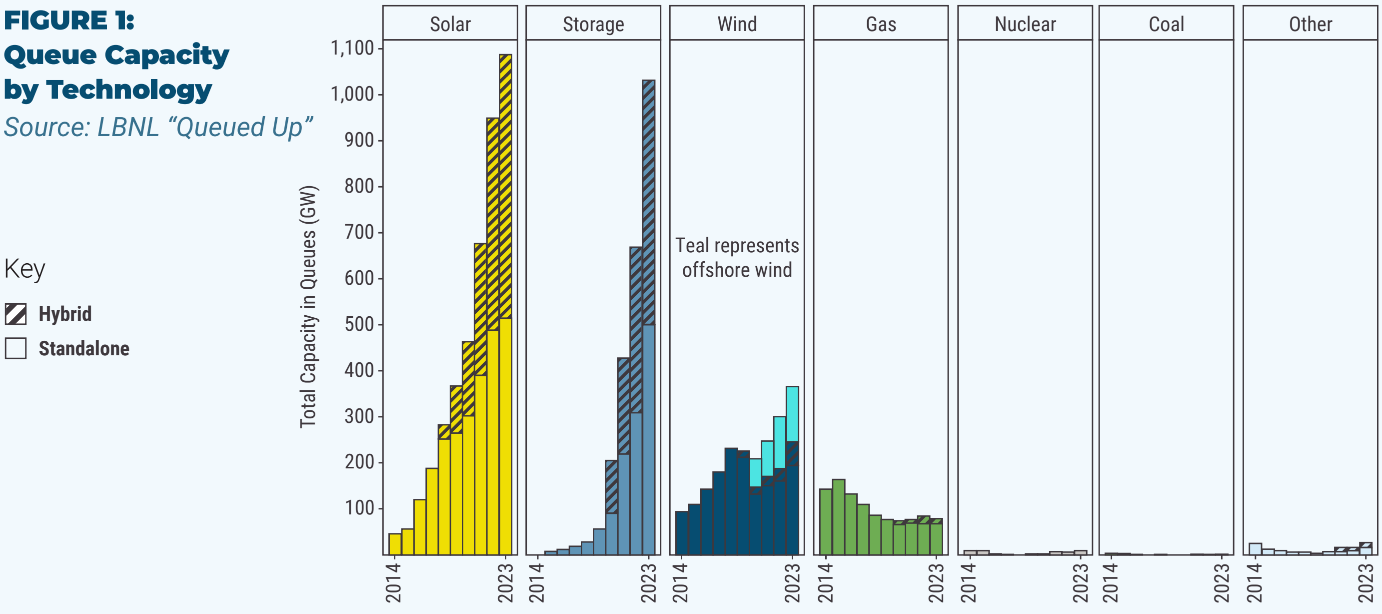
8 U.S. Department of Energy, Solar Technologies Office, *Solar Futures Study* (September 2021) P vii.
9 New York State Energy Research and Development Authority: https://www.nyserda.ny.gov/Impact-Renewable-Energy.
10 U.S. DOE, *supra* note 8. P 8.
11 Rand, *supra* note 3.

FIGURE 1: Queue Capacity by Technology
Source: LBNL "Queued Up"



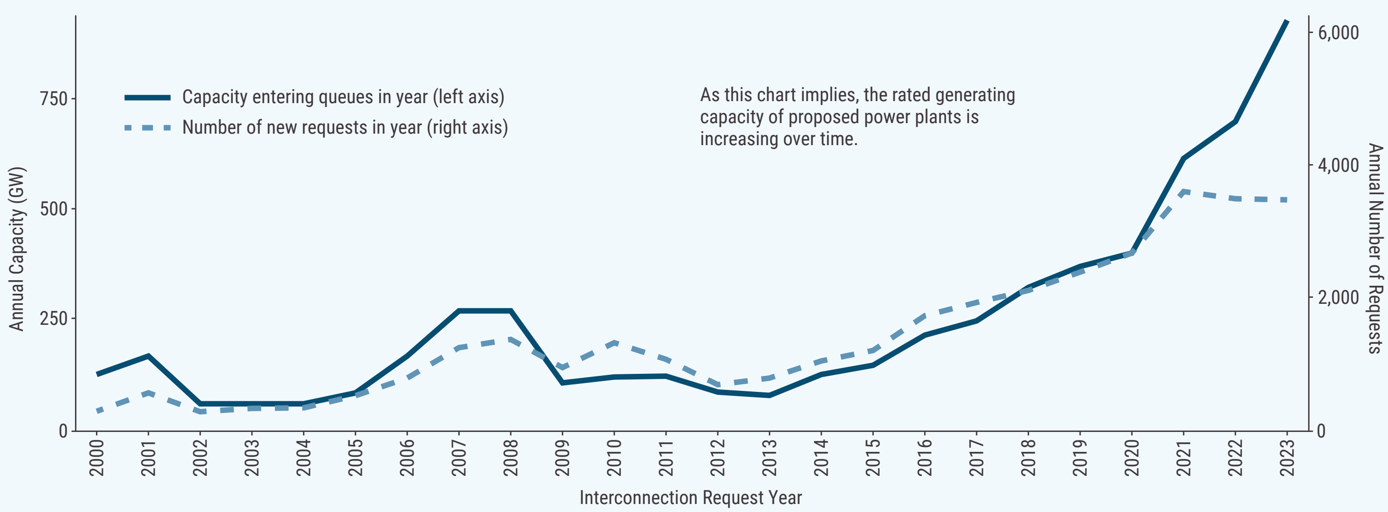
Not only are completion rates for these projects generally low, with only 14 percent of solar projects in the queues from 2000-2018 reaching commercial operation by the end of 2023, but the time it takes to complete the interconnection process is also increasing. Analysis by LBNL shows that projects that came online in 2023 spent nearly five years in the queue on average, up from roughly three years for projects completed in 2015 and two years in 2008.[12]

Furthermore, LBNL data presented in Figure 2 shows a substantial increase in the number of annual interconnection requests submitted to grid operators since 2013 in terms of both the total electric capacity of the applications and the number of applications themselves.[13] The number of new requests reached nearly 3,300 applications in 2023 accounting for more than 700 GW of capacity.[14] This reflects a roughly four-fold increase from the number of applications submitted in 2013.

12 *Id.*

13 *Id.*
14 *Id.*

FIGURE 2: Total Queue Capacity by Year
Source: LBNL "Queued Up"



This backlog ultimately burdens homes and businesses with higher costs for electricity and delays access in areas that need clean energy now.[15] If one gigawatt of generation produces enough energy to power nearly 750,000 homes, then the interconnection queue backlog of 2,600 gigawatts is now having an impact on millions of homes and businesses nationwide.

INTERCONNECTION COSTS ARE RISING.

To understand increasing interconnection costs it is important first to understand the three distinct statuses grid operators apply to projects in interconnection queues: complete, active, and withdrawn. Complete projects have finished all the required studies, paid their assigned fees or deposits, have an interconnection agreement, and are commercially operational. Active projects are those that are actively working through the study process to be approved. Lastly, withdrawn projects have been removed from the queue or cancelled for various reasons.

Presented in Figure 3 below, analysis from LBNL shows increasing interconnection costs across the grid operator territories studied. These studies also break down interconnection costs into costs associated with attaching the project to the grid itself, sometimes called "attachment facilities costs," and broader "network upgrade costs," or needed major investments in the local or neighboring transmission system that can be triggered by reliability and stability violations.

Interconnection costs across all grid operator territories studied have grown over time, from \$225/kW from 2010-2017, to \$422/kW from 2018-2021.[16] Notably, projects that have been completed or are active tend to have lower interconnection costs than withdrawn projects. Between the study periods, interconnection costs for withdrawn projects more than doubled, to \$633/kW from 2018-2021. And network upgrade costs, the far-flung transmission system upgrades that are assigned to interconnection projects have grown significantly over the last few years, rising from under 10 percent of the total project costs for most projects to between 50 to 100 percent of the generation project costs.[17] Several projects have resulted in billion-dollar network upgrade costs.[18]

Withdrawn projects represent a significant loss of time, resources and capital from the project developer, utility,

[15] Caspary, Goggin, Gramlich, and Schneider, Disconnected: *The Need For A New Generator Interconnection Policy* (January 2021).

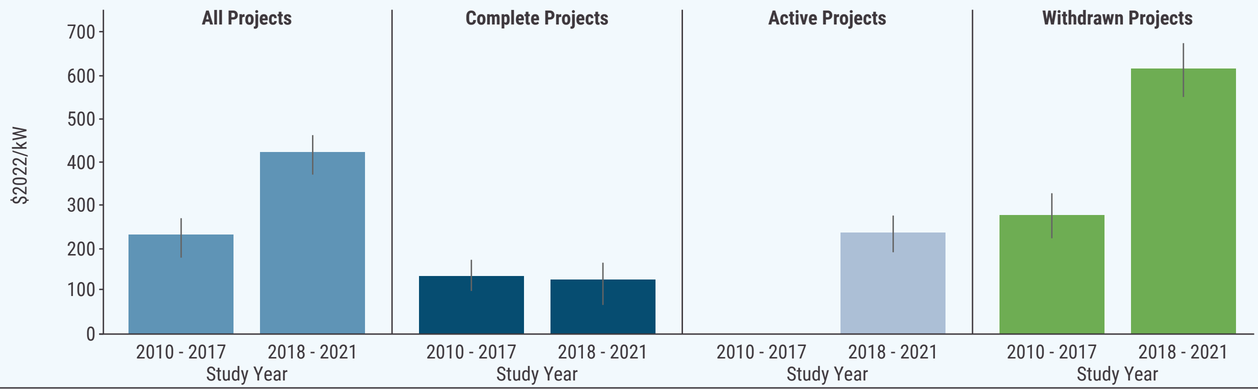
[16] Seel, *supra* note 4.

[17] Caspary, *supra* note 15.

[18] Sankaran, Parmar, Collison, *Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits*, (2021) P 1-2.

FIGURE 3: Average Interconnection Costs by Year and Status

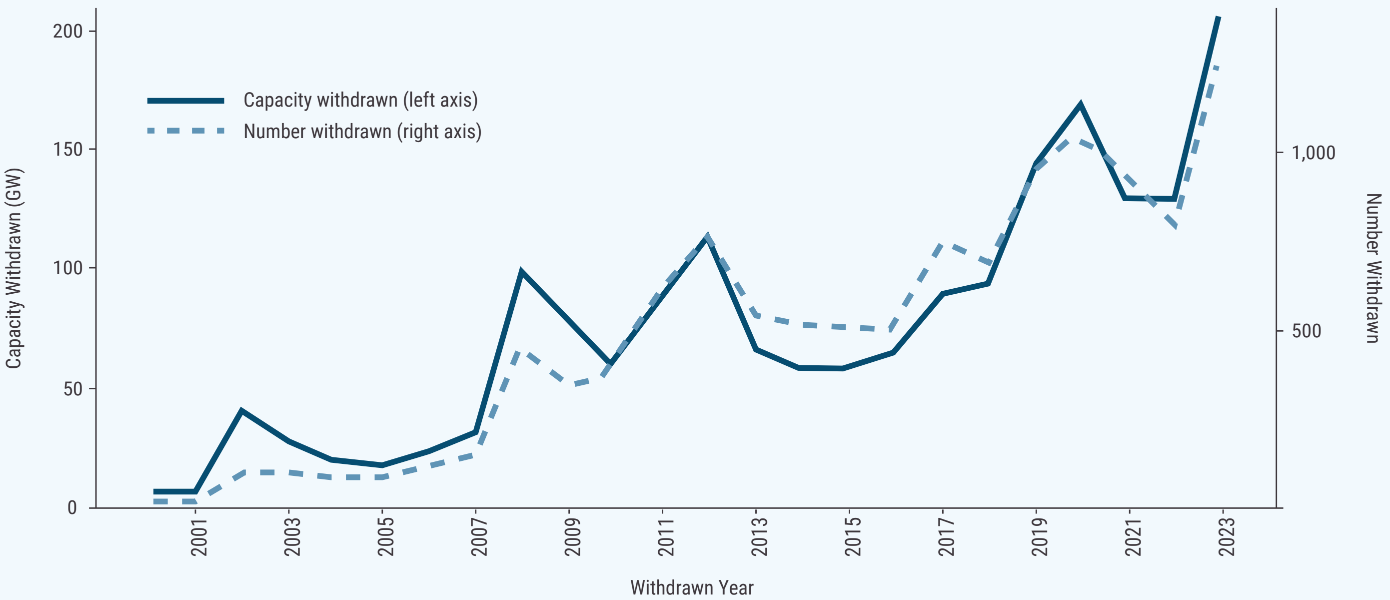
Source: LBNL: Generator Interconnection Costs to the Transmission System



	2010 - 2017	2018 - 2021	2010 - 2017	2018 - 2021	2010 - 2017	2018 - 2021	2010 - 2017	2018 - 2021
Mean Capacity	168 MW	231 MW	131 MW	47 MW	–	307 MW	187 MW	172 MW
Project Count	54	140	18	4	–	65	36	71
Mean Cost (\$/kW)	**225**	**422**	**134**	**114**	**–**	**233**	**270**	**613**

FIGURE 4: Withdrawn Projects

Source: LBNL: "Queued Up"



and grid operator communities. Figure 4, above, shows the growing pool of projects withdrawn from the queue annually.[19] In 2023 alone, more than 200 GW of projects withdrew from the queue, while only 30 GW of projects were completed. Although one could argue that high interconnect costs are sending an important market signal not to build projects in a proposed location, the combination of higher interconnection costs across all classes of projects and the increased rate of withdrawn projects, should give policy makers additional cause for concern.

DESPITE RECENT REFORMS INTERCONNECTION POLICY REMAINS STUCK IN THE PAST.

Current interconnection policy has its origins in Orders issued by FERC more than twenty years ago. In Order No. 2003, FERC issued a set of standardized interconnection procedures that would "minimize opportunities for undue discrimination and expedite the development of new generation, while protecting reliability and ensuring that rates are just and reasonable."[20] FERC required transmission-owning utilities to allow new, often independently owned, electric generation to connect to their transmission facilities. The new standardized procedures included the Commission's policy on funding network upgrades triggered by an interconnection request.

FERC identified two methods for initially funding network upgrades through the generation interconnection process. Under the customer funding option, the interconnection customer provides funds to the transmission provider or owner to cover all network upgrade costs until the upgrades are completed

19 Rand, *supra* note 3.

20 *Id.*

and operational. The transmission owner then must either repay the interconnection customer over time by providing transmission credits against the cost of transmission service or provide cash reimbursement if the interconnection customer did not take transmission service.[21] After application of credits or cash reimbursement, the transmission owner then could include the network upgrade amount in its transmission rate base and earn a rate of return.

FERC's expectation was that "the Transmission Provider would want to roll-in the costs of any network upgrades necessary to interconnect the new generator to enable its existing transmission customers to benefit from this overall lower average embedded cost rate."[22] The transmission crediting policy, which was a key feature of this funding mechanism, recognized that though the interconnection customer caused the network upgrades, once constructed, it is the entire transmission system that benefits from those upgrades.[23]

Order No. 2003 alternatively allowed for the interconnection customer and transmission provider to mutually agree that the transmission provider could fund the network upgrades itself, "with no advance payment by the Interconnection Customer, and thus no need for subsequent credits."[24] This allowed the transmission owner to initially fund network upgrade costs and roll these costs into its transmission rate base, developing a corresponding charge consistent with the "higher of" policy[25] that would be assessed to the interconnection customer.[26] This funding methodology came to be known as "participant funding."

Order No. 2003, while helpful at the time, did not anticipate the volume of interconnection requests and the need for new transmission to accommodate those new projects. The participant funding mechanism created by Order No. 2003 has led to a system in which individual interconnection customers are paying for substantial grid upgrades for which they are not solely responsible. This methodology has led to a largely piecemeal expansion of the transmission system and may be partially responsible for the disinvestment in transmission capacity that we noted in the introduction of this paper. Furthermore, it allocates all or most of the transmission upgrade costs to the interconnecting customers themselves, even though the upgrades that it funds have major benefits to all transmission system users.

Based in part of the growing grid operator interconnection backlogs, and increased concern around this issue, FERC's highly awaited interconnection reform order (Order No. 2023) attempts to streamline and standardize the interconnection process across grid operator territories. FERC Order No. 2023 requires grid operators to evaluate batches or clusters of project applications seeking to connect to the grid, instead of analyzing the impact of projects one at a time. Furthermore, FERC requires stricter "project readiness" requirements, such as demonstrations that the developer has control of most of the land on which the power project would be built, higher financial deposits by companies when submitting interconnection applications, and penalties for withdrawing projects. [27]

But the underlying issues such as lowering interconnection upgrade costs, burdening interconnecting customers with all or most of the costs of needed transmission system upgrades and creating a more aligned set of incentives that encourage robust transmission planning remain unaddressed. In the end Order No. 2023 is just a starting point for "game changing" interconnection reforms and there is more work for the Commission to do.[28]

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[21] Order No. 2003, 104 FERC ¶ 61,103, PP 28, 721.
[22] Order No. 2003-A, 106 FERC ¶ 61,220, P 581.
[23] *Id.* P 584.
[24] Order No. 2003, 104 FERC ¶ 61,103, P 720.
[25] A transmission provider has the option of charging the higher of the incremental cost rate for Network Upgrades required to interconnect a generating facility or an embedded cost rate for the entire transmission system (including the cost of the Network Upgrades). Order No. 2003-A,106 FERC ¶ 61,220, P 580. Order No. 2003-A,106 FERC ¶ 61,220, PP 581, 657, and 694.
[26] Order No. 2003-A,106 FERC ¶ 61,220, PP 581, 657, and 694.

[27] *Improvements to Generator Interocnnection Procedures and Agreements*, Order No. 2023, 184 FERC ¶ 61,054 (2023).
[28] Norris, *Beyond FERC Order 2023 Considerations on Deep Interconnection Reform*, Nicholas Institute Duke University (August 2023).

THE SOLUTION:
INTEGRATED TRANSMISSION PLANNING AND DELINKING NETWORK UPGRADE COSTS

INTEGRATING THE INTERCONNECTION QUEUE INTO THE TRANSMISSION PLANNING PROCESS ENSURES TRANSMISSION IS BUILT TO SERVE THE ENERGY SUPPLY AND DEMAND OF TOMORROW.

The transmission planning process must change.

Transmission planners must engage in comprehensive, long-term, forward-looking transmission planning that incorporates the interconnection queue.[29] Transmission upgrades that could have potentially significant benefits for a broad range of entities are currently planned through a process that focuses on a small number of interconnection customers.[30] This process is unlikely to identify the most efficient or cost-effective solutions to transmission needs driven by changes in the resource mix and demand. And it has resulted in inefficient transmission investment that cannot meet the needs of the changing resource mix.[31] A transmission system built on the backs of interconnection customers is not just bad for the interconnection process, but bad for anyone who relies on the grid.

The transmission planning process must change. Transmission planners must engage in forward-looking analyses that would identify transmission needs driven by changes in the resource mix and demand identified through the development of long-term scenarios and then evaluate transmission requirements to meet those needs.

As FERC proposed in its April 2022 Notice of Proposed Rulemaking, transmission providers must engage in scenario planning that considers the supply and demand factors that affect transmission needs over a 20-year horizon.[32] Further, transmission planning that reflects both resource adequacy needs and resource mix as it evolves through retirements and queue entry, will help develop a transmission system that

[29] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028, P 25 (2022) ("Transmission Planning NOPR").
[30] Transmission Planning NOPR P 27; see also Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, 176 FERC ¶ 61,024, Glick Concurrence, P 10 (2021) ("ANOPR").
[31] Transmission Planning NOPR, P 39.
[32] Transmission Planning NOPR, P 3.

would increase capacity on the system in a way that reduces costs to both consumers and interconnection customers. But to do this, planners must incorporate the interconnection queue into transmission planning. Transmission planners should evaluate network upgrades that have been identified multiple times in the generator interconnection process but have not been constructed due to the withdrawal of the upgrade-triggering interconnection requests.

An integrated planning approach can help resolve the cost allocation and market entry barrier problems created by participant funding, because it would charge the planning process with finding more efficient or cost-effective transmission solutions to facilitate interconnections of new generation and meet other identified transmission needs. While current transmission planning processes incorporate future scenarios, 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 broad benefits to consumers.

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 entered into the regional planning process, would remove uncertainty and delay in the interconnection process.[33] This would accelerate transmission upgrades that benefit the region and should be included in the regional planning process.

[33] Enel Green Power, *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*, https://www.enelgreenpower.com/content/dam/enel-egp/documenti/share/working-paper.pdf

REIMAGINE PARTICIPANT FUNDING AND REALIGN THE INCENTIVES TO REBUILD THE TRANSMISSION SYSTEM.

Ballooning interconnection costs are a symptom of the failure of grid operators to plan and build the transmission system. Better long-term transmission planning will help to address these ballooning costs, but other protections must go into place to encourage better transmission plannings. To address the failure to plan the transmission system, regulators and grid operators must realign the incentives to build out the transmission system so that the grid operators and transmission owners not only benefit from existing transmission investment incentives, but they also bear the cost of failing to build that transmission system in a cost-effective manner. Because of the misalignment of incentives created by the participant funding model, this model no longer serves the needs of the transmission system.

Network upgrades associated with interconnection requests only address the incremental changes of a single interconnection request, or cluster of requests, on the transmission system. And it is not just interconnection customers that pay the price of high network costs. These network upgrade costs are typically incorporated into power purchase agreements, integrated resource plan proposals, and market bids, all of which are ultimately paid for by the end use consumer.

FERC and Congress must delink the buildout of large-scale transmission from the interconnection process. While interconnection customers should pay for *some* share of the network upgrade costs, it should not be incumbent on them to pay for the *entire* share of the network upgrade costs. In its place, FERC should put into place a two-payment system.

First, an interconnection customer pays a non-refundable entry fee, based on project size, as part of its interconnection request. This fee would be applied generally towards transmission system network upgrades identified in the grid operator's long-term regional transmission plan. Second, as part of the interconnection study process, the grid operator would identify, and the interconnection customer would pay for, local transmission system network upgrades that are needed to connect the interconnection project to the grid.

This entry fee and local network upgrades payment scheme is based on the proposed planning framework in FERC's transmission planning NOPR.[34] To establish the entry fee, the grid operator would conduct a 20-year assessment of supply and demand needs, based on the following factors:

1. federal, state, and local laws and regulations that affect the future resource mix and demand;
2. federal, state, and local laws and regulations on decarbonization and electrification;
3. state-approved utility integrated resource plans and expected supply obligations for load serving entities;
4. trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation;
5. resource retirements;
6. generator interconnection requests and withdrawals; and
7. utility and corporate commitments and federal, state, and local goals that affect the future resource mix and demand. [35]

During this process, the grid operator would identify the regional, subregional, and local transmission lines and associated costs[36] required to meet these supply and demand needs. The total queue entry fee would be comprised of three components: 25 percent of the costs of the regional transmission lines; 25 percent of the costs of the subregional; and 25 percent of the local line costs.[37] The total queue entry fee would then be divided by the expected capacity of the completed interconnection requests. While the entire region would pay the same regional component, the entry fee itself would vary based on the grid operator load zone in which a project is located. This fee would be reevaluated each time the long-term transmission plan is reassessed.

TOTAL QUEUE ENTRY FEE =

[25% costs of regional lines + 25% costs of subregional lines + 25% of local lines] ÷ expected capacity of completed interconnection requests

In order to identify the local network upgrades,[38] the transmission provider would establish a Distribution Factor ("DFAX") threshold to assign network upgrades to interconnection customers. DFAX represents the change (or sensitivity) of active power flow on a transmission asset with respect to a change in injection at the generator bus and a corresponding change in withdrawal at the reference system. In the case of generation interconnection studies, the transfer size is the amount of generation added to the system. Several transmission providers already use DFAX to assign network upgrade costs.[39] However, it is the use of low DFAX thresholds that results in the assignment of large network upgrade costs.[40] A standard threshold of at least 20

[34] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022) ("Transmission Planning NOPR").
[35] Transmission Planning NOPR P 104.

[36] This analysis would reflect inflation in the costs.
[37] The 25 percent proposal reflects a starting point for discussion. Further analysis is needed to determine whether a different percentage would be more appropriate.
[38] Local upgrades in this context means line replacement or extension, reconductoring, or other upgrades to transmission lines that allow increased electric capacity/decreased line losses. Under the paradigm proposed here, interconnection customers would still be responsible for the costs of any Transmission Provider or Interconnection Customer Interconnection Facilities identified in the interconnection studies.
[39] *See e.g.*, MISO Generation Interconnection Business Practices Manual (Manual No. 015), at 2 (effective Mar. 1, 2023), *available at*: https://www.misoenergy.org/legal/business-practice-manuals.
[40] *See e.g.*, Enel Green Power, *Plugging In: A Roadmap for Modernizing & Integrating Interconnection and Transmission Planning*, Appendix B, https://www.enelgreenpower.com/content/dam/enel-egp/documenti/share/working-paper.pdf ("Enel Working Paper"); *see also* National Grid Renewables v. Midcontinent System Operator, Inc., FERC Docket No. EL23-85 (July 25, 2023) (arguing that MISO's lowering of the DFAX threshold to 10% in certain subregions results in a higher allocation of network upgrade costs).

percent across transmission providers will help ensure that interconnection customers are paying for local costs.

SPP is already contemplating novel methods of network upgrade cost contribution principles as part of its Strategic and Creative Re-Engineering of Integrated Planning Team ("SCRIPT"). As part of the SCRIPT, SPP began to develop a comprehensive policy proposal for the Cost and Policy Planning ("CPP") Entry Fee. These efforts are still underway, but can be used as both a positive example and a cautionary tale. The CPP Entry Fee can potentially provide a known cost of interconnection in advance of future queue windows. The fee can serve to mitigate volatile cost assignments that pervade interconnection studies and render the current process highly uncertain. However, without ensuring cost containment when assessing transmission costs, such a policy could result in a cost shift to interconnection customers under a different name.

Delinking the interconnection process and network upgrade investments is important not just because it lowers interconnection costs, but because it provides cost certainty.[41] The benefits of delinking are that interconnection customers would only be paying for local network upgrades that have a clear connection to their projects, rather than a massive transmission upgrade located hundreds of miles away. With lower costs and a more rational connection to the incurred costs, interconnection customers would be less likely to withdraw from the queue and less likely to cause restudies that would delay the interconnection process.[42]

This framework would help realign the incentives to engage in holistic transmission planning by shifting the risk of transmission buildout back to the transmission owners and planners. Under the current participant funding method, transmission planners identify the transmission needs but the financial risk is borne by the interconnection customers. With the financial risk on the interconnection customers, the incentive to plan in a cost-effective manner does not exist. Inefficient planning leads to interconnection delays, which could cause resource adequacy issues. Consumers end up paying more money for inefficient transmission build out that does not ensure the reliability they need in the energy transition.

41 Caspary, *supra* note 15.

42 This benefit is in addition to the benefit of higher upfront costs reducing the number of projects entering the queue in the first place.

CONCLUSION

Although FERC Order No. 2023 is a step in the right direction toward addressing some issues that are driving up large-scale solar interconnection costs, wait times, and resulting in more withdrawn projects, the underlying problems remain unaddressed.

As we have shown, using the interconnection process to pay for major improvements to the transmission system is deeply flawed. Relatedly, placing the entire burden of transmission system improvements on interconnecting customers is inequitable, especially when many different users benefit from these improvements. In short, participant funding must be revisited.

This paper briefly explains two important game-changing reforms:

- Developing comprehensive regional transmission planning processes that integrate the interconnection queue into planning for the full range of transmission projects.
- Charging interconnecting customers only for the costs of upgrading the immediate infrastructure needed to connect their project using a two-part fee.

Although a companion paper to be released in the coming months will address many needed additional interconnection process reforms, the two major changes proposed here would help fix the underlying problems that have clogged up the interconnection works, killed projects, and threatened progress towards federal and state clean energy goals.

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ACKNOWLEDGMENTS

The Institute would like to thank John Moore and Thomas Rutigliano at the Natural Resources Defense Council, Cailtin Marquis and Jeremy McDiarmid at Advanced Energy United, Jackson Ewing and Tyler Norris at the Nicholas School of the Environment at Duke University, and John Wilson at Grid Strategies for their review and thoughtful comments on this paper. We also appreciate the review of this document by various SEIA member companies.

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