



All Queued Up and Nowhere to Go

The Massive Interconnection Challenge Facing
Net-Zero Electricity Deployment

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CLEARPATH

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Glossary of Terms

Affected System is a transmission or distribution system owner or operator, other than one's direct transmission or distribution system owner or operator, whose system may be impacted by the proposed project.

Contingent Facilities are the unbuilt network upgrades or new equipment and infrastructure that are determined to be necessary for an interconnection customer to connect to the grid. If these contingent facilities are not developed or have delayed development, this may trigger re-studies and impact costs and timing for other interconnection customers.

Cost Allocation is the process of identifying which party, i.e. interconnection customer(s) or transmission provider and their customers, is responsible for paying for contingent facilities.

Independent System Operator (ISO)/Regional Transmission Operator (RTO) are a collection of utilities and can include federal system operators, whose transmission systems and wholesale electricity markets are operated and governed by a non-governmental, non-profit entity. While the legal context for ISOs and RTOs differs – ISOs originated in Order 888/889 while RTOs, which are developed and joined voluntarily, originated in Order 2000 – this distinction is not pertinent to this paper and may be used interchangeably.

Interconnection Customer is any project owner, either a utility, utility affiliate or private developer, seeking to interconnect its generation or storage resource to the grid.

Interconnection Facilities Study determines the cost for and development timeline of an interconnection customer's contingent facilities identified in the system impact study.

Interconnection Feasibility Study is the initial assessment of a project's system impact and cost of interconnecting to the grid.

Interconnection System Impact Study is the second interconnection study that evaluates the impact of an interconnection customer's project on their direct transmission provider's system and any identified affected system transmission provider's system for reliability constraints.

Federal Energy Regulatory Commission (FERC) is an independent agency that regulates the interstate sale of electricity, natural gas, and oil. Additional responsibilities include licensing hydropower projects and reviewing liquefied natural gas (LNG) terminal and interstate natural gas pipeline project proposals.

Material Modification is a change made to a proposed project that would impact the cost or timing of any following interconnection customer. In the NOPR, FERC proposed to update this definition to include interconnection customers of equal or later positions in the queue.

Notice of Proposed Rulemaking (NOPR) is issued by FERC and contains a summary of the set of problems in a particular regulatory process or rule and details the proposed set of reforms the Commission is considering. There is a public comment period after which FERC will conduct additional analysis to determine what proposed reforms, if any, will become a final rule.

Transmission Provider is the owner or operator, such as a utility or ISO/RTO, of the transmission system that a project developer seeks to interconnect.

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Executive Summary

Hundreds of gigawatts of energy projects – predominantly wind, solar, natural gas, and storage – spend years in the interconnection process, where projects undergo evaluation by transmission providers, regional grid operators or utilities, to determine their impact on the broader transmission system. The interconnection queue, the list of projects under evaluation for grid connection, has become so dysfunctional that some transmission providers are freezing their process to work through the project backlog and pausing the acceptance of new applicants.¹

We examine the current state of interconnection queues, the implications of current delays and withdrawals for net-zero, and potential policy solutions to remedy existing barriers to significant reliable, clean energy development. Our major takeaways are as follows:

1. Escalated queue delays make it harder to deploy all forms of electricity generation and storage;
2. Net-zero models project resource deployment levels that are unrealistic under the current state of the interconnection queue. Ultimately transformational and flexible reforms are needed;
3. Retirement of existing energy capacity is anticipated to outpace new additions due to interconnection inefficiencies.

In 2022, the Federal Energy Regulatory Commission (FERC) passed a unanimous and bipartisan Notice of Proposed Rulemaking (NOPR) on interconnection queue reform. The proposed reforms are a mixed bag of carrots and sticks that incorporate many existing practices into the standard procedures but are overly prescriptive in many respects. Overall, the reforms are likely not transformative or flexible enough for the speed and scale of deployment required.

Additional actions necessary to address these challenges include:

- Opportunities to better integrate the interconnection and transmission planning processes that scale with the challenge of future deployments projected by net-zero models should continue to be evaluated at FERC.
- Judicious use of funds available through DOE's Transmission Facilitation Program and Transmission Infrastructure Program that prioritizes reliability, resilience, and decarbonization in the implementation and selection of projects.
- Siting and permitting challenges necessitate greater coordination between FERC and other relevant agencies to identify and expedite opportunities to pre-site and permit projects in existing rights of way and National Interest Electric Transmission Corridors.
- Workforce development programs should provide grants or scholarships for electrical engineers contingent on their employment at utilities or regional grid operators for a minimum of years.
- DOE and the National Labs should develop cutting-edge tools and provide technical assistance to states, other agencies, or non-governmental organizations (such as RTOs and utilities) to facilitate their capabilities.

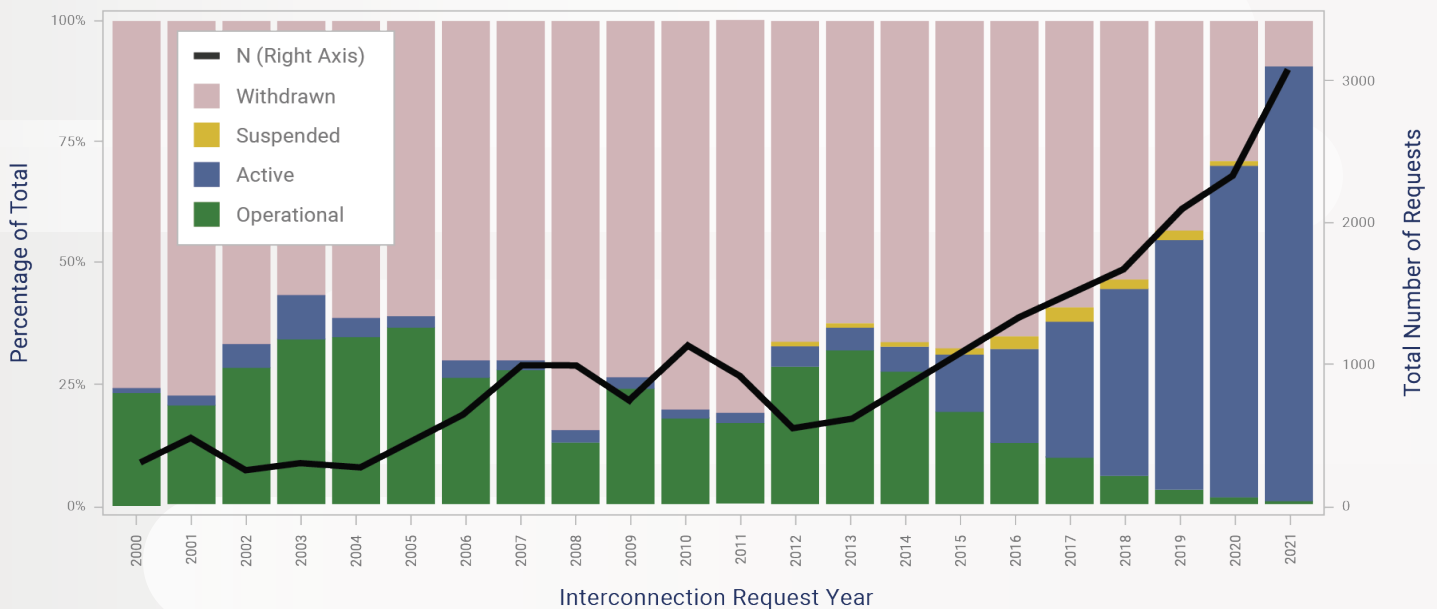
Failure to address the current interconnection process at scale will limit the ability to reduce emissions affordably and could hurt grid reliability. At this point, achieving net-zero emissions in the U.S. by 2050 – as has been proposed by several states and some of the largest electric utilities in the nation – is impossible without interconnection improvements.

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The Dual Challenge of Net-Zero and Reliability

1. Queue delays and backlogs have escalated, making it more difficult to deploy all forms of clean energy:

Projects seeking connection to the grid, also referred to as interconnection customers, currently wait an average of 3.7 years to advance through the queue.² This is a dramatic increase over the historical average of 2.1 years between 2000 and 2010.³ Interconnection customers pay for new transmission facilities or upgrades to existing facilities that enable them to connect to the grid. Shrinking available capacity on the existing transmission system increasingly necessitates the construction of new transmission lines or more extensive upgrades that come with higher costs. The cost of these contingent facilities, coupled with a first-come-first-served process of evaluating projects and allocating costs, has incentivized developers to submit multiple interconnection requests with the intent of discovering the lowest cost points of interconnection or benefiting from investments made by an earlier customer. Relatedly, projects withdraw from the queue when the cost of contingent facilities makes a project uneconomic. These withdrawals can trigger cascading re-studies for other projects in the queue. The turmoil and scale of projects entering and leaving the queue have resulted in only 23% of projects entering the queues nationwide between 2010 and 2016 reaching commercial operation.⁴ This has become a major impediment to energy infrastructure deployment, imperiling both power sector decarbonization and future grid reliability.



Credit: Lawrence Berkeley National Laboratory “Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2021”. The completion rate is calculated by the number of projects, not capacity-weighted. Includes data from six ISOs and 25 utilities.

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2. Net-zero models project unprecedented levels of deployment, which are unrealistic under the current interconnection regime:

Avoiding significant climate impacts will require a large increase in overall electricity generation provided by a majority share of new, low-emission resources by 2050.⁵ The necessary deployment pace is unprecedented, requiring hundreds of gigawatts of new capacity over just a few decades.

Energy models consistently predict that the cheapest power sector mix to reach net-zero on this timeline will include a resource mix of nuclear, renewables, and natural gas with carbon capture. One example of this is an analysis from the REPEAT project at Princeton University, which finds that a total of about **1,101 GW** of wind and solar, along with **179 GW** of natural gas and **6 GW** of nuclear, would need to be deployed by 2035 to reach net-zero by 2050 (see Figure 1). Retaining the existing nuclear fleet, which represents over half of carbon-free electricity,⁶ increases emission reductions, avoids additional new capacity, and could generate significant power system savings.⁷ Hitting net-zero targets is a huge undertaking and implies stakeholder support.

Approximate 2035 Cumulative Capacity Additions for 2050 Net-Zero

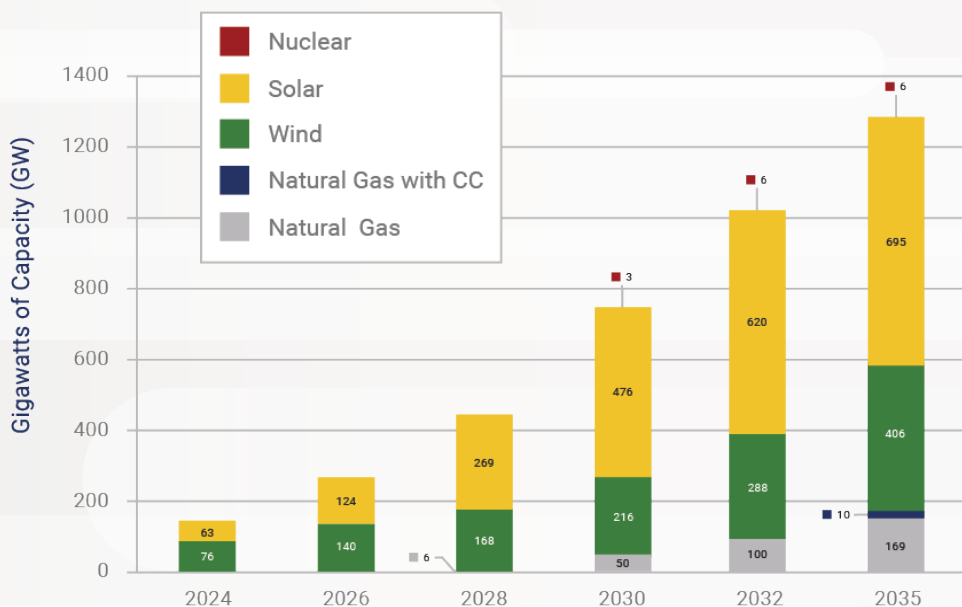


Figure 1: End of the year 2021 Capacity by Generation values were subtracted from Princeton University's REPEAT Project Net-Zero Benchmark Capacity Additions to determine Cumulate New Capacity Additions. Negative values were excluded from the chart.

Total electricity generating capacity in the United States at the end of 2021 was 1,144 GW, meaning that Princeton's projected deployment is more than the total current electricity grid's capacity in just 12 years.⁸ This is a massive deployment, and with only 23% of projects from 2010-2016 reaching operation under the current regulatory regime, interconnection delays and project withdrawals will hinder future clean energy deployment. Similar deployment levels are projected due to the recently enacted clean energy tax credit law, which will spur additional project development.⁹

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We use the commercial operation success rate from Lawrence Berkeley National Laboratory (LBNL) and net-zero projected build-outs from REPEAT, to determine that the volume of proposed capacity that would need to enter the queue by 2035 to stay on track for net-zero by 2050 is staggering, as shown in Figure 2 below.

Unprecedented Queue Volumes Needed for Net-Zero Build Rates

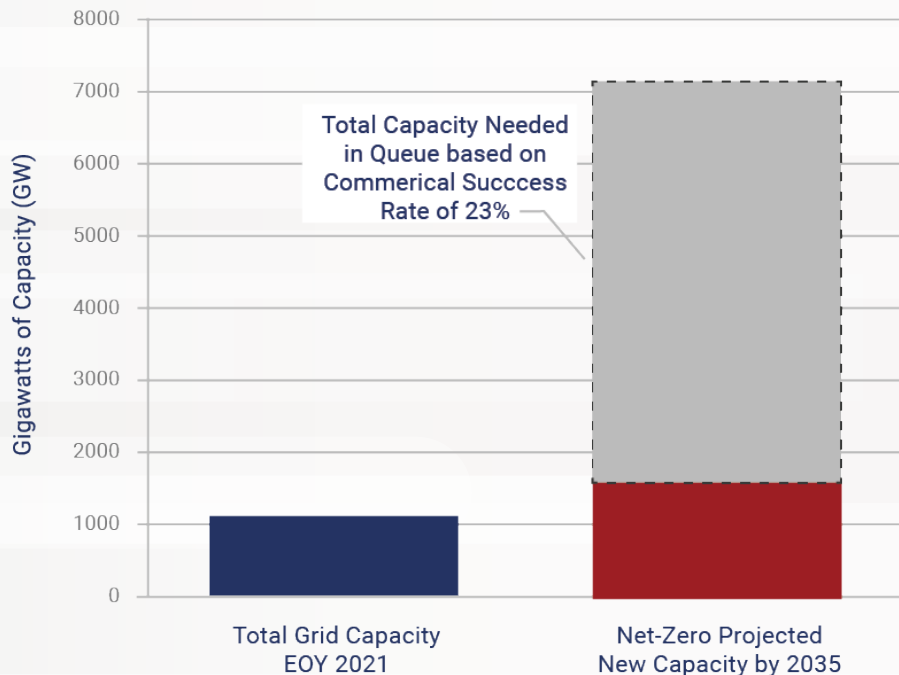


Figure 2: Total grid capacity at the End of Year 2021 from the Energy Information Administration. End of the year 2021 Capacity by Generation values were subtracted from Princeton University's REPEAT Project Net-Zero Benchmark Capacity Additions to determine Cumulate Capacity Additions by 2035. LBNL commercial operation rate of 23 percent determined the total volume of projects needed in the queue.

According to REPEAT Net-Zero Projections, approximately 1,300 gigawatts of new capacity would need to be added by 2035.¹⁰ This would more than double 2021 nationwide capacity within the next 12 years. If the 23% completion rate is maintained, over 7,000 GW of capacity would need to enter the queue over the same period to reach this goal.

The historical maximum for annual electric capacity additions is 67 gigawatts (GW) in 2002.¹¹ By comparison, the lowest annual capacity addition projected by models for net-zero is 74 GW, with annual additions reaching as high as 156 GW in a single year: over twice the historical maximum. The annual capacity entering the queue has grown to nearly 500 GW in recent years,¹² but completion rates have declined, and some overwhelmed grid operators have temporarily paused processing of existing requests and stopped accepting new ones.¹³ Utility and state decarbonization targets are strongly supported by robust financial incentives to deploy record-breaking capacity additions, but the current system will not allow that to happen.

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3. Net-zero scale additions are impossible under current speed and success:

If current backlogs and withdrawals continue, it's clear that the development pipeline of energy projects is insufficient to reach net-zero projected deployment levels. Under a 23% success rate, building the new electric capacity projected by modeling would require over 7,000 GW in development by 2035, compared to over 1,000 GW today. Due to delays, much of that new development must begin in the next 2-years to have any chance of coming online in the next decade. When interconnection wait times are combined with current supply chain and permitting challenges, the cumulative impact severely limits the scale and pace of clean energy deployment.

Annual Proposed Capacity Additions Required to Achieve Net-Zero Under Current Completion Rate

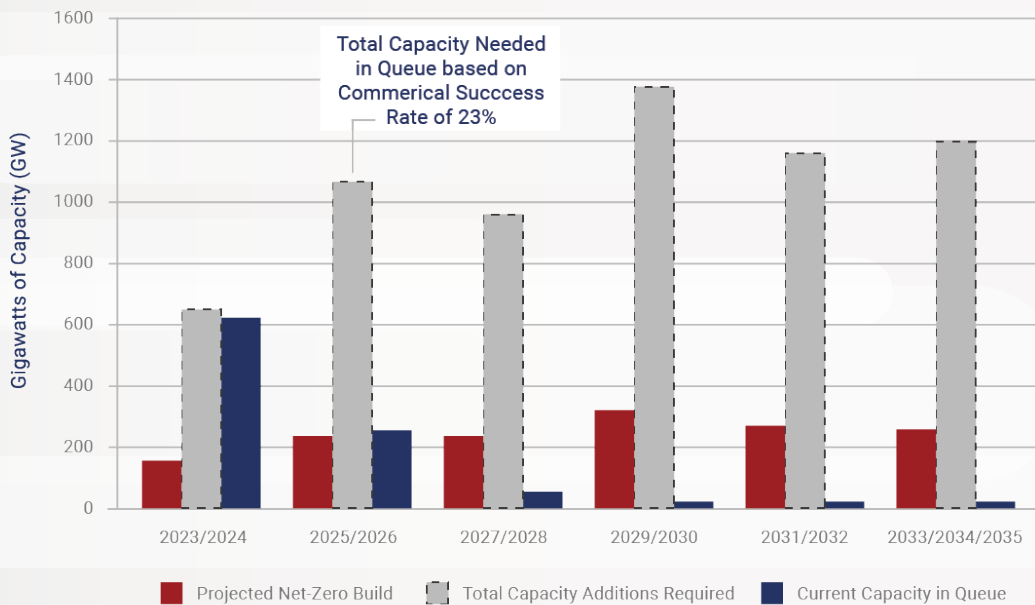


Figure 3: Princeton University REPEAT Net-Zero Benchmark projections are shown in purple and represent the total capacity additions for their respective years. LBNL interconnection queue dataset was used to display the volume of active projects in the queue by expected year of operation.

While existing models can simulate the impacts of economic incentives for clean electricity development, other factors that influence development speed, such as regulatory regimes, supply chain maturity, and workforce availability, are often omitted. Most significantly the current interconnection procedures, transmission capacity, and workforce availability are major rate limiters for deployment and impact reliability. Addressing each of these challenges, in turn, is critical to facilitate the deployment of affordable, reliable, and clean energy.

4. Interconnection Inefficiencies Impact Grid Reliability

The recent trend of generation retirements outpacing new additions is already challenging grid reliability in many deregulated jurisdictions. One example is the Midcontinent Independent System

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Operator (MISO). MISO’s capacity auction structure¹⁴ has consistently been criticized for sending inadequate price signals leading to the premature retirement of resources, outpacing the sufficient addition of new capacity.¹⁵ This recently manifested in MISO North’s capacity shortfall this summer.¹⁶ However, shortfalls are projected to continue longer term as the 8 GW of new resources anticipated to interconnect by 2024 will not fully compensate for the estimated potential retirement of existing resources totaling 13 GW over the same period.¹⁷

Elsewhere, the New York Independent System Operator (NYISO) reported that between 2019 and 2020, over 3 GW (mainly coal and nuclear) retired while only 1.4 GW of capacity was added.¹⁸ By 2025, another 1.5 GW of peaking capacity could be offline during the summer to comply with new NOx regulations.¹⁹ California similarly faces resource adequacy challenges even with the tentative extension of Diablo Canyon Nuclear Plant operations through 2030.²⁰

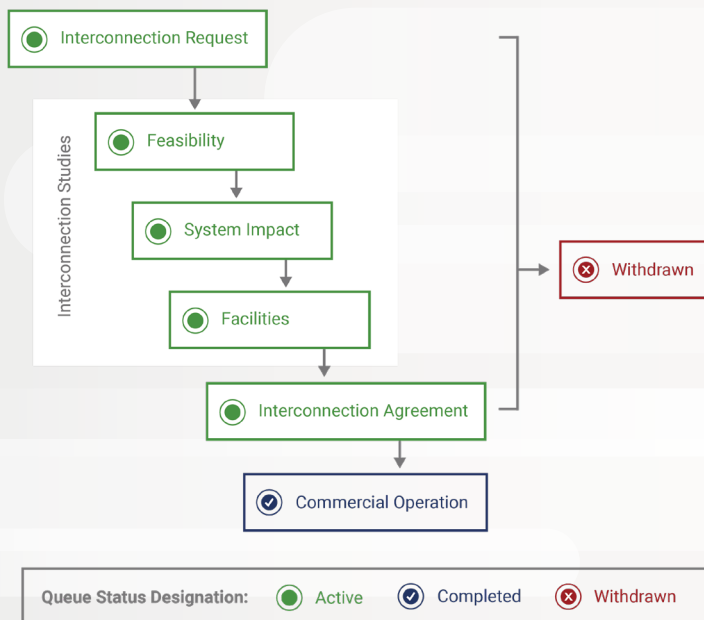
Wholesale market designs contribute to this mismatch in retirements and additions. We support FERC’s Order Directing Reports from RTOs and ISOs on Modernizing Wholesale Electricity Market Design issued on April 21, 2022.²¹ We believe solving these reliability challenges requires a holistic assessment and solution set and look forward to reviewing these reports on reforms for wholesale market designs.

Interconnection Procedures and Cost Allocation

What is the Interconnection Process?

FERC Order 2003 formalized the interconnection process by requiring transmission providers to develop standardized agreements for generators to minimize opportunities for discrimination against new market entries.

Simplified Interconnection Study Process



To the left is a diagram of the current interconnection process adapted from Lawrence Berkeley National Laboratory. It starts with project developers sending an interconnection request to the relevant transmission provider, who will review and enter projects into the interconnection queue. Historically, projects in the queue are processed individually, on a first-come, first-served basis. Projects undergo a 3-phase interconnection study – Feasibility, System Impact, and Facilities – in order to determine the scope and cost of contingent facilities, like network-related system upgrades or transmission facilities, necessary to accommodate their request.

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Notably, the system impact study includes an affected system study that determines how a project impacts another transmission provider's grid. An interconnection customer may be responsible for paying the cost of contingent facilities on the affected system in addition to these facility costs on the system operated by their transmission provider.

After the study process, a transmission provider extends a project owner an interconnection agreement outlining the conditions and costs for interconnecting. Projects can be withdrawn from the process at any time and can expect, at a minimum, to pay the costs incurred by the transmission provider to conduct that customer's studies.

Depending on the jurisdiction, the costs for contingent facilities, either on their transmission provider's system or an affected system, are allocated using one of two approaches: crediting or participant funding. Under the crediting approach, an interconnection customer is responsible for the contingent facility's cost upfront but is reimbursed with interest by their transmission provider via transmission rates paid by consumers.

Under participant funding, an interconnection customer pays for the entire cost of the contingent facility regardless of whether the facility provides system-wide benefits or is used by subsequent interconnection customers. This approach is only allowed in RTO/ISO regions that service the majority of the nation's load. Due to the first-served approach to processing requests and cost-causation principle²² for allocating costs, these subsequent customers are not responsible for any portion of the costs. A benefit of this cost allocation method to interconnection customers is that it provides them with the transmission capacity rights generated by their contingent facilities.

The participant funding model is designed to incentivize new generators to choose the most cost-effective siting locations and works efficiently with non-location constrained generation on a transmission system that has sufficient available capacity. Non-location constrained generation, such as natural gas or nuclear, has the flexibility to choose locations near load or in areas without congestion on the system, eliminating the need for new infrastructure or upgrading existing infrastructure.

While individual transmission providers have amended or overhauled their interconnection procedures and cost allocation approaches to address challenges and inefficiencies, completion rates have trended down and time spent in the queue has trended up nationwide. The unintended consequences have led to a dysfunctional system.

How has Interconnection become a Bottleneck?

Dramatic changes in the make-up and scale of projects requesting interconnection are being driven partly by increasingly ambitious decarbonization targets and the rapid techno-economic declines in clean energy technologies. Wind, storage, and solar projects now represent well over half of the total capacity in the interconnection queue at the end of 2021. Wind and solar resources, in particular, are geographically constrained, leading to the most productive projects frequently being far from either load, transmission, or both. The combination of this siting limitation with an oversubscribed or non-existent transmission system has contributed to escalating contingent facility costs.²³

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Additionally, the much quicker development timelines of these new technologies combined with the rapid rate of technological innovation may lead to project changes, such as new equipment becoming available or economically advantageous. Adjustments to the technical specifications of projects already in the queue can be considered a material modification that bumps these interconnection customers to the back of the queue.

Interconnection customers are typically processed individually in the order they enter the queue. This first-come, first-served basis of studying projects creates interdependence among customers. For example, if projects farther along in the study process withdraw, it may trigger re-studies for the subsequent customers in the queue. One example of this challenge is presented below, although there are many possible permutations.

Example of the Electricity Interconnection Restudy Cascade

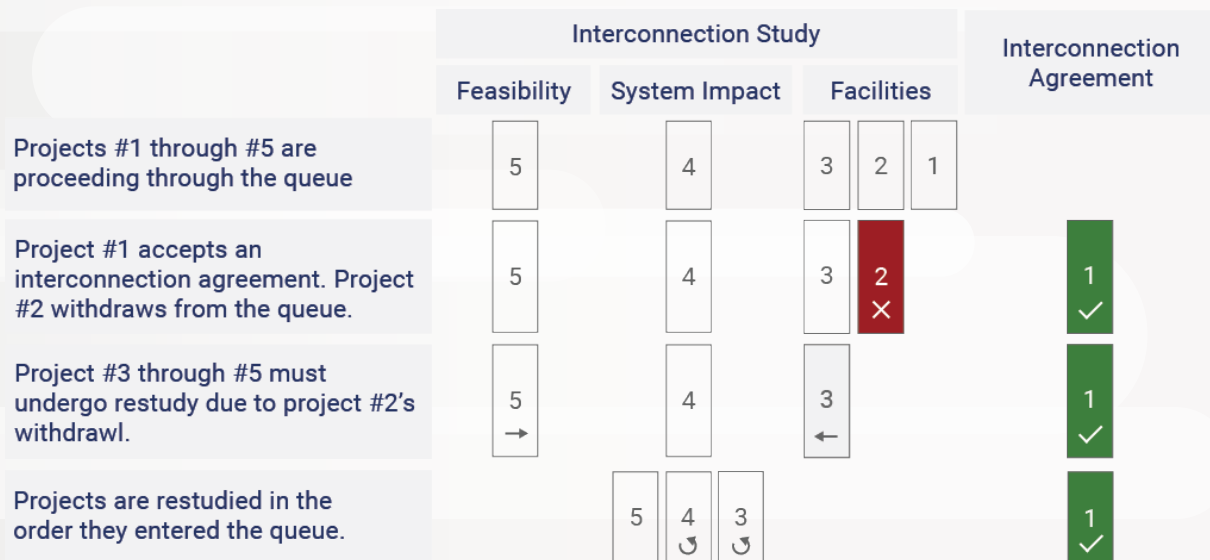


Figure 4: An example of how cascading re-studies can be triggered by withdrawals.

Additionally, this approach misses more cost-effective opportunities for transmission facilities that benefit multiple interconnection customers. Non-wire solutions for contingencies triggered by interconnection customers, such as grid-enhancing technologies or different market-based dispatch patterns that may preclude the need for or greatly reduce the cost of transmission solutions, are not required to be considered under the current procedure.

Next, the current baseline cost to apply and proceed through each study phase of the interconnection process and penalties for withdrawing are too low to disincentivize project developers from submitting multiple requests compared to the savings they may achieve with a favorable queue position or point of interconnection. With the participant funding policy in particular, an interconnection customer presented with prohibitive contingent facility costs may withdraw from the queue, potentially leading to a cascade of re-studies for customers in later queue positions. The combined impact of numerous interconnection requests, higher withdrawal rates, and subsequent

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re-studies have only further backlogged queues, creating a feedback loop of increasing wait times. The absence of timely, accurate, and publicly available data on the existing transmission system capacity and interconnection points leaves entering the queue as the only avenue for price and information discovery.

Transmission providers are expected to make a reasonable effort in processing interconnection customers and are held to no firm deadlines or penalties. There are zero expectations or accountability for affected system transmission providers: not even the standard of making a reasonable effort applies. Differences between the interconnection procedure timeline, analytical tools and assumptions, and other inputs in the study process between an interconnection customer's direct transmission provider and an affected system transmission provider can and have resulted in exacerbated waiting times and prohibitive costs. For example, an interconnection request in the Southwest Power Pool (SPP) was "assigned \$17.6 million of upgrades...with only \$3 million of that amount related to upgrades within 280 miles of the project's Point of Interconnection".²⁴ The interdependence of projects in the queue likewise extends to the affected system, making project costs and timelines vulnerable to withdrawals and re-studies.²⁵

There are also additional challenges for new technologies and business models, such as hybrid or co-located projects. Hybrid projects are gaining traction with 42% of proposed solar capacity, 8% of proposed wind, and 3% of proposed natural gas capacity, including a storage component. These rates for solar and wind are up from 2020 when 34% and 6%, respectively, were hybrid. One such example is that current models and technical studies may misrepresent or lack the ability to simulate them accurately and under realistic operating conditions.

In short, the current system incentivizes the submission and withdrawal of multiple interconnection requests, which has created turmoil and delays for all prospective resources trying to connect to the transmission system.

Recent Proposed Reforms Are an Improvement But Don't Uncork the Bottle

FERC's latest Notice of Proposed Rulemaking (NOPR), passed unanimously on a bipartisan basis, addresses many of the issues related to interconnection procedures and cost allocation. This document presents an issue or set of problems of a particular FERC jurisdictional process or rule and details the proposed set of reforms it is considering. There is a public comment period after which FERC will conduct additional analysis to determine what proposed reforms, if any, will become a final rule.

We echo the concurring statements by Commissioner Christie and Commissioner Danly that FERC should provide flexibility to entities in compliance with any potential final ruling. We recommend the Commission accept existing or new tariffs from ongoing reform efforts that achieve just and reasonable rates even if they differ from reforms in a possible final rulemaking.

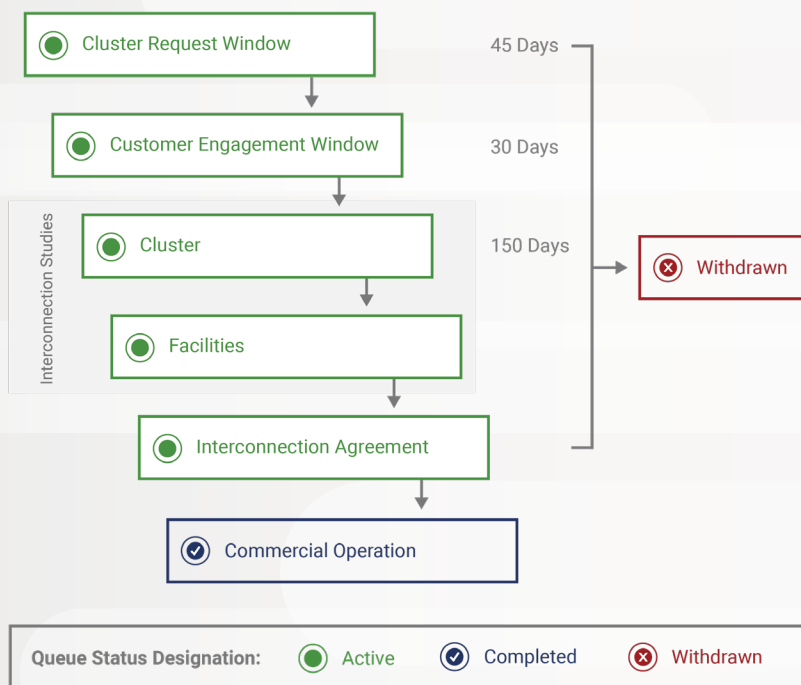
The following is a high-level summary of FERC's proposed reforms.

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Increased Information Access

There are numerous proposed reforms to increase access to information on the transmission system outside the interconnection queue process. First, transmission providers must offer Informational Interconnection Studies to prospective interconnection customers. They could submit up to 5 proposed project specifications and receive contingent facility cost estimates from the transmission provider before entering the queue. Second, the NOPR includes a proposal for Public Interconnection Information in the form of an interactive visual representation of available transmission capacity and a table of interconnection metrics. Third, the NOPR introduces a requirement for transmission providers to offer Optional Resource Solicitation Studies whereby state agencies or utilities implementing a state mandate would identify a combination of projects in the queue to be evaluated as a group. The findings of this study could help inform which combination of projects is the lowest-cost procurement option, including their interconnection costs. This study would parallel but not interfere with the interconnection process.

Proposed Interconnection Study Process



To the left is a diagram of the FERC proposed interconnection study process. The NOPR calls for transmission providers to assess interconnection customers on a first-ready, first-served cluster basis rather than on a first-come first-served basis. Queue position would be determined by commercial readiness and 100% exclusive site control demonstrations. Commercial readiness demonstrations include offtake agreements, reasonable evidence of selection in a resource plan or solicitation, being developed for a large-end use customer or utility, or a provisional interconnection agreement. The NOPR introduces much greater in-lieu payments for developers should they not meet these stricter commercial readiness and site control requirements

but wish to proceed. The use of payments will also increase the penalty amount for those projects in the event of withdrawal. Exceptions for withdrawal penalties are made in cases where a project's exit does not negatively impact other customers, or whose cost to interconnect escalates by more than 25% compared to previously received estimates.

The NOPR introduces increased study deposit and withdrawal penalty amounts that will be tiered to reflect the magnitude of influence that larger projects have on process efficiency should they withdraw. The intended impact of these proposed changes will be to ensure that projects entering the queue are commercially viable and less likely to withdraw, thus triggering re-studies that delay other

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projects. Study costs for a cluster will be allocated using two methods. The first method allocates 90% percent of the study costs based on the interconnection customers' capacity proportional to the total capacity of the cluster. The second method allocates the remaining 10% of study costs based on the number of customers in the cluster.

The costs for a cluster's contingent facilities will be determined using a Proportional Impact Method. Under this proposal, interconnection customers that cause the need for and benefit from a contingent facility would be allocated a pro-rata share of the costs using a methodology determined by the transmission provider. Additionally, the NOPR proposed that interconnection customers who benefit directly from an upgrade in service for less than 5-years would contribute to the cost initially borne entirely by an earlier cluster. This proposed reform intends to reduce the incentive to withdraw from the queue in order to free-ride off previous projects or clusters' investments.

The intended cumulative impact of the larger, tiered deposit and withdrawal amounts, commercial readiness requirements, and demonstration of site control is that only commercially viable project proposals request interconnection, the cost of progressing through the interconnection process is predictable, and re-study delays are mitigated.

Reforms for Transmission Providers

This NOPR also proposes several reforms for transmission providers. First is the institution of firm deadlines for each step of the process and a \$500 per day penalty for missing deadlines not to exceed the study cost. Secondly, the NOPR requires streamlined study processes, mandates timely communication protocols, and improves predictability concerning affected system modeling scope and timing. Specifically, projects will be assessed on a first-ready, first-served basis in the affected transmission providers' queue, and penalties will be administered to these providers when contractually established deadlines are missed. Additionally, FERC proposes that affected system transmission providers repay interconnection customers within 20 years for any contingent facility on the affected system. Finally, transmission providers would be required, upon request, to consider alternative transmission solutions as an alternative or component of contingent facilities. The transmission provider is not required to implement these technologies but would be required, under the proposal, to develop annual information reports on how these technologies were evaluated in interconnection requests.

Reforms for New Technologies and Business Models

FERC is proposing reforms that enable the co-location of resources behind a single point of interconnection with the goal of removing barriers to entry for hybrid business models and storage devices while also enabling greater flexibility for interconnection customers already in the queue. Additionally, FERC would require interconnection modeling assumptions to accurately reflect how generation and storage resources operate, thus improving reliability and facilitating non-discriminatory market access. Critically, the proposed rulemaking updates interconnection reliability standards to eliminate the existing gap between synchronous and non-synchronous resources. The NOPR would mandate the submission of accurate models and inputs demonstrating the resource's ability to continue providing power and voltage support during grid disturbances.

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Why it's still not enough

Many transmission providers have already implemented many, if not all, of these reforms and continue to have significant challenges managing their queues. Notably, MISO innovated and operationalized many of these reforms over the past decade but continues to face challenges in processing the volume of requests. Earlier this year, FERC approved a MISO plan to allow prospective projects to begin the interconnection agreement negotiations concurrently with the study process, effectively trading cost uncertainty with process expediency. This new pathway is estimated to take about 373 calendar days compared to the current process timeline of 463 days.²⁶

ClearPath submitted comments underscoring our concerns and highlighting opportunities for improvements on the proposed reforms. Overall, we find it is unlikely that these reforms alone are sufficient to enable deployment at the scale and pace necessary for net-zero.

Alternatively, FERC could consider the connect and manage approach implemented by ERCOT, where projects pay for the direct costs of interconnection, and other transmission system needs are addressed by transmission providers through planning processes. This method reduces interdependency between projects, and it is regarded²⁷ as a driving factor in ERCOT achieving one of the highest project completion rates in the country, 30%, and has had a more consistent, shorter queue wait time.²⁸ A connect and manage interconnection policy may be a more scalable solution to processing net-zero scale deployments and is worth considering in greater detail by the Commission.

Additional challenges, including siting and land use constraints covered in our report *Hawkeye Headwinds*, are already escalating.²⁹ Improved state and federal coordination around transmission permitting is a necessary next step, and any politically viable solution must accelerate transmission permitting while maintaining an affirmative role for States. From the transmission providers' perspective, workforce shortages are an emerging challenge and concern as the length of the interconnection queue grows. Conducting these studies typically requires a master's degree in electrical engineering and transmission providers are increasingly competing with developers and other firms for personnel with this skill set.³⁰ The scale and different operating characteristics of resources requesting interconnection introduce additional complexity to the study process that would benefit from innovative new tools.

While there is no silver bullet to rapidly and reliably connect resources to the grid, proactive, forward-looking transmission planning and expansion is unequivocally the biggest lever.

Transmission is the Cork in the Bottle

Transmission is the backbone of the electric grid and is essential to transport electricity, particularly over long distances. Regional transmission occurs between states or within transmission planning regions, while interregional transmission occurs between neighboring transmission planning regions.

Since the last set of reforms passed in 2011, transmission expansion has predominantly occurred via local transmission planning processes or the interconnection process. FERC finds that “across all

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the non-RTO/ISO regions, there has not yet been a single transmission facility selected in a regional transmission plan for purposes of cost allocation” and “investment in regional transmission facilities in some regions has declined.” A recent REPEAT Project report assessed the transmission expansion necessary to optimize the emission reductions possible from the recently enacted suite of funding and tax incentives for clean energy. It found that high-voltage transmission expansion will need to increase “25% over 2020 levels by 2030 and 41% by 2035” to avoid power sector emissions increasing significantly, 200-800 million tons higher in 2030, as demand growth is met by fossil fuel plants.³¹

The unprecedented scale and pace of interconnecting clean energy to stay on track for net-zero and commensurate development of the transmission system necessitate procedural reforms that integrate and streamline these processes. Earlier this year, FERC issued a bipartisan NOPR on regional transmission planning and cost allocation.³² The regional transmission proposals address many of the procedural challenges and barriers to regional transmission expansion: notably, scenario-based planning on a longer time horizon, identification of geographic zones with the “potential for development of large amounts of new generation”, greater transparency and coordination with local transmission, and elevation of the states in siting and cost allocation discussions.

Notably, the regional transmission NOPR proposed reforms to better integrate the interconnection and transmission planning process by considering contingent facilities that have been identified in at least 2 interconnection cycles over the previous 5-years and have not been constructed in the regional transmission plan for the purpose of cost allocation.³³ It is unclear if this proposal will be effective when combined with the interconnection reforms outlined above. For example, when developers must meet heightened commercial readiness and site control requirements along with the increased deposit and penalty amounts, the probability that a contingent facility will be identified but not developed multiple times seems low.

Both the interconnection and regional transmission NOPRs require the consideration of new grid enhancing technologies (GETs) that may be more efficient or cost effective solutions for transmission facilities. GETs encompass different types of technologies, such as dynamic line rating or advanced power flow control devices, that can increase the capacity, efficiency, or reliability of new or existing transmission facilities. Significantly, these technologies may expedite the near-term deployment of new resources because they can be quicker to deploy than building new transmission lines or making extensive network upgrades and can optimize operations.³⁴

Ultimately, we need to make it easier to build transmission and move beyond a project-by-project interconnection process. The proposal in the regional transmission planning NOPR for transmission providers to identify geographic zones with the “potential for development of large amounts of new generation” emulates the successful programs executed by a few grid operators – the Electricity Reliability Council of Texas (ERCOT), MISO, and SPP – where proactively planned transmission lines facilitated the integration of renewable energy without creating stranded assets.³⁵

Another proactive approach to transmission planning that could eliminate interconnection delays, identify cost-effective reliability and congestion solutions, and allocate costs fairly is the Joint Targeted

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Interconnection Queue (JTIQ) effort by SPP and MISO. This process identified projects along the SPP-MISO seam that would address system needs and unlock capacity for anticipated interconnection customers. This effort can potentially reduce the time and cost uncertainties of affected system studies. Whether this approach is successfully accepted by FERC and executed in practice remains to be seen, but it could serve as a more time and cost-efficient substitute for affected system studies.³⁶

Recommendations to Release the Pressure

Decarbonizing the power sector at the pace necessary to mitigate significant climate impacts hinges on our ability to connect new low-emission technologies and cost-effectively transport their electricity to load. The existing interconnection and transmission expansion procedures will lead us woefully short of the unprecedented levels of deployment necessary to reach net-zero and could lead to increasing emissions and decreased grid reliability and affordability.

There are several Federal actions both at FERC and beyond that can build on the proposed interconnection reforms to enable an electricity system that is capable of a much higher throughput.

Federal Energy Regulatory Commission

- Consider how to better integrate regional and interregional transmission planning with interconnection processes.
 - Focus on the ways to optimize the integration, where necessary, of interconnection and regional transmission planning proposed reforms in the two recent Notices of Proposed Rulemakings.
 - Evaluate alternative approaches to interconnection that more readily scale with net-zero deployment levels when combined with proactive transmission planning, such as the connect and manage approach implemented by ERCOT.

Department of Energy (DOE)

- Implement workforce development funding for interconnection.
 - Provide scholarships for electrical engineering masters degrees³⁷ contingent on graduates remaining employed at a transmission provider or regional grid operators for a minimum set of years.
- Maximize synergies and impact of DOE grid initiatives, including:
 - Judicious use of funds available through the Transmission Facilitation Program and Transmission Infrastructure Program that prioritizes reliability, resilience, and decarbonization in the implementation and selection of projects.³⁸
 - Identifying and updating National Interest Electric Transmission Corridors (NIETCs) through national transmission studies to enable FERC, with its newly clarified authority, to issue construction permits for transmission facilities within NIETCs.
 - Developing cutting-edge tools and providing technical assistance to states, other agencies, or grid operators to facilitate their capabilities. For example, the newly launched interconnection Innovation e-Xchange is a stakeholder-driven initiative to increase knowledge sharing and innovation to solve interconnection challenges.³⁹

All Queued Up and Nowhere to Go

Pre-siting & Permitting Reform

- Strengthen coordination between DOE, FERC, and DOI, particularly with permitting, to facilitate expeditious reviews and construction of transmission and generation projects.
- Proactively pre-site areas on federal land for clean energy and transmission projects along identified NIETCs.
- Expedite Federal permitting within rights of way under the Department of Transportation.
- Expedite Federal permitting for new generation or storage resources at retiring large electricity generator's point of interconnection.

At this point, achieving net-zero emissions in the U.S. by 2050 is **impossible** without interconnection and transmission improvements. An average completion rate of 23% and queue wait time of 3.7 years makes meeting any target for a reliable and affordable clean energy system infeasible. Similarly, transmission development must accelerate beyond the recent rate of ~1% per year to prevent demand-side growth spurred by federal incentives from increasing emissions.

Thankfully, there is growing bipartisan recognition of these challenges. A combination of thoughtful interconnection process improvements, permitting reforms, technological innovation, and workforce development will help avoid clean energy deployment from hitting a wall.

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