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Americans for a
Clean Energy Grid

DISCONNECTED: THE NEED FOR A NEW GENERATOR INTERCONNECTION POLICY

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About Americans for a Clean Energy Grid

Americans for a Clean Energy Grid (ACEG) is the only non-profit broad-based public interest advocacy coalition focused on the need to expand, integrate, and modernize the North American high voltage grid.

Expanded high voltage transmission will make America's electric grid more affordable, reliable, and sustainable and allow America to tap all economic energy resources, overcome system management challenges, and create thousands of well-compensated jobs. But an insular, outdated and often short-sighted regional transmission planning and permitting system stands in the way of achieving those goals.

ACEG brings together the diverse support for an expanded and modernized grid from business, labor, consumer and environmental groups, and other transmission supporters to educate policymakers and key opinion leaders to support policy which recognizes the benefits of a robust transmission grid.

About the Macro Grid Initiative

The Macro Grid Initiative is a joint effort of the American Council on Renewable Energy and Americans for a Clean Energy Grid to promote investment in a 21st century transmission infrastructure that enhances reliability, improves efficiency and delivers more low-cost clean energy. The Initiative works closely with the American Wind Energy Association, the Solar Energy Industries Association, the Advanced Power Alliance and the Clean Grid Alliance to advance our shared goals.



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I. Executive Summary

America's system for planning and paying for the nation's transmission grid is causing a massive backlog and delay in the construction of new power projects. While locally produced electric power is gaining in popularity, most of the lowest cost new power production comes from projects which are located in rural areas and, thus, depend on new electricity lines to deliver power to the urban and suburban areas which use most of the nation's power. Project developers must apply for interconnection to the transmission network, and until the network capacity is expanded to accommodate the resources, the projects must wait in an "interconnection queue." At the end of 2019, 734 gigawatts of proposed generation were waiting in interconnection queues nationwide.¹

This massive backlog has multiple negative impacts on the nation. First, it needlessly increases electricity costs for America's homes and businesses in two ways: (1) it slows or prevents the adoption of new power sources which are cheaper than existing power generation; and (2) it also significantly increases the costs of each new power source. Americans for a Clean Energy Grid's (ACEG) recent study demonstrates that a comprehensive approach to building transmission to connect remote power resources to electricity load centers in the Eastern half of the U.S. can cut consumers electric bills by \$100 billion and decrease the average electric bill rate by more than one-third, from over 9 cents/kWh today to around 6 cents/kWh by 2050,

¹ Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

Key Findings

- » The current system for planning and paying for expansion of the transmission grid is so unworkable and inefficient it is creating a huge backlog of unbuilt energy projects. At the end of 2019, 734 gigawatts of proposed generation were waiting in interconnection queues nationwide.
- » This backlog is needlessly increasing electricity costs for consumers by delaying the construction of new projects which are cheaper than existing electricity production.
- » Because most of these projects are located in remote rural areas, this backlog is harming rural economic development and job creation.
- » Almost 90 percent of the backlog is for wind, solar, and storage projects. The backlog may delay or prevent achievement of commitments that states, utilities, and Fortune 500 companies have made to scale up their renewable energy use or reduce their pollution.
- » The risk from the uncertainty of the interconnection process significantly increases the cost of capital for generation developers, which increases the cost of energy for customers.
- » Although Regional Transmission Organizations (RTOs) and the Federal Energy Regulatory Commission (FERC) have undertaken worthwhile attempts to alleviate interconnection backlogs, the interconnection queues remain costly, lengthy, and unpredictable.
- » The current "participant funding" policy that places nearly all costs of shared large network upgrades on the interconnection customer violates FERC's "beneficiary pays" principle and is therefore no longer a "just and reasonable" policy and violates the Federal Power Act.

Key Recommendations

- » FERC should discontinue the policy of participant funding for new generation. Shared network upgrades resulting from generation interconnection requests provide economic and reliability benefits to loads and reduce congestion to improve grid efficiencies and operational flexibility, and therefore should not be fully assigned to interconnection generators.
- » FERC and planning authorities should expand and improve regional and inter-regional transmission planning processes to be pro-active, incorporating future generation additions and retirements and the multiple benefits, and spread costs to all beneficiaries.

saving a typical household more than \$300 per year.²

Second, because the lowest cost proposed power projects are often located in rural areas, this backlog is blocking rural economic development and job creation. In addition, rural power projects expand the tax base of local communities and typically generate lease payments or other revenue for farmers and other landowners. New transmission in the Eastern half of the U.S. alone will unleash up to \$7.8 trillion in investment in rural America and create more than 6 million net new domestic jobs.³

Third, almost 90 percent of the backlog is for wind and solar projects, thus blocking the resources which dominate new electricity production, reflecting the changing resource mix in the power sector and America's abundance of high-quality renewable resource areas where the sun shines bright and the wind blows strong.⁴ The U.S. Energy Information Administration (EIA) projects wind and solar will account for 75 percent of new electricity generation in 2020.⁵ Many states, utilities, Fortune 500 companies and other institutions have adopted large commitments or requirements to scale up their renewable energy use or reduce their carbon pollution and this backlog may delay or impede achievement of these commitments or requirements. In addition, delays in developing these projects unnecessarily exposes Americans, especially those in environmental justice communities, to the harmful impacts of smog, and nitrogen oxide, sulfur dioxide, fine particulate and carbon dioxide pollution.

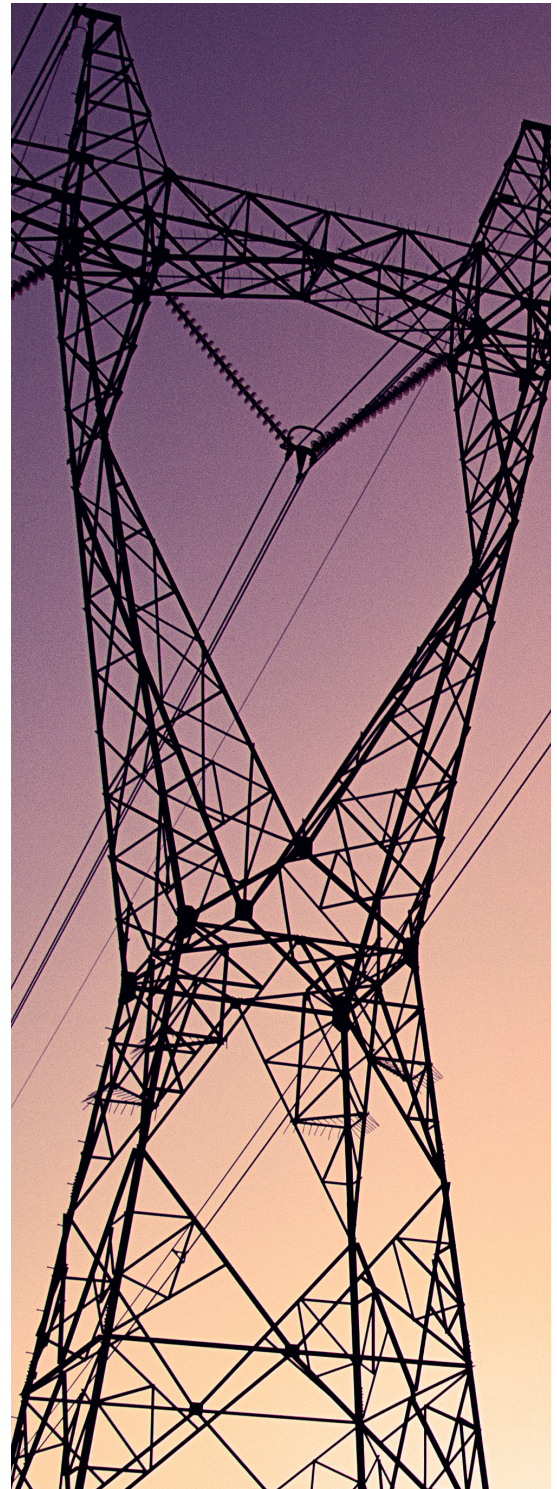
Policies governing the interconnection of generators to the grid network stand in the way of accessing these remote resources. Interconnection policies and procedures governing transmission engineering studies, queuing, and allocating transmission upgrade costs are set by the Federal Energy Regulatory Commission (FERC) and implemented in

² Christopher T.M. Clack et al., *Consumer, Employment, and Environmental Benefits of Electricity Transmission Expansion in the Eastern U.S.*, October 2020.

³ *Id.*

⁴ Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

⁵ U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.



detail by all of the hundreds of transmission providers around the country including the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).⁶

Although FERC and the RTOs have undertaken worthwhile reforms to alleviate interconnection backlogs, the interconnection queues are costly, lengthy, and unpredictable. Power project developers are uncertain if their project will be approved and this risk significantly increases the cost of capital for generation developers, which increases the cost of energy for customers.

The current process also places nearly all costs of network upgrades on the energy project developer, even though many others will benefit from the construction of the project. Until a few years ago, these interconnection charges for new renewable resources would comprise under 10 percent of the total project cost for most projects. In recent years - due to the lack of sufficient large-scale transmission build - these costs have dramatically risen and interconnection charges now can comprise as much as 50 to 100 percent of the project costs. The system has reached a breaking point recently as spare transmission has been used up. Presently in most regions, new network capacity is needed for almost all of the projects in the queues.

Participant funding for new grid connections is no longer a “just and reasonable” policy and violates FERC’s “beneficiary pays” principle and the Federal Power Act. Relying on the interconnection process to identify needed transmission leads to a piecemeal approach and inefficiently small upgrades, raising costs to consumers. The incremental reforms at the RTO-level over the past decade have only served to treat symptoms of this fundamental issue – the lack of alignment between regional planning processes and the interconnection process.

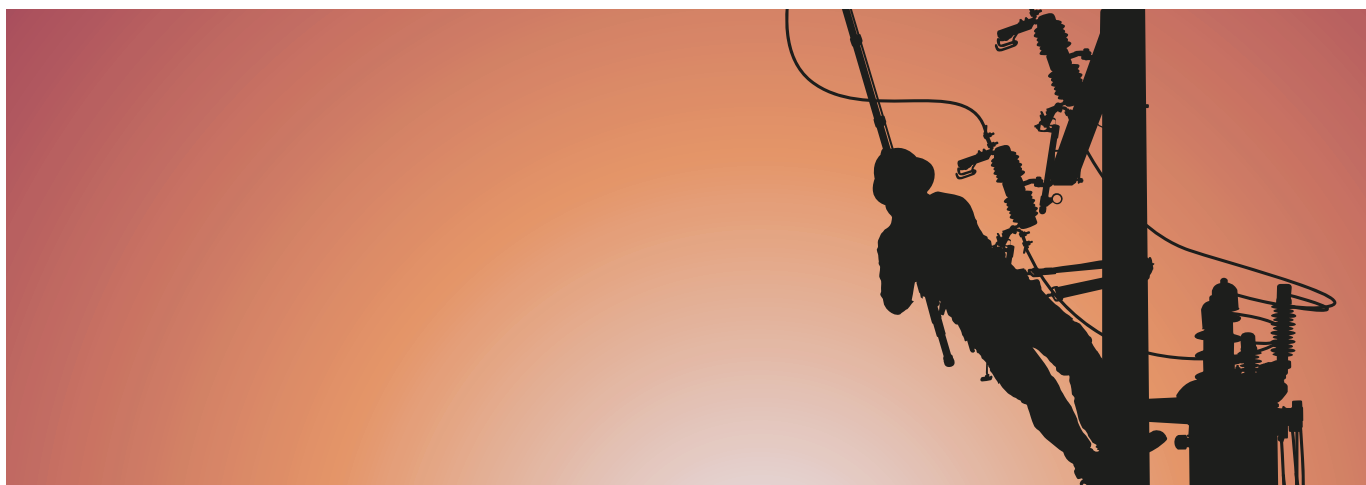
There is a better way. RTOs could conduct comprehensive transmission planning which would identify the transmission lines to connect many new energy projects to the grid and deliver the greatest benefits for consumers. It is time for FERC and RTOs to undertake a fundamental re-thinking of interconnection and transmission planning policy based on different circumstances than those that existed when these policies were developed. Full participant funding should no longer be allowed in RTO or non-RTO areas.

More broadly, FERC and RTOs should pursue planning reforms. Consumers would benefit from more efficient transmission at a scale that brings down the total delivered cost, rather than continuing the current cycle of incremental transmission built in the project-by-project or generator-only cost assignment regime. That shift will not happen in the current interconnection process. Instead, FERC should fundamentally reform the regional and inter-regional transmission planning process to require broader pro-active and multi-purpose transmission planning.

This paper is structured as follows:

- Section II explains the origin of current interconnection policy;
- Section III describes implications of a different set of resources than those for which the policies were designed;
- Section IV provides evidence that the current policy no longer works for the current mix;
- Section V describes incremental solutions to those problems;
- Section VI argues that the real solution must involve broader transmission planning reform; and
- Section VII concludes.

⁶ Throughout this paper, we refer to RTOs and ISOs together simply as “RTOs.”



II. Interconnection Queue Policy Inherited from a Bygone Era

Generator interconnection policy was established two decades ago when almost all new interconnecting generators were natural gas-fired. Gas generators can interconnect with transmission systems in a relatively wide variety of locations, allowing them to avoid transmission constraints. As a result, transmission planning is less important with gas generation, as locational wholesale market prices and network upgrade costs assigned to interconnecting generators are able to direct gas generation investment to economically efficient locations.

Our current interconnection policies are an increasingly obsolete vestige of that era. FERC Order No. 2003, issued in the year 2003, standardized Large Generator Interconnection Procedures (LGIPs) and Large Generator Interconnection Agreements (LGIAs). As part of the Order, FERC determined that RTOs may propose that interconnecting generators be solely responsible for paying for Generation Interconnection (GI) network upgrades—a cost allocation policy referred to as “participant funding.”⁷ The Commission reasoned that “...under the right circumstances, a well-designed and independently administered participant funding policy for Network Upgrades offers the potential to provide more efficient price signals and a more equitable allocation of costs than [a] crediting approach.”⁸ The policy also included a serial approach to interconnection, wherein each generator was reviewed independently for its own impacts on the network in the order they enter the interconnection queue. The Commission’s participant funding policy applied only to RTOs and not to utilities non-RTO areas.

That policy of a generator-by-generator transmission planning process and individual assignment of network upgrade costs worked reasonably well for the gas generation additions of the early 2000s. A whopping 191,745 megawatts (MW) of natural gas capacity was added between 2000 and 2005,

⁷ *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 28, July 24, 2003. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 715, July 21, 2011 (defining “participant funding”).

⁸ *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 695, July 24, 2003.

compared to 23,434 MW for the entire decade from 2010-2019.⁹ After that gas generation boom, the resource mix of new interconnecting generators changed as interest in renewable energy grew among states and customers and the costs of utility-scale wind and solar projects continued to decline. Utility-scale wind and solar projects have dominated generating capacity additions over the last decade, with around 100,000 MW added, and they are expected to account for an even larger share of capacity additions going forward.

The transmission policy embodied in FERC Order 2003 that provided efficient incentives for the siting of gas generation has proven inefficient and unworkable for today's resource mix. Wind, and to a lesser extent solar generation, is heavily location-constrained, unlike gas generation. Wind turbines located near the best wind resources are several times more productive than wind turbines at a typical site selected at random, while the best solar resource sites are about twice as productive as less optimal sites, corresponding to a proportional impact on the cost of energy from renewable energy resources. Wind and solar are also scalable and benefit from economies of scale, so most projects are large and built in remote areas where large amounts of land are available at low cost.¹⁰ As a result, these renewable projects often require larger transmission upgrades to serve load.

As wind capacity grew in the late 2000s, interconnection queues became overloaded in certain areas. When transmission capacity extending to good wind resource areas reached capacity, large network upgrade costs would be assigned to the next wind projects entering the queue. When these wind project owners saw the hefty price tag and the difference between what they were paying compared to their competitors that might have been just ahead of them or behind them in the queue, they would often drop out of the queue. 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. Project developers, knowing there was a chance of getting lucky with a lower network upgrade cost assignment, had an incentive to enter multiple project proposals and multiple locations. Thus, many projects would enter queues, and many projects would cancel, leading to a cycle of continuous churn. RTOs are required to study all projects, leading to lengthy workloads and inevitable delays.

Over the years FERC and RTOs have noticed the problem and attempted to fix it with process changes. In 2008, FERC held a technical conference to discuss interconnection queue-related issues that arose after Order No. 2003, and issued an Order directing RTOs to develop solutions to address queue delays and backlogs.¹¹ RTOs held numerous interconnection queue reform stakeholder processes, many resulting in FERC filings and tariff changes. Some of these incremental reforms, as described in more detail below, helped to reduce the churn and the quantities of projects backlogged in the queue. MISO stakeholder fora such as the Interconnection Process Task Force and the Planning Advisory Committee, for example, developed a series of queue reforms between 2008 and 2012 to address queue delays and project cancellations.¹² In 2016, MISO proposed tariff revisions to minimize restudies and introduced new milestones to improve project readiness, among other revisions to improve process efficiency.¹³ MISO later built upon these reforms in 2018 to reduce cancellations and logjams by eliminating fully refundable milestone payments and requiring site control demonstration.¹⁴

SPP, like MISO, experienced high renewable energy interconnection interest in the late 2000s and reformed its interconnection process to transition to an approach that discouraged speculative projects

⁹ Headwaters Economics, *U.S. Generation Capacity, 1950-2030*, Updated April 2020.

¹⁰ American Wind Energy Association, *Grid Vision: The Electric Highway to a 21st Century Economy*, at 30-42, May 2019.

¹¹ *Interconnection Queuing Practices*, 122 FERC ¶ 61,252, March 20, 2008.

¹² MISO, *Filing of Revisions to the Open Access Transmission, Energy and Operating Reserve Markets Tariff to Reform MISO's Generator Interconnection Procedures*, at 5-6, December 31, 2015.

¹³ *Id.* at 3-4.

¹⁴ Jasmin Melvin, *FERC Clears MISO Interconnection Reforms Targeting Recent Influx in Speculative Projects*, December 4, 2019.

from proceeding through the queue. These reforms included a “first-ready, first served” policy and a greater use of cluster interconnection studies, among other measures.¹⁵ In 2013, SPP further increased milestone requirements and required generators to post a financial milestone upon execution of a Generator Interconnection Agreement (GIA),¹⁶ and in 2019 further refined its interconnection process to include a three-stage study process with financial deposits required at each stage.¹⁷

As renewable energy expanded into the Mid-Atlantic states in the 2010s, PJM began facing the same challenges. In 2012, FERC accepted PJM tariff modifications selected by the PJM Interconnection Process Senior Task Force, which among other changes, extended the length of the queue cluster to avoid queue study overlap and associated restudies.¹⁸ The reforms also included an alternate queue for the hundreds of projects under 20 MW that were observed to drop out at higher rates and trigger constant restudies.

California proceeded down a similar policy evolution as MISO, SPP, and PJM. After transitioning to a cluster approach in 2008 and creating requirements to demonstrate project viability,¹⁹ CAISO filed tariff revisions in 2010 to combine its small and large generator interconnection procedures in an attempt to streamline the processes.²⁰ Citing an increase in renewable generator interconnection requests due to renewable portfolio standards and related dropouts, CAISO later filed additional revisions in 2012 to integrate the transmission planning process and generation interconnection procedures.²¹ In 2013, CAISO launched its first Interconnection Process Enhancement initiative, a stakeholder process to improve interconnection procedures.²²

Despite these various incremental reforms at the RTO level, however, the fundamental problem driving the queue backlog, a reliance on participant funding and individual generators to build a large share of needed transmission upgrades, remains in place. The share of location-constrained relative to location-flexible generation continued rising through the 2010s, and increasingly affected solar generation as well as wind. Multiple RTOs continue to tinker with reforms to generator interconnection queue processes.²³

FERC also acted again in 2016 by holding another technical conference²⁴ on generator interconnection issues partially in response to a 2015 request of formal rulemaking from the American Wind Energy Association to revise FERC’s proforma LGIP and LGIAs.²⁵ The Commission later issued Order No. 845 in 2018,²⁶ which addressed queue interconnection procedure issues by revising FERC’s pro forma LGIP and LGIA’s to implement ten specific reforms. The Order was followed up by Order No. 845-A in 2019,²⁷ which left Order No. 845’s major reforms intact, but amended the LGIP and LGIA in an attempt to further improve interconnection processes.

¹⁵ *Southwest Power Pool, Inc.*, 167 FERC ¶ 61,275, at P 4, June 28, 2019.

¹⁶ *Id.* at P 5.

¹⁷ *Id.* at P 11-13.

¹⁸ *PJM Interconnection L.L.C. Filing Via eTariff*, at 5, February 29, 2012.

¹⁹ K. Porter, S. Fink, C. Mudd, and J. DeCesaro, *Generation Interconnection Policies and Wind Power: A Discussion of Issues, Problems, and Potential Solutions*, at 28, January 2009.

²⁰ *California Independent System Operator Corporation*, 140 FERC ¶ 61,070, at P 3, July 24, 2012.

²¹ *Id.*

²² *Reform of Generator Interconnection Procedures and Agreements*, Docket No. RM17-8, at 4, April 13, 2017.

²³ MISO, for example, recently created the Coordinated Planning Process Task Team in November of 2019 to examine how MISO can better coordinate the separate studies underlying the generator interconnection process and the MISO transmission expansion plan. See Amanda Durish Cook, *MISO Floats Ideas on MTEP, Interconnection Coupling*, May 17, 2020. PJM is in the midst of holding interconnection process workshops to explore potential queue reforms that would allow for more renewable and storage resources to interconnect. See PJM, *Update: Interconnection Process Workshop Dates Announced*, October 6, 2020.

²⁴ *Transcript of FERC Technical Conference on Generator Interconnection Agreements and Procedures and the American Wind Energy Association*, Docket No. RM16-12, May 13, 2016.

²⁵ *Petition for Rulemaking of the American Wind Energy Association to Revise Generator Interconnection Rules and Procedures*, Docket No. RM15-21-000, June 19, 2015.

²⁶ *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845, 163 FERC ¶ 61,043, April 19, 2018.

²⁷ *Reform of Generator Interconnection Procedures and Agreements*, Order No. 845-A, 166 FERC ¶ 61,137, February 21, 2019.



III. Implications of a Different Resource Mix

Interconnection policy must work for the resource being interconnected, and the resource mix is clearly changing.²⁸ Regardless of climate or clean energy policies, renewable energy growth is nearly certain because the costs of renewables have fallen so much to make them competitive with any other resource. Wind and solar energy costs have fallen 70 and 89 percent, respectively, in the last ten years, from 2009 through 2019.²⁹ As a result of falling costs, consumer preferences, and public policies, wind and solar resources now make up the majority of resources in interconnection queues across the country.³⁰ There were 734 GW of proposed generators waiting in interconnection queues nationwide at the end of 2019, almost 90 percent of which were renewable and storage resources.³¹ In 2019 alone, 168 GW of solar and 64 GW of wind projects entered interconnection queues, as shown in figure 1. The U.S. EIA forecasts that wind and solar will make up over 75 percent of new capacity additions in 2020.³²

When an increasing amount of location-constrained generation applies for interconnection in the same area, the grid begins to require not only “driveway” type transmission facilities, but also bigger roads and highways. Much like a new community of homes requires a webwork of larger roads to connect to neighboring towns, a more regional network is needed for the U.S. power system. What we are observing is that interconnection studies for individual generators (or groups of generators) are increasingly identifying costly regional upgrades. This is a predictable dynamic.

The future resource mix is made up increasingly of wind and solar energy, which are location-constrained, so it is quite predictable that larger regional network upgrades will be identified in the interconnection processes. Unfortunately, large system upgrades are not efficiently planned or paid for by the interconnection process, which relies on generator-by-generator assessments and participant

²⁸ Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the 2020 *Wind Energy Technology Data Update* accompanying the slide deck.

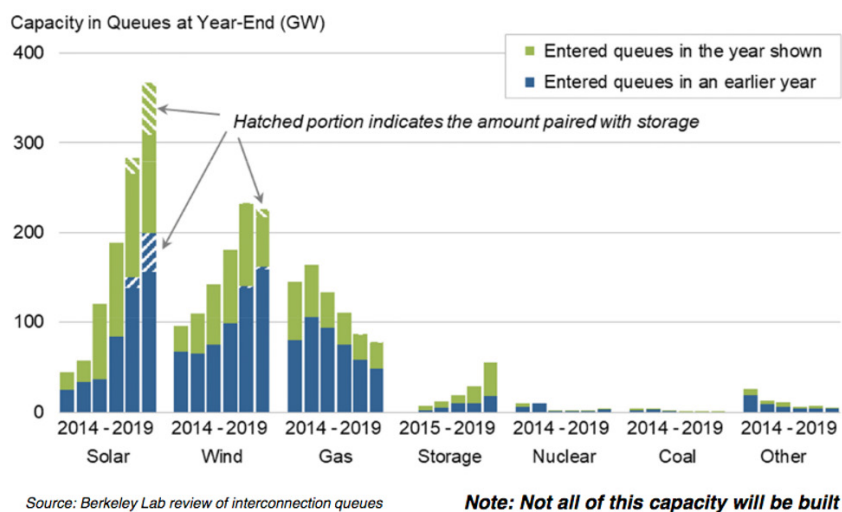
²⁹ Lazard, *Lazard's Levelized Cost of Energy Analysis - Version 13.0*, a 8, November 2019.

³⁰ Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 18, August 2020. See also underlying data in the 2020 *Wind Energy Technology Data Update* accompanying the slide deck.

³¹ *Id.*

³² U.S. Energy Information Administration, *New Electric Generating Capacity in 2020 Will Come Primarily From Wind and Solar*, January 14, 2020.

Figure 1: Capacity in Queues at Year-End by Resource Type



funding for network upgrades. Interconnection costs are governed by Order No. 2003, which established the “at or beyond rule,” pursuant to which the costs of facilities and equipment that lie between the generation source and the point of interconnection with the transmission network are borne by the incoming generator.³³ While Order No. 2003 set a default rule that transmission owners would cover the cost of “network upgrades,” (equipment “at or beyond” the point of interconnection), it gave RTOs “flexibility to customize . . . interconnection procedures and agreements to meet regional needs.”³⁴ Some RTOs have since adopted methodologies that place the lion’s share of network costs on the interconnecting generator.³⁵

The current interconnection process simply does not work well when there is not adequate regional transmission capacity or a functioning mechanism to plan and pay for regional transmission. Without transmission planning reform that links the interconnection and regional transmission planning processes and eliminates the use of participant funding for significant system upgrades in the interconnection process, interconnection processes will become mired in ever-longer delays. This problem could potentially be addressed by broader transmission planning reform to support holistic, proactive planning processes in conjunction with accompanying narrow Order No. 2003 reform eliminating participant funding.

³³ See *Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).

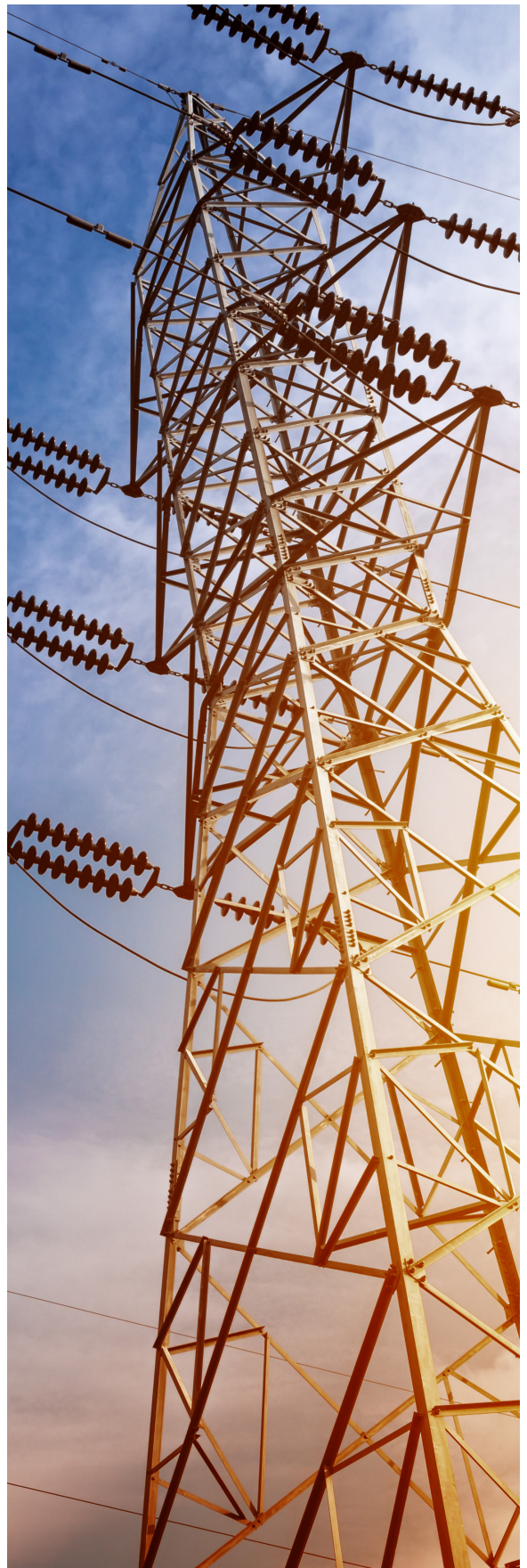
³⁴ *Id.*

³⁵ For example, MISO adopted a methodology allocating 90 percent of even network upgrades above 345 kV to generation owners, and requiring generation owners to pay 100 percent of such costs for lines below 345 kV. See *Ameren Services Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018).

The current process also misses opportunities to design new infrastructure in a more cost-effective fashion and of sufficient scale that maximizes all benefits of transmission, including reliability and economic benefits, and accommodates all likely new generation rather than just the particular generator(s) supporting the upgrades. Given the broad benefits of large-scale regional transmission, it is a violation of FERC's "beneficiary pays" principle to place all the costs of large network upgrades on the interconnection customer. It is clear that the large upgrades being identified and assigned to generators in interconnection studies would provide benefits to users across the network, even if those may be difficult to quantify with certainty. FERC Commissioner LaFluer noted the challenges with the siloed study processes when she commented "...where does the interconnection process leave off and the transmission planning process start?"³⁶

Transmission expansion planning for generator interconnections based on generator-by-generator assessments will not result in optimal plans as the resource mix continues to change. Moving to studying clusters of generators simultaneously, as some areas have done, is a step in the right direction. However, current cluster approaches are still based only on what is in the current queue rather than well-known information about what generation is coming and where it is likely to be, and still does not account for the economic and reliability benefits of the transmission expansion.

³⁶ See transcript of FERC technical conference in the matter of *Review of Generator Interconnection Agreements and Procedures*, Docket No. RM16-12, at 47, May 13, 2020.





IV. Evidence of a Broken Interconnection Policy

a) Upgrade costs assigned to customers are high

Analysis by Lawrence Berkeley National Laboratory, shown in tables 1 and 2 below, indicates that the costs to integrate new resources, not just renewable projects, have reached levels that are unreasonably high for a developer to proceed in MISO and PJM. As expected, the costs for integrating new resources in MISO are rising substantially relative to previous years, indicating that the large-scale network has reached its capacity and needs to expand to connect more generation. In other words, much more than “driveway” type facilities are needed; larger roads and highways are required to alleviate the traffic. Table 1³⁷ below shows that historically, interconnecting wind projects have incurred interconnection costs of \$0.85 per megawatt hour (MWh) or \$66 per kilowatt (kW). However, newly proposed wind projects now face interconnection costs that are nearly five times higher, at \$4.05/MWh or \$317/kW. For reference, this is about 23 percent of the capital cost of building a wind project.

Table 1: MISO Interconnection Costs for Selected Utility-Scale Projects (as of 2018)

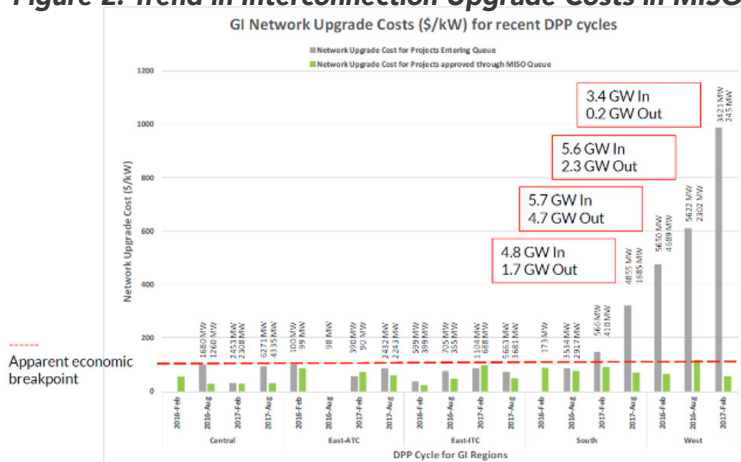
| Generator Type | Projects | Costs (\$2018 B) | | | Unit Cost (\$/kW) | | Levelized (\$/MWh) | | |
|----------------|----------|------------------|--------|---------|----------------------|-------------------|--------------------|----------------------|-------------------|
| | | | MW | Overall | Constructed Projects | Proposed Projects | Overall | Constructed Projects | Proposed Projects |
| Natural Gas | 55 | \$0.55 | 14,642 | \$38 | \$31 | \$55 | \$0.34 | \$0.28 | \$0.50 |
| Wind | 161 | \$4.51 | 23,232 | \$194 | \$66 | \$317 | \$2.48 | \$0.85 | \$4.05 |
| Solar | 33 | \$0.18 | 3,277 | \$56 | \$70 | \$53 | \$1.56 | \$1.95 | \$1.48 |
| Coal | 19 | \$0.01 | 2,991 | \$4 | \$4 | NA | \$0.03 | \$0.03 | NA |
| Hydro | 13 | \$0.06 | 4,234 | \$13 | \$13 | NA | \$0.18 | \$0.18 | NA |

³⁷ Will Gorman, Andrew Mills, and Ryan Wiser, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*, at 10, October 2019.

New solar projects in MISO South have much higher upgrade costs. The most recent 2019 system impact study for solar projects in MISO South estimated upgrade costs to total \$307/kW, with upgrade costs for individual interconnection requests as high as \$677/kW.³⁸

The rapidly increasing cost of interconnection in recent years shows that the breaking point has been reached. MISO, for example, has reported that "...interconnection studies for new generation resources in MISO's West sub-region have indicated the need for network upgrades exceeding \$3 billion to accommodate the initial queue volume, and a similar trend is expected to occur in other areas with high wind and solar potential, including MISO's Central and South sub-regions."³⁹ Figure 2⁴⁰ below illustrates the large increase in assigned network upgrade costs to generators in MISO West, from approximately \$300/kW in 2016 to nearly \$1,000/kW in 2017. The costs to build proposed wind projects will likely result in developers abandoning those resources as project integration costs exceed \$100/kW.

Figure 2: Trend in Interconnection Upgrade Costs in MISO



The same trend of rising network upgrade cost assignments is occurring in PJM. Historically, the levelized costs for constructed wind and solar projects were \$0.25/MWh and \$1.72/MWh, respectively, or \$19.07/kW and \$61.83/kW, respectively. As shown in Table 2,⁴¹ upgrade costs for newly proposed wind and solar projects, however, have now risen to \$0.69/MWh and \$3.66/MWh, respectively, or \$54/kW and \$131.90/kW, respectively – more than a 100 percent increase.

Table 2: PJM Interconnection Costs for Selected Utility-Scale Projects (as of 2019)

| Generator Type | Projects | Unit Cost (\$/kW) | | | Levelized (\$/MWh) | | |
|----------------|----------|-------------------|--------|----------|----------------------|-------------------|---------|
| | | Costs (\$2018 B) | MW | Overall | Constructed Projects | Proposed Projects | Overall |
| Natural Gas | 98 | \$1.43 | 38,733 | \$36.92 | \$18.40 | \$76.63 | \$0.34 |
| Wind | 72 | \$0.25 | 10,859 | \$22.73 | \$19.07 | \$54.10 | \$0.30 |
| Solar | 134 | \$1.17 | 10,057 | \$116.17 | \$61.83 | \$131.90 | \$3.22 |
| Coal | 4 | \$0.05 | 1,303 | \$36.26 | \$36.26 | NA | \$0.25 |
| Nuclear | 2 | \$0.03 | 1,674 | \$19.63 | \$19.63 | NA | \$0.12 |

³⁸ MISO, *Final MISO DPP 2019 Cycle 1 South Area Study Phase I Report*, at 8-15, July 16, 2020.

³⁹ MISO, *MISO 2020 Interconnection Queue Outlook*, at 9, May 2020.

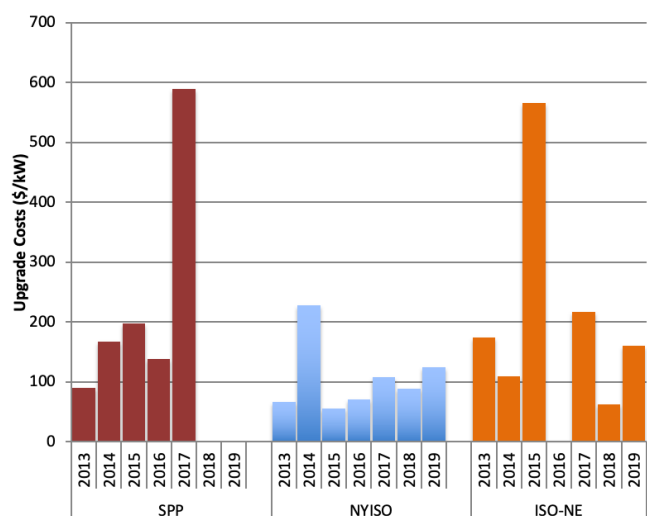
⁴⁰ ITC, *MISO Generation Queue and Renewable Generation: Update to the Advisory Committee*, at 5, May 20, 2020.

⁴¹ Will Gorman, Andrew Mills, and Ryan Wisser, *Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy*, at 12, October 2019.

In 2019, one 120 MW solar plus storage project in southern Virginia was informed it could be required to pay as much as \$1.5 billion, or \$12,086/kW, in system upgrades in order to connect to the PJM grid.⁴² Among the many upgrade costs associated with the GI request includes the demolition and rebuilding of a handful of 500kV lines.⁴³ The construction of large transmission lines required by some interconnection studies which leads to such high network upgrade costs are not isolated incidents. A number of offshore wind projects in PJM, for example, are expected to build long, 500kV lines that are clearly network elements that benefit the entire region and should be planned and paid for through the regional planning process.⁴⁴

This trend of rising network upgrade costs is happening across RTOs as the ratio of location-constrained generation rises and the existing network in the renewable resource areas becomes constrained. The typical increase in costs over time associated with GI studies, as shown in Figure 3⁴⁵ below, are indicative that the assigned network upgrades are high enough that most projects will not proceed.

Figure 3: Trend in Generator Interconnection Network Upgrade Costs in SPP, NYISO, and ISO-NE (\$/kW)



In SPP, GI-assigned network upgrade costs from the 2013 interconnection queue were roughly \$89/kW while the most recent 2017 study costs approached \$600/kW. Put differently, network upgrade costs increase from composing around 8 percent of the capital cost of wind generation, to over 43 percent.⁴⁶ The most recent 2017 SPP study upgrade costs included massive 765kV lines up to 165 miles long.⁴⁷

⁴² PJM, *Generator Interconnection Feasibility Study Report for Queue Project AE1-135*, at 6, January 2019.

⁴³ *Id.* at 18.

⁴⁴ See PJM, *Generator Interconnection Feasibility Study Report for Queue Project AF2-193*, at 15, Revised August 2020; PJM, *Generator Interconnection Impact Study Report for Queue Project AE2-251*, at 58, February 2020; PJM, *Generator Interconnection Impact Study Report for Queue Project AE2-122*, at 28, February 2020.

⁴⁵ See publicly available SPP, *Generator Interconnection Studies* (note that SPP is behind in processing impact studies). NYISO and ISO-NE generator interconnection studies are not available to the public and require a Critical Energy Infrastructure Information (CEII) non-disclosure agreement with the ISOs.

⁴⁶ In 2019, installed wind power project costs were approximately \$1,387/kW in the region that includes most of SPP and MISO. We use the range of network cost increases from SPP generator interconnection studies and the aforementioned cost of installed wind power projects to estimate network upgrade costs as a share of the cost of generation in 2013/2014 vs. 2016. See Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 56, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

⁴⁷ See tab titled "Assigned Upgrade Costs" in SPP *DISIS-2017-001 Phase One*, Revised, November 11, 2020.

NYISO has also experienced an increase in upgrade costs from \$67/kW in 2013 to \$124/kW in 2019. Experience in ISO-NE on the other hand, while not a linear display of upgrade cost increases, demonstrates how high the network upgrade costs can get in any given year with 2015 upgrade costs reaching \$566/kWs. Upgrade costs for ISO-NE also increased by 160 percent from 2018 to 2019.

b) Paying for transmission through the interconnection process fails to capture efficiencies that benefit all users

The system of funding major transmission upgrades through the generation interconnection process is ineffective and violates the beneficiaries pays principle. Large new transmission additions create broad-based regional benefits by providing customers with more affordable and reliable power, so charging only interconnecting generators for this equipment requires them to fund infrastructure that benefits others. MISO, for example, has estimated that its 17 Multi-Value Projects (MVPs) approved in 2011 will generate between \$7.3 to \$39 billion in net benefits over the next 20 to 40 years, producing cost-to-benefit ratios ranging from 1.8 to 3.1.⁴⁸ Additionally, SPP's portfolio of transmission projects constructed between 2012 and 2014 is estimated to generate upwards of \$12 billion in net benefits over the next 40 years, with a cost-to-benefit ratio of 3.5.⁴⁹ Charging only interconnecting generators for the construction of transmission additions that generate benefits similar to those found in MISO and SPP is a classic example of the "free rider" problem. This type of market failure found in various other economic sectors involving networks, such as water and sewage systems and highways, signals why it is more efficient to broadly allocate the cost of "public goods." If required to pay for upgrades that mostly benefit others, interconnecting generators tend to balk and drop out of the interconnection queue.

c) Interconnection queue project cancellations are rising

The interconnection process relies upon sequential studies that are highly unpredictable for participating generators who do not know whether their interconnection request

⁴⁸ MISO, *MTEP19*, at 6-7, n.d.

⁴⁹ SPP, *The Value of Transmission*, at 5, January 26, 2016.



will require large upgrades. The uncertainty of interconnection costs leads wind and solar developers to often submit multiple interconnection applications for the same generator, typically for different project sizes, configurations, and interconnection points, which leads to a queue with far more projects than will actually be developed. This is a rational strategy from the developer's perspective; however, the proliferation of projects only exacerbates the number of re-studies and the number of uncertainties that can affect every project. When studies reveal significant costs, those projects tend to drop out of the process, necessitating restudies for all remaining generators and prompting delays (and often higher costs) for projects that are part of the same interconnection class year or further down in the interconnection queue. That vicious cycle continues, with the next round of wind and solar projects submitting even more interconnection applications to protect against this uncertainty. Cancelled projects lead to a vicious reinforcing cycle increasing the potential of further cancellations.

The high cost of interconnection is increasing the rate at which generators drop out of the interconnection queue, which exacerbates the uncertainty. Between January of 2016 and July of 2020, 245 clean energy projects in advanced stages of the MISO generator interconnection process chose to withdraw from the queue.⁵⁰ Interviews with the owners of these projects indicates that network upgrade costs were the primary reason for withdrawing.

Queue dropout rates are increasing. In 2019, approximately 3.5 of 5 GWs of renewable energy projects that had been a part of the MISO West 2017 study group dropped out of the interconnection queue due to high transmission upgrade costs. These projects, some of which already had power purchase agreements in place,⁵¹ each faced transmission upgrade costs in the range of tens to hundreds of millions of dollars.⁵² As of December of 2019, all but 250 MW of the 5,000 MWs had withdrawn from the queue. The remaining 250 MW was comprised of a 200 MW wind project and a 50 MW solar project; it is unlikely that the wind project will move forward as its engineering study showed the project would require transmission upgrades totaling \$500 million.⁵³ This leaves the success rate at 1 percent for the MW in that queue study group.

Queue reform has attempted to reduce queue length and dropouts with larger financial deposits from interconnecting generators, yet queue backlogs continue to grow because queue reform has not addressed the fundamental problem of requiring interconnecting generators to pay for large network transmission elements that benefit the entire region.

d) Queue backlogs are large and growing

Interconnection queue timelines are increasing across the country due to the churn of re-studies and the high and unpredictable upgrade costs assignments, harming consumers' ability to access generation. Developers have said processing interconnection requests in PJM can take over two years, while processing in SPP can take nearly four years in some areas.⁵⁴ Currently, the MISO interconnection queue suggests processing times to be around three years, with the time it takes for a request to get through the process trending up over time.⁵⁵

⁵⁰ Sustainable FERC, *New Interactive Map Shows Clean Energy Projects Withdrawn from MISO Queue*, n.d.

⁵¹ Advanced Power Alliance, Clean Grid Alliance, and the American Wind Energy Association, *Comments to the SPP RSC and OMS Regarding Interregional Transmission Planning*, at 3, 2019.

⁵² Peder Mewis and Kelley Welf, *Clarion Call! Success has Brought Us to the Limits of the Current Transmission System*, November 12, 2019.

⁵³ Jeffery Tomich, *Renewables 'Hit a Wall' in Saturated Upper Midwest Grid*, December 12, 2019.

⁵⁴ Interviews with developers.

⁵⁵ See MISO, *Interactive Queue*. We approximate the time it takes for an interconnection request to be processed by taking the difference between the "done date" of a request and the date the project entered the queue.

e) Interconnection challenges exist for offshore as well as onshore projects

Limitations of the current interconnection process hinder offshore wind development and state clean energy goals. Interconnection studies for offshore wind illustrate that most interconnection sites have a finite amount of capacity for new power injection before upgrade costs increase considerably, as the supply curve of available injection capacity among sites and at individual sites slopes steeply upward. According to upgrade costs estimated in PJM offshore wind interconnection studies and as shown in Appendix A, one can see that the first tranche of 605 MWs can be accommodated for an upgrade cost of around \$275/kW at an interconnection site. The second tranche of 605 MW, however, incurs a marginal upgrade cost of over \$1,100/kW, and the third tranche of 300 MWs incurs a marginal upgrade cost of over \$1,300/kW. In this case, costs quadruple for projects later in the queue. The upgrades required for the later tranches involve rebuilding large segments of the transmission system. These investments benefit all interconnecting generators and consumers, who receive lower-cost and more reliable electricity from a stronger grid.

Appendix A also demonstrates that onshore transmission upgrade costs for interconnecting offshore generators tend to be very large. A review of 24 interconnection studies comprising 15,582 MWs of offshore wind capacity that have proposed to interconnect to PJM reveals \$6.4 billion in total onshore grid upgrade costs for those projects, with an average of \$413 per kW of offshore wind capacity.⁵⁶ Onshore grid upgrade costs for these offshore projects range from \$10 per kW to \$1,850 per kW.⁵⁷

The status quo approach of relying on sequential interconnection studies with participant funding, without any pro-active regional planning, is leading to ballooning costs for offshore wind just like land-based renewables.

f) The problems occur mainly where participant funding is allowed—in RTOs and ISOs

FERC's interconnection policy as established in Order No. 2003 allowed participant funding inside RTOs and ISOs and not for transmission providers outside RTO/ISO areas. The problems described above are all in RTO/ISO areas. Where transmission upgrade costs are rolled into rates for all users, we do not find evidence of similar problems.

⁵⁶ Brandon W. Burke, Michael Goggin, and Rob Gramlich, *Offshore Wind Transmission White Paper*, at 14, October 2020.

⁵⁷ *Id.*



V. Incremental Solutions Can Help but Not Solve the Problem

a) Cluster study approaches have been a modest improvement

Some regions have implemented “cluster” interconnection studies, in which many interconnection requests are evaluated in the same study, as opposed to sequential project-by-project studies. The sequential processing approach is untenable for each new project that is the proverbial straw that breaks the camel’s back and incurs a disproportionate share of upgrade costs. Clusters of similarly situated GI study requests, on the other hand, proved to be a preferred approach as transmission expansion is lumpy with large economies of scope and scale, so several developers in one area are able to pay a prorated share of the costs of required network upgrades. Additionally, grouping many interconnecting projects together instead of studying them individually allows for less queue reshuffling. Despite these advantages of a clustered approach, however, this does not solve the fundamental problem that all, or nearly all, costs are still assigned to interconnecting generators.

While clustering has helped in the past, it alone cannot solve the challenges associated with efficient and effective processing of generation interconnection queue requests. Current cluster sizes are extremely large in many cases, and planning for only one tranche of the future grid does not address the long-range needs, and certainly doesn’t allow the capture of economies of scope and scale for large regional and interregional solutions to address aggregate network needs of resolving economic congestion and reliability concerns.

b) Eliminating participant funding would help

As part of FERC’s Notice of Proposed Rulemaking (NOPR) for Order No. 2003, the Commission sought comment on whether or not they should retain their interconnection pricing policy.⁵⁸ At the time of the

⁵⁸ Standardizing Generator Interconnection Agreements Procedures, Notice of Proposed Rulemaking, Docket No. RM02-1, at 25, April 24, 2002.

NOPR, FERC's current policy required generators to pay 100 percent of the cost of "interconnection facilities" needed to establish the direct electrical connection between the generator and the existing transmission provider network. The costs of "network facilities," however – facilities at or beyond the point of interconnection to assist in accommodating the new generation facility (e.g. facilities needed for stability and short-circuit issues) – were borne initially by the generator and subsequently credited back to the generator through credits applied through transmission rates.⁵⁹

In the final rule for Order No. 2003, FERC explained its reasoning for switching from such a "rolled-in" credit approach to one that is participant-funded.⁶⁰ One main reason included the credit approach's potential to provide price signals to direct developers to better locations from a network perspective. FERC argued at the time that a participant-funded pricing policy under which those who benefit from the project pay would help solve this problem.

FERC's decision to allow participant funding was based on the gas generation being added at the time. The Commission agreed with a number of commenters that objected to how the credit approach diminishes the incentive for interconnection customers to make efficient siting decisions while taking into account new network upgrade transmission costs, while effectively subsidizing interconnection customers who decide to sell output off-system.⁶¹ The participant funding of network upgrades, FERC argued, would send more efficient price signals, more equally allocate costs, and potentially provide the framework necessary to allow incumbent transmission owners to overcome their reluctance to build much needed transmission.

The failure of the current system under the new resource mix, including excessive costs and risk, an inability to build needed transmission, and generators paying for large network upgrades that primarily benefit customers suggest that participant funding may no longer be a just and reasonable policy. Participant funding of network upgrades not only imposes costs on interconnection customers that are often exorbitant and rising, but is also not the solution to the inability to build large-scale transmission.

One policy solution would be to end participant funding for new generation. It is clear that major network upgrades resulting from generation interconnection requests provide economic and reliability benefits to loads and reduce congestion to improve grid efficiencies and operational flexibility, and therefore should not be directly assigned as a result of participant funding. The Commission can and should change this policy within the scope of interconnection policy.

c) Other incremental reforms to the interconnection process would help

The American Wind Energy Association (AWEA) petition for rulemaking in June of 2015 urged FERC to revise the pro forma LGIP and LGIA to alleviate "...unduly discriminatory and unreasonable barriers to generator market access."⁶² AWEA's petition detailed a total of 14 recommendations and FERC later adopted 10 of the 14 under Order No. 845. The four recommendations FERC declined to adopt were regarding periodic restudies requirements, self-funding of network upgrades, publication of congestion and curtailment information, and the modeling of electric storage resources. In Order No. 845, FERC did not provide insight into what steps still needed to be taken to address these deficiencies in the current interconnection process.

⁵⁹ *Standardizing Generator Interconnection Agreements Procedures*, Advance Notice of Proposed Rulemaking, Docket No. RM02-1, at 15, October 25, 2001. This was true unless the transmission provider elected to fund the network upgrades.

⁶⁰ *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, 104 FERC ¶ 61,103, at P 678, July 24, 2003.

⁶¹ *Id.* at P 695.

⁶² *Petition for Rulemaking of the American Wind Energy Association to Revise Generator Interconnection Rules and Procedures*, Docket No. RM15-21-000, at 1, June 19, 2015.

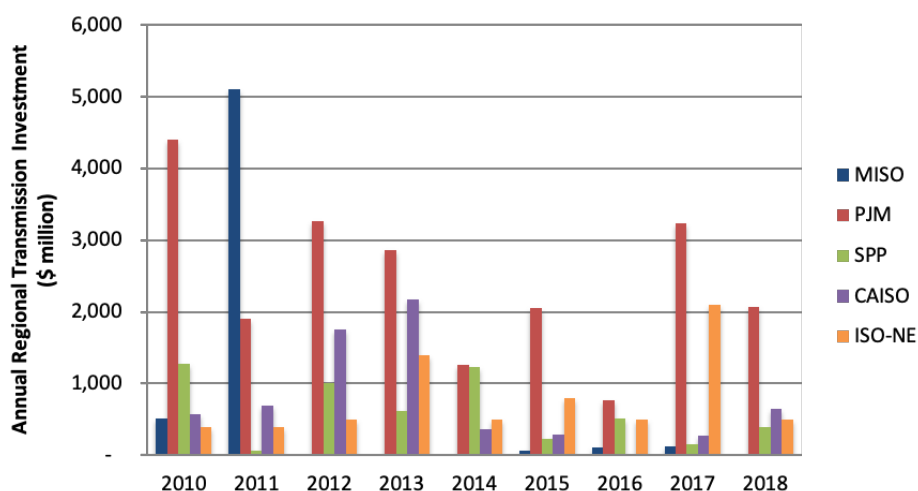
d) Interconnection process changes would still leave a shortage of efficient regional transmission

Even with the incremental changes above, there would be a continued lack of efficient regional transmission without more fundamental reforms. Integrated and comprehensive planning efforts to address to effectively integrate expected generation while also meeting economic and reliability needs have not happened since major initiatives such as Competitive Renewable Energy Zones (CREZ) in ERCOT, MVPs in MISO, and Priority Projects in SPP. Once those lines were fully subscribed, upgrade costs and queue backlogs quickly returned to unworkable levels.

While current transmission investment numbers are relatively high by historical standards, the majority of recent transmission investments have been small local projects, as demonstrated by Brattle: “[A]bout one-half of the approximately \$70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions are approved outside the regional planning processes or with limited ISO/RTO stakeholder engagement.”⁶³

Without sufficient regional and interregional transmission capacity to facilitate the integration of location-constrained resources onto the grid, the cost of constructing the network upgrades necessary to interconnect new wind and solar resources falls on generators as part of the interconnection process. As demonstrated in most RTO regional transmission planning statistics and reports, regionally planned transmission investment has decreased substantially since 2010. Specifically, between 2010 and 2018, total regionally planned transmission investment in RTOs decreased by 50 percent as shown in Figure 4.⁶⁴

Figure 4: Annual Regionally Planned Transmission Investment in RTOs/ISOs (\$ million)



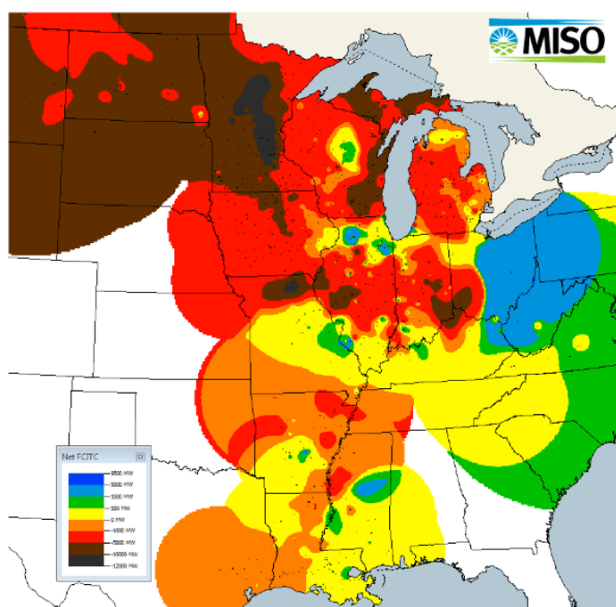
⁶³ Johannes P. Pfeifenberger et al., *Cost Savings Offered by Competition in Electric Transmission: Experience to Date and the Potential for Additional Customer Value*, at 4, April 2019 (“Significant investments have been made, but relatively little has been built to meet the broader regional and interregional economic and public policy needs envisioned when FERC issued Order No. 1000. Instead, most of these transmission investments addressed reliability and local needs.”)

⁶⁴ Note: all RTOs/ISOs provide regional transmission investment information. Grid Strategies assembled data using the following sources to assemble figure 4: Coalition of MISO Transmission Customers, Industrial Energy Consumers of America, and LS Power Midcontinent, LLC, *Section 206 Complaint and Request for Fast Track Processing*, at 31-32, January 21, 2020; PJM, *Project Statistics*, at 6, January 10, 2019; Lanny Nickell, *Transmission Investment in SPP*, at 5, July 15, 2019; CAISO, *ISO Board Approved Transmission Plans*, years 2012-2021 available under “Transmission planning and studies” section of webpage; CAISO, *2011-2012 Transmission Plan*, March 14, 2012; CAISO, *Briefing on 2010 Transmission Plan*, 2010; and ISO New-England, *Transmission*, accessed October 2020.

There have been successful examples of region-wide coordination in planning and cost allocation achieving efficient levels of transmission investment. Transmission expansion efforts with pro-active multi-value planning and broad cost allocation, like the CREZ in ERCOT, MVPs in MISO, and Priority Projects in SPP, for example, have led to the large buildout of backbone transmission. These transmission expansion plans pro-actively incorporated wind and solar development assumptions, and also designed transmission upgrades that would maximize other economic and reliability benefits. Most importantly, these policies were successful because the costs of transmission were broadly allocated across the region, consistent with the benefits of the transmission being broadly spread across the region, instead of unworkably attempting to recover the costs through the generator interconnection process. However, these successful pro-active transmission planning efforts were not sustained. Subsequent renewable development requests in these areas have been burdened with unreasonable costs for interconnections, and queue backlogs have grown as a result.

The decline of regional plans is inconsistent with the evolving resource mix. Because the best locations for wind and solar resources are significantly different from those of retiring coal and other thermal resources, the current grid based on approved plans cannot be expected to support future needs. Transmission has a long infrastructure life, so the infrastructure built today should be designed with the next 50 years in mind. While almost all generation resources are location-constrained to some extent, wind and solar tend to be more constrained to areas with high-quality resources and therefore require more transmission.⁶⁵ Yet less transmission is being planned as wind and solar resources make up an increasing portion of the resource mix, which can severely constrain the amount of transmission transfer capacity out of renewable-heavy areas. Figure 5⁶⁶ below, for example, shows the majority of western MISO (highlighted in blue) had an estimated 5 GW or more deficit of transfer capacity to the rest of the region in 2016. This means that at least that amount of transmission capacity must be constructed across MISO and into the PJM region before any new generation can be added.

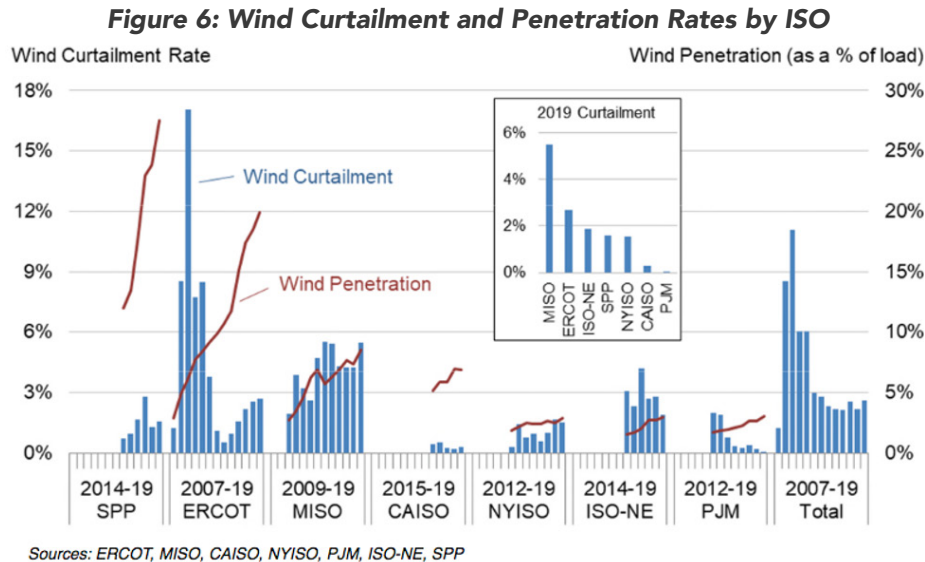
Figure 5: MISO West Transfer Capacity Deficit



⁶⁵ See American Wind Energy Association, *Grid Vision: The Electric Highway to a 21st Century Economy*, at 31, May 2019; Scott Madden, *Informing the Transmission Discussion*, at 29, January 2020; FERC, *Report on Barriers and Opportunities for High Voltage Transmission*, at 12-14, June 2020.

⁶⁶ See MISO transfer capacity contour map, available at https://cdn.misoenergy.org/GI-Contour_Map108143.pdf, July, 11, 2018.

Efficient regional transmission capacity for location-constrained renewables can help lower renewable curtailment levels. Average wind curtailment levels for the RTOs hovered around 2.6 percent in 2019, up from 2.2 percent in 2018, with the highest levels in MISO and ERCOT at 5.5 percent and 2.7 percent, respectively.⁶⁷ Regions with high wind curtailment levels, specifically in western MISO and northwestern ERCOT, benefitted from the construction of new, large regional transmission. As shown in Figure 6⁶⁸ below, wind curtailment in MISO decreased from 2015 through 2018 shortly after the completion of a number of MVPs in western MISO between 2013-2017.⁶⁹ Similarly, wind curtailment in ERCOT has declined dramatically since 2011 after the completion of CREZ transmission projects from 2010 through 2013 allowed more than 18,500 MWs of wind capacity to be transported throughout the state.⁷⁰



⁶⁷ Ryan Wiser et al., *Wind Energy Technology Data Update: 2020 Edition*, at 49, August 2020. See also underlying data in the *2020 Wind Energy Technology Data Update* accompanying the slide deck.

⁶⁸ *Id.*

⁶⁹ MISO, *Regionally Cost Allocated Project Reporting Analysis*, October 2020.

⁷⁰ ERCOT, *Report on Existing and Potential Electric System Constraints and Needs*, at iii, December 2018. U.S. Energy Information Administration, *Fewer Wind Curtailments and Negative Power Prices Seen in Texas After Major Grid Expansion*, June 24, 2014.



VI. The Real Solution Must Be Regional and Inter-regional Planning Reforms

Transmission expansion needs to be driven by a multi-value plan to address overall system needs, including economics, reliability, and generator interconnection. Some regions have demonstrated success in integrated transmission plans to accommodate projected futures that resulted in very cost-effective transmission expansion. CREZ in ERCOT, MVPs in MISO and Priority Projects in SPP are case studies where loads, generators and stakeholders benefited from holistic planning efforts. SPP and MISO have found the benefits of that transmission expansion exceeded the cost by 2 to 3 times.⁷¹

The changing resource mix and electrification of the energy sector will have a profound impact on the future grid, yet in many cases those factors are not being included in regional and interregional planning efforts. Most recent regional planning studies have not included reasonable projections regarding the changing resource mix and expected retirements. State policies should also be accounted for in regional transmission planning process.

Network upgrades benefit everyone, and all costs ultimately flow to customers, so cost allocation needs to reflect that reality. Consumers benefit from minimizing costs and maximizing the benefits of transmission expansion. Customers are also harmed by the inefficient and unworkable status quo that attempts to force upgrade costs on interconnecting generators. This policy leads to a sub-optimal level of transmission investment, driving billions of dollars annually in unnecessary congestion and reliability costs, while the cost of energy offered to customers by generators is higher than necessary due to lengthy queue delays and risk and an inability to build generation in low-cost resource areas.

Transmission policy can and should include Grid-Enhancing Technologies (GETs), not just new infrastructure. As FERC has recognized, a set of GETs are now widely commercialized and deployable to address a number of transmission challenges speedily and at low cost. GETs can be incorporated into interconnection policy, transmission planning, and FERC incentives policy. As with infrastructure,

⁷¹ See SPP, *The Value of Transmission*, at 5, January 26, 2016; MISO, *MTEP17 MVP Triennial Review*, at 4, September 2017.

addressing only interconnection policy will not be sufficient for GETs.

a) Generator lead lines should be incorporated into regional plan

In many cases, a lack of transmission capacity, queue backlogs, and excessive participant funding upgrade costs have forced renewable developers to build and own generator lead lines that are dozens of miles long. For example, wind projects such as Horse Hollow in ERCOT and Flat Ridge in SPP had in-service dates and commitments for deliveries that could not wait for approved, regionally funded Extra High Voltage (EHV) network upgrades. As a result, developers of these projects built long, high capacity EHV generator leads to integrate their projects into existing transmission facilities in advance of planned regionally funded upgrades. In the case of Horse Hollow, the developer constructed a private 345 kV line extending from West ERCOT to South ERCOT – a distance spanning ten Texas counties.⁷² Often long generator leads reduce congestion and curtailments and become network elements benefitting

b) Affected system studies need to be part of improved interregional planning processes

Affected system studies occur when a generator interconnection in one RTO triggers a need for transmission upgrades in more than one RTO. These studies increase upgrade costs for generators. The fact that the transmission need is large enough to cross into another RTO clearly indicates that the transmission expansion benefits others, and therefore should be planned and paid for in a regional, and ideally inter-regional, process.

Planning is tough enough within an RTO, and the planning and cost allocation obstacles for building transmission between RTOs are currently insurmountable. Part of the problem is there is significant divergence among RTO planning processes, with different models, assumptions, benefit-cost thresholds, and timing. As a result, no large-scale transmission upgrades have been able to pass what is called the “triple hurdle,” which requires an inter-regional transmission project to pass a benefit-cost ratio test in each RTO and for the entire region. The free rider problem is an even greater challenge for inter-regional cost allocation than it is within RTOs. However, the large need for inter-regional transmission will not be met without solving that problem, likely by broadly allocating the cost of inter-regional lines across those regions.

The voluntary nature of RTOs has resulted in footprints that create seams issues that stymie collaborative planning. Expansion of RTO footprints helps to mitigate seams issues to a large extent and needs to be strongly encouraged. The lack of transmission capabilities between zones of an RTO creates challenges that have plagued effective expansion planning. Transmission capabilities are critical to an efficient and effective bulk power system and electricity market, as transmission is the critical link to enabling and defining markets.

c) Regional planning studies and generation interconnection studies need better alignment

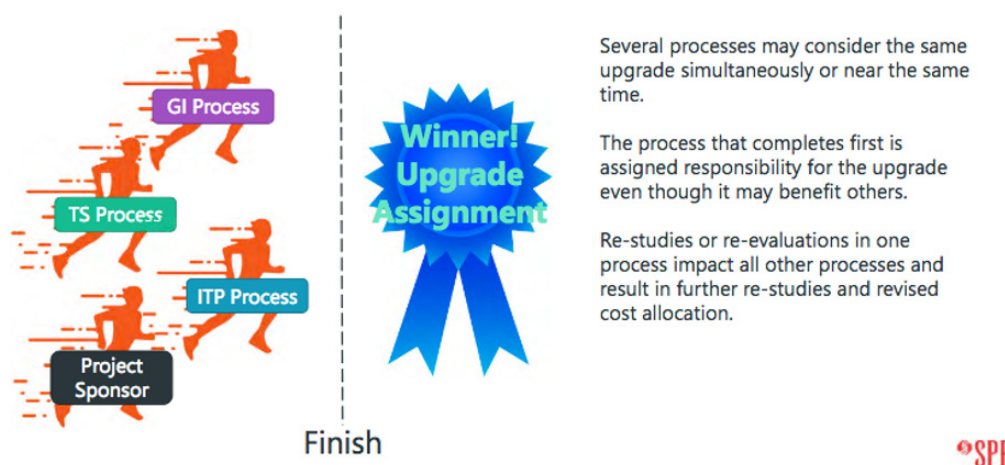
Planning entities often employ siloed study processes that consider reliability, economic, and public policy

⁷² Hillard Energy, *Horse Hollow Generation Tie*, Comfort, Texas, n.d.

transmission projects separately rather than considering all benefits at once under a holistic planning approach. The main factor driving siloed planning processes is that different cost allocation methods for each category of transmission project results in a race that no one wants to win, as it will result in them bearing the cost for the transmission upgrades. Said another way, each group of stakeholders attempts to free ride on other groups of stakeholders by failing to plan transmission that they would have to pay for, in the hope another group of stakeholders will plan and pay for it. Unfortunately, the typical result is that nobody builds the transmission, and all customers suffer from increased congested and reduced reliability.

A great case study that demonstrates this failure in action involves SPP's filing of an unexecuted GIA between SPP - the transmission provider, Oklahoma Gas & Electric (OG&E) Company - the transmission owner, and Frontier Windpower II - the interconnection customer.⁷³ After Frontier's GIA identified shared network upgrades including a new transmission line with a \$62 million price tag, of which Frontier had been allocated 22.5 percent of the total cost, Frontier then asked SPP to file the GIA as an unexecuted agreement. When SPP later revised Frontier's GIA to remove all costs associated with the new transmission line, the back-and-forth continued as OG&E submitted a filing in protest of SPP's decision as they believed that because Frontier is imposing costs on the SPP system, they should bear their share of the cost so others, including OG&E, do not have to pay more.⁷⁴ SPP's Strategic & Creative Re-Engineering of Integrated Planning Team (SCRIPT) has identified this problem, as shown in Figure 7.⁷⁵

Figure 7: Process Interaction



SPP is working on a solution, which builds on the successes achieved through pro-active transmission planning and broad cost allocation identified a decade ago with the ERCOT CREZ, MISO MVP, and SPP Priority Project lines. The new SCRIPT effort at SPP appears to be a positive step forward and may serve as a model for other RTOs. The scope of the SCRIPT at SPP is noteworthy in several respects. "The SCRIPT is tasked with developing policy recommendations that result in:

- Appropriate consolidation, modification, or elimination of SPP's transmission planning and study processes, in order to:
 - » Develop more optimal solutions that meet a broader set of customer needs

⁷³ *Protest of Oklahoma Gas and Electric Company*, Docket No. ER19-2747-002, March 16, 2020.

⁷⁴ *Id.* at 7-8.

⁷⁵ See the minutes and meeting materials for SCRIPT's meeting held on October 9th, 2020 (attachment D at slide 49).

-
- » Synergize analysis so that beneficiaries and cost-causers can be identified in a holistic, uniform fashion
 - » Improve planning efficiency, effectiveness and timeliness
 - » Reduce the number of model sets needed
 - » Reduce reliance on customer-requested, queue-driven studies
- Improved responsiveness, efficiency and cost certainty of studies needed to provide customer-requested service
 - Reduced dependence on queue-driven studies, with consideration given to development of proactive processes that identify and make transparent underutilized transmission capacity
 - Utilization of processes and information needed to ensure decisions being made about future investment in transmission infrastructure are made with a high degree of confidence and quality
 - Optimization of the existing and planned transmission network to most cost effectively meet future needs while providing maximum value to the region
 - Facilitation of generation transfers in a way that will provide future net benefits to the SPP region
 - Improved cost sharing among users of the transmission system that appropriately recognizes causers and beneficiaries of transmission investment decisions”

d) Both incremental and broader reforms would still be fuel-neutral

If FERC were to change its policies based in part on the evolving resource mix, that could still be a fuel neutral policy. FERC has always tried to be neutral, with no discrimination or preference to any particular resource, and that can remain true. Transmission policy necessarily takes into account the physical location of resources. For example, in 2007, FERC issued policies on interconnection and transmission service for “location-constrained” resources that differed from the Order 2003 approach in CAISO.⁷⁶ It was not a preference or any value judgment on the renewable resources, just the recognition that there was a large resource area that could be tapped with a higher voltage transmission lines than any one generator or group of generators could be assigned, leading to more just and reasonable rates for consumers. Transmission planning reforms could follow this general approach.

⁷⁶ See *California Independent System Operator Corporation*, Order Granting Petition for Declaratory Order, 119 FERC ¶ 61,061, April 2007; and Bracewell LLP, *FERC Tailors Transmission to Connect Renewables*, May 1, 2007. See also Pedro J. Pizarro, *Transmission Planning and Development: Examples and Lessons*, at 17, February 25, 2010; CAISO, *Memorandum re: Decision on Tehachapi Project*, at 6, fn. 3 January 18, 2007 (explaining how generators would pay a pro-rata share to the extent the Tehachapi improvements are characterized as bulk transfer gen-tie lines, with customers in SCE’s service territory paying the costs of the network upgrade portions of the project).



VII. Conclusion: Transmission Planning as Well as Interconnection Policy Reforms Are Needed

The current system of participant funding and network planning through the interconnection process is increasingly unworkable and inefficient. While participant funding and serial interconnection studies created workable signals for siting interconnecting gas plants, they create inefficiencies for interconnecting location-constrained renewable resources. Needed transmission remains unbuilt because the vast majority of new proposed projects drop out of the queue, lengthy queue backlogs create massive uncertainty and risk for generation developers, and congestion and reliability problems from a constrained grid impose billions of dollars per year in unnecessary costs on customers. All generation and transmission costs ultimately flow to electricity consumers, so there is no benefit from policies that seek to shift transmission costs from RTO customers exclusively to generators. The risk from the uncertainty of the interconnection process significantly increases the cost of capital for generation developers, which increases the cost of energy for customers. The question for policymakers is how to create a workable and efficient system of planning and paying for transmission that minimizes customer costs.

Interconnection policy and transmission planning policy both need to fit the resource mix going forward. This paper provides evidence of how the interconnection policy is broken now, given the current and expected future resource mix. It proposes some recommendations within the scope of interconnection policy such as ending the policy of assigning all the costs of network upgrades just to generators. However, major progress requires improved transmission expansion policies in order to build out grid capacity to accommodate the future resource mix. Reform to regional transmission planning raises a number of issues that are beyond the scope of this paper. A companion paper from ACEG will address the need for planning reform, consider various policy options, and recommend a number of specific policy changes. It is clear that regional and inter-regional planning must be pro-active, consider future generation additions and retirements, consider multiple benefits, and spread costs to all beneficiaries. That is the only real solution to the broken interconnection processes around the country.

Appendix ⁷⁷

| Queue Position | MW | Request Date | COD | Interconnection Point | State | County | Trans. Owner | Feasibility Study | System Impact Study | Facilities Study | \$ upgrade cost | \$/kW upgrade cost |
|----------------|-------|--------------|----------|---------------------------|-------|------------------------|--------------|-------------------|---------------------|------------------|------------------------|-------------------------|
| Z1-035 | 18 | 7/5/13 | 9/30/17 | Lake Road 11.5 kV | OH | Unknown | ATSI | Complete | Complete | Not required | \$2,468,558 | \$137 |
| AB1-056 | 255.1 | 8/31/15 | 10/31/21 | Indian River 230kV I | DE | Sussex | DPL | Complete | Complete | Complete | \$2,556,112 | \$10 |
| AE1-020 | 816 | 5/22/18 | 6/1/23 | Oyster Creek 230 kV | NJ | Ocean | JCPL | Complete | Complete | In Progress | \$111,316,644 | \$136 |
| AE1-104 | 432 | 9/6/18 | 6/1/23 | BL England 138 kV | NJ | Cape May | AEC | Complete | Complete | In Progress | \$65,050,000 | \$151 |
| AE1-117 | 152 | 9/14/18 | 6/1/22 | Bethany 138 kV | DE | Sussex | DPL | Complete | Complete | In Progress | \$9,698,945 | \$64 |
| AE1-238 | 816 | 9/28/18 | 6/1/24 | Oceanview Wind 230 kV | NJ | Monmouth | JCPL | Complete | Complete | In Progress | \$13,498,200 | \$17 |
| AE2-020 | 604.8 | 12/14/18 | 12/1/24 | Cardiff 230 kV I | NJ | Atlantic | AEC | Complete | Complete | In Progress | \$167,856,800 | \$278 |
| AE2-021 | 604.8 | 12/14/18 | 12/1/25 | Cardiff 230 kV II | NJ | Atlantic | AEC | Complete | Complete | In Progress | \$668,716,213 | \$1,106 |
| AE2-022 | 300 | 12/14/18 | 12/1/24 | Cardiff 230 kV III | NJ | Atlantic | AEC | Complete | Complete | In Progress | \$399,595,257 | \$1,332 |
| AE2-024 | 882 | 12/14/18 | 12/1/25 | Larrabee 230 kV I | NJ | Ocean | JCPL | Complete | Complete | In Progress | \$179,417,245 | \$203 |
| AE2-025 | 445.2 | 12/14/18 | 12/1/26 | Larrabee 230 kV II | NJ | Ocean | JCPL | Complete | Complete | In Progress | \$171,405,063 | \$385 |
| AE2-122 | 800.1 | 2/28/19 | 12/31/25 | Birdneck-Landstown 230 kV | VA | City of Virginia Beach | Dominion | Complete | Complete | In Progress | \$304,108,327 | \$380 |
| AE2-123 | 800.1 | 2/28/19 | 12/31/27 | Birdneck-Landstown 230 kV | VA | City of Virginia Beach | Dominion | Complete | Complete | In Progress | \$243,757,023 | \$305 |
| AE2-124 | 800.1 | 2/28/19 | 12/31/29 | Landstown 230 kV | VA | City of Virginia Beach | Dominion | Complete | Complete | In Progress | \$215,266,218 | \$269 |
| AE2-222 | 300 | 3/22/19 | 6/1/23 | Higbee 69 kV | NJ | Atlantic | AEC | Complete | Complete | In Progress | \$285,840,760 | \$953 |
| AE2-251 | 1200 | 3/26/19 | 6/1/24 | Cardiff 230 kV | NJ | Monmouth | AEC | Complete | Complete | In Progress | \$923,771,404 | \$770 |
| AE2-257 | 120 | 3/27/19 | 6/1/22 | Cedar Neck 69 kV | DE | Sussex | DPL | Complete | Complete | In Progress | \$105,062,883 | \$876 |
| AF1-101 | 800 | 9/6/19 | 11/23/22 | Oyster Creek 230 kV III | NJ | Atlantic | JCPL | Complete | Complete | | \$572,211,265 | \$715 |
| AF1-123 | 880 | 9/17/19 | 12/31/25 | Fentress 500 kV | VA | City of Chesapeake | Dominion | Complete | Complete | | \$76,200,000 | \$87 |
| AF1-124 | 880 | 9/17/19 | 12/31/26 | Fentress 500 kV | VA | City of Chesapeake | Dominion | Complete | Complete | | \$156,865,407 | \$178 |
| AF1-125 | 880 | 9/17/19 | 12/31/24 | Fentress 500 kV | VA | City of Chesapeake | Dominion | Complete | Complete | | \$149,505,894 | \$170 |
| AF1-222 | 1326 | 9/27/19 | 12/30/25 | Oceanview Wind 2 230 kV | NJ | Monmouth | JCPL | Complete | Complete | | \$131,556,667 | \$99 |
| AF2-193 | 440 | 3/23/20 | 10/31/26 | Indian River 230 kV I | DE | Sussex | DPL | Complete | | | \$534,708,000 | \$1,215 |
| AF2-194 | 880 | 3/23/20 | 10/31/26 | Indian River 230 kV II | DE | Sussex | DPL | Complete | | | \$664,582,000 | \$755 |
| AF2-196 | 150 | 3/23/20 | 6/1/22 | Cedar Neck 69 kV II | DE | Sussex | DPL | Complete | | | \$277,459,000 | \$1,850 |
| | | | | | | | | | | | \$6,432,473,885 | \$413/kW average |

⁷⁷ See PJM, New Services Queue. To gather the data found in Appendix A, we filtered the queue for offshore wind projects. Upgrade cost information was taken from the most recent interconnection study available for each request (e.g. feasibility study, system impact study, or facilities study).



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