Comments – National Transmission Needs Study Public Draft – Spring 2023

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*This comment was submitted after the deadline but DOE has exercised its discretion to accept the late comment.

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ADVANCED ENERGY GROUP

April 20, 2023

Prepared comments per the U.S. Department of Energy (DOE) for the National Transmission Needs Study

On March 30, 2023, Advanced Energy Group convened over 36 public and private stakeholders to discuss key challenges, needs and priorities for the Northeast states to deliver the transmission capacity necessary to ensure a successful clean energy transition. The following summary submitted as comments to the U.S. Department of Energy (DOE) for the National Transmission Needs Study reflects the key points of alignment from this workshop among participating leaders. Several of these leaders have added their signature in support of this summary on page 4.

Regarding Transmission, Equity and Energy Security in the Northeast, a critical obstacle to collectively address in the next 12 months is **the absence of a common methodology to earn the support of key stakeholders** for transmission + storage infrastructure buildout per the critical nexus of decarbonization, resource adequacy, and electric transmission + stored energy.

Alignment and support among a broad range of public and private stakeholders is essential to achieve the needed scale of transmission build out; however, there is no ideal model or methodology to deliver this level of stakeholder activation. As Janny Dong, Manager, Transmission System Planning, Eversource and Jacob Lucas, Director, Transmission System

Planning, Eversource pointed out, “there is a critical need to educate regional stakeholders on the critical nexus of decarbonization, resource adequacy and electric transmission buildout.”

This education needs to be provided in a manner that best supports the needs and concerns of front line communities. How will increased transmission infrastructure provide immediate relief and benefits —in terms of equity metrics such as wealth creation, energy cost burden and public health? By keeping these needs and priorities at the forefront of stakeholder discussions, trust and support can be earned.

Natalie Hildt Treat, Senior Policy Manager for the Northeast Clean Energy Council, said that to earn that trust and to *activate* community organizations and citizens to become proponents of transmission projects, we need to begin by *listening*. “It’s not simply a matter of the powers-that-be ‘educating’ frontline communities, but working to understand what matters to them, and what could win them over,” said Treat.

“Do they care about home energy costs, electric reliability, cleaner air, jobs? Probably, but we need to ask them. Furthermore, we need to find a way to compensate and support grassroots community groups or even individuals for their time and effort to participate in stakeholder processes, or to serve as trusted liaisons—particularly with environmental justice populations,” said Treat.

Regarding transmission capacity, an essential consideration also agreed upon by those in attendance is the need to incorporate stored energy (including but not limited to battery storage) into aspects of planning, design and deployment. As Marianne Perben, Director, Planning Services, ISO New England stated, it is critical to, “maintain and enhance the region’s access to stored energy."

A new stakeholder engagement methodology should be developed first in high priority areas that reflects a convergence of stakeholder needs and serves as a model to strategically repeat throughout the region. In the Northeast region, Southeastern Massachusetts (SEMA) is an area of importance regarding renewable generation penetration and transmission adequacy affecting many people. Please see below an illustration of this need.

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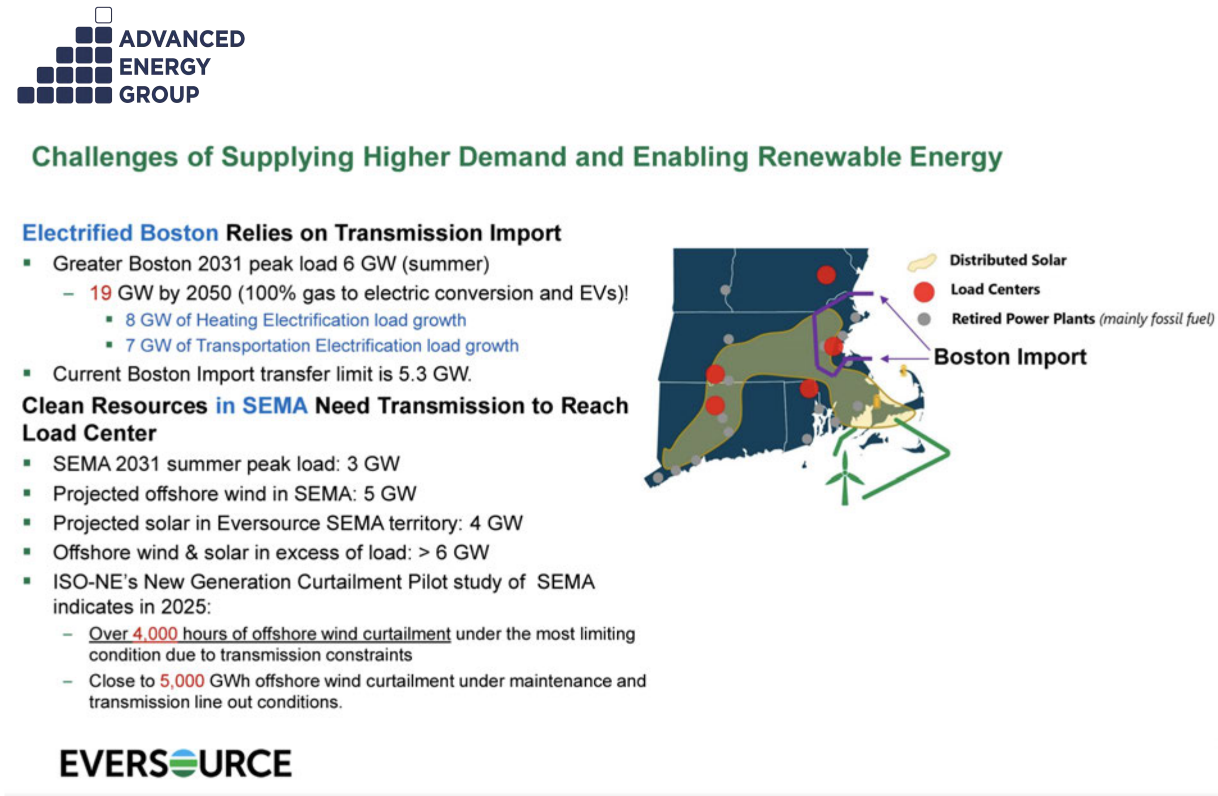

Another important challenge to address is the very small number of projects that successfully result from the interconnection process as illustrated in the diagram below presented by Sara Mochrie, Senior Vice President, Market Director Earth & Environment - Energy for WSP USA. Considerable time is required for resources to support review of interconnections, with many projects that eventually withdraw applications and fail to proceed to execution. To best allocate resources to support needed stakeholder engagement and successful navigation of the interconnection process, some participants agreed that we should align on a set of metrics that would prioritize certain transmission projects as "National Interest Projects" prior to starting the interconnection process.

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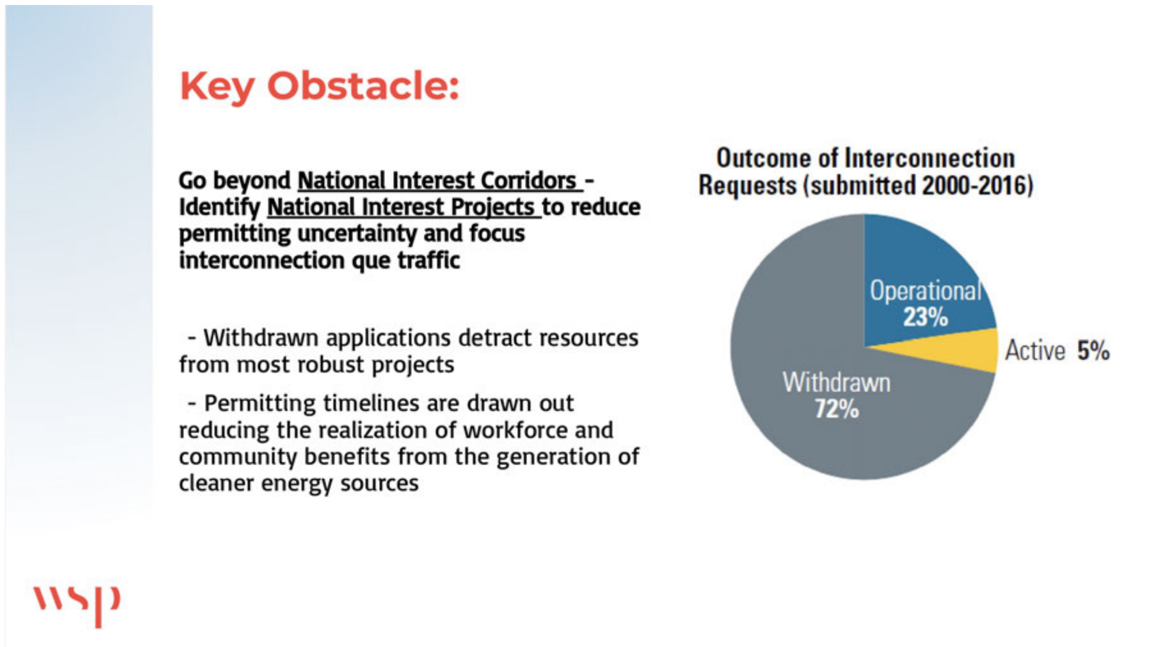

In summary, as stated by Sonny Anand, Director, Infrastructure Investments for National Grid there is an immediate need for, “a holistic, sustainable model for stakeholder engagement for transmission coordination that becomes a catalyst in making progress towards 2050 clean energy goals." Successful development of this engagement model will benefit 1) from prioritizing specific regions and specific projects prior to the interconnection process, such as the SEMA region, 2) a commitment to ongoing, inclusive, proactive stakeholder dialogue that demonstrates an authentic concern to realize economic opportunities and address potential adverse impacts among affected communities, especially among those most vulnerable. Making sure the right-of-ways for new transmission are identified, communicated, and do not further impact these communities negatively must be a key consideration in determining how we meet our decarbonization goals. Similarly, the economic benefit of the jobs created by projects, the enabling benefits of reliability and resiliency, and the clean energy benefits need to be shared with these communities. Opportunities such as disadvantaged business set asides and training/apprenticeship programs can be developed and co-created with communities in mind.

Earning the support of affected communities and stakeholders to successfully develop and construct the transmission and stored energy infrastructure we need requires a new approach to engagement that fosters understanding, trust and excitement for a better future.

Building out transmission capacity is essential to providing customers access to renewable energy and achieving our transportation and building electrification goals. The climate challenge means we must go big and move swiftly with the clean energy transition. Authentic community engagement, creating shared plans that support both system and community needs, must be purposeful from the start and at all phases of project siting and development for us to succeed with this work.

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ADVANCED ENERGY GROUP

Signatures of Support:

The undersigned participated in this stakeholder workshop and are in agreement with these comments to the Department of Energy National Transmission Needs Study.

HG Chissell Founder/CEO Advanced Energy Group April 6, 2023	Natalie Hildt Treat Senior Policy Manager Northeast Clean Energy Council April 11, 2023
Gary Leatherman Managing Director Baker Tilly US, LLP April 12, 2023	Kathryn Cox-Arslan Director, Transmission Policy New Leaf Energy, Inc April 12, 2023
Barry L. Reaves Vice President for Diversity, Equity, Inclusion Justice (DEI/J) & Workforce Development NECEC April 20, 2023	Jeremy McDiarmid Managing Director & General Counsel Advanced Energy United April 17, 2023
Sara Mochrie Market Director – Earth & Environment – Energy WSP April 20, 2023	Richard Brody VP North America Sales and Business Development CTC Global April 20, 2023
Sonny Anand Director - Infrastructure Investments National Grid April 20, 2023	Jacob Lucas Director, Transmission System Planning Eversource Energy April 20, 2023
	Zach Humphrey Regional Director | Power & Utility Consulting 1898 & Co. | Part of Burns & McDonnell April 20, 2023

DOE National Transmission Needs Study Draft
Comments of Advanced Energy United

Introduction

Advanced Energy United is pleased to provide these comments and appreciates the Department of Energy's ("DOE") efforts in developing this comprehensive Draft National Transmission Needs Study ("Draft Study") to facilitate necessary changes in planning, expansion, and development of our aging transmission infrastructure. Advanced Energy United ("United") is a national business association representing over 100 companies and organizations that span the advanced energy sector and its value chains. Our member companies provide a diverse array of technologies and services, including energy efficiency, demand response, solar, wind, storage, electric vehicles, advanced metering infrastructure, fuel cells, hydro power, combined heat and power, enabling software, and more. Together, these technologies and services create and maintain a high performing energy system that is reliable, resilient, and cost-effective.

With the nation's electricity mix changing from centralized fossil fuel generation to utility-scale and distributed advanced energy technologies such as solar, wind, and battery storage, a robust transmission network will be needed to deliver all the benefits these technologies can provide. The Draft Study underscores the critical need for regional and interregional transmission not only to connect new clean energy generation, but also to meet projected demand growth and usage shifts while improving reliability and resilience in the face of increasing extreme weather events. The transmission grid buildout must also take into account the need to plan for cybersecurity risks and physical threats. The Draft Study provides an important foundation for reinvigorating the regional and interregional transmission planning process that can address all of these challenges.

Background

Despite its significant benefits, there has been very little buildout of interregional transmission in recent decades. Since FERC Order 1000 was issued in 2011 encouraging interregional transmission planning, there have been no new major interregional transmission projects approved and built.[1] The challenges to planned interregional transmission buildout include, but are not limited to, the difficulty of aligning stakeholders across multiple regions with different priorities, processes, and benefit analyses; sequenced planning processes that result in prioritizing local projects and then regional projects over interregional ones (even when interregional projects would deliver greater benefits and lower costs); agreeing on cost allocation; and overcoming multiple siting and permitting hurdles.[2] Barriers to interregional planning make it virtually impossible to maximize net consumer benefits and have created a gap in investments near and across market seams as regional planning authorities have shifted away from development along seams with neighboring regions, and instead have focused primarily on local and regional investments and generator interconnection requests.[3]

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[1] The Brattle Group, Inc., *A Roadmap to Improved Interregional Transmission Planning* (Nov. 2021), *available at* https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf, at 3.
[2] *Id.* at 4.
[3] See, e.g., *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking ("NOPR"), 179 FERC ¶ 61,028 at PP 36-42 (2022)

Multi-state, interregional, long-distance transmission projects that are needed the most have historically also been the most difficult and protracted ones to build. The draft study summarizes this as follows:

> "Multiple studies specify siting of high-voltage lines as one major challenge, indicating that developers often must navigate multiple state processes and local and federal government requirements. Criteria used to make determinations may differ in each state and may even be inconsistent. For example, some states may focus on intrastate benefits and costs only, while others may also take into account or even require interstate, regional, or national benefits and costs. Further, some states may require broad environmental and economic benefits and costs, while others may consider specific policy goals. Obtaining approvals in each state also may be difficult because many states focus on intrastate burdens and benefits. A line that does not directly connect resources within a state might not receive permits required to traverse the state."[4]

Advanced Energy United agrees with this assessment, which is consistent with the experience of our members who are engaged in transmission development. Additionally, while interregional projects are more difficult to build and should be the primary focus of the Draft Study, DOE should not ignore the fact that regional transmission lines also bring significant benefits and face many of the same barriers.

In the context of these challenges, the Draft Study establishes a common set of facts around regional transfer capability and need required to facilitate cost-effective national and regional transmission planning that can address the many obstacles to interregional planning. The

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("The vast majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities"); Continuum Associates, *Expert Consultations on PJM Supplemental Transmission Projects: Standards and Oversights* (September 13, 2019), *available at* *https://0201.nccdn.net/4_2/000/000/076/de9/final-report---caps---pjm-supplemental-transmission-projects_wo_.pdf*, at 1 (finding that PJM local transmission projects have increased from $3 million in 2013 to $3.9 billion in 2020, an increase of almost 1,300%); Initial Comments of Advanced Energy Economy, Federal Energy Regulatory Commission Docket No. RM22-14 (Oct. 13, 2022), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20221013-5196&optimized=false, at 3 ("Without a planning process that enables more robust buildout of transmission infrastructure and that accounts for transmission needs driven by interconnection queues, the interconnection process will continue to be bogged down by its de-facto role as a transmission planning process of last resort.").

[4] Transmission Needs Study ("Draft Study") at 77.

Draft Study contains valuable insight into current regional and national transmission needs, and those it anticipates in the coming decades. The Study indicates that, in a scenario with a high rate of clean electricity generation and electrification, interregional transfer capacity would need to increase nationally by 120 GW by 2035 and 655 GW by 2040. The needs of each region are then projected based on several key factors: system reliability and resilience, load and generation growth, and high price/demand areas. While there have been many recent studies focusing on various locations and specific aspects of the transmission system, the Draft Study provides an important, comprehensive national and regional picture of transmission needs across the United States that will be critical to allowing regional planning authorities to work together to achieve mutually beneficial outcomes. The Draft Study provides indisputable evidence that the United States' energy grid must rapidly expand interregional transmission to meet our nation's reliability needs and state and federal climate targets.

DOE's study comes at a critical time in the transition of the fuel mix for electric generation. Significant investment in transmission, including interregional transmission, will be needed to: improve grid reliability, resilience, and resource adequacy; and to enhance renewable resource integration and access to clean energy. Expended transmission facilitates delivery of affordable clean energy from where it is produced to where it is needed; decreases energy burden; supports electrification efforts; and reduces congestion and curtailment—all of which will lower consumer costs and improve grid performance over the long term. While investments in transmission facilities of all kinds (as well as distribution facilities) will be needed to meet these needs, it is understood that regional and interregional transmission facilities are the type most needed to meet demands for advanced energy resources to satisfy state policy requirements, large customer commitments, and emerging frameworks to decarbonize the electricity system by 2050.[5]

There are currently many barriers that hinder and prevent the approval of transmission lines, including: competing state policy priorities; absence of dedicated siting authorities, lack of staff, expertise, and required funding where siting authorities exist; and the abundance of "veto points" where any single siting process can result in a project's rejection. While addressing these issues will be a multi-year effort, the Draft Study is an important benchmark and guidepost to help advance these efforts.

Study Highlights

The Draft Study acknowledges the importance of Grid Enhancing Technologies ("GETs"), stating: "GETs deployment can also improve the reliability of the existing transmission system, which can serve as an economical alternative to transmission expansion in certain scenarios."[6] GETs can also be instrumental in rapidly freeing up the underlying congestion points as clean energy deployment accelerates, providing a solution to rapidly clear congestion points while new transmission infrastructure deployment is underway. GETs are a critical component of comprehensive transmission solutions, and the study should go much further in advancing the full deployment and utilization of GETs as they can provide key solutions in advance of, during, and following the construction of new transmission projects.

The Study emphasizes the importance of regional and interregional transmission planning to ensure reliability in the face of increasingly common extreme weather events, finding that

[5] *See* Initial Comments of Advanced Energy Economy, Federal Energy Regulatory Commission Docket No. RM21-17 (Oct. 12, 2021), available at https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5539&optimized=false, at 23.
[6] Draft Study at 75.

"[r]ecent experience with extreme weather events demonstrates that planning for the bulk power system needs to extend beyond the footprint of individual utilities or regions to provide assurance that energy can be delivered from where it is available to where it is needed to mitigate risks associated with common mode failures."[7] Highlighting the importance of scenario-based multi-value transmission planning in reducing costs for consumers, the Draft Study also finds that "holistic, scenario-based, multi-value transmission expansion planning can also provide energy price benefits to consumers."[8]

Failure to conduct transmission planning across a regional and interregional portfolio using a multi-value and scenario-based methodology produces an inefficient patchwork of incremental transmission projects that limit the planning processes' ability to identify more cost-effective investments that meet both current and rapidly changing future system needs, address uncertainties, and reduce system-wide costs and risks that systematically results in inefficient infrastructure and excessive electricity costs. As a result, current transmission planning processes across the nation result in inefficient investments that foreclose meaningful competition, miss out on economies of scale, and result in consumers paying considerably more for significantly less - less choice, less capacity, less flexibility, less resiliency, and ultimately less reliability.

The Draft Study cites several indicators that point to an immediate need for more transmission infrastructure, including removing or reducing the variation in prices caused by congestion by allowing lower-cost energy to reach high demand areas. The Draft Study also notes that over the last several years, installation of new generation, the vast majority of which is renewable, has been delayed because of longer wait times for interconnection agreements and

[7] Draft Study at 3.
[8] Draft Study at 3.

increased costs to connect to the grid, demonstrating that a "piecemeal" approach to transmission deployment through the interconnection process is less effective than a fulsome and proactive regional transmission planning process.[9]

The Draft Study demonstrates that transmission investment in lines greater than 100-kV and the pace of high-voltage transmission buildout generally has slowed significantly since 2011, as transmission operators have largely sought to avoid the regional planning process. Order No. 1000 excludes local reliability projects from the regional planning process,   the vast majority of transmission investment over this period have been local projects.[10] The result has been the buildout or replacement of local transmission projects (lower voltage lines) that are built outside of the context of an efficient, optimized regional plan and without competition or effective oversight.[11] Further, this local, piecemeal approach has had the effect of failing to result in sufficient buildout of the regional transmission grid, resulting in backlogged interconnection queues in many regions as interconnection requests trigger increasingly significant network

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[9] Draft Study at 19.

[10] See, e.g., *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking ("NOPR"), 179 FERC ¶ 61,028 at PP 36-42 (2022) ("The vast majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities").

[11] See, e.g., The Brattle Group, "Cost Savings Offered by Competition in Electric Transmission" (April 2019), *available at* https://www.brattle.com/wp-content/uploads/2021/05/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf, at 6-7 ("about one-half of the approximately $70 billion of aggregate transmission investments by FERC-jurisdictional transmission owners in ISO/RTO regions [was] approved outside the regional planning processes or with limited ISO/RTO stakeholder engagement."); Americans for a Clean Energy Grid (ACEG), "Planning for the Future" (Jan. 2021), *available at* https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf, at 25-26, Figure 8 (showing steep decline in regionally-planned transmission investments in RTOs); PJM, "2020 Regional Transmission Expansion Plan" (Feb. 28, 2021), *available at* https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx, at 4 (showing that in 2020, PJM approved investments in 43 baseline projects (which includes larger regional and interregional projects) totaling $413 million versus 236 supplemental projects at a total cost of $4.7 billion); MISO Transmission Expansion Plan 2020 (MTEP20), available at https://www.misoenergy.org/planning/planning/previous-mtep-reports/#nt=&t=10&p=0&s=FileName&sd=desc, at Appendix A (showing that nearly all new transmission is built outside of regional planning processes in MISO today).

upgrade requirements. The slowdown in higher-voltage transmission buildout since Order No. 1000 has led to an increase in congestion and constraints along with increased costs.

The regional and interregional coordination process required by Order No. 1000 clearly has not produced the intended results. Eliminating existing barriers to regional and interregional transmission projects can maximize net consumer benefits across regions and improve reliability and resilience in the face of increasing extreme weather events. Barriers to interregional planning have made it virtually impossible to maximize net consumer benefits by providing access to lower cost renewable resources. The focus on local projects has created a gap in investments near and across market seams as regional planning authorities have shifted away from development along seams with neighboring regions and instead have focused primarily on local and regional investments and generator interconnection requests.

Conclusion

Advanced Energy United strongly agrees with DOE that expanded transmission capacity between the three US interconnections, between different regions of the country, and between different utility service territories is essential for developing the transmission necessary to facilitate a reliable, affordable, and clean energy system. Advanced Energy United views the Draft Study as a positive step toward accelerating the transmission buildout, and we support DOE's efforts in the Draft Study to identify national transmission corridors and review proposed transmission projects that may be eligible for funding through the Infrastructure Investment and Jobs Act and the Inflation Reduction Act. It would be very beneficial if the DOE could articulate in the final Study how the Study results will be used to evaluate corridors going forward as part of DOE-FERC permitting authority under section 216 of the Federal Power Act.

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Advanced Energy United thanks the DOE for the opportunity to comment on this Study and we look forward to working with the DOE and other stakeholders in advancing a national transmission infrastructure agenda.

Respectfully,

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The AES Corporation ("AES") appreciates the opportunity to comment on the U.S. Department of Energy's ("DOE") National Transmission Needs Study (the "Study"). The detailed summary of United States transmission needs provides a useful shared reference of the type and magnitude of needs that exist by region and nationally. This catalog should drive focus to scalable solutions that can be funded, deployed, and supported with national policy and appropriate localizations based on regional insights.

The Study does not specifically enumerate solutions to the identified needs but leaves that task to industry and the public. AES supports this needs-based, technology-agnostic approach and looks forward to helping identify the significant and growing list of available technologies that can address both near and long-term transmission needs. These technologies are not only the traditional wires and substations required for new transmission builds, but also enhancements through reconductoring and storage-as-transmission, digital improvements through dynamic line rating, topology optimization, power flow controls, and demand-side solutions like demand response and aggregations of energy.

AES sees an enormous opportunity from the once-in-a-lifetime transformation of the electricity sector driven by decarbonization, electrification, and digitalization to make our grid "smart," capable of delivering our customers' needs, and connecting renewable energy at speed. We must deploy the best available technologies into our grid to solve our transmission needs with optimal speed and flexibility while maintaining a safe, reliable, and affordable energy system.

I. Introduction to AES

AES is a Fortune 500 global energy company accelerating the future of energy. Together with our many stakeholders, we're improving lives--and our planet--by delivering greener, smarter energy solutions to businesses and organizations, cities and nations, and whole industries. AES is an industry leader in developing and operating the solutions that will enable the transition to zero and low-carbon sources of energy and achievement of the Paris Agreement's goal of net-zero emissions by 2050.

AES is uniquely positioned as a clean energy developer and owner, transmission-owning utility, and innovation incubator to identify insights to the systems level challenges and opportunities in our electrical grid, including those related to transmission capacity. As the #1 global clean energy developer for corporations,[1] we are consistently engaged in permitting and interconnection processes and with our customers to deliver the solutions they need. With our utilities, we are working to modernize our transmission and distribution grid assets to serve our customers and move to lower carbon forms of energy while promoting a Just Transition for the workers and communities who may be negatively impacted by the closure of fossil fuel facilities. AES is also developing and incubating new technologies that add value today and will drive the electrical grid of the future.

AES shares the same concerns as many stakeholders in the electricity system related to interconnection queue delays, project curtailment, transmission congestion, and the time required to site, permit, and build new transmission lines. These challenges require system-level collaboration between participants and an inclusive multi-solution approach leveraging a combination of new transmission build and existing system optimization. As we build the new transmission infrastructure needed for an electrified and decarbonized future, we should also make the most of the grid we already have and unlock existing and underutilized transmission capacity at an accelerated rate. Existing technologies like dynamic line rating and storage-as-transmission are ready to deliver increased transmission capacity today as we build out new transmission assets. We must make use of all available technology where best applied.

[1] *Corporate clean energy buying TOPS 30GW mark in record year*. BloombergNEF. (2022, January 30). Retrieved April 2023, from https://about.bnef.com/blog/corporate-clean-energy-buying-tops-30gw-mark-in-record-year/.

II. AES supports DOE's National Transmission Needs Study

AES values DOE's attention to the pressing issue of transmission capacity in the United States and the decision to facilitate a baseline understanding of the topic by summarizing the existing state of literature and highlighting the historical and anticipated drivers, benefits, and challenges of expanding the Nation's electric transmission infrastructure. We support the periodic update of this Study and thank DOE for keeping momentum on this important topic while encouraging broad and continuously updated thinking about solutions to transmission capacity needs.

AES supports DOE's stated purpose of the Study, specifically "to identify needs that could be alleviated by transmission solutions…in order for industry and the public to suggest best possible solutions for alleviating them in a timely manner."[2] AES understands that DOE will use the results of the Study to "inform…the use of its authorities and funding relates to electric transmission"[3] and encourages DOE to apply a similar needs-based and technology-agnostic approach to its authority and funding.

AES appreciates that the needs summarized by DOE relate to "the existence of present or expected electric transmission capacity constraints or congestion in a geographic area."[4] AES values the further detailing of transmission needs through several technology-neutral "use case" descriptions, including:

- Improved reliability and resilience;
- Alleviation of transmission congestion on an annual basis and during real-time operations;
- Alleviation of unscheduled power flows as a result of unplanned congestion or constraint;
- Improve transfer capacity and transfer limits;
- Renewable resource integration and access to clean energy;
- Meet projected generation and demand growth with cost-effective generation.[5]

AES notes that the above paraphrasing of transmission needs is not consistently applied throughout the Study and recommends that DOE further help industry and the public by clearly applying the above, or similar, needs categories to specific Study findings. This consistency would enable a mapping of needs and solutions by category, ultimately providing a helpful guidebook to how system operators may most flexibly, quickly, and at best-cost to ratepayer increase transmission capacity. AES would appreciate the opportunity to collaborate on such a guidebook.

While AES understands that transmission capacity needs differ in type and magnitude between regions, and values DOE's enumeration of those regional differences, we are confident that there are sufficient shared needs to support solutions, processes, and policies that can be deployed at scale across the electrical grid for system-level impact. These scalable solutions can be deployed where they are the best available technology for identified needs and adapted, as appropriate, to the regional context in which they are used. This approach will allow participants to address transmission capacity needs more optimally by building new transmission as well as making the most of latent transmission capacity in our existing electrical grid to accelerate decarbonization in a timely and cost-effective way.

AES notes that DOE included "non-wire alternatives" in its description of "upgraded or new transmission facilit[ies]."[6] AES is pleased to see that DOE considers the broad category of solutions

[2] U.S. Department of Energy, National Transmission Needs Study (Draft for Public Comment, February 2023) at ii.
[3] *Ibid.*
[4] *Ibid.* at 9.
[5] *See, e.g., ibid.* at ii.
[6] *Ibid.* at ii.

generally referred to as "non-wire alternatives" to be on par with transmission facilities and applauds the DOE for including a dedicated section of the Study discussing the benefits.[7] AES approves of the simple definition of transmission conveyed on page 8 of the Study and recommends that the DOE broadly use this definition in defining both needs and solutions: "Transmission can refer to any facility that helps in the delivery of power from where it is generated to where it is used." Such a simple and inclusive definition would fully support DOE's purpose in this Study and enable both new transmission build and deployment of advanced technologies as best suited to address an identified need.

Finally, AES values DOE's dedicated section on interconnection queues and the correlation between the delays in those queues and the need for transmission capacity.[8] The greatest symptom showing a connection between proactive planning of transmission capacity and interconnection is the ballooning queue that now often takes five years to navigate and results in a record number of project withdrawals.[9] AES supports the Study's connection between interconnection delays, the need for proactive transmission capacity planning (including clarity in scope and cost)[10] and investment, the allocation of transmission upgrades to the developer through the interconnection process, and limited alignment around the allocation of benefits (and related costs) from increased transmission capacity. AES continues to be supportive of utility integrated planning between new and existing generators, transmission, and load and encourages transparency and solutions-oriented collaboration in planning.

III. There are market-ready technologies in addition to traditional transmission build that can more quickly and less expensively address certain needs identified by the Study

AES thanks DOE for the opportunity to begin identifying certain key technologies and benefits that address the needs collected in the Study. Although these market-ready technologies do not obviate the need for new transmission build or upgrades through traditional approaches or advanced conductors, for example, these technologies can deliver increased transmission capacity in a short period of time and at a lower cost than traditional transmission build. These technologies have the added benefit of advancing our electrical grid to a more capable, digitally facilitated, and dynamic form. These technologies can therefore be utilized now to unlock additional, existing, transmission capacity while we simultaneously plan and develop new transmission infrastructure for the grid of the future.

Storage-as-transmission is a set of utility-scale energy storage systems placed at strategic points on a transmission line, that can inject and absorb real and reactive power to the transmission grid to mimic the addition of traditional wires capacity. The Study found that 50% of transmission congestion value comes from only 5% of hours.[11] Strategic planning to site energy storage near load centers can provide flexible peaking capacity, system stabilization, and can **mitigate transmission congestion**. Storage-as-transmission can further address **renewable resource integration and access to clean energy** by effectively reducing grid congestion and increasing transmission capacity through energy shifting or replacing n-1 contingency reserves, offsetting certain needs to make additional investments in conventional assets like wires, poles, and substations.

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[7] U.S. Department of Energy, National Transmission Needs Study (Draft for Public Comment, February 2023. at 73-76.

[8] *Ibid* at 37-39.

[9] Rand, J., Strauss, R., Gorman, W., Seel, J., & Others. (2023). (tech.). Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2022. Lawrence Berkeley National Laboratory. Retrieved April 2023, from https://emp.lbl.gov/sites/default/files/queued_up_2022_04-06-2023.pdf at 3.

[10] Transmission capacity can be unlocked through a combination of new infrastructure and the integration of technologies to optimize the system.

[11] U.S. Department of Energy, National Transmission Needs Study (Draft for Public Comment, February 2023) at ii.

Dynamic Line Rating ("DLR") uses sensors to monitor a line's properties and ambient conditions to maximize its capacity. The Study highlights that "power flow could be constrained by the maximum thermal limit of a [power line conductor]. As a result, power is rerouted through less optimal paths to deliver more expensive generation while curtailing delivery of less expensive generation to safely meet customer demand."[12] Effective deployment of DLR optimizes grid utilization by making available maximum usable transmission capacity.[13] This, in part, addresses the specific need of **improving transfer capacity and transfer limits** through less grid congestion and improved operations and planning. DLR also is a measure to better inform operators of conductor thermal limitations referenced in the Study.[14] DLR could also help reduce interconnection queue delays and improve **renewable resource integration and access to clean energy** if data and insights from DLR is incorporated into transmission planning models.

Aggregations of energy (e.g., virtual power plants) include networks of decentralized, medium-scale power generating units such as solar plants and combined heat and power units, as well as grid-interactive storage systems and flexible load consuming assets that can engage in demand response. The Study identifies needs for additional transmission capacity to meet peak demand in energy systems that are highly dependent on variable energy resources, particularly during extreme weather conditions.[15] Aggregations of energy can help balance energy supply and demand close to load, thereby reducing the overall need for additional transmission capacity by reducing peak demand by 60 GW by 2030.[16] Through effective dispatch of aggregated energy, grid operators can leverage decentralized energy assets at scale and participate in wholesale energy markets while **improving reliability and resilience**. As decentralized assets proliferate, aggregation can yield increased grid capacity and utilization within the status quo footprint while being faster and cheaper to deploy than traditional transmission build, thereby **meeting projected generation and demand growth with cost-effective generation**.

Enhanced grid visualization and simulation software ingest a broad set of data to build a shared view of the electrical grid through visualization of the as-built electrical and/or physical system. Grid planners and operators may run scenarios to simulate grid response for improved operations and maintenance and to plan for an electrical grid that meets the needs of our changing system. The Study notes that "capacity expansion modeling studies help quantify the range of new transmission needed to meet future demand."[17] Enhanced grid visualization and simulation software can provide a more accurate view of grid conditions and yield **improved reliability and resilience** with and without the need to invest in additional transmission capacity. Enhanced grid software will continuously improve with ingestion of the various data streams enabled by the $3 billion authorization for Smart Grid Investment Matching Grants managed by the DOE.[18] Of the technologies listed, this is the most nascent, but as system participants realize the value of enhanced visualization and simulation in their operations and planning, we will **alleviate transmission congestion and unplanned power flows** and plan a path to accelerated **renewable resource integration and access to clean energy**.

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[12] U.S. Department of Energy, National Transmission Needs Study (Draft for Public Comment, February 2023) at 9.

[13] Static thermal ratings prevent the grid from operating at maximum capacity without sacrificing reliability.

[14] *Ibid* at 10.

[15] *Ibid* at iv.

[16] K. Brehm, A. McEvoy, C. Ursy, M. Dyson, Virtual Power Plants, Rocky Mountain Institute (Report, 2023), retrieved April 2023, from https://rmi.org/insight/virtual-power-plants-real-benefits/.

[17] *Ibid.* at 106.

[18] Grid Deployment Office, Smart Grid Grants, retrieved April 2023, from https://www.energy.gov/gdo/smart-grid-grants.

In addition to encouraging the development of new technologies, AES urges DOE to support the numerous existing market-ready solutions that address the challenges of transmission capacity constraints and congestion, whether traditional transmission facilities or wires enhancing technologies. Only through a full portfolio of technologies will we accelerate the transition to a decarbonized and digitally enabled electrical grid and deliver our customers' needs safely, reliably, and affordably.

IV. Conclusion

To decarbonize our electrical grid by 2050, the U.S. will need to build more than twice the transmission capacity in the next seven years than was built in the last decade.[19] The U.S. will struggle to meet this objective if the industry relies solely on new transmission line build, as those lines regularly take ten or more years to build.[20] Recognizing that fact, we must make use of the various market available technologies that address transmission needs as they deliver improvements – even if sometimes incremental – in a fraction of the time and cost of new line build.

AES appreciates the opportunity to submit these comments on the DOE's National Transmission Needs Study. We have a once-in-a-lifetime opportunity to deliver step-change improvements to our grid, customers, and communities through a smart digital grid that is safe, reliable, affordable, and decarbonized. We respectfully ask the DOE to consider the observations and recommendations made.

[19] Jenkins, J.D., Farbes, J., Jones, R., Patankar, N., Schivley, G., "Electricity Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act," REPEAT Project, (September 2022) at 4.

[20] Clifford, C. (2023, February 22). *Why it's so hard to build new electrical transmission lines in the U.S.* Retrieved April 2023, from https://www.cnbc.com/2023/02/21/why-its-so-hard-to-build-new-electrical-transmission-lines-in-the-us.html/.

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ALASKA
ENERGY
AUTHORITY

ELECTRONICALLY SUBMITTED March 3, 2023

U.S. Department of Energy
NeedsStudy.Comments@hq.doe.gov

RE: National Transmission Needs Study
Comments on the Public Draft – Entire Study

Dear Grid Deployment Office,

The Alaska Energy Authority (AEA) is a public corporation of the State of Alaska governed by a board of directors with the mission to "reduce the cost of energy in Alaska". AEA is the state's energy office and lead agency for statewide energy policy and program development.

The National Transmission Needs Study public draft (Study) is very interesting but ignores Alaska and Alaska was not consulted. The existing transmission systems serves 90+% of the State of Alaska population and strategic military bases. Because of the past minimal federal investment in the Alaska transmission system in the system is aged with little resiliency or redundancy. A transmission incident may take longer to fix in Alaska because of the remote locations and lack of alternative power routing. If a power failure occurs at minus forty degrees the potential impacts of house and water systems freezing up will be much greater than in warmer states. Alaska is studying a substantial build out of the system for resilience, reliability, and to meet future electrification loads.

AEA believes Alaska should be considered, consulted, and in the National Transmission Needs Study.

Questions related to this request should be directed to Bryan E. Carey at 907.771.3065 or bcarey@akenergyauthority.org.

Sincerely,

Curtis W. Thayer
Executive Director

Cc: The Honorable Lisa Murkowski, United States Senate
The Honorable Dan Sullivan, United States Senate
The Honorable Mary Peltola, United States House of Representatives
John Espindola, Special Assistant, Office of the Governor

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April 20, 2023

U.S. Department of Energy
Grid Deployment Office
1000 Independence Avenue, SW
Washington, DC 20585

Re: Alliant Energy Comments on the Draft of the National Transmission Needs Study

I. Introduction

Alliant Energy ("AE") is a service company affiliate of Interstate Power and Light Company ("IPL") and Wisconsin Power and Light Company ("WPL") (collectively, the "Alliant Energy Operating Companies"). IPL is a load-serving entity ("LSE") that owns and operates electric facilities engaged in the generation, purchase, distribution, and sale of electric power and energy in Iowa. WPL is an LSE that owns and operates electric facilities engaged in the generation, purchase, distribution, and sale of electric power and energy in Wisconsin. Neither of the AE Operating Companies owns or operates transmission facilities. The AE Operating Companies are MISO Market Participants and incur costs associated with purchasing transmission, capacity, energy, and ancillary market service within the MISO market.

AE is taking bold steps to address climate change through its Clean Energy Blueprint.[1] With an eye toward reducing carbon dioxide emissions and delivering cleaner, more cost-effective energy, AE is working toward retiring all coal resources from its generation fleet by 2040. To

[1] https://www.alliantenergy.com/cleanenergy/ourenergyvision/poweringwhatsnext/cleanenergyblueprint

achieve these goals, AE plans to add up to 400 megawatts ("MW") of solar in its IPL territory and 1,100 MW of solar in its WPL territory by 2024. It is also currently the third-largest utility owner-operator of regulated wind in the United States, with over 1,300 MW installed.

AE appreciates the Grid Deployment Offices ("GDO") detailed work in putting together the National Transmission Needs Study ("Needs Study"). AE notes that the Needs Study is helpful when looking at historical transmission investment and where constraints on the system exist or existed. However, AE is concerned that the study does not provide adequate context for transmission investment decisions, misses an important focus on system optimization, lacks discussion on the customer impacts of transmission spending, and generally lacks applicable context in how we can build-out the transmission system in a cost-effective manner. As the Needs Study is looking at both historic and anticipated needs, it is important to understand policies and business incentives that have led to the current needs identified in the Needs Study to ensure that the future grid is not hampered by the same inefficiencies we see today.

II. General Comments

1) AE Supports Building Out the Transmission System When Necessary

AE supports building out the transmission grid where necessary to maintain reliability, resilience and connect new generation resources to the grid. As system expansion is being considered, there also needs to be a strong focus on optimizing current and future infrastructure. As transmission needs and costs grow, it becomes even more imperative that the existing transmission system be utilized to the greatest extent possible along with targeted, cost-effective expansion. Transmission has real costs to customers. System optimization is an important component to achieving increased renewable energy deployment quickly and at an affordable cost for customers. As recognized in Section V.h.3, Grid Enhancing Technologies ("GETs") deployment, which can aid in system optimization, can also improve the reliability of the existing transmission system. These types of solutions can serve in multiple roles including acting as economical alternatives to transmission expansion in certain scenarios, aid in extracting more value from system expansion, and help address system needs while other transmission construction takes place. However, in current transmission planning processes, alternatives, including GETs, are not given appropriate consideration. AE is concerned that the Needs Study only serves to reinforce the biases inherent in the current transmission planning processes for traditional solutions (e.g. traditional upgrades and wires projects). AE would encourage the DOE to conduct a formal study and analysis of how to incorporate GETs into transmission planning processes, such as those conducted by MISO, so they can be utilized to meet identified needs more cost-effectively.

2) AE Supports the Need for Enhanced Interregional Transmission Planning

AE agrees that increasing the ability to transfer energy between regions can help with reliability of the transmission grid and potentially provide low-cost renewable power from generation to load centers. However, AE notes that a minimum interregional transfer capability requirement was the subject of a recent FERC technical conference and comments on that technical conference are due in May 2023.[2] The panelists at the technical conference raised many important concerns that should be considered when determining a need for interregional transfer capability expansion. Questions and issues around the potential establishment of a minimum interregional transfer capability requirement need to be considered carefully as well as other potential ways transfer capability between regions could be improved. Examples of concerns include cost allocation, non-transmission solutions, including generation alternatives and, the cost for customers of transmission solutions to meet interregional transfer requirements versus the

[2] Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements held December 5-6, 2022 (Docket No. AD23-3-000).

commensurate benefit. Specifically, cost allocation for these projects should be based on a beneficiary pays approach where the beneficiaries from improving the ability to transfer energy will need to be identified and considered as this topic evolves.

3) AE Agrees That Needs Will Shift Overtime

AE acknowledges that transmission needs will shift over time with electrification, cleaner intermittent generation, and other societal changes that will come with the energy transition. In addition to these changes, other technologies are likely to evolve and advance that can help meet future transmission needs. Going forward, the transmission planning processes must become more dynamic and flexible to respond to changing needs and solutions. We cannot simply rely on finding new ways to do the same old thing with planning the system. Grid planners are grappling today with how to integrate a wide variety of storage, distributed resources, and demand-response offerings that were not contemplated even five years ago. These technological advances are important and can lead to a more efficient and well-functioning grid. But they also make reliance on long-term planning to approve transmission projects more prone to costly inefficiencies, as the rapidly evolving grid makes some approved transmission projects obsolete before they are even completed.

AE supports long-term transmission planning but with a requirement that long lead time projects are reviewed every 3-years to ensure assumptions in the initial project planning and approval remain valid. A 3-year reassessment period can ensure that if there has been a material change in the assumptions driving a project, the project is reevaluated to ensure that the effectiveness and benefits of the project remain similar to when it was originally proposed. The results of this review process could mean that either a larger or smaller project is required or potentially that another solution should move forward to best meet expected needs of the grid and customers. In addition, while the Needs Study is a valuable resource for understanding the challenges facing the electric grid, it is important to note that some transmission needs may have already shifted from those identified in the study due to its reliance on historical studies.

III. Section Specific Comments

Below AE provides comments to specific sections of the Needs Study. Although some of the comments may be applicable to more than one section of the Needs Study, AE has attempted to include the comment in the most relevant section.

1) Section I: Introduction

a. AE appreciates that the Department recognizes the Needs Study should not replace the current planning processes that are undertaken by the regional planning entities. AE believes that regional planning processes should be robust and transparent with long lead time projects periodically reviewed on set intervals of no less than 3 years to ensure the right solution is being pursued. Planning must use robust bookend futures with stakeholder feedback meaningfully considered. Planning also should recognize the increasing role of alternative solutions such as energy storage and the potential for High Voltage DC lines to improve reliability of the transmission system. Projects that move forward should be supported by robust business cases, with proper cost to benefit ratios and a demonstration made that alternatives were considered. The integration of increased renewable energy resources as well as a greater overall reliance on the electric system will involve a range of solutions across transmission, distribution, generation and rate design. Transmission planning processes need to evolve to ensure a growing range of solutions and changes are being appropriately factored. Not doing so creates a growing risk of sub-optimal system planning and higher costs than necessary for customers.

b. AE believes that the Needs Study should identify ongoing reforms, at the federal, state and regional levels, that may address the needs that are identified in the study. For example, a need identified for the Midwest region is to "Increase transfer limits between the Midwest and Plains regions to meet future load and generation growth." This need is being targeted as part of the MISO and SPP Joint Targeted Interconnection Queue (JTIQ) Study as well as with MISO's Long Range Transmission Planning (LRTP) effort which consists of multiple tranches of projects focused on various areas and needs of the MISO footprint. It is important to identify not only needs but as well as efforts underway to address these needs. This will help identify gaps either in planning that needs to occur or silos that exist with efforts underway.

2) Section IV.a:. Historical Transmission Investment

a. In Figure IV-1 (top and bottom) the Needs Study shows transmission investment spending by all regions and specific regions, however, when looking at project drivers (Figures IV-2 and IV-3) the data is only shown at the national level. AE believes that representing this data at a regional level could help corelate specific project driver trends and transmission investment in various regions to understand key differences that market rules and policies can have on transmission development.

b. In Figure IV-2, the Needs Study shows the proportion of transmission investment by developer type (incumbent and non-incumbent). AE believes that additional context is necessary. The Needs Study should identify federal policies (such as FERC Order No. 1000), state policies (such as state ROFR laws), and regional policies that may have contributed to the decrease in non-incumbent transmission investment.

c. In Figure IV-3, the Needs Study identifies primary drivers of projects. AE believes that adding how the MAPSearch database defines each project driver may be beneficial to understand how regional definitions are being categorized in the data.

d. Generally, AE believes that additional context is needed to understand why many of the needs identified exist. For example, in Figure IV-3, the chart shows a large decrease in high-capacity circuit-miles installed each year after 2013. Based on Figure IV-3, there were almost zero high-capacity transmission circuit-miles installed in 2014, 2017, 2019 and 2020. Why is that? High-capacity lines, such as HVDC, can certainly serve as a cost-effective way to increase inter-regional transfer capability and increase reliability. However, without understanding the drivers of the data trends, such as policies and business incentives that drive transmission investment, it is difficult to make informed conclusions and decisions on how best to correct for the need. AE is concerned that transmission owners will use the Needs Study to justify continued large increases in transmission spending without making the necessary reforms to cost-effectively built-out the transmission grid.

e. AE believes that the Needs Study should include a conversation about how transmission spending will ultimately be paid for by customers and the burden that increased transmission investment will have on ratepayers. According to S&P Global Market Intelligence, in MISO for transmission owners with formula rates, rate base has increased from $11.1 billion in 2012 to $36.9 billion in 2022.[3] The compound annual growth rate (CAGR) in transmission rate base between 2012 to 2022 was 11.6%. The growth in rate base is passed onto consumers through their monthly utility bill, resulting in transmission representing a growing percentage of a customer's overall bill. For Interstate Power and Light Company (an AE subsidiary that operates in the state of Iowa), transmission costs make up approximately 19-25% of the monthly electric bill. For residential customers, transmission makes up 19% of the customer's bill and the year-over-year increase from 2022 to 2023 was 8.5%.[4] AE notes that the words "rate base" are not included in the Needs Study. Transmission investment leads to costs for customers and this cost impact cannot simply be an afterthought as future system needs are considered.

3) Section V.h: Alternatives

a. AE appreciates GDO recognizing the cost-effective impacts that non-wire alternatives, such as GETs, can have on the transmission system. AE supports optimizing the use of the system and evaluating project alternatives to cost effectively meet future needs. Alternatives, such as GETs, should be considered in any planning process. GETs (like flow control, storage and enhanced line

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[3] S&P Global Market Intelligence, *Transmission rate base, authorized ROEs of US utility operating companies in the Midcontinent ISO.*

[4] https://www.alliantenergy.com/accountandbilling/billmeterrates/ratesandtariffs/electricratesiowa/regionaltransmissionservice.

ratings) can complement current grid infrastructure by providing better system utilization which lowers costs for customers. In addition, the application of alternatives with new build (e.g., flow control added to new lines) can also help maximize the benefits received from expended infrastructure and aid in optimizing the overall amount of new transmission required. AE believes the final Needs Study should have a greater focus on alternatives and better recognize the multiple ways future system needs can be met.

b. AE believes the GDO should incorporate the study *Unlocking the Queue with Grid-Enhancing Technologies*[5]. The study found that GETs (Advanced Power Flow Control, Dynamic Line Ratings, and Topology Optimization which were looked at in the study) enable more than twice the amount of additional new renewables to be integrated into the SPP footprint (Kansas and Oklahoma). In addition, the study found an estimated annual production cost savings of $175 million, estimated carbon emissions reduction of over 3 million tons per year, and estimated tax revenues of $32 million per year.

c. As recognized in Section V.h.3, GETs deployment can also improve the reliability of the existing transmission system and can serve as an economical alternative to transmission expansion in certain scenarios. However, in current transmission planning processes, alternatives such as GETs, are not given appropriate consideration. For example, the MISO planning process essentially places the onus on interested, non-transmission owning, stakeholders to propose non-

[5] Tsuchida T, Ross S and Bigelow A. 2021. Unlocking the Queue with Grid-Enhancing Technologies. https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf

transmission alternatives to address transmission system issues. Many stakeholders do not have the knowledge, information, or ability to study and propose alternatives. Further, the level of understanding that many stakeholders have of the regional transmission grid is a fraction of that held by transmission operators like MISO. As a result, the population of proposed non-transmission solutions or non-traditional transmission solutions is limited. By not considering a full range of solutions and seeking to optimize the use of the system, the result can be unnecessary transmission expansion and cost burdens on customers. Future efforts by the GDO should look at policies that prohibit the incorporation of alternatives in the transmission planning process and not just focus on traditional transmission solutions.

d. In *U.S. Department of Energy: Grid-Enhancing Technologies: A Case Study on Ratepayer Impact*, the DOE looked at GETs impact on the NYISO. AE found the study useful but asks that additional resources are dedicated to exploring how GETs can be incorporated in other regions to alleviate needs identified in the Needs Study. AE, as a stakeholder in the MISO transmission planning process, advocates for the consideration of alternatives and is seeking to better implement solutions such as flow control. It is clear; however, that other voices and resources are needed in order to make progress with the study and application of GETs. AE sees a role for the DOE to fund studies that explore opportunities for GETs to alleviate transmission needs through better utilization of the grid and to better build-out the grid of the future with GETs.

4) Section IV.d: Interconnection Queues

a. From AE’s experience, delays in the interconnection process have been largely created by affected system issues and projects dropping out of the queue creating the need for re-studies to be performed. Considering this, a more effective way to decrease interconnection timelines is reforms that address these underlying issues. For example, MISO’s now three-phase interconnection process essentially builds re-restudies into the process. This enables projects to exit the queue more naturally without creating unexpected process issues. Although not perfect, AE supports the reforms being undertaken in MISO and believe that the Needs Study should identify reforms that have been undertaken to address specific issues in various regions.

b. The Needs Study mentions various barriers that generators face when trying to manage the interconnection process. AE believes the Needs Study should also recognize the barriers for storage resources (including hybrid resources) in the interconnection process. Study assumptions that are typically used in interconnection studies do not adequately reflect how an extremely flexible resource like storage can operate which can lead to higher interconnection costs. AE supports a focus on improving the integration of storage into planning to better reflect its capabilities and benefits that can be made available to the system. AE has firsthand experience of trying to interconnect storage resources and subsequently withdrawing requests due to the high cost of network upgrades, driven in part from overly conservative assumptions that are not reflective of how the resource would actually operate. AE believes there is more progress to be made in ensuring that the ability to precisely control storage resources (both charging and discharging) is reflected in the interconnection process and that these resources are able to make use of available transmission capacity in order to provide a highly flexible resource to the system.

5) Section V.a: Reliability

a. In multiple instances, the Needs Study cites MISO's Renewable Integration Impact Assessment (RIIA). AE acknowledges the value of the RIIA but would also like to make clear the limitations of this study work. RIIA was very helpful in understanding the types of system issues that could be experienced under increasing renewable energy penetration levels. The study, however, was not intended to show how these issues should be addressed and did not focus implementation steps that would likely be taken as more renewables are brought online. For example, when asked if the system breaks at 30% renewable penetration, MISO answered "RIIA found the challenges to integrate renewables increase as the penetration increases, with a stark escalation occurring between the 30-40% penetration levels. However, even at the 50% milestone, the system can still operate reliably once solutions utilizing existing technology are deployed. MISO did not find any milestones of the system being inoperable, up to the 50% milestone studied."[6] There is much work yet to do in understanding how best to integrate higher renewable energy levels which will influence potential inflection points on the system. The RIIA results showed that there is more analysis needed to truly understand how to optimally integrate renewable energy resources onto

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[6] MISO's Renewable Integration Impact Assessment (RIIA) at 203. https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

the system.

6) Section V.c Clean Energy

a. Figure V-2 has an error and shows an 80% clean energy percentage twice.

b. Figure V-2 shows clean energy penetration and the amount of estimated spending on transmission. The graph has clear outliers and may be more useful if there was a best fit line to show the mathematical relationship between the two variables. Also, removal of outliers may be necessary to ensure the fitted line is not influenced by unrealistic variables. Finally, the Needs Study lacks context for Figure V-2. In *DOE, Queued Up and In Need of Transmission*, the analysis provides additional context for why estimates can vary widely. It would be helpful to include the additional information in the Needs Study.

IV. Conclusion

AE appreciates the opportunity to provide comments on the Needs Study. AE looks forward to continued dialogue with the GDO on efforts to built out the transmission system in a cost-effective manner. AE stresses the importance of keeping the customer top of mind when developing policies that will have a real impact on the budgets of American's nationwide.

Respectfully Submitted,

/s/ Cy McNeill
Cy McNeill
Federal Regulatory Relations Manager
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Alliant Energy
801 Pennsylvania Ave, N.W.
Suite 640
Washington, D.C. 20004

4/20/23

To: Hon. Jennifer Granholm, Secretary
U.S. Department of Energy

Re: Comments on the Public Draft Transmission Needs Study

Via: NeedsStudy.Comments@hq.doe.gov

Dear Secretary Granholm:

On behalf of our members, the American Chemistry Council (ACC) appreciates the opportunity to provide comments on the Department's draft Transmission Needs study. The Department's analysis and decisions with respect to national energy policy, including investment in industrial-scale transmission, will be critical to successful implementation of the Bipartisan Infrastructure Law (BIL), Inflation Reduction Act (IRA), and other federal programs intended to expand access to reliable lower-emissions energy sources. Successful implementation, in turn, is critical to empowering our members to lead in a rapid national transition to a lower emissions future.

ACC represents a diverse set of companies engaged in the business of chemistry, an innovative, $517 billion enterprise.[1] ACC members work to solve some of the biggest challenges facing our nation and our world, driving innovation through investments in research and development (R&D) that exceed $11 billion annually, providing 537,000 skilled, good-paying jobs—plus over 4.1 million related jobs—that support families and communities, and enhances safety through a diverse set of products.

[1] ACC's delivers value to our members through advocacy, using best-in-class member engagement, political advocacy, communications, and scientific research to foster progress in our economy, environment, and society.

A. Background

The business of chemistry operates by creating complex chemical reactions requiring large amounts of process heat and power. This, in turn, gives chemical manufacturers a particular interest in the local, state, regional, and federal policies governing generation, transmission, and distribution of electric energy across national grid. The U.S. chemical industry competes in global markets, and our ability to grow, hire, and decarbonize is linked to our ability to access competitive supplies of electricity, natural gas, and other energy sources and feedstocks.

ACC's members are not just energy users, they are essential engines in the broader national economy. Nearly all manufactured goods are directly touched by the business of chemistry, and chemical manufacturing accounted for 37% of the total construction spending by the U.S. manufacturing sector in 2021. In 2021, 11% of all chemicals were produced by the U.S. and 10% of U.S. goods exports ($153 billion in 2021) came from the business of chemistry, making the U.S. the world's second largest chemical producer and the U.S. chemical sector one of the largest exporting sectors in the U.S.

Finally, our members are helping to reduce the loads on transmission grids by providing products, materials, and chemistries that enable significant energy savings and greenhouse gas reductions across the US economy. – including but not limited to the next-generation materials used in transmission and distribution infrastructure.[2]

[2] *See, e.g.*, DOE, *Advanced Transmission Technologies* (Dec. 2020), available at https://www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf; Energetics Incorporated, *Materials Innovation For Next Generation T&D Grid Components: Scoping Document*, October 2015, available at https://www.energy.gov/sites/default/files/2016/06/f32/OE%20ORNL%20Materials%20Innovation%20for%20Grid%20Workshop%20Scoping%20Document%20FINAL.pdf.

B. Principles for Sound Transmission Policy

Reliable, affordable, and accessible electricity, supported by strategic investment in 21st century transmission infrastructure and sound federal, regional, and state transmission policies, is essential to a competitive manufacturing sector and a prosperous national economy. Maintaining, strengthening, and expanding this transmission backbone will play an even greater role in the future as industries and countries compete for markets in an increasingly competitive and carbon-constrained global economy.

Federal and state policies governing investment, siting, construction, and rate allocation for transmission infrastructure will be significant factors in the ability of manufacturers to innovate and adapt. ACC supports the Commission's policy objectives in this proceeding, including enhancing system reliability, improving resource adequacy and efficiency, providing access to lower cost and diverse resources, and ensuring fair and equitable cost allocation to shared transmission resources.

Consistent with these objectives, ACC offers the following broad principles for sound electric transmission investment and siting policy:

1. Protect US competitive advantage in manufacturing.
2. Support continued growth of US economy and manufacturing jobs
3. Maintain nation's energy diversity and security.
4. Expedite project reviews, approvals, construction, & permitting
5. Harness competition to lower costs and incentivize innovation.
6. Ensure 24/7 access to reliable, industrial scale power.
7. Provide infrastructure foundation for current operations as well as innovation and deployment of low-carbon energy and manufacturing solutions.

With these principles in mind, ACC offers the following comments on the Proposal, focusing on the unique perspective U.S. chemical manufacturing bring to the discussion on transmission siting policy.

C. The Chemical Industry Needs Reliable Access to Power, and an Has an Outsized Role in Leading Industrial Decarbonization

As noted above, chemical manufacturing is one of the most energy intensive sectors of the economy, including a significant reliance on reliable industrial scale electricity. Our members are continuing their efforts transition to lower emissions energy, feedstock, and manufacturing practices, and these efforts will contribute to a significant national demand for lower emissions electricity.

To put our electricity needs into perspective, a chemical facility making one million metric tons of ethylene annually would use 278 million kilowatt-hours of electricity. That's equivalent to the electricity used by 22,681 homes. Indeed, according to the Energy Information Agency's 2018 Survey, the chemicals and plastics industry accounts for over 29 percent of all electricity use in the industrial sector,[3] making it one of the largest industrial users of electricity. The industry's reliance on electricity will only increase as our members look for electrification opportunities within their operations and seek to increase the use of renewable and other low-carbon sources of power and heat energy into more areas of their operations.

D. Increased access to Renewable or Lower Emissions Energy Sources and Process Electrification Will Require Rapid and Unprecedented Expansion to the Transmission Grid

There is no single solution for our members, who are diverse in size, supply chains, and production processes, but increasing access to lower emissions power and leveraging opportunities for electrification are

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[3] Energy Information Administration, *2018 Manufacturing Energy Consumption Survey* (February 2021) (Table 11.1 Electricity: Components of Net Demand, 2018), https://www.eia.gov/consumption/manufacturing/data/2018/#r13.

important for many of our members, and in some cases offer some of the most immediate opportunities for action.

For the U.S. chemical industry and other energy intensive manufacturing sectors to lower their scope 2 emissions and leverage the emissions reductions for electrification, DOE, FERC, and States will have to build a national transmission reflecting the Report's most aggressive scenario for transmission investment – the one referenced as "High/High" for high load growth above 7,000 TWh and high clean energy penetration above 80 percent in 2040. Report at 84.

Understanding the presumptions and requirements to reach these ambitious projections is important for both federal and state policy makers. For context, DOE's own analysis illustrates the staggering challenge the nation faces in making the investments and permitting decisions necessary to support broad deployment of lower-emissions infrastructure. According to the Reports draft findings, transmission infrastructure investment has been flat or declining in many regions, the opposite direction to what is necessary to maintain a competitive, lower-emission economy. See Figure 1.

Figure 1: Draft Report Analysis of Investment Trends in New Transmission

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Table IV-1. Qualitative trends in new transmission investments between 2011 and 2020 for each region and for the United States as a whole. Decadal mean of both load-weighted transmission investments and circuit-miles for new transmission rated over 100 kV and energized in each year of the decade are shown.

Region	Load-Weighted Investment (US$/MWh)		Load-Weighted Circuit-Miles (ckt-mi/TWh)	
	Decade Average	General Trend	Decade Average	General Trend
New England	5.29	Sharp increase 2015 Sharp decrease 2018	1.20	Notable increase 2015-2017
CA/MX	3.36	Sharp decrease in 2019	0.47	Sharp decrease 2019-2020
NWPP/RMRG	3.33	Sharp decrease in 2016	1.57	Sharp decrease in 2016
ERCOT	2.84	Sharp decrease in 2016	2.38	Sharp decrease 2016-2020
SPP	1.99	Steady decrease since 2014	1.58	Steady decrease since 2014
All Regions	1.88	Relatively flat	0.86	Steady decrease
MISO	1.85	Steady increase	1.09	Steady increase 2013-2017 Steady decrease 2017-2020
PJM	1.82	Steady increase through 2016 Steady decrease after 2017	0.44	Slight increase through 2017 Slight decrease after 2017
SRSG	1.66	Steady increase through 2016 Steady decrease after 2016	1.17	Steady increase through 2016 Steady decrease after 2016
New York	1.50	Steady decrease	0.62	Slight increase through 2017 Slight decrease after 2017
SERC	0.38	Relatively flat	0.18	Relatively flat
SERC – FP	0.19	Relatively flat	0.09	Relatively flat

Source: Transmission data from MAPSearch (2022) and load data from NERC ES&D (2020).

DOE, FERC, and other Federal Agencies will need to work with Regional Transmission Planners and states to reverse this dynamic quickly if the Administration and industry are to achieve their ambitions goals for investment in lower-emissions energy and manufacturing technologies. The numbers in the report demonstrate the challenge ahead. Citing a recent report by NREL, the report notes that:

> NREL's Solar Futures Study (Ardani et al. 2021) came to a similar conclusion, finding in its scenario with extensive solar and wind deployment and increased electrification that transmission capacity expansion is 56,000 GW-mi by 2035 (39 percent increase relative to 2020 system) and 129,000 GW-mi by 2050 (90 percent increase relative

to 2020 system). Larson et al. (2021) model various scenarios, with high-voltage transmission capacity additions ranging from over 94,000 GW-mi in the reference case to over 813,000 GW-mi in the high electrification, high variable renewables case. This results in a range of total capital transmission investments of $0.95 trillion to $3.6 trillion, respectively, stressing the role that electrification plays in driving transmission need. Report at 72-73.

Looking across the country, the numbers reinforce the nationwide imperative for rapid investment and deployment to support decarbonization and electrification. See Table 2 and 3.

Table 2: Percentage Increase in Electric Transmission Required to meet aggressive 2030 decarbonization goals (against 2020 baseline

Region	in 2030	in 2035	in 2040
	% Growth	% Growth	% Growth
California	1.10%	3.70%	5.40%
Mountain	89.70%	173%	221%
Northwest	4.10%	30.90%	56.10%
Southwest	48.70%	118%	135%
Texas	51.80%	113%	136%
Delta	88.70%	231%	262%
Florida	0.30%	24.40%	34.90%
Mid-Atlantic	17.10%	60.50%	80.10%
Midwest	64.80%	174%	196%
New England	18.90%	126%	154%
New York	12.50%	46.10%	50.40%
Plains	98.70%	408%	449%
Southeast	30.10%	102%	129%

See Report at 89 "Table VI-3. Median new transmission deployment in all study scenarios in 2030, 2035, and 2040 for all regions."

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Table 3: Percentage increase in transfer capacity to reach highest electrification scenarios (from 2020 baseline)			
Region	in 2030	in 2035	in 2040
	% Growth	% Growth	% Growth
California - Mountain	57%	130%	204%
California - Northwest	5%	25%	38%
California - SW	36%	102%	132%
California NW	49%	202%	308%
Mountain - SW	51%	129%	149%
Mountain - Plains	663%	2100%	3170%
Plains-SW	1380%	3240%	3600%
Plains – TX	1750%	3520%	4260%
Delta-Midwest	3%	30%	44%
Delta-Plains	434%	1020%	1160%
Delta-SE	171%	572%	637%
Florida SE	24%	295%	360%
Mid-Atlantic- Midwest	196%	475%	550%
Mid- Atlantic - New York	102%	412%	634%
Mid-Atlantic- Southeast	62%	140%	173%
Midwest-Plains	204%	731%	819%
Midwest-Southeast	125%	416%	483%
New England-New York	195%	835%	1050%

Table VI-4. Median new transfer capacity estimated by all study scenarios in 2030, 2035 and 2040 for all regions. Report at 86-88.

A recent study by Princeton's Zero Carbon lab, puts the challenge in stunning context, finding that:

- "Failing to accelerate transmission expansion beyond the recent historical pace (~1%/year) increases 2030 U.S. greenhouse emissions by ~800 million tons per year, relative to estimated reductions in an unconstrained IRA case."[4]

- "Emissions are 200 million tons higher if transmission growth is limited to 1.5%/year."[5]

- "Over 80% of the potential emissions reductions delivered by IRA in 2030 are lost if transmission expansion is constrained to 1%/year, and roughly 25% are lost if growth is limited to 1.5%/year."[6]

- "To unlock the full emissions reduction potential of the Inflation Reduction Act, the pace of transmission expansion must more than double the rate over the last decade to reach an average of ~2.3%/year. That rate of expansion is comparable to the long-term average rate of transmission additions from 1978-2020.[7]

ACC urges DOE to consider this draft Transmission Needs Report in the context of the historic and ambitious goals the Administration has set for the nation with respect to economy-wide carbon reduction, which will rely heavily on a 21st century electric grid that is more robust, more flexible, more reliable, and more secure. It is also important to recognize that many of the industrial decarbonization strategies like fuel switching and electrification require these investments as predicates to sector deployment.

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[4] *See* Jenkins, J.D., Farbes, J., Jones, R., Patankar, N., Schivley, G., "*Electricity Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act,*" REPEAT Project, Princeton, NJ, September 2022. DOI: 10.5281/zenodo.7106176, page. 4, *available at* https://repeatproject.org/docs/REPEAT_IRA_Transmission_2022-09-22.pdf.

[5] *Id.*

[6] *Id.*

[7] *Id.*

E. DOE’s Transmissions Needs Study Must Recognize the Continued Need for Transmission Infrastructure Supporting Natural Gas Generation

Any realistic federal and state strategy for transitioning to lower emissions energy and manufacturing technologies must recognize that natural gas generation will be a necessary component for a secure, reliable, and evolving lower-emissions grid. The report notes in a number of areas where constrained natural gas systems pose risk to system reliability (*e.g.*, CA, TX, New England, New York) and DOE”s own definition of “clean energy generation” includes “all solar energy (concentrating solar power, utility-scale photovoltaic systems, rooftop photovoltaic systems), land-based wind, offshore wind, hydropower, nuclear, hydrogen-based technologies, biomass energy, coal and natural gas plants paired with carbon capture and sequestration, and landfill gas plants.” Report at 84.

We urge both DOE and the Federal Energy Regulatory Commission to avoid making assumptions that new transmission investments can be designed to shut out or ignore the critical contribution that natural gas plays in the country today as a fuel and energy source, generally, and a competitive advantage for U.S. manufacturing generally.

F. A Successful Transmission Deployment Strategy will Require Review and Optimization of Federal and State Permitting Policies

The draft Report makes one fact clear: The country cannot achieve these unprecedented rates of transmission expansion needed to achieve climate and competitive goals under business-as-usual government operations.

Federal and state policymakers and permitting authorities must take a hard look at the processes used to plan, site, and permit critical interstate transmission projects to reduce the time required to deploy new transmission. Given the time required to complete the transmission planning, approval, and permitting process right now, the US is already off track to reach the ambitions increases recommended in Table 1 and 2. There is no time to waste.

Contemporaneously with the development of the Transmission Needs report, multiple other federal agencies are engaged in policy proceedings that will have direct implications for the nation's ability to achieve the promise of Congressional legislation like the IRA and BIL, and DOE's ability to support the rapid expansion of the U.S. transmission grid. At present, for example, the FERC is considering proposed changes to its transmission siting application policy, and the Council on Environmental Quality is considering comments on proposed new NEPA Guidance governing federal processes for evaluating federal actions, including permits and funding programs.

A consistent theme in these proposals is an effort to inject a variety of valid, but tangential policy goals into the permitting review process, well outside the traditional scope of legislative authority or programmatic focus. This trend raises the concern that the Administration may undermine its ability to achieve its own policy goals by repeatedly and unnecessarily complicating and delaying the process for developing, reviewing and approving critical energy and lower emissions manufacturing infrastructure projects.

ACC shares the Administration's commitment to economy wide GHG reduction, advancing principles of environmental, energy, and economic justice, promoting domestic manufacturing, reshoring the U.S. energy supply chain, promoting job growth, and directing federal resources toward disadvantaged communities. These are all important policies and federal and state policy can and should identify effective mechanisms for advancing these interests. ACC is concerned that the Administration's everything-all-at-once approach to conditioning clean energy and manufacturing investment on often unclear or irreconcilable policy conditions could impede progress on all of these important agendas, particularly with respect to energy and industrial innovation and decarbonization - where Congress has granted the Administration time-limited funds and where progress will require early investments in transmission and other infrastructure.

For these reasons, ACC urges DOE to recognize, both in this Report and more broadly in its implementation of IRA, BIL and other statutory funding and investment programs, that the primary objective should be to carry out its Congressionally-delegated authority and expertise, and avoid attempting to shoe horn ancillary Administration policy goals into federal actions that are neither designed for nor compatible with a kitchen sink policy strategy.

G. Conclusion

Thank you for your consideration of these comments. If you have any questions or would like more information, please free to contact ACC at (202) 297-4420 or Charles_Franklin@americanchemistry.com.

Sincerely,

Charles Franklin

Charles Franklin, Senior Director
Energy, Climate, and Environment

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April 20, 2023

U.S. Department of Energy
1000 Independence Avenue SW
Washington, DC 20585

RE: Request for Comment on National Transmission Needs Study

Submitted via email: NeedsStudy.Comments@hq.doe.gov

The American Clean Power Association ("ACP")[1] appreciates the opportunity to provide comments on the Department of Energy's ("DOE's") draft National Transmission Needs Study ("Needs Study").[2] ACP largely supports DOE's overall findings in the Needs Study, as detailed below. ACP also submits that finalization of the study is well within DOE's responsibility, and is consistent with Congress' direction in enacting (and recently revising) § 216 of the Federal Power Act.[3]

ACP agrees with the findings of the draft Needs Study that increased transmission capacity is vital for reliability, grid decarbonization by 2035, and economic decarbonization by 2050. Transmission can also catalyze major investments in clean energy while reducing customer costs and ensuring reliable system operations as the resource mix evolves. As our electricity system transitions to increasingly rely upon clean energy resources in every region, along with significant electrification of sectors such as transit and industry, the transmission system must expand to accommodate these new resources - which often are not located in the same area as historic generation. Current transmission deployment, however, is not keeping pace with the changing resource mix, and new infrastructure is needed to deliver energy to customers. For example, as the Needs Study notes, insufficient transmission capacity is among the key

[1] ACP is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind, solar, energy storage, and electric transmission in the United States. The views and opinions expressed in this filing do not necessarily reflect the official position of each individual member of ACP.
[2] U.S. Department of Energy, *Draft National Transmission Needs Study* (Feb. 24, 2023) https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.
[3] 16 U.S.C. § 824p.

drivers in ever-expanding interconnection queue backlogs.[4] These issues will only increase as (for example) the emerging U.S. offshore wind industry ramps up, because coordinated transmission development will be necessary to integrate new resources into coastal transmission systems, which are often lower-voltage.[5]

The Needs Study also properly drives home the importance of interregional transmission in particular, which is extraordinarily valuable in terms of reliability and economic benefits - while also having received little investment for years.[6] The Needs Study builds on a growing body of work showing that increased interregional transmission infrastructure deployment would deliver substantial economic benefits in every region, and would also improve system reliability throughout the country. This deployment will not only help in day-to-day system operations, but will also assist in recovery from increasingly common extreme weather events. The Needs Study also rightly notes that advanced transmission technologies can play a role in necessary system improvements.[7] In many cases, advanced technologies can help to maximize the use of the existing grid, help to increase transfer capacity, and improve real-time data and controllability for new transmission.

ACP urges DOE to finalize the Needs Report as quickly as possible, while also making clear how it will apply its determinations of transmission needs in utilizing the broad range of federal transmission authorities. These include designation of National Interest Electric Transmission Corridors ("NIETCs") under § 216 of the Federal Power Act, as well as selection of projects under the Transmission Facilitation Program, public-private partnerships through the Power Marketing Administrations, and a suite of loan and grant programs. The Needs Study can help to inform investment decisions and leverage these federal programs to maximize the impact of investments in our transmission system.

[4] Needs Study at 37-39.
[5] Needs Study at 57-58.
[6] Needs Study at iii ("Interregional transmission investments will help improve system resilience by enabling access to diverse generation resources across different climatic zones, which is becoming increasingly important as climate change drives more frequent extreme weather events that damage the power system.").
[7] Needs Study at 75-76.

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I. The Needs Study is Consistent with Congressional Intent, and Reinforces Findings that More Transmission Capacity is Essential.

Section V of the Needs Study reviews a wide range of existing studies (some commissioned by DOE, as well as independent reports) that discuss the current and future needs for transmission.[8] In total, the Needs Study surveys nearly 50 recent reports on transmission drivers, benefits, and challenges.[9] ACP supports the inclusion of these studies and the subsequent conclusions that DOE draws from them: specifically, that even in moderate growth scenarios, significant transmission is needed – and in scenarios that incorporate robust clean energy deployment and electrification policies, a dramatic expansion of the current grid is necessary.[10] DOE's findings reflect a clear engagement with the substantial body of research and analysis over the past decade, and appropriately identifies – with a range of sensitivities based upon particular policy scenarios – multiple areas that are "expected to experience [] energy transmission capacity constraints or congestion."[11] The Needs Study also clearly shows on a preliminary basis that, *inter alia*:[12]

- a lack of transmission may constrain economic vitality and development in many regions;
- diversification of supply is warranted, for reasons such as increased operating flexibility;[13]
- transmission development would enhance the ability of facilities that generate or transmit firm or intermittent energy to connect to the electric grid; and
- transmission expansion is in the interest of national energy policy.

For these reasons, ACP recommends that DOE act to finalize its draft findings in the final version of the Needs Study, and affirmatively make clear how it will apply these findings (as discussed further below).

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[8] Needs Study at 41.
[9] *Id.*
[10] Needs Study at 106-07 ("Median model results suggest 47,300 GW-mi of new transmission will be needed nationwide by 2035 to meet the scenario conditions of this group, a 57 percent growth in today's transmission system… The need for transmission growth is even greater in future scenarios that have high load and high clean energy assumptions.").
[11] 16 U.S.C. § 824p(a)(2)(ii).
[12] *See generally* 16 U.S.C. § 824p(a)(4). Several of the statutory factors in this section may depend on findings that are highly particularized to a specific corridor.
[13] Needs Study at 46.

II. DOE Appropriately Highlights Several Key Aspects of Transmission Expansion

Several aspects of transmission expansion are rightly highlighted in the Needs Study. First, and perhaps most significantly, interregional transmission is extraordinarily valuable, but has received negligible investment in recent years. The Needs Study provides detailed information – largely by assessing market price differentials – on how interregional transmission could provide substantial consumer benefits.[14] However, ACP notes that Section IV.A, regarding historical transmission investments, does not contain specific findings regarding investment in interregional transmission in particular. Even with the accelerating pace of the energy transition under current regulatory processes, investment in and deployment of interregional transmission has not kept up with the need for high-capacity, long-distance transmission lines to facilitate dramatic leaps in clean energy deployment. Given this, ACP recommends that in the final Needs Study DOE specifically note the dearth of investment in interregional transmission – as this may help to bolster any subsequent use of DOE programs to address these needs. Siting assistance, loans, and capacity contracts might all be mechanisms that could help to address this lack of interregional transmission investment; DOE should note that the gap exists.

Next, ACP fully supports DOE identifying the persistence and growth of interconnection queue delays as being linked to transmission needs. When generators connect to the electric grid, they often must fund upgrades to the transmission system – but in some instances, these network upgrades have resulted in generators funding large-scale transmission that has not been properly planned for. For example, in the Southwest Power Pool, generators have been assigned the full cost of 765kV lines up to 165 miles long.[15] Reliance upon generators' willingness to pay for large-scale upgrades is insufficient and cannot yield transmission expansion adequate to resolve the issues (or rise to the opportunities) identified in the Needs Study. In many regions, regional power networks are being planned and expanded on a piecemeal basis through the project-by-project interconnection process, which leads to inefficient outcomes that ultimately cost consumers. Similarly, offshore wind integration will necessarily drive significant upgrades

[14] Needs Study at 28-30.
[15] Grid Strategies, *Disconnected: The Need for a New Generator Interconnection Policy,* (2021) https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.pdf at 15.

to coastal transmission systems in many parts of the country. Addressing upgrades on a generator-by-generator basis cannot sustain the anticipated deployment of offshore wind needed to meet state and federal goals. Many coastal transmission facilities are lower-voltage, and ACP supports the Needs Study taking note of the likelihood that the number of offshore wind projects will significantly outstrip available capacity. ACP does note, however, that the Needs Study's discussion of offshore wind focuses almost entirely on the Atlantic coast. Given the burgeoning U.S. offshore wind industry, the growth in state procurement targets, and the potential for offshore wind in the Gulf of Mexico, the West Coast, and the Great Lakes, ACP recommends that DOE consider offshore wind as a transmission driver in other regions of the country as well.

Finally, ACP appreciates DOE's acknowledgement of the role that Grid-Enhancing Technologies can play in maximizing the efficacy of existing and new transmission.[16] While not necessarily appropriate in all circumstances, advanced technologies such as power flow controls, dynamic line ratings, energy storage-as-transmission, and advanced conductors can increase power flows in many intervals, while also providing grid operators with valuable telemetry and control capabilities to support reliability. In addition, because Grid Enhancing Technologies are rapidly deployable, they can play an important role in helping integrate new resources by fully utilizing the existing grid while new transmission is built. Accordingly, ACP supports deployment of these technologies where they can safely and reliably increase transfer capacity, particularly in the near term as the country builds out new transmission lines.

III. DOE should make clear how it will apply the Needs Study to support transmission development.

The Needs Study can provide a valuable touchstone for applicants to a wide range of DOE programs. Most notably, as DOE indicates, the finalized Needs Study will serve as the initial step in utilizing § 216 of the Federal Power Act. However, DOE's work can also serve to inform multiple other programs. Thus, ACP urges DOE to provide further detail on how it will utilize its various statutory authorities, discussed below, to address the national needs it has identified.

[16] Needs Study at 75-76, 85-87.

A. National Interest Electric Transmission Corridors

Finalizing the Needs Study will satisfy the statutory requirements of §216(a)(1) of the Federal Power Act, but a subsequent report is necessary under §216(a)(2) to designate any NIETCs.[17] Section 216 is one of the primary tools available to DOE to support transmission development, but it has never been successfully used. ACP therefore recommends that DOE make clear that transmission project sponsors may submit applications for narrowly tailored §216(a)(2) reports (designating a NIETC for specific lines that would address one or more needs identified in the final Needs Study), and that DOE provide procedures for doing so. The ability to request tailored NIETCs is necessary to effectively respond to the findings in the Needs Study. As noted above, the Needs Study's conclusions indicate a need for rapid and comprehensive expansion of electric transmission capabilities.[18] Applicants' ability to request tailored NIETC lines will not only make the application of federal siting authority, if necessary, more streamlined and efficient, but will also enable projects deemed in the national interest to access other DOE programs linked to a national interest designation under § 216.

Finally, approving tailored NIETCs is within the authority of the Secretary of the DOE under §216(a)(2). The Secretary is authorized to approve a NIETC in "any geographic area" that is experiencing or expecting "transmission capacity constraints or congestion that adversely affects consumers,"[19] among other factors. ACP recommends that DOE issue regulations or guidance on a tailored, route-specific § 216(a)(2) NIETC application process no later than the date upon which it finalizes the Needs Study.

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[17] 16 U.S.C. §824p.

[18] Needs Study at 78 ("Altogether, the studies reviewed in this section signify a pressing need to expand electric transmission—driven by the need to improve grid reliability, resilience, and resource adequacy, enhance renewable resource integration and access to clean energy, decrease energy burden, support electrification efforts, and reduce congestion and curtailment").

[19] 16 U.S.C. §824p(a)(2)(i).

B. Non-NIETC Programs

DOE should also clarify how applicants to other federal transmission programs can utilize the Needs Study in support of their applications. The Needs Study can play a useful role in helping DOE efficiently and accurately disburse funds aimed at improving the grid and increasing transmission capabilities, as DOE acknowledges briefly.[20] Indeed, many criteria identified in the Needs Study are consistent with Congressional criteria for multiple loans and grant programs. Several loan and grant programs (some enacted in 2021 in the Infrastructure Investment and Jobs Act (IIJA), and others predating that Act) would benefit from guidance on how applicants can utilize the Needs Study to support their applications. For example:

- The Transmission Facilitation Program allows DOE to enter into a capacity contract, issue loans, or enter public-private partnerships.[21] The Needs Study could help applicants tailor an application for a capacity contract, loan, or public-private partnership with DOE. Public-private partnerships under the TFP can also be linked to a NIETC designation,[22] heightening the need for clear guidance in this area.
- DOE's Grid Resilience and Innovation Partnerships (GRIP) grants are another example of the useful role the Needs Study can play in grant applications. GRIP Grant applicants may be required to show how a project proposal would improve regional energy infrastructure.[23] The information provided in the Needs Study could provide a well-understood baseline to compare proposals seeking to improve existing regional energy infrastructure, while also aligning with DOE's transmission goals and Congress's intended requirements.
- The Needs Study criteria are generally consistent with the Congressional criteria for the Title XVII Innovative Technologies Loan Guarantee Program. To qualify under Title XVII, a loan applicant must show intent to utilize a new or significantly improved technology in their proposed project.[24] The Needs Study identifies that

[20] Needs Report at 1 ("This Needs Study will also support the implementation of existing Department programs, including the Department's Loan Programs and Transmission Infrastructure Program, the regional transmission planning processes, and the potential designation of National Interest Electric Transmission Corridors…").
[21] 42 U.S.C. §18713.
[22] 42 U.S.C. § 18713(h)(1).
[23] *See generally* U.S. Dep't of Energy, GRIP Grant Program (2023), https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program.
[24] 42 U.S.C. §16512

innovative technologies could be used in transmission expansion.[25] This aspect of the Needs Study potentially compliments the requirements in Title XVII, and provides a basis for meeting the innovative technology requirement under Title XVII.

- The Western Area Power Administration's Transmission Infrastructure Program (TIP) also overlaps with the criteria identified in the Needs Study. TIP loan recipients must show that their project is "in the public interest".[26] The Needs Study offers a potential foundation for TIP applicants to ground their project in public interest criteria.
- Finally, §1222 of EPACT 2005 authorized the Western Area Power Administration or Southwestern Power Administration to collaborate with third parties on electric power transmission facility projects.[27] Qualifying third party entities are required to show that their proposed project is necessary to "accommodate an actual or projected increase in demand for electric transmission capacity".[28] Here, the Needs Study could be used by applicants to show how their project aligns with increases in demand as outlined by DOE.

[25] Needs Study at 73, 75, 80.
[26] 42 U.S.C. § 16421a.
[27] 42 U.S.C § 16421.
[28] 42 U.S.C § 16421 (a)(1)(B).

In sum, the Needs Study provides critical data and information that is relevant to a diverse array of federal transmission programs. As a result, to the maximum extent allowable DOE should enable applicants for these programs to directly reference the Needs Study, and should prioritize transmission projects that would directly address these needs. ACP requests that DOE issue guidance or regulations accompanying a final Needs Study to ensure that applicants to any or all of these programs can make full use of the valuable work contained in the Needs Study.

Respectfully submitted,

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April 20, 2023

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<u>DOE National Transmission Needs Study – Draft for Public Comment</u>

Comments of the American Council on Renewable Energy (ACORE)

April 20, 2023

I. Introduction

The American Council on Renewable Energy (ACORE) is a national nonprofit organization that unites finance, policy and technology to accelerate the transition to a renewable energy economy. ACORE's members include developers, manufacturers, top financial institutions, major corporate renewable energy buyers, grid technology providers, utilities, professional service firms, academic institutions and allied nonprofit groups.

ACORE appreciates the Department of Energy (DOE)'s compilation and analysis of these data and studies of transmission needs and development for this important assessment of the nation's transmission needs. Not only does the draft National Transmission Needs Study ("Needs Study") show the critical need for new transmission, but it also highlights the limitations of the current transmission planning processes. This analysis provides further impetus for the Federal Energy Regulatory Commission (FERC) to act on the pending proposed rulemakings on Regional Transmission Planning and Cost Allocation ("Transmission Planning Proposed Rule")[1] and on Generator Interconnection Procedures and Agreements ("Interconnection Proposed Rule").[2] Moreover, once finalized, the Needs Study will serve as a resource for other DOE endeavors that contribute to the needed expansion of transmission, as recognized by DOE's statement that the Needs Study "will also support the implementation of existing Department programs, including the Department's Loan Programs and Transmission Infrastructure Program, the regional transmission planning processes, and the potential designation of National Interest Electric Transmission Corridors (NIETC)."[3]

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Docket No. RM21-17-000, 179 FERC ¶ 61,028 (2022).

[2] *Improvements to Generator Interconnection Procedures and Agreements*, Docket No. RM22-14-000, 179 FERC ¶ 61,194 (2022).

[3] Needs Study at 1.

II. Scope of the Study

DOE provides a sound basis for the scope of the study by defining a transmission need as "the existence of present or expected electric transmission capacity constraints or congestion in a geographic area"[4] and then incorporating the full array of benefits that result from addressing such needs. Specifically, ACORE supports the following description of need provided by DOE:

> Geographic areas where a transmission need exists could benefit from an upgraded or new transmission facility— including non-wire alternatives—to improve reliability and resilience of the power system; alleviate transmission congestion on an annual basis; alleviate transmission congestion during real-time operations; alleviate power transfer capacity limits between neighboring regions; deliver cost-effective generation to high-priced demand; or meet projected future generation, electricity demand, or reliability requirements.[5]

The comment matrix contained in Appendix A-2 lists comments received during the consultive period. ACORE strongly disagrees with the comment from the Southeastern Regional Transmission Planning (SERTP) entity that the Needs Study "undertakes a very broad analysis of 'transmission needs' rather than the statutorily specified study of 'electric transmission capacity constraints or congestion.'"[6] The breadth of the study is needed to show that the existence of capacity constraints and congestion on the current transmission system directly impedes achievement of the myriad benefits of transmission, including access to more cost-effective generation, including resources developed in future years, and enhanced reliability and resilience, especially in the face of extreme weather. Therefore, DOE's description of need and the scope of the study fit squarely within Section 216 of the Federal Power Act which requires DOE to conduct a study of electric transmission system capacity constraints and congestion.[7]

The draft Needs Study particularly demonstrates the strong reliability benefits that arise from addressing transmission capacity constraints and congestion, especially during extreme weather events and the added benefit of mitigating price spikes during such events. These benefits are also confirmed by the following findings of several recent studies issued by ACORE:

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[4] *Ibid.*

[5] *Id.* at 1-2.

[6] *Id.* at 123.

[7] 16 U.S.C. 824p(a)(1); Needs Study at 5.

- During Winter Storm Uri in February 2021, an additional gigawatt (GW) of transmission ties between the Texas grid and the Southeast could have saved nearly $1 billion during that storm.[8]

- Similarly, an additional GW of interregional transmission capacity between a number of regions would have saved nearly $100 million during Winter Storm Elliott in December 2022.[9]

- While the Midcontinent ISO (MISO) benefits analysis of the first tranche of lines in its Long-Range Transmission Planning initiative estimates the value of reduced power outages to be between $1.2 billion to $11.5 billion, a more accurate measurement would be $21 billion.[10]

III. Improvements to Transmission Planning

The draft Needs Study correctly highlights not just the critical need for transmission itself, but for improvements to regional and interregional planning. While DOE states that the Needs Study is not meant to displace current planning processes, they also explain that it "is intended to help inform and drive effective regional and interregional planning to properly assess the multiple values of transmission."[11] Further, DOE points out that:

> More holistic and comprehensive planning assessments that consider a range of scenarios of the future of the bulk power system help ensure a more robust and cost-effective bulk power system that will address future needs and ensure that expected transmission constraints and congestion are identified and mitigated before they harm consumers.[12]

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[8] Goggin, Michael, Grid Strategies LLC, *Transmission Makes the Power System Resilient to Extreme Weather* (July 2021), available at: https://acore.org/wp-content/uploads/2021/07/GSResilient-Transmissionproof.pdf.

[9] Goggin, Michael, Grid Strategies LLC, *The Value of Transmission During Winter Storm Elliott* (February 2023), available at: https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf.

[10] Gramlich, Rob, *Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study of MISO's Long Range Transmission Planning* (August 2022), https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf.

[11] Needs Study at 2.

[12] *Id.* at 3.

ACORE strongly agrees with DOE's findings regarding the shortcomings in the current transmission planning processes and the necessity of improving regional and inter-regional transmission planning. This is confirmed by the Brattle Group and Grid Strategies LLC's finding in their assessment of transmission planning:

> Most of the planning processes used today result in inefficient investments that increase total system-wide costs. The narrowly focused current approaches do not identify opportunities to take advantage of the large economies of scale in transmission that come from "up-sizing" reliability projects to capture additional benefits, such as congestion relief, reduced transmission losses, and facilitating the more cost-effective interconnection of the renewable and storage resources needed to meet public policy goals.[13]

The identification of transmission needs is fundamentally intertwined with a more holistic, long-term transmission planning process that covers a wider geographic area, and that incorporates interregional transmission needs. Current shortcomings in transmission planning highlight the importance of this analysis. The final Needs Study therefore presents an opportunity for DOE to further enhance the discussion of the improvements needed to transmission planning. ACORE asks that DOE provide additional clarity about where there are shortcomings in the regional and interregional transmission planning processes and where there are best practices employed.[14]

Improved transmission planning should also involve greater incorporation of grid-enhancing technologies (GETs). DOE explains that GETs "are not explicitly modeled in the studies considered here," but that a need for additional transmission capacity "could be met, at least in part, by increasing the carrying capacity of existing grid infrastructure already within the region." ACORE agrees and strongly supports incorporation of GETs into transmission planning and the interconnection studies.[15]

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[13] Pfeifenberger, et al, *Transmission Planning for the 21st Century: Proven Practices That Increase Value and Reduce Costs*, (October 2021) at 3, available at: https://acore.org/transmission-planning-for-the-21st-century/.

[14] See for example, Gramlich (August 2022).

[15] See ACORE Comments on Transmission Planning Proposed Rule at 15-16 (August 2022), available at: https://acore.org/wp-content/uploads/2022/08/ACORE-Comments-on-FERCs-Transmission-Planning-NOPR.pdf; ACORE Comments on Interconnection Proposed Rule at 6-7 (October 2022), available at:

IV. Recommended Improvements for Final Needs Study

While ACORE is supportive of the draft Needs Study, we also recommend several areas for improvement for the final study.

Section IV of the draft Needs Study provides valuable data on historical transmission investments, both in total and by driver and developer. These data affirm the findings in the prior section about the limitations of the current transmission planning process, as shown by the following notable data points:

- Incumbent transmission developers, or entities that develop transmission within their own retail distribution footprint, have always dominated project development space nationwide.[16]
- The proportion of circuit-miles installed to provide high transmission capacity for moving generation long distances dropped precipitously after 2013, and few circuit-miles have been installed in response to this primary driver since. The proportion of circuit-miles installed to increase system reliability, however, has grown with time.[17]

These two findings are interrelated and reflect FERC's findings that "the regional transmission planning and cost allocation processes have yielded limited investment in regional transmission facilities"[18] and "the vast majority of investment in transmission facilities since the issuance of Order No. 1000 has been in local transmission facilities."[19] To shed further light on the implications of the shortcomings in current planning processes, ACORE therefore recommends that the final Needs Study provide an additional breakdown of this historical data as follows:

- Show how the data on transmission drivers in Figure IV-3 is aligned with the types of developers of such transmission shown in Figure IV-2, and whether or not these projects were incorporated into the regional planning process.

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https://acore.org/wp-content/uploads/2022/10/ACORE-Comments-on-FERC-Proposed-Rule-on-Improvements-to-Generator-Interconnection-Procedures-and-Agreements.pdf.

[16] Needs Study at 20.

[17] *Id.* at 22.

[18] Transmission Planning Proposed Rule at P 39.

[19] *Id.* at P 40.

- Within the above data, include the share that is built to replace existing lines, which are not typically included in the planning process.[20]

DOE characterized the studies reviewed into three scenarios regarding load growth and clean energy penetration: Moderate/Moderate; Moderate/High; and High/High, and notes that "modeling for all studies was performed before the passage of the bipartisan Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022," and that the "Moderate/Moderate scenario group most closely represents the evolution of the power system had IIJA and IRA not been enacted."[21]

ACORE recommends the final Needs Study use the High/High scenario as the most reflective of the drivers of transmission needs. Moderate clean energy projections are not reflective of these two important pieces of legislation and their significant impact on future clean energy growth. Moreover, due to the ongoing efforts at greater electrification of buildings and transportation, the high load scenario is best representative of the base case.

For regional transmission comparisons, DOE uses the "carrying capacity (GW or TW) of a modeled power line multiplied by the length (miles) of the line," explaining that "GW-mi or TW-mi is a convenient unit for capacity expansion models but is not a common practice in industry. Transmission planners and developers quantify power lines by their nominal voltage rating (kilovolts, kV) multiplied by the length (miles) of the line."[22] As DOE explains, shorter lines have a higher carrying capacity. Yet these different lengths and voltages serve different purposes and grouping them all into a single measure can make it more difficult to compare the identified needs to the planned transmission**.**

DOE uses a different measure of interregional transmission. For the analysis of interregional transfer capacity, the draft study uses "the amount of power that new or upgraded lines can move between neighboring regions, regardless of the length of the lines that make that connection across boundaries."[23]

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[20] *Id.* at P 385.

[21] Needs Study at 84.

[22] *Id.* at 88.

[23] *Id.* at 96.

The Needs Study therefore uses different measures for the interregional and regional transmission needs and plans, but the developments of interregional transmission could impact regional transmission. For example, power delivered into a region would then need to be distributed through a regional line. DOE should at a minimum qualitatively discuss the relationship between these two analyses.

V. Additional Resources for Final Study

ACORE recommends that the following resources be reviewed and incorporated into the final analysis. A brief summary of the primary findings from each is also provided.

- The Value of Transmission During Winter Storm Elliott, Grid Strategies LLC (2023)

An additional GW of interregional transmission capacity between a number of regions would have saved nearly $100 million during Winter Storm Elliott in December 2022.

- The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals, The Brattle Group (2023)

Well-planned offshore transmission can integrate offshore wind generation more cost effectively while also reinforcing the onshore grid, with cost and resilience benefits spread across regions.

- Enabling Low-Cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis: A Case Study of MISO's Long Range Transmission Planning, Grid Strategies LLC (2022)

The multiple benefits analyzed by the Midcontinent Independent System Operator for its Long-Range Transmission Planning process generally follow best practices for benefits analysis.

- Multi-Value Transmission Planning for a Clean Energy Future: A Report of the Transmission Benefits Valuation Task Force, Telos Energy (2022)

A wide range of benefits should be considered when evaluating transmission, including reduced operating costs, environmental benefits, access to low-cost renewable energy, generation capital cost reductions, risk mitigation, and improvements in reliability and resilience; and should be measured over the lifetime of the asset.

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VI. Conclusion

ACORE greatly appreciates the significant value of this Needs Study and looks forward to the final version.

Respectfully submitted,

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UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

National Transmission Needs Study)
Draft for Public Comment)
February 2023)

VIA EMAIL
NeedsStudy.Comments@hq.doe.gov

COMMENTS OF AMERICAN ELECTRIC POWER SERVICE CORPORATION

American Electric Power Service Corporation ("AEP") appreciates the U.S. Department of Energy's ("DOE") efforts to evaluate current and anticipated future transmission needs and the opportunity for public comment on its draft National Transmission Needs Study ("Draft Study"). AEP agrees that a robust transmission system is critical to the nation's economy, energy, and national security and that the grid is facing challenges from aging infrastructure and a shift in resource mix.

AEP operates a large, interconnected network of facilities that generate, transport and deliver electricity across the United States to serve approximately 5.5 million residential, commercial, industrial and wholesale customers in 11 states. AEP also owns the nation's largest electric transmission system, with more than 40,000 miles of transmission lines and more 765 kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas).

AEP agrees with the key findings of the Draft Study that (i) there is a pressing need for additional electric transmission infrastructure; (ii) increasing interregional transmission results in significant benefits; and (iii) needs will shift over time. In fact, AEP has submitted comments in a number of other forums that support several of the DOE's positions and findings included in the Draft Study, as discussed herein. However, the Draft Study only briefly mentions that local transmission planning is part of the overall solution. In fact, interregional, regional, and local transmission planning processes are inextricably intertwined. AEP urges the DOE to recognize the necessity of local transmission planning and the important role it plays in ensuring a reliable and resilient transmission system.[1]

AEP agrees there is an urgent need for transmission development. Incremental transmission development is needed to facilitate the changing national resource mix, achieve decarbonization goals, and deliver low-cost energy to consumers. As noted in the Draft Report, "studies have repeatedly shown that given the nation's changing resource mix, a least-cost power grid requires enhanced transmission links within and among regions" (p. 37). This is acutely recognized by AEP, as it continues to reduce its carbon footprint by investing in renewable energy and deploying new technologies, all the while working to build a more modern, resilient energy grid.

Transmission development also is needed to ensure reliability during extreme weather events, which the nation is facing with increasing frequency. The Draft Study notes (at p. 3) that recent experience "demonstrates that planning for the bulk power system needs to extend beyond the footprint of individual utilities or regions to provide assurance that energy can be delivered from where it is available to where it is needed". Indeed, history demonstrates that during extreme weather events, customers benefit when regions are interconnected and can rely upon one another to maintain system reliability and thus reduce costs to customers. Resilience to extreme weather

[1] *See* "Value of Local Transmission Planning" report prepared by Charles River Associates on behalf of WIRES. https://wiresgroup.com/value-of-local-transmission-planning/.

events will not be realized until actionable interregional planning and a minimum transfer capability requirement are in place. Establishing reasonable minimum transfer capabilities provides an effective insurance policy against such extreme events and will ensure that generation capacity is not overbuilt within each region.[2]

Finally, the economic benefits associated with transmission expansion cannot be overlooked. AEP is focused on keeping rates affordable and maintaining reliable service for customers – both of which require transmission investment. AEP agrees with the DOE that holistic, scenario-based, multi-value transmission expansion planning can provide energy price benefits to consumers. The Draft Study states:

> More holistic and comprehensive planning assessments that consider a range of scenarios of the future of the bulk power system help ensure a more robust and cost-effective bulk power system that will address future needs and ensure that expected transmission constraints and congestion are identified and mitigated before they harm consumers. (p. 3)

AEP also has commented upon the need for such holistic planning.[3] It is AEP's position that the benefits of regional transmission facilities should be evaluated collectively – through a "multi-value" analysis – to ensure that projects that provide benefits in multiple categories are properly identified and justified in the planning process.

AEP agrees that increased transfer capacity has many benefits. The Draft Report several benefits that would result from increased transfer capacity among regions. For example, regional grid reliability would be strengthened by the diversity of generation provided by interregional transfers (p. 96). Increased transfer capacity also is necessary to achieve a resilient transmission system in the face of extreme weather events, as discussed above. Further, enhanced transfer

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[2] This is discussed further in AEP's comments filed in the Federal Energy Regulatory Commission ("FERC") Docket RM22-10, *Extreme Weather Notice of Proposed Rulemaking.*

[3] *See* AEP's Comments filed in FERC Docket RM21-17, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection Notice of Proposed Rulemaking* (p. 21-22).

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capability will allow for increased economic transfers during both emergency and non-emergency situations, making lower-cost generation available to customers at all times.

AEP supports reforms that would establish actionable interregional planning to increase transfer capacity.[4] AEP's interregional planning, minimum transfer proposal includes both a short-term and a long-term solution. In the short-term, a baseline minimum transfer capability of approximately 25 percent should be established on a regional basis.[5] Alternatively, regions should be allowed flexibility to perform a region-specific study that incorporates specific fundamental parameters to determine the required transfer capability needed on a regional basis. In the long term, a more holistic approach to planning is needed and AEP suggests that an Interregional Reliability Planning Assessment ("IRPA") be initiated to identify the appropriate minimum interregional transfer capability that is necessary for each region to maintain reliable system operation at a just and reasonable cost. The IRPA should incorporate a diverse range of planning scenarios and evaluate how each region will react and rely on neighboring regions and determine a minimum transfer capability that must be available to allow the impacted regions to collectively respond to the extreme event. The IRPA process should be iterative and integrated.

The DOE should acknowledge the important role of local transmission planning in alleviating capacity constraints and congestion. The Draft Study notes that transmission planning is conducted today by local utilities, who plan for local transmission needs on their own transmission systems, as well as Regional Planning Authorities, which plan for regional needs and identify regional transmission projects (p. 2). It further notes that **in aggregate**, these assessments evaluate the reliability, economic and public policy requirements of the future power system.

[4] *See* AEP's comments filed in FERC Docket AD21-15, *Federal State Joint Task Force Post-Meeting Comments*.

[5] A minimum transfer capability of 25 percent is supported by past events as further explained in AEP's comments filed in FERC Docket AD21-15, *Federal State Joint Task Force Post-Meeting Comments*.

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However, absent from the Draft Study is any meaningful discussion of the role of local transmission planning to alleviate capacity constraints and congestion.

The Draft Report states that local and regional assessments "typically are performed to ensure that future system will address expected reliability needs for a select set of futures that reflect a more limited set of potential resources changes" (p. 2). This statement overlooks the fact that there is significant overlap between reliability violations and economic congestion, meaning that facilities that drive reliability violations are also likely to drive economic congestion, and vice versa. As such, addressing reliability violations through reliability projects (whether local or regional) is highly likely to also proactively address economic congestion. The economic benefits of these reliability projects often are overlooked due to the order in which the transmission analyses are performed (*i.e.*, reliability analyses are performed first, followed by economic analyses). AEP recommends that the DOE further illustrate the importance of local transmission planning and resulting projects in this and future Transmission Needs Studies.

Thank you again for the opportunity to provide these comments on the Draft Study.

Respectfully submitted,

s/ Jessica Cano

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Americans for a Clean Energy Grid

Americans for a Clean Energy Grid Comments on the Department of Energy's Draft National Transmission Needs Study

Americans for a Clean Energy Grid (ACEG)—a not-for-profit public interest advocacy organization that brings together a diverse coalition of stakeholders focused on the need to expand, integrate and modernize the high-capacity grid in the United States[1]—appreciates this opportunity to provide input to the Department of Energy (DOE) Draft National Transmission Needs Study.[2] The Draft Needs Study provides an important overview of transmission needs in each region of the country and reinforces the findings of multiple experts that, regardless of the scenario considered, all regions in the nation need significant additional regional and interregional transmission to protect reliability, improve resilience, provide access to diversified and lower cost energy resources, and meet our nation's climate goals.

The Needs Study is a foundational document that every transmission planner, regulator, energy policymaker, and stakeholder should review when final, as its discussion and findings can increase public understanding of transmission needs and benefits. Further, it can help improve how regional planners execute their respective responsibilities to plan for their area's transmission needs. Specifically, the Draft Needs Study:

- Describes the multiple values of transmission and lays a foundation for the minimum set of potential benefits that should be considered when planning and building transmission;
- Validates why optimized planning includes an examination of historical, current, and expected needs, especially as transmission lines have 40+ year life expectancies and should be planned with future needs in mind; and
- Underscores the importance of interregional transmission lines and the need for neighboring regions to harmonize planning processes and develop transmission jointly to improve resilience in the system, especially in the face of continuing extreme weather events.

[1] The ACEG coalition includes: multi-state utilities that develop, own, and operate transmission; trade groups that include transmission owners and transmission equipment manufacturers among their members; renewable energy trade groups, developers, and advocates; environmental and labor advocacy organizations; buyers of energy; and energy policy experts. ACEG seeks to educate the public, opinion leaders, and public officials about the needs and potential of the transmission grid. These comments do not necessarily reflect the views of individual members.

[2] Department of Energy, *DRAFT National Transmission Needs Study* (February, 2023) ("Needs Study").

Americans for a Clean Energy Grid

ACEG's limited comments provide recommendations aimed at bolstering both the contents and the uses of the Needs Study to inform transmission planning policies and processes.

I. Background

Electricity is an essential service, and nearly all aspects of modern life depend on a robust and reliable power grid. But our nation's existing grid is neither technically nor locationally sufficient to meet our modern needs. According to the American Society for Civil Engineers, most of the nation's transmission and distribution lines were constructed in the 1950s and 1960s and have a 50-year life expectancy, meaning they have reached or surpassed their intended lifespan.[3] Simply replacing old lines will not resolve current and expected future problems, however. Real-world experience suggests that generation shortfalls resulting from severe weather and other threats are occurring with greater intensity and frequency. These events tend to be at their most extreme in areas lacking fully interconnected power systems.[4] Transmission can address such capacity shortfalls by enabling imports from areas less affected by the weather events.

Similarly, a recent report by national security experts noted, "[o]ur electricity grid's resilience—its ability to withstand shocks, attacks and damages from natural events, systemic failures, cyber-attack or extreme electromagnetic events, both natural and man-made—has emerged as a major concern for U.S. national security and a stable civilian society."[5] The report described large scale, modernized, transmission as a solution noting that:

> Transmission buildout is critical to resilience as it can relieve line overloading—or 'congestion' . . .—on the existing system, lessening the compounding risks that come with a strained grid that could then be tested by an extreme weather event or an attack incident. Moreover, by enabling further development of renewable energy resources over wider geographic areas,

[3] American Society of Civil Engineers, "Policy Statement 484 - Electricity Generation and Transmission Infrastructure," Adopted by the Board of Direction on July 13, 2019.

[4] Goggin, Michael, Transmission Makes The Power System Resilient To Extreme Weather, 2021.

[5] National Commission on Grid Resilience, "Grid Resilience: Priorities for the Next Administration," at 1, 2020.

Americans for a Clean Energy Grid

> well-planned transmission expansion can make targeted attacks on the grid more difficult to plan and carry out.[6]

Furthermore, large-scale transmission buildout is vital to achieving climate policies and bringing on the lower-cost and cleaner resources that utilities, states, and consumers have been calling for. Independent estimates indicate that high voltage transmission will need to double by 2030 and triple by 2050 at a cost of $360 billion through 2030 and $2.2 trillion by 2050 in order to achieve a zero-carbon future by 2050.[7]

Despite the wide-spread acknowledgment that we need to expand and modernize transmission, the rate of construction has fallen behind the pace needed to meet our present and future reliability needs and our climate goals. Indeed, in the last decade, regionally planned transmission investment has decreased by 50% and few interregional lines have been planned.[8] Even when lines get planned, transmission projects can take at minimum 5-10 years to plan, permit, and construct,[9] and in some cases have taken over 15 years to receive permits and begin construction.[10]

In recognition of the need for additional transmission and the hurdles facing such expansion, Congress—through the Infrastructure Investment and Jobs Act (IIJA)—expanded its directive under Federal Power Act (FPA) Section 216(a)(1) and required DOE to conduct a study of both electric transmission congestion *and* electric transmission capacity constraints.[11] In so doing, Congress did not provide a definition of the terms "transmission congestion" or "transmission capacity constraints," nor did it dictate the time horizon that should be reviewed in the study. Instead, it left such details to DOE—the expert agency. Moreover, while Congress required DOE to conduct the study "in consultation with affected States and Indian Tribes," it did not mandate any additional consultation, again leaving such details to the expert agency.

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[6] *Ibid*., at 42.

[7] Larson et al, Net-Zero America: Potential Pathways, Infrastructure, and Impacts at 108, (October 29, 2021), Princeton University https://netzeroamerica.princeton.edu/the-report; *see also DOE, "DOE Launches New Initiative From President Biden's Bipartisan Infrastructure Law To Modernize National Grid," January 12, 2022.*

[8] Pfeifenberger et al., Cost Savings Offered by Competition in Electric Transmission at 1, April 2019.

[9] Pfeifenberger, Johannes and John Tsoukalis, "Transmission Investment Needs and Challenges" at 13, June 2021.

[10] *E.g.* Permit applications for the Gateway South line were submitted in November 2007, but the project did not begin construction until June 2022.

[11] 16 U.S.C. § 824p(a)(1) as amended by Pub. L. 117–58, div. D, title I, § 40105, Nov. 15, 2021, 135 Stat. 933.

Americans for a Clean Energy Grid

II. Comments on Draft Needs Study

ACEG commends DOE for conducting a proactive examination of historical and expected congestion and capacity constraints and for seeking broad based input on the study before issuing in final form. The study provides a baseline finding of national transmission needs. In other words, the Needs Study can be integrated into regional planning or serve as a check on the adequacy of regional planning, but it is not the final say on what must be built or where transmission should be built. In order to bolster the utility of the Needs Study, ACEG recommends that DOE integrate a discussion of the regional benefits of high-capacity transmission in the final report. ACEG further recommends that the DOE provide greater detail, either in the Needs Study or in a companion document, on how the agency plans to socialize the study and how the discussion and findings can be used to improve existing planning processes.

A. Emphasizing the Value of High-Capacity Transmission to an Entire Region

The Draft Needs Study identifies the need for greater regional and interregional transmission throughout the country. While the final Needs Study will not identify particular solutions, at least some of the optimal solutions are expected to consist of long-distance lines that cross multiple states. But, as recognized in the Draft Needs Study, "many states focus on intrastate burdens and benefits. A line that does not directly connect resources within a state might not receive permits required to traverse the state."[12] ACEG recommends that DOE add to the final study information on the multiple benefits of high-capacity, long-distance transmission to an entire region, not just to the end points of the line. Such discussion could include information on how improving long-distance lines will improve overall regional reliability and reduce congestion, potential associated economic development opportunities (e.g., opportunities to pair transmission with broadband), and methods that developers have used on long-distance transmission lines to augment local power delivery opportunities (e.g., converter stations, interconnection lines, etc.).

B. Ensuring the Study Does Not Gather Dust

The Draft Needs Study provides valuable information about not only our nation's transmission needs, but also strategies for how regions and states can more optimally investigate and address their own transmission needs. These strategies include recognizing multi-value benefits of transmission, planning on longer time horizons,

[12] Needs Study at 77.

optimizing capacity expansion models by examining both generation and demand needs, and standardizing planning protocols between neighboring regions to streamline and strengthen planning of interregional facilities.

Too often studies are developed and placed on back shelves after being issued. But our nation's transmission needs are too significant and immediate to ignore available tools such as this Needs Study. Existing regional planning processes are not considering these cross-cutting issues and therefore are failing to prepare the grid to meet our evolving energy needs. Processes–and transmission plans–must fundamentally change if we are to timely construct the network improvements needed to ensure our essential energy systems are reliable and cost-effective.

In order to ensure optimal use of the Needs Study, ACEG encourages DOE to lay out a roadmap of how it plans to share the findings of the study. Moreover, DOE should provide greater details on how planners, regulators, and energy stakeholders can use the study to better identify their own transmission needs and improve their transmission planning processes. Specifically, ACEG encourages DOE to address:

- How energy stakeholders and regional planners can integrate the Needs Study into their own planning processes;
- How the information in the document—which is presented on a regional basis—can help state and tribal decision-makers better understand the transmission needs in, or that cross-over, their respective jurisdictions;[13] and
- If, and if so how, DOE plans to work with neighboring regions to improve collaboration and interregional planning.

Further, ACEG recommends that DOE clarify how it plans to use the results of the Needs Study for its own work.[14] In particular, DOE should explain how the final Needs Study will be used to inform the designation of National Interest Electric Transmission Corridors, the implementation of IIJA and Inflation Reduction Act transmission provisions, and the execution of its Loan and Transmission Infrastructure programs. By proactively providing this information, DOE can help mitigate concerns over the use of the assessment. Moreover, such information will help stakeholders better engage in DOE's programs and processes and in maximizing the benefits of federal action on transmission.

[13] To this end, ACEG recommends DOE present, in either the final Needs Study or in companion materials, the assessment results with greater geographic specificity (e.g., state specific fact sheets or where interregional needs have been identified, multi-state fact sheets).

[14] *See, e.g.* Draft Needs Study at 1 (discussing potential uses of the needs assessment).

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III. Conclusion

ACEG again commends DOE for seeking public input on the Draft Needs Study and encourages DOE to incorporate the recommendations provided herein.

Sincerely,

/s/ Christina Hayes

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Dated: April 20, 2023

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ARIZONA MUNICIPAL POWER USERS' ASSOCIATION

IRRIGATION & ELECTRICAL DISTRICTS ASSOCIATION OF ARIZONA

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April 14, 2023

Re: Department of Energy National Transmission Needs Study

Dear Director Robinson:

On behalf of AMPUA and IEDA, we submit the following comments in response to the Draft Department of Energy (DOE) National Transmission Needs Study, published in the Federal Register Notice on March 6, 2023 (Document Number:2023-04521).

AMPUA is an association of Arizona public and consumer owned power including irrigation districts, electrical districts, electric cooperatives, municipally owned electric systems, Salt River Project, and Central Arizona Project.

IEDA consists of 25 members representing a collection of public power entities in Arizona. It is comprised of Irrigation & Electrical Districts, municipalities, and two tribal entities. IEDA has been in existence since 1962, with a focus on power and water related issues, including transmission.

The United States electrical grid has been described as one of the most complex machines ever created, and we recognize the amount of time and effort that has gone into this report. We submit the following suggestions for potential improvements.

It has been evident over the last few years that transmission needs have been growing in focus and importance. The ongoing retirement of baseload plants and shift towards intermittent renewable resources as replacements has necessitated the expansion of the transmission system to get resources to load. Transmission development had been stymied due to a decade of limited to no load growth.

However, the recent awareness that electrification could double our 2020 power needs by 2050 (page 72) highlights the need to begin the transmission expansion now. We would recommend that the increased need for capacity due to electrification, as well as the time it takes for transmission projects to be completed (page 55) be given more emphasis in the Executive Summary.

While this is a transmission report, we appreciate the acknowledgement of resource diversity being critical to enhanced resilience. In ISO-NE, resource diversity reduced the need for new capacity by up to 17 GW (page 51). With the accelerated pace of electrification, an "all of the above" approach to capacity to ensure grid reliability is necessary. This is highlighted by the report's acknowledgement of the capacity shortfalls in MISO and WECC. Transmission infrastructure will be a long-term solution to a very real and current problem.

The report highlights the cost of achieving 80% clean energy at approximately $500B, but the report doesn't provide enough detail with regards to the cost of construction of transmission lines. The report uses a $/MWH and graphs that do not provide the granularity that we were hoping for regarding construction costs per region. We also found one error in the report, with 80% being listed twice in Figure V-2 (page 53).

We appreciate the approach the report took to projecting transfer capacity needs between regions but feel that a table describing existing transmission capacity between regions would also be helpful. Without a reference to existing capabilities, the scale of the need is lost. In addition, the report recommends increased transfer from the Southwest to Texas regions but fails to include this in Table VI-4 (pages 96-98).

The Southwest region is heavily dependent on transmission from California, but the report fails to include reference to FERC Docket No. ER21-1790-003, which allows CAISO to prioritize its load over energy being wheeled through CAISO to the Southwest region. As long as this is in place, CAISO can essentially sever transmission into the Southwest when it deems that it needs the resources. Much like the regional diversification of resources discussed in the report, the need to diversify the Southwest's reliance away from CAISO transmission should be discussed.

The Southwest's transmission limitations make it like ERCOT, with limited import-export abilities. As such, the need for increasing and improving interconnection seams between ERCOT and the Eastern & Western Interconnects should be stressed.

The Executive Summary highlights "the best possible solution for alleviating issues in a timely manner (page 2)." Unfortunately, despite multiple references to wildfires due to climate change, there was no mention of vegetation management as a mitigation alternative. We believe this would be the timeliest non-wires alternative, and its absence is a weakness in the report.

We appreciate the reference to other non-wires alternatives (new generation, storage, and distributed energy resources (page 73-75) as possible alternatives to new transmission. Cost comparisons of these alternatives to assist in short- and long-term planning to compare alternatives would be additionally helpful.

New transmission will allow for improved integration of different resources regionally, while also providing some protection from weather related impacts. This geographic diversity will help provide carbon-free resources to different parts of the country when there is excess.

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However, we feel that the construction of new transmission just to reduce curtailment of subsidized resources isn't sufficient justification for the expense. More discussion on non-wires solutions would benefit this part of the report.

With record amounts of new generation and storage in the queues, now is the time to maximize results and minimize consumer costs through proper regional planning. This report will be a great help to that, and we hope that the suggestions included in the letter will enhance this process.

Sincerely,

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AMPUA

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April 20, 2023

Submitted by email

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RE: Draft National Transmission Needs Study Request for Public Comment

I. Introduction

The Association for Modern Powerlines (AMP) appreciates the opportunity to provide comments to the Department of Energy (DOE) and Grid Deployment Office (GDO) for the Draft National Transmission Needs Study (Needs Study) Request for Comment. We commend DOE for its work on the Draft National Transmission Needs Study and generally support the findings that the United States needs significant increases in transmission capacity, both intra- and interregionally, through 2040.[1] AMP encourages DOE and GDO to quickly finalize the National Transmission Needs Study so that the National Interest Electric Transmission Corridors process can continue to proceed expediently.

AMP proposes the Needs Study should use a scenario with high load and high clean energy assumptions as its base case, given recent decisions by EPA and the passage of the Inflation Reduction Act.[2] The Needs Study finds that increased transmission capacity is needed to maintain overall reliability and connect a changing resource mix to increasing demand.[3] The Needs Study finds that scenarios with moderate load and high clean energy assumptions in line with the IIJA and IRA requires a 57 percent growth over today's transmission system by 2035, and the high load and high clean energy assumptions require doubling of the U.S. transmission system by 2040.[4] The study also notes that the U.S. has an aging grid overall, with many lines needing to be replaced or upgraded.[5]

Replacing aging transmission conductors and upgrading planned new transmission lines with high-ampacity conductors can quickly facilitate increasing grid capacity and relieving the resulting underlying grid congestion, interconnecting more clean energy, increasing energy efficiency of the system, and creating greater resilience against wildfires and severe weather threats.

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[1] U.S. Department of Energy, "National Transmission Needs Study Draft for Public Comment," February 2023, 88-105, https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.
[2] U.S. Environmental Protection Agency, "Proposed Rule: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles," April 12, 2023, https://www.epa.gov/regulations-emissions-vehicles-and-engines/proposed-rule-multi-pollutant-emissions-standards-model.
[3] Needs Study, 106.
[4] Needs Study, 106-107.
[5] Needs Study, ii & 47.

DOE leadership have been vocal supporters of the benefits of high-ampacity conductors. Secretary of Energy Jennifer Granholm pointed out the benefits of high-ampacity conductors in her keynote address to NARUC this February 2023 and more recently at SXSW.[6] Loan Program Office Director Jigar Shah expressed support for high-ampacity conductors noting the ability of high-ampacity conductors to increase grid capacity and facilitate the addition of new renewable generation.[7]

AMP respectfully proposes that high-ampacity conductors be included in the "Non-Wire Alternatives" section of the Needs Study and suggests the section could be renamed "Advanced Transmission Technology," which would align better with previous DOE reports. AMP believes high-ampacity conductors demonstrate many of the benefits found for non-wire alternatives, warranting their inclusion in the final National Transmission Needs Study.

II. About AMP

AMP is an ad hoc coalition of CTC Global Corporation, TS Conductor, and VEIR, Inc. AMP's goal is to further the use of high ampacity conductors as a tool for modernizing the grid, increasing grid capacity, and improving the overall resilience, reliability, and energy efficiency of the grid. High ampacity conductors encompass two types of modern cables: Advanced Conductors and Superconductors.

III. Technology Types

Advanced Conductors are overhead, bare conductors that use a trapezoid shaped wire of annealed aluminum to carry the electrical current and a carbon or composite core as the strength (support) member.[8] These conductors are alternatives to the conventional Aluminum Conductor Steel Reinforced ("ACSR"). ACSR was developed roughly 100 years ago and is still utilized in large quantities today due to its low initial cost even though it is one of the most wasteful (high resistance) conductors in use worldwide. ACSR uses hardened, high-resistance aluminum alloy strands to carry the electric load. These high resistance materials result in unnecessary line losses. In addition, ACSR uses a spring-steel core that sags dramatically when the line is heated from high loading. Line sag results in capacity limitations that exacerbate grid-congestion and expose power lines to potential contact with undergrowth and under-build. For equivalent size (diameter) conductors, Advanced Conductors provide two-times the current flow, 30 percent or more reduced heating losses, and half the conductor sag as the conventional ACSR conductors. Because the Advanced Conductors and ACSR conductors are similar weight for similar size (diameter), the Advanced Conductors can be used upgrade and modernize a powerline by replacing the legacy ACSR conductor (reconductoring) with Advanced Conductors using the existing structures and avoid the time-consuming and costly permitting processes required for

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[6] The Hon. Jennifer Granholm, U.S. Secretary of Energy, U.S. Department of Energy, speech to NARUC 2023 Winter Policy Summit, "The Changing Energy Landscape and Regulatory Challenges," February 2023, https://www.naruc.org/meetings-and-events/naruc-winter-policy-summits/2023-winter-policy-summit/agenda/; Craig Huber, "Energy Sec. Jennifer Granholm touts Biden's ambitious climate goals at SXSW," Spectrum 1 News, Austin, TX, March 13, 2023, https://spectrumlocalnews.com/tx/south-texas-el-paso/news/2023/03/12/energy-sec--jennifer-granholm-touts-biden-s-ambitious-climate-goals-at-sxsw.

[7] Jigar Shah, LinkedIn post, October 2022, https://www.linkedin.com/posts/jigarshahdc_upgrading-transmission-lines-could-enable-activity-6983969644789260288-w1vd/?utm_source=share&utm_medium=member_ios.

[8] "Advanced Conductor" or "Advanced Overhead Conductors" generally refers to electrical conductors with carbon and/or composite cores, rather than the steel wire cores used for conventional conductors.

conventional rebuild solutions. Advanced Conductors are widely deployed worldwide with multiple advanced conductor technologies available in the U.S. market.

High Temperature Superconducting (HTS) power lines operate with negligible resistive losses. Negligible losses enable HTS lines to operate at levels of electrical current that are much higher than conventional copper- and aluminum- based power lines. Very high current enables HTS lines to (a) transmit much more power than conventional lines at a given voltage level, and (b) transmit the same amounts of power as conventional lines but at much lower voltage levels. Because of those characteristics, HTS power lines can greatly increase the transfer capacities of narrow and pre-existing corridors. AC HTS power lines offer about a five-fold increase in power flow capacity relative to ACSR conductors, at a given voltage level. DC HTS power lines offer a ten-fold or more increase in power flow capacity. HTS power lines can add much-needed transfer capacity to the grid without triggering as many or as onerous and time-consuming siting and permitting requirements as projects that require new or expanded corridors.

HTS power lines are actively cooled with nitrogen (N2), a noncombustible, nontoxic, non-warming gas that comprises 78 percent of the atmosphere. Active cooling means that HTS power lines sag less while they are energized and in operation, even while operating at maximum power flow. It also means that the power flow capacity and sag of HTS lines do not vary with ambient weather conditions. It takes some energy to produce N2 and to pump N2 into HTS power lines. However, because resistive losses in HTS lines are negligible, HTS lines are at least 50 percent more energy efficient than ACSR conductors.

Throughout our comment, we refer to Advanced Conductors and Superconductors as "High Ampacity Conductors."

IV. Applications

High ampacity conductors can be deployed in the following ways:

- Replace conductors at congestion points on the grid.
- Deploy them when network upgrade needs are identified in generator interconnection processes, both for clusters and individual projects.
- Include in regional long-term planning.
- Replacing aging assets. Rather than replace 60+ year old wires with technology from the time they were originally installed, modern cables can be utilized using the existing structures.
- Deploy as a critical part of a resilience program given the low sag and greater strength of the cables.
- Increase grid resilience in urban areas.
- Provide additional storm hardening against major climatic events.
- Prepare the grid for an unpredictable future by providing additional, flexible capacity.

V. Comments on National Transmission Needs Study

High-ampacity conductors should be included in the Needs Study as a technology in the "Non-Wire Alternatives"[9] section, which AMP proposes could be renamed "Advanced Transmission Technology."[10] AMP believes high-ampacity conductors fall into a similar category as many of the non-wire alternatives included in the Needs Study and necessitates a descriptive section for high-ampacity conductors in the Needs Study.

High-ampacity conductors are an effective tool for increasing capacity on the existing grid through reconductoring or rebuilds as well as increasing overall energy efficiency of the grid, which saves ratepayers money and reduces the need for new generation. A 2020 report from DOE found that Advanced Conductors "can have a maximum current-carrying capacity of up to two times that of conventional conductors."[11] Using this estimate, a report by the American Council on Renewable Energy estimated that reconductoring 5,000 miles of transmission annually with Advanced Conductors would integrate roughly 27 GWs more of renewable capacity per year.[12] Including superconductors in the study would have enabled even higher integration of renewables, given that the maximum current-carrying capacity of superconductors is up to ten times that of conventional conductors.

In addition, significantly increasing grid capacity and connecting large amounts of new generation resources will create considerable new congestion on the underlying grid. This reality will require swift action to relieve the congestion and avoid stifling development of need generation resources. Reconductoring and rebuilding transmission lines on the underlying system with high-ampacity conductors is a solution that allows grid operators to quickly alleviate congestion and meet the system needs.

The Needs Study highlights the role advanced transmission technologies can have in today's grid by maximizing the capacity of the existing grid and increasing the capacity of new transmission.[13] High-ampacity conductors are not "non-wire alternatives" but are an advanced transmission technology that were not included in the Needs Study or the underlying capacity expansion studies examined.[14] Therefore, the increased energy efficiency and ability to expand capacity over traditional conductors by high-ampacity conductors was not considered by the Needs Study.

AMP understands that the Needs Study is focused on quantifying U.S. transmission needs, rather than prescribing solutions, but the Needs Study does identify non-wire alternatives as solutions

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[9] Needs Study, 73-76.

[10] DOE produced a 2020 report titled "Advanced Transmission Technologies" that includes high-ampacity conductors along with many of the non-wire alternatives identified in the Needs Study, such as Dynamic Line Rating, Topology Optimization, and Power Flow Controllers; *See* U.S. Department of Energy, "Advanced Transmission Technologies," December 2020, https://www.energy.gov/sites/prod/files/2021/02/f82/Advanced%20Transmission%20Technologies%20Report%20-%20final%20as%20of%2012.3%20-%20FOR%20PUBLIC.pdf.

[11] Advanced Transmission Technologies, 26.

[12] Jay Caspary and Jesse Schneider, "Advanced Conductors on Existing Transmission Corridors to Accelerate Low Cost Decarbonization," ACORE, March 2022, 19-20, https://acore.org/wp-content/uploads/2022/03/Advanced_Conductors_to_Accelerate_Grid_Decarbonization.pdf.

[13] Needs Study, 73-76, 85.

[14] Needs Study, 82-83.

which could potentially meet some of the modeled transmission capacity needs in a region.[15] The Needs Study states that non-wire alternative solutions "could help lower, but are unlikely to eliminate, the need for new transmission infrastructure."[16] The Needs Study also finds that non-wire alternatives "may not be adequately considered in existing planning processes. Although it may be a paradigm shift compared to traditional operations, leveraging technology to increase an operator's visibility, and understanding of power system flows and capabilities on critical components should actually improve grid security, not jeopardize reliability."[17] Both statements could be made about high-ampacity conductors.

Respectfully submitted on behalf of AMP,

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[15] Needs Study, 85.
[16] Needs Study, 85.
[17] Needs Study, 2-3.

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DEPARTMENT OF ENERGY
NATIONAL TRANSMISSION NEEDS STUDY

Comments on the Public Draft **Grid Deployment Office**

Comments of Avangrid, Inc.
April 20, 2023

Avangrid, Inc. ("Avangrid") submits these comments to the Department of Energy ("DOE") in response to its request for feedback from the public about analysis gaps or any other comments or suggestions on the February 2023 Public Draft of the National Transmission Needs Study ("Needs Study").[1] Avangrid appreciates the opportunity to provide comments responding to the request for feedback and looks forward to continued active participation in this effort.

Avangrid is a leading, sustainable energy company with $39 billion in assets and operations in 24 U.S. states. Avangrid has two primary lines of business, Avangrid Networks, Inc. ("Avangrid Networks") and Avangrid Renewables, LLC ("Avangrid Renewables"). Avangrid Networks owns eight electric and natural gas utilities, serving 3.3 million customers in New York and New England. It provides interconnection services to generators in its service territories, as well as participates in regional electric transmission planning in New York and New England. Avangrid Renewables is a leading renewable energy company that owns and operates a portfolio of approximately 8,000

[1] *National Transmission Needs Study*, Department of Energy, February 2023 Draft. Available at https://www.energy.gov/gdo/national-transmission-needs-study

MW of renewable energy generation facilities across the U.S. Avangrid Renewables also has a significant pipeline of onshore wind and solar as well as offshore wind projects under development, including the 800 MW Vineyard Wind 1, 1,232 MW Commonwealth Wind, and 804 MW Park City Wind offshore wind projects.

Avangrid's New England Clean Energy Connect ("NECEC") transmission project[2] will bring 1,200 new megawatts of clean, renewable generation with incomparable quality of availability around the clock, every day, year-round into New England. NECEC will provide 3 million metric tons per year of reduction in regional CO_2 emissions while also reducing electricity supply rates by tens of millions of dollars per year.

Avangrid hopes that the DOE finds these comments helpful in finalizing the National Transmission Needs Study.

I. Comments

The Needs Study correctly identifies the need for more interregional and international transmission capacity. Avangrid supports the report's findings highlighting the continued need for transmission build out in the New York and New England, regions where Avangrid is most involved with transmission planning activities. In particular, Avangrid concurs with the following DOE findings for the New England Region:

[2] https://www.necleanenergyconnect.org

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- A constrained natural gas system poses a risk to winter reliability when demand for gas is high for both heating and electricity.
- Increased transfer capacity between New England and Canada will enable bidirectional flow of hydropower, wind and solar generation between the regions, helping to meet State clean energy targets.

DOE notes that the Needs Study will support the implementation multiple DOE programs as well as the potential designation of National Interest Electric Transmission Corridors (NEITCs). Avangrid encourages DOE to move forward expeditiously in its efforts to designate NIETCs on a route-specific, applicant driven basis, pursuant to Section 216 of the Federal Power Act. As part of this process, DOE should focus on how potential corridor designations address specific regional needs.

II. Conclusion

Avangrid respectfully thanks DOE for the opportunity to provide comment to help DOE finalize its National Transmission Needs Study.

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April 20, 2023

Sent via Email to: NeedsStudy.Comments@hq.doe.gov

Re: Blue Lake Rancheria Comments on the *Public Draft of the National Transmission Need Study February 2023*

To All This May Concern,

The Blue Lake Rancheria, a federally recognized Tribal Nation in northwest coastal California, respectfully submits the following comments on the February 2023 Public Draft of the National Transmission Need Study ("Draft").

General Comments

The transmission needs in Tribal lands are severe. The Rural Electrification Act of 1936 and subsequent efforts to electrify rural and remote areas of the U.S., have largely excluded Tribal Nations. The Climate Crisis and related impacts (wildfires, flooding, extreme heat, extended drought, landslides, weather volatility) have created cascading effects on electric transmission serving Tribal lands.

Currently transmission and distribution grids providing electrical service to Tribal Nations are at capacity, which constrains clean-energy-based economic development and other kinds of growth. Further, at least ~threefold increases in electrical load and related hosting capacity are needed for clean energy transitions, additions of distributed energy resources (DERs), and full electrification of buildings and transportation.

Blue Lake Rancheria recommends focused outreach to Tribal Nations regarding the National Transmission Needs Study before it is finalized, to incorporate input from a variety of Tribal Nations with transmission needs. Since building its microgrids in 2017, the Blue Lake Rancheria Tribe has experienced over 30 grid outages that required extended islanding of its systems. Many Tribes in Northern California have experienced several multiple-day and *multiple-week* extended outages in the last three years due to wildfires, storms, earthquakes, and other disasters. Other areas of Tribal Nations in this region have never had access to the electrical grid. These conditions must be improved, and part of the solution is transmission upgrades to and within Tribal lands.

California Section

The Tribe adds the following to the need to improve system reliability and resilience:

- ⇒ Seismic activity – in coastal Humboldt and Del Norte counties, and Tribal Nations within those areas, all energy transmission lines and pipelines (electric and natural gas) run through areas with extreme seismic risk.
- ⇒ Transmission in Humboldt County has a single point of failure due to over-reliance on a single fossil fuel (natural gas) powered electrical plant.

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    - As a recent example, during a 6.4 earthquake on December 20, 2022 the entire region lost power due to the immediate outage of that one power plant.
    - The region's anchor power plant is served by a single 10-inch natural gas pipeline that is also at severe seismic risk of rupture.
- ⇒ Grid capacity shortfalls – California is already experiencing capacity shortfalls. In southern Humboldt County, a hospital cannot be built today – and several Tribes seeking to build DERs cannot connect to the grid – because of grid capacity constraints.
    - The Humboldt County region is transmission capacity constrained as it cannot import more than 70 MW, roughly half its base electricity use.
        - Transmission upgrades to the single 115kV line serving the region should be a top priority, with or without the addition of offshore wind generation transport needs (see below).
            - The Blue Lake Rancheria Tribe cannot build small utility scale solar PV array(s) to serve its lands and the region's clean energy needs due to these constraints.
- ⇒ Tribal Nations along existing and new transmission routes need upgrades to substations and distribution grids, as many areas are rural, remote, and subject to multiple hazards.\
    - Tribal facilities are often the only critical infrastructure in rural, remote areas, and with climate resilient electrical infrastructure can deliver a wide array of emergency services.
- ⇒ Sea level rise – Humboldt Bay in Northern California has the fastest rate of sea level rise on the Pacific Coast, and this threatens the region's sole anchor natural gas-to-electricity power plant, which in turn threatens the electrical and natural gas power supply to the entire region. Sea level rise also threatens transmission infrastructure to and within several Tribal Nations on or near the coast.

Offshore Wind Section

To the section on Offshore Wind in the Draft, the Tribe adds the following needs: Off the Northern California / Southern Oregon coasts, there is potential for ~15-45 GW (or more) of offshore wind generation, due to demonstrated resource potential. To deliver the offshore wind power to load centers to the east, south, and north, new high voltage transmission lines must be built.

Tribal Nations must be included in planning and design activities for offshore wind transmission upgrades - *and deployment investments* - with state and federal counterparts. Including Tribal Nations early and designing transmission to also solve for Tribal energy needs will ensure energy benefits to Tribal Nations are delivered, and impacts from construction and operation of these corridors are minimized or avoided. Activities such as new substations for Tribal communities, undergrounding or otherwise hardening transmission infrastructure for the regional risks noted above, in addition to full engagement on cultural resources and environmental review, are crucial. Tribal Nations may also pursue building, owning, and operating transmission infrastructure, and need frameworks for collaboration and coordination in development and regulatory spaces.

Transmission upgrades designed with sufficient capacity for Tribal Nation's full electrification, clean energy transitions, DER development, and resiliency needs as well as offshore wind capacity will be exponentially more effective, and may present opportunities for Tribal support and transmission project acceleration.

Clean Energy on Tribal Lands Section

To the section on Clean energy on Tribal lands, the Tribe adds the following needs: The majority of Tribal Nations are actively seeking to build electrical infrastructure at various scales. The inadequacy of

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transmission capacity, and poor quality of electricity delivery, is creating a chilling effect on adoption of electrified transportation, building electrification, and development of DERs in Tribal lands. This chilling effect has the practical impact of leaving Tribal Nations further behind the nation in terms of electrical infrastructure. Lack of transmission is also severely constraining Tribal economies, e.g., high-quality, resilient power is required for digitally-connected economies of today and the immediate future. Crossing the digital divide requires crossing the clean energy divide. And, Tribes are still relying on high-emission and polluting diesel generators for baseload and back-up power needs, primarily due to transmission constraints.

The Tribal clean energy and economic potential statistics cited in the Draft are dated. With future-proofed transmission capacity, Tribal Nations, and particularly those in markets where energy costs and constraints have increased in the past few years, can develop greater amounts of clean energy, both as economic enterprises, and as economy-enabling infrastructure. The Tribe recommends updating the studies referenced with new research and data.

Thank you in advance for your close attention and time-sensitive review. For further information, please contact me at jganion@bluelakerancheria-nsn.gov

Sincerely,

/ s /

Jana Ganion
Director, Sustainability and Government Affairs

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CENTER for BIOLOGICAL DIVERSITY Because life is good.

April 18, 2023

Department of Energy
Grid Deployment Office
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NeedsStudy.Comments@hq.doe.gov

Re: National Transmission Needs Study, Comments on the Public Draft (Entire Study)

Thank you for the opportunity to comment on the Department of Energy's (DOE) draft National Transmission Needs Study (2023 Needs Study), which will be used for DOE to complete the congressionally mandated Transmission Needs Report and make decisions about national interest transmission corridors. The Center for Biological Diversity (Center) is a national, non-profit conservation organization with more than 1.7 million members and online activists who care about the country's urgent need to expedite the renewable energy transition and protect human health, the natural environment, and species from the ravages of the climate emergency, extinction crisis, and environmental degradation. The Center's Energy Justice Program focuses on advancing energy justice and renewable energy deployment, including advocating for the broadest reliance on Distributed Energy Resources (DER) and other non-wires alternatives as key elements of a just and equitable clean energy transition.

Given the critical need to rapidly decarbonize the Nation's energy system to address the climate emergency, and the current political momentum for streamlining the processes of connecting more clean energy to the grid, it is essential for DOE to move forward with the grid planning process as expeditiously as possible. Unfortunately, as discussed below, in recent years DOE has missed key deadlines and has even moved in the wrong direction entirely, particularly by focusing on the North American Energy Resilience Model (NAERM). DOE therefore must keep this current process on track, and issue a final Transmission Needs Report as soon as possible.[1]

It is also essential that the final Transmission Needs Report address the many ways the Nation's ongoing energy needs can be met *without* building new transmission lines. As discussed below, there are numerous alternatives to transmission development that can better serve our current and projected energy needs, while at the same time avoiding the adverse impacts of new transmission projects. At the same time, the Transmission Needs Report must also address how to minimize the adverse impacts of any new transmission that will be built. Both of these issues must be fully and fairly treated to satisfy the Congressional mandates of the Infrastructure Investment and Jobs Act (IIJA), Pub. Law 117-58 (2021), including, *inter alia*, that in considering transmission needs,

[1] We raised some of these issues in an earlier letter to the agency. *See* Letter of July 20, 2022, https://www.biologicaldiversity.org/programs/public_lands/pdfs/DOE-Grid-Study-Letter-072022.doc.pdf.

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DOE work to "avoid[ ] and minimize[ ] to the maximum extent practicable [impacts on] sensitive environmental areas and cultural heritage sites."[2]

Finally, as also discussed below, it is vital that DOE engage in appropriate and early consultations with potentially impacted communities before designating any national interest transmission corridors where new transmission will be built.

A. DOE Must Issue A Timely Final Needs Report That Does Not Rely On NAERM.

Congress first directed DOE to conduct grid studies and consider designating national interest electric transmission corridors in Section 1221 of the 2005 Energy Policy Act. Pub Law 109-58 (2005). Section 1221 requires that "every three years" DOE (1) conduct a Study of electric transmission congestion, and then, after considering public input, (2) issue a subsequent Grid Congestion Report "which may designate any geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor."[3] Once designated, the statute provides for the Federal Energy Regulatory Commission (FERC) to consider permits for transmission projects in the corridors.

Over the past almost twenty years, DOE has rarely complied with these requirements, only issuing several Grid Studies and subsequent Reports, rather than completing the process every three years as mandated by Congress.[4] The last time DOE fully completed the process was in 2015.[5]

In 2020, DOE issued its last draft Grid Congestion Study.[6] In that draft, DOE asserted that transmission constraints "have abated," and suggested a new approach to these issues focused on the North American Energy Resilience Model (NAERM) – described as a "an integrated modeling approach to study the impact of critical energy and other infrastructures, including

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[2] 16 U.S.C. § 824p(a)(4).

[3] 16 U.S.C. § 824p.

[4] *See* DOE, Previous National Electric Transmission Congestion Studies
Office of Electricity, *https://www.energy.gov/oe/previous-national-electric-transmission-congestion-studies*

[5] Report Concerning Designation of National Interest Electric Transmission Corridors (Sept. 2015) , *https://www.energy.gov/sites/default/files/2015/09/f26/2015%20Report%20on%20Designation%20of%20National%20Corridors.pdf*

[6] National Electric Transmission Congestion Study (Draft, Sept. 2020), *https://www.energy.gov/sites/default/files/2020/10/f79/2020%20Congestion%20Study%20FINAL%2022Sept2020.pdf*.

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natural gas, renewables, coal, and others, on the electric power system."[7] In particular, DOE indicated that it expected that going forward the NAERM would somehow *be a substitute* for the Congressionally mandated Grid Congestion Study and Report. Thus, the 2020 Study stated that "DOE expects that the assessments called for in [the triennial transmission congestion study] will be synonymous with assessments the Department will prepare through applications of the NAERM."[8]

The 2020 Draft Study was never finalized, and a subsequent Report was never issued. Accordingly, while Congress directed that this process be completed every three years, DOE has not completed the process and issued a Grid Congestion Report—now called a Transmission Needs Report—a single time for eight years.

In the 2021 IIJA, Congress amended the existing Grid Study requirements, and added new deadlines. While Congress previously had only directed that the Grid Congestion Study be issued every three years, and left the deadline for the subsequent Report up to DOE, in the IIJA Amendments Congress, for the first time, added a *firm statutory deadline* for the Transmission Needs Report that follows the Study, requiring that it be issued "[n]ot less frequently than once every 3 years."[9]

The IIJA amendments also expand the list of factors DOE should consider in determining whether to designate a national interest electric transmission corridor, including whether the designation:

- "would enhance the ability of facilities that generate or transmit firm or intermittent energy to connect to the electric grid";
- "maximizes exiting rights-of-way";
- "avoids and minimizes, to the maximum extent practicable, and offsets to the extent appropriate and practicable, sensitive environmental areas and cultural heritage sites"; and

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[7] *Id*. at 21 and 26; *see also* U.S. Dep't of Energy, Office of Electricity, North American Energy Resilience Model, 2 https://www.energy.gov/oe/articles/north-american-energy-resilience-model-july-2019 (July 2019).

[8] 2020 Draft Congestion Study at 26.

[9] 16 U.S.C. § 824p(a)(2).

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- "would result in a reduction in the cost to purchase electric energy for consumers."[10]

It is therefore vital (a) that DOE remain on track to complete the Transmission Needs Report on the timeline set forth by Congress, and (b) that each of these mandates be fully addressed in the final Report.[11]

In February 2023, DOE issued the 2023 Needs Study for public comment. Despite the heavy reliance on the NAERM in DOE's 2020 draft Grid Study, the 2023 Needs Study does not mention NAERM. Given that NAERM was largely unhelpful to the solutions we actually need to address the Nation's energy needs, we urge DOE to continue to leave that model outside this planning process.

In particular, it is apparent that NAERM was intended—at least in part—to create a pretext for preserving the Nation's reliance on fossil fuels. As then-Secretary of Energy Dan Brouillette explained to Congress, the NAERM was established to help "maintain our baseload facilities throughout the country, and that includes not only coal but natural gas and nuclear as well."[12]

Further adding to that concern, DOE has provided little public information about the NAERM, and refused to timely respond to multiple Freedom of Information Act (FOIA) requests from the Center concerning both whether implementation of the NAERM might lead to increased reliance on fossil fuels, and DOE's fossil-fuel industry collaborations in NAERM's development.[13] The scant records the Center has received in response to these requests further confirm communications and coordination between DOE and various natural gas companies, as well as

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[10] *Id.* at § (a)(4). This would include, for example, whether non-wires alternatives might be a more economical approach to address congestion in certain areas. *See, e.g.*, *Beyond Wires, Using Advanced Transmission Technologies to Accelerate the Transition to Clean Energy*, Envtl Law & Policy Center 2021, https://elpc.org/wp-content/uploads/2021/05/BeyondWires_ELPC_Final2021.pdf.

[11] As we explained in our earlier letter, given how many years it has been since DOE completed a Congestion Report, the agency is long out of compliance with the statutory deadline. *See* Letter of July 20, 2022, *supra* n.1. However, even assuming *arguendo* that the deadline clock somehow began anew with the enactment of the IIJA, the deadline would be next Fall. While we urge DOE to complete the process sooner, it certainly must be completed by this Congressional deadline.

[12] *The President's Budget Request for the Department of Energy for Fiscal Year 2021: Hearing Before the S. Comm. on Energy & Natural Resources*, 116th Cong. 33 (2020) https://www.govinfo.gov/content/pkg/CHRG-116shrg40911/pdf/CHRG-116shrg40911.pdf (during the hearing the Secretary was asked whether he agreed that "early closure of critical baseload assets including our coal-fired power plants will have an impact on reliability," and responded by saying: "I do, Senator. I do share your concern. It's one of the reasons why we've established [NAERM] . . . . It is critical that we maintain our baseload facilities throughout the country, and that includes not only coal but natural gas and nuclear as well").

[13] *See Ctr. for Biol. Div. v. DOE*, No. 20-2950 (DLF) (D.D.C. 2020) (first FOIA suit over NAERM records) ; *Ctr. for Biol. Div. v. DOE*, No. 22-2131 (D.D.C. 2022) (second FOIA suit over NAERM records).

natural gas trade associations such as the Interstate Natural Gas Association of America, in connection with the NAERM.

The precise status of DOE's work on the NAERM today is not clear. When DOE announced its Building a Better Grid Initiative in January, 2022, the agency indicated that it was still working on the NAERM.[14] However, the Notice did not provide any further details.

As noted, the current 2023 Needs Study does not reference NAERM at all. We therefore assume it is no longer an important part of DOE's grid planning process. At the very least, the NAERM must not distract DOE from moving forward as quickly as possible to complete its assessment on the Nation's energy needs, which must be driven by the urgently needed renewable energy transition, not on NAERM's focus of preserving fossil fuel resources.

B. DOE Must Fully Address Alternatives To Transmission, And Ensure Any New Transmission Projects Minimize Adverse Impacts.

We have two principal concerns with the substance of the 2023 Needs Study.

First, the Study fails to fully explore non-wires alternatives as a meaningful solution to energy needs, and does not even discuss one of the most important of these alternatives: energy efficiency. Indeed, the Study largely ignores the myriad benefits of non-wires alternatives like distributed renewable energy, microgrids, energy efficiency, demand response, and grid enhancing technologies as compared to transmission and centralized, utility-scale renewable energy development. These benefits include, *inter alia*, greater affordability; greater resilience in extreme weather events, power outages and disasters; local economic benefits of jobs; avoided wildlife impacts with larger scale clean energy projects and transmission; avoided waste of power lost in line transmission, as 5-20% of such energy is lost just in the transmission alone; and public health benefits when quickly displacing fossil fuel generation and pollution.[15] Before DOE can make any determinations about the need for new transmission infrastructure, *the agency must fully assess the extent to which energy needs can be satisfied with these kinds of alternative and cost-effective solutions.*

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[14] Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization, 87 Fed. Reg. 2,769, 2,773 (Jan. 19, 2022), https://www.federalregister.gov/documents/2022/01/19/2022-00883/building-a-better-grid-initiative-to-upgrade-and-expand-the-nations-electric-transmission-grid-to.

[15] *See*, *e.g*., Nat'll Renewable Energy Lab., *Distributed Energy Planning for Climate Resilience* (2018), https://www.nrel.gov/docs/fy18osti/71310.pdf; Nat'l Acad. of Science, Eng'g & Med., *Enhancing the Resilience of the Nation's Electricity System* (2017), https://nap.nationalacademies.org/catalog/24836/enhancing-the-resilience-of-the-nations-electricity-system; Mark Dyson& Becky Li, Rocky Mountain Institute, *Reimagining Grid Resilience: A Framework for Addressing Catastrophic Threats to the US Electricity Grid in an Era of Transformational Change* (2020), https://rmi.org/wp-content/uploads/2020/07/reimagining_grid_resilience.pdf.

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Second, the Study does not squarely address the Congressional mandate that transmission development, and utility-scale generation projects they support, must minimize adverse environmental impacts.[16] As discussed below, there are numerous ways that DOE's final Transmission Needs Report can help to ensure that, where these projects do go forward, they are located on degraded lands and near the load they will serve.

1. DOE must make non-wires alternatives central to this evaluation process and prioritize them first in meeting energy demand.[17]

Building new long-distance transmission capacity often comes with a variety of associated harms. When new transmission lines are placed in previously undisturbed areas, they can damage and fragment sensitive ecosystems, including critical habitats for threatened and endangered species.[18] Construction and operation of large-scale transmission projects also causes local air, water, and noise pollution, and sometimes disrupts commercially and culturally important natural vistas. These burdens fall on communities that are not always the beneficiaries of the electricity the projects carry. Indeed, for these reasons these projects can generate fierce local opposition and sometimes fail to get necessary state permits, resulting in significant delays that dramatically reduce their effectiveness in facilitating the urgently needed clean energy transition.[19]

Communities of color also disproportionately bear the brunt of service disruptions that often result from infrastructural issues combined with extreme weather or natural disasters (themselves often likely linked to climate change). For example, during the 2021 Texas power outage, the blackouts hit minority neighborhoods first.[20] Researchers at Lawrence Berkeley National

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[16] 16 U.S.C. § 824p(a)(4)(G)(ii).

[17] We addressed many of these issues in our earlier comments on DOE's Grid Resilience and Innovation Partnerships (GRIP) Program, which we urge DOE to consider here as well. *See* Center's Oct. 14, 2022 Comments on GRIP Program.

[18] *See, e.g.,* Jose Antonio Sánchez-Zapata et al., *Effects of Renewable Energy Production and Infrastructure on Wildlife*, US. Dep't of Agriculture Nat'l Wildlife Research Center, 97–123 (Apr. 26, 2016), https://doi.org/10.1007/978-3-319-27912-1_5; Manitoba Hydro, *Fur, Feather, Fins and Transmission Lines, How Transmission Lines And Rights of Way Affect Wildlife* (3d ed.) (2010), https://www.hydro.mb.ca/environment/pdf/fur_feathers_fins_and_transmission_lines.pdf; Antonella Battaglini, *Reducing the Environmental Impacts of Power Transmission Lines*, *in* Eco-friendly Innovations in Electricity Transmission and Distribution Networks (2015), https://www.sciencedirect.com/book/9781782420101/eco-friendly-innovations-in-electricity-transmission-and-distribution-networks.

[19] Robert Bryce, *Maine Voters' Rejection of Transmission Line Shows Again How Land-Use Conflicts are Halting Renewable Expansion*, Forbes, Nov. 5, 2021, https://www.forbes.com/sites/robertbryce/2021/11/05/maine-voters-rejection-of-transmission-line-shows-again-how--land-use-conflicts-are-halting--renewable-expansion/?sh=711f9a2868e8.

[20] James Dobbins & Hiroko Tabuchi, *Texas Blackouts Hit Minority Neighborhoods Especially Hard*, N.Y. Times, Feb. 16, 2021, https://www.nytimes.com/2021/02/16/climate/texas-blackout-storm-minorities.html.

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Laboratory, the Colorado School of Mines, and University of Massachusetts Amherst found that "areas with a high share of minority population were more than four times as likely to suffer a blackout than predominantly white areas" during that storm.[21]

Non-wires alternatives (NWA)—including, *e.g.*, distributed renewable energy, microgrids, energy efficiency, demand response, and grid enhancing technologies—avoid all these issues, reducing demand for centralized energy infrastructure, which can include the need to build new costly and environmentally damaging transmission projects.[22] A 2019 report from DOE's National Renewable Energy Laboratory found that increased use of rooftop solar in particular can "reduce the need for new transmission lines, displace expensive power plants, and save the energy that is lost when electricity is moved long distances."[23]

Accordingly, it is vital that in assessing the Nation's energy needs, DOE make these NWA a central component of its analysis, not an afterthought.

- *Energy Efficiency*

To begin with energy efficiency related initiatives, buildings play an outsized role in energy use and greenhouse gas emissions, accounting for 75% of electricity use,[24] and 34% of U.S. Greenhouse Gas emissions.[25] Deployment of energy efficiency and conservation technologies could reduce annual electricity use by 26% in 2030.[26] Energy efficiency technologies include

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[21] JP Carvallo, Feng Chi Hsu, Zeal Shah & Jay Taneja, Rockefeller Foundation, Frozen Out in Texas: Blackouts and Inequity (Apr. 14, 2021), https://www.rockefellerfoundation.org/case-study/frozen-out-in-texas-blackouts-and-inequity/.

[22] *See* Alison Holm et al., *Distributed Solar Photovoltaic Cost-Benefit Framework Study: Considerations and Resources for Oklahoma*, Nat'l Renewable Energy Lab. 22 (August 2019), https://www.nrel.gov/docs/fy19osti/72166.pdf; American Council for an Energy-Efficient Economy, Distributed Energy Resources, https://www.aceee.org/topic/distributed-energy-resources.

[23] *Id.; see also* Ivan Penn & Clifford Krauss, More Power Lines or Rooftop Solar Panels: The Fight Over Energy's Future, N.Y. Times, updated Sept. 8, 2021, https://www.nytimes.com/2021/07/11/business/energy-environment/biden-climate-transmission-lines.html.

[24] Langevin et al., *US building energy efficiency and flexibility as an electric grid resource*, Joule 2103 (July 7, 2021, https://www.cell.com/action/showPdf?pii=S2542-4351%2821%2900290-7.

[25] Robert Walton, *Growing building sector carbon emissions threaten 2050 net-zero goal, report warns*, Utility Dive, Aug. 24, 2022, https://www.utilitydive.com/news/building-sector-carbon-ghg-emissions/630380/#:~:text=The%20building%20sector's%20total%20emissions,in%20air%20conditioning%20and%20refrigeration.

[26] Jared Langevin et. al., *US building energy efficiency and flexibility as an electric grid resource*, 5 Joule 2102 (Aug. 18, 2021), https://www.sciencedirect.com/science/article/pii/S2542435121002907#bib24.

basic electrification and weatherization like insulation, as well as demand response technologies[27], like smart equipment, sensors, and controls.

Energy efficiency measures, especially when paired with demand response strategies, can dramatically reduce buildings' energy consumption, thereby furthering emissions reduction goals. These include weatherization, which involves processes such as insulation installation, duct sealing, and air filtration mitigation. Weatherization can also be complemented with discrete energy efficiency measures, like the replacement of old and inefficient appliances, lighting, faucets, and showerheads. Energy efficiency also often incorporates building electrification strategies that eliminate the use of fossil fuels, predominantly natural gas, for household functions like space and water heating, cooking, and drying. Gas systems are often replaced with high efficiency heat pumps and induction ranges.[28]

These measures also provide additional benefits missing from new transmission projects. As the EPA has explained, energy efficiency improves "the reliability of the electricity system and [lowers] the risk of blackouts."[29] It also lowers the cost and risk of meeting reliability needs, because it minimizes energy use and demand, reducing the likelihood that load exceeds generation and providing greater assurance that the system has adequate resources.[30] For distribution systems in particular, energy efficiency decreases the likelihood of equipment failure as lower loads cause less overloading and thermal wear and tear.[31]

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[27] These technologies optimize the timing and intensity of their energy use depending on the weather, grid congestion, occupancy needs, and related factors. *See* Christopher Perry, *et al.*, *Grid-Interactive Efficient Building Utility Programs: State of the Market*, (Am. Council for an Energy-Efficient Econ 2019), https://www.aceee.org/sites/default/files/pdfs/gebs-103019.pdf.

[28] The Greenlining Inst. & Energy Efficiency for All, *Equitable Building Electrification, A Framework for Powering Resilient Communities* 9 (Sept. 30, 2019), https:// .org/wp-content/uploads/2019/10/Greenlining_EquitableElectrification_Report_2019_WEB.pdf.

[29] U.S. Envt'l Prot. Agency, *Quantifying the Multiple Benefits of Energy Efficiency and Renewable Energy* 3-2 (July 2018), https://www.epa.gov/sites/default/files/2018-07/documents/epa_slb_multiple_benefits_508.pdf.

[30] *Id.*

[31] It also bears emphasizing that the U.S. grid is vulnerable to service disruptions precisely because it depends on long-distance, high-voltage (HV) transmission lines, which means damage at a small number of points can cause power outages for large numbers of residents. For example, HV transformers make up less than 3% of the total transformers in power substations across the U.S., but carry 60-70% of the country's electricity. Paul W. Parfomak, *Physical Security of the U.S. Power Grid: High Voltage Transformer Substations*, Cong. Rsch. Serv. (June 17, 2014), https://sgp.fas.org/crs/homesec/R43604.pdf. Because this relatively small number of HV transformers handle such relatively high volumes of electricity serving large, interconnected geographic areas, damage to a comparatively small number of HV transformers can cause widespread, extended blackouts. *Id.* at 2.

Energy efficiency measures also speed up restoration times during power interruptions.[32] This is especially important for energy poor households who are more likely to experience power interruptions and inhabit homes that offer limited protection from extreme temperature without electricity. Energy efficient equipment also allows stored backup power to last longer during interruptions.[33] For people who rely on electricity to refrigerate medicine or operate medical equipment, long-lasting power storage can be lifesaving, especially in the aftermath of a natural disaster.[34]

Another specific example of technology that can assist with energy needs is Grid-Interactive efficient Buildings (GEBs). These buildings pair building energy efficiency and electrification with demand response technology, compounding the above benefits. These buildings leverage distributed energy resources and use smart equipment, sensors, and controls to optimize the timing and intensity of their energy use depending on the weather, grid congestion, occupancy needs, and related factors.[35] They help smooth and manage peaks by shifting a building's "demand to times of high peak supply," which allows them to replace carbon intensive energy sources.[36] GEBs' load shifting capabilities provide the grid with a flexible resource that reduces utility and customer costs, lessens the need for transmission and distribution expansion, and improves climate resilience for occupants.[37] DOE itself estimates that GEBs "could save up to

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[32] *Id.* at 3-32.

[33] *Id.* at 3-37.

[34] During extreme weather events, lack of electricity can be a matter of life and death. Lack of access to air conditioning during heat waves or heat during winter storms, or the inability to run medical equipment or refrigerate medication can be life-threatening, and elderly, young, disabled, and low-income residents are the most vulnerable to these impacts. When severe winter storms caused widespread blackouts in Texas in 2021, for example, independent experts estimated that 700 people died as a result of the power outage. Lewis Milford & Shelley Robbins, *Texas power outage deaths: Is cruelty and neglect our new energy policy?* The Hill, June 28, 2021, https://thehill.com/changing-america/opinion/560540-texas-power-outage-deaths-is-cruelty-and-neglect-our-new-energy/. Similarly, when Hurricane Maria devastated Puerto Rico in 2017, many of the resulting deaths occurred not during the storm but after it, when people were unable to run lifesaving medical equipment or refrigerate lifesaving medicine because they had no access to electricity. Ruth Santiago, *Puerto Rico's future is solar. Recovery funds should go there, not to its outdated grid*, Grist, July 26, 2021, https://grist.org/fix/opinion/puerto-rico-rooftopsolar-energy-fema-recovery-funds/.

[35] Christopher Perry, et al., *Grid-Interactive Efficient Building Utility Programs: State of the Market*, American Council for an Energy-Efficient Economy 2 (Oct. 2019), https://www.aceee.org/sites/default/files/pdfs/gebs-103019.pdf.

[36] *Id.* at 4.

[37] Nat'l Assoc. of State Energy Officials, *Demand Flexibility and Grid-interactive Efficient Buildings 101* 4 (Sept. 2022), https://www.naseo.org/data/sites/1/documents/publications/NASEO%20DF%20GEB%20101%209%20Sept%202022_Finalb.pdf.

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$18 billion per year in power system costs by 2030 and cut 80 million tons of CO_2 emissions each year."[38]

- *Solar, storage, and microgrids*

Distributed energy generation and storage can and must also play a central role in meeting the Nation's energy needs.[39] This includes distributed solar, battery storage, and microgrids that can be placed on roofs of residential, commercial and public buildings, and warehouses; roofs on parking lots; and other developed areas that are near the source of consumption and can be fully incorporated with electrified vehicles as additional storage. The technical potential of solar on rooftops, parking lots and degraded lands is more than 23 times the demand for electricity in 2021.[40]

In addition to helping to address generation and transmission needs, distributed renewable energy like rooftop solar, especially when paired with storage or as part of a solar microgrid, can reduce the length of outages from extreme weather events, or avoid them altogether.[41] If a disaster takes a large, centralized generating facility, or a high voltage transmission line responsible for transporting power to a large area, out of service, distributed renewable

[38] U.S. Dep't of Energy, *A National Roadmap for Grid-interactive Efficient Buildings* 7 (May 18, 2021), https://gebroadmap.lbl.gov/A%20National%20Roadmap%20for%20GEBs%20-%20Final.pdf.

[39] *See* Rooftop Solar Justice, Ctr. for Biol. Div. 2023, https://www.biologicaldiversity.org/programs/energy-justice/pdfs/Rooftop-Solar-Justice-Report-March-2023.pdf.

[40] The technical potential of rooftop solar is estimated to be 1,430 TWh, about 37% of the ~3,909 TWh of electricity sold in 2021. *See* Pieter Gagnon et. al., *Estimating rooftop solar technical potential across the US using a combination of GIS-based methods, lidar data, and statistical modeling*, 13 Environ. Res. Lett. 024027(2018), https://iopscience.iop.org/article/10.1088/1748-9326/aaa554/meta; For data on electricity sales, *see* Table 5.1. Sales of Electricity to Ultimate Customers, *Electric Power Monthly*, Energy Info. Admin., (Jan. 2023), https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_01. The combined solar technical potentials from a collection of studies totals 90,570 TWh, about 23x times the ~3,909 TWh of electricity sold in 2021. *See* Michael Kinneman, *Paved, but still alive*, New York Times, January 6, 2012, https://www.nytimes.com/2012/01/08/arts/design/taking-parking-lots-seriously-as-public-spaces.html; Robert S. Spencer et. al., *Floating Photovoltaic Systems: Assessing the Technical Potential of Photovoltaic Systems on Man-Made Water Bodies in the Continental United States*, 53 Environ. Sci. Technol. 1680 (2019), https://pubs.acs.org/doi/pdf/10.1021/acs.est.8b04735; Madison K. Hoffacker et. al. *Land-Sparing Opportunities for Solar Energy Development in Agricultural Landscapes: A Case Study of the Great Central Valley, CA, United States*, 51 Environmental Science & Technology 14472 (2017), https://pubs.acs.org/action/doSearch?field1=Contrib&text1=Madison+K.++Hoffacker; Rebecca Hernandez et. al., *Techno–ecological synergies of solar energy for global sustainability*, 2 Nature Sustainability 560 (2019), https://doi.org/10.1038/s41893-019-0309-z.

[41] *See* Gridworks & GridLAB, *The Role of Distributed Energy Resources in Today's Grid Transition* 7-9 (Aug. 2018), http://gridlab.org/wp-content/uploads/2019/04/GridLab_RoleOfDER_online-1.pdf.

generation may not be affected at all.[42] In addition, DERs can be used to create "islandable" generation that operates even when outages do occur.[43] A 2017 National Academies of Sciences study found that more distributed energy generation (combined with more advanced controls) has the potential to prevent or limit widespread electric grid outages by enhancing power quality and allowing problematic components to be isolated.[44]

The effectiveness of these technologies in improving the resilience of the electricity grid have been demonstrated repeatedly. After the extended outages caused by Hurricane Maria, many residents and businesses installed rooftop solar with battery storage. When Hurricane Fiona hit the island, homes and essential community services, including a local fire station, that had installed rooftop solar with battery storage kept their power on.[45] Hurricane Irma knocked out electricity to 6.8 million customers across Florida in 2017, but homeowners and businesses with off-grid solar had electricity.[46]

- *Grid-enhancing technologies*

There are also a host of technologies that can be deployed to better utilize the Nation's existing transmission system. For example, as Environmental Law and Policy Center's 2021 report on non-wires alternatives explains, grid enhancing technologies, like advanced line rating management systems and power flow control, can "significantly increase the effective capacity of existing and future lines" and preclude the need for additional transmission infrastructure.[47] DOE needs to consider the extent to which these technologies can be deployed to meet energy needs with the existing transmission system.

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[42] Nat'l Renewable Energy Lab. & U.S. Agency for Int'l Dev., *Cybersecurity and Distributed Energy Resources* 1 (April 2020), https://www.nrel.gov/docs/fy20osti/76307.pdf.

[43] *Id.*

[44] *See* Nat'l Acad. of Science, Eng'g & Med., *Enhancing the Resilience of the Nation's Electricity System*, Washington, DC: The National Academies Press 108 (2017), https://nap.nationalacademies.org/catalog/24836/enhancing-the-resilience-of-the-nations-electricity-system.

[45] Maria Gallucci, *Solar is lifeline in Puerto Rico after Hurricane Fiona knocks out power,* Canary Media, Sept. 19, 2022, https://www.canarymedia.com/articles/solar/solar-offers-lifeline-in-puerto-rico-after-fiona-knocks-out-power.

[46] Lyndsey Gilpin, *After the Hurricane, Solar Kept Florida Homes and a City's Traffic Lights Running*, Inside Climate News, Sept. 15, 2017, https://insideclimatenews.org/news/15092017/after-hurricane-irma-solar-florida-homes-power-gird-out-city-traffic-lights-running/

[47] *Beyond Wires, Using Advanced Transmission Technologies to Accelerate the Transition to Clean Energy*, Envt'l Law & Policy Ctr. (May 2021), https://elpc.org/wp-content/uploads/2021/05/BeyondWires_ELPC_Final2021.pdf; *see also, e.g.* DOE, *Grid-Enhancing Technology: A Case Study on Ratepayer Impact* (Feb. 2022), https://www.energy.gov/sites/default/files/2022-04/Grid%20Enhancing%20Technologies%20-%20A%20Case%20Study%20on%20Ratepayer%20Impact%20-%20February%202022%20CLEAN%20as%20of%20032322.pdf

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Similarly, DOE is separately working to improve transformer efficiency standards in a manner that will allow us to get substantially more energy from existing transmission infrastructure. In January 2023, DOE issued new proposed efficiency rules for distribution transformers.[48] Again, in developing the Transmission Needs Report, DOE must take into account all the ways that future energy needs can be met by better utilizing our existing transmission system, such as these and similar conservation improvements.

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We appreciate that the 2023 Needs Study mentions non-wires alternatives.[49] Indeed, in the Study DOE recognizes that siting "storage and generation close to load centers could help mitigate need for transitional transmission wires," and that "non-wire transmission solutions [ ] can serve some of the same purposes as traditional wires . . . ."[50] As DOE also explains, citing a separate Study, "because DERs can provide the same services as utility-scale PV, they offset the need for generation and transmission resources to maintain resource adequacy."[51]

However, before DOE can make any determinations about the need for new transmission infrastructure, *the agency must fully assess the extent to which energy needs can be satisfied with these kinds of alternative and cost-effective solutions.* Non-wires alternatives should be prioritized as the first line of offense in the clean energy transition, instead of a marginalized solution. Non-wires alternatives also avoid the morass of permitting issues that plague interconnection of large-scale generation and transmission projects—saving both time and money in clean energy deployment.

2. DOE must ensure that any utility-scale transmission development, and utility-scale generation projects they support, minimize adverse environmental impacts.

As noted, in the IIJA Congress specifically directed DOE to facilitate transmission in a manner that "avoids and minimizes, to the maximum extent practicable, and offsets to the extent appropriate and practicable, sensitive environmental areas and cultural heritage sites."[52] To fulfill this mandate, as noted above DOE must ensure that new transmission development is limited to areas where grid needs cannot be satisfied with non-wires alternatives like rooftop solar, solar

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[48] 88 Fed. Reg. 1,722 (Jan. 11, 2023); *see also DOE Proposes New Efficiency Standards For Distribution Transformers*, DOE Dec. 28, 2022, https://www.energy.gov/articles/doe-proposes-new-efficiency-standards-distribution-transformers.

[49] 2023 Needs Study at 73-75.

[50] *Id.* at 73.

[51] *Id.* at 75.

[52] 16 U.S.C. § 824p(a)(4).

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microgrids, energy efficiency, and energy storage, along with additional measures such as demand response, energy efficiency initiatives, and upgrades to existing transmission infrastructure.[53]

However, even where it is ultimately determined that additional transmission is necessary—including through the designation of national interest transmission corridors—to comply with the IIJA's mandates, DOE must steer this development to previously degraded lands, which will minimize impacts on communities, habitats, and species.

As the Federal Energy Regulatory Commission (FERC) has emphasized, the build-out of new transmission projects across the country is largely driven by the coming growth in remotely sited renewable energy projects.[54] However, both generation and transmission projects are too often placed in environmentally sensitive habitats. Similarly, energy projects also tend to be disproportionately sited in environmental justice communities, further burdening populations.

To address these concerns, to the extent DOE determines transmission projects are necessary, the agency should *explicitly prioritize development in already degraded areas*.[55] Around the country, there are degraded landscapes that should be prioritized for large-scale renewable energy projects. This includes Superfund sites, brownfields, landfills, abandoned mine areas, and contaminated or abandoned agricultural lands, with enormous renewable energy potential:

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[53] *Beyond Wires, Using Advanced Transmission Technologies to Accelerate the Transition to Clean Energy*, Envt'l Law & Policy Ctr. (May 2021), https://elpc.org/wp-content/uploads/2021/05/BeyondWires_ELPC_Final2021.pdf; *Non-Wires Alternatives As a Path To Local Clean Energy*, Center for Energy & Env. (Feb. 15, 2021), https://www.mncee.org/sites/default/files/report-files/Non-Wires%20Alternatives%20as%20a%20Path%20to%20Local%20Clean%20Energy.pdf; Mark Dyson, *et al.*, *The Non-Wires Solutions Implementation Playbook*, Rocky Mountain Institute (2018), https://rmi.org/wp-content/uploads/2018/12/rmi-non-wires-solutions-playbook-report-2018.pdf.

[54] 87 Fed. Reg. 26,504 (May 4, 2022).

[55] We emphasize in this regard that under no circumstances should DOE facilitate the development of additional transmission in order to connect to *any* fossil fuel power generation. The climate emergency demands a rapid shift away from all fossil fuel resources, and DOE must not use its transmission siting authorities to facilitate any further reliance on dirty fossil fuels.

Degraded lands	**Renewable Energy Potential**[56]
Toxic Superfund sites, brownfields	3.87 million GWh
Landfills	0.54 million GWh
Abandoned mine land	0.94 million GWh
Contaminated agricultural lands	2.39 million GWh
Abandoned agricultural lands	56.22 million GWh

By prioritizing renewable energy projects and associated transmission in these areas, DOE can most effectively minimize conflicts, delays, and adverse impacts on the environment.[57]

For example, one study found that if every canal in California was covered by solar panels, that would generate approximately 13 gigawatts of energy annually—enough to power nearly 10 million homes—while simultaneously reducing water loss by 63 billion gallons of water per year due to evaporation, and reduce aquatic weed growth, reducing the need for pesticides.[58] The canals covered by solar panels would also reduce the use of diesel-powered irrigation pumps, which would improve the local air quality.

Additional renewable energy and needed transmission should be built, with appropriate community input, on degraded lands or lands with existing rights-of-way, such as highway or railway corridors, which would not require significant new review processes.[59]

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[56] *See* Rebecca R. Hernandez *et al.*, *Techno–Ecological Synergies of Solar Energy for Global Sustainability*, 2 Nat. Sustainability 560, 560–568 (2019), https://doi.org/10.1038/s41893-019-0309-z.

[57] *See also, e.g.,* Jordan Macknick, *et al*., Solar Development on Contaminated and Disturbed Lands, Natl Renewable Energy Lab., Dec. 2013, https://www.nrel.gov/docs/fy14osti/58485.pdf; U.S. EPA, *RE-Powering America's Land*, https://www.epa.gov/re-powering#:~:text=RE%2DPowering%20America's%20Land%20is,community's%20vision%20for%20the%20site; U.S. EPA, *Alternative Energy Projects at Superfund Sites: Status Update and Highlights from Across the Country*, (Sept. 2022), https://semspub.epa.gov/work/HQ/100003067.pdf.

[58] Brandi McKuin et al. *Energy and water co-benefits from covering canals with solar panels*, 4.7 Nature Sustainability 609 (2021).

[59] Jordan Macknick et al., Nat'l Renewable Energy Lab'y, *Solar Development on Contaminated and Disturbed Lands* (2013), https://www.nrel.gov/docs/fy14osti/58485.pdf. *See also* Steven King, *Using parking lots and highways for solar power,* Env't California (Feb. 24, 2023), https://environmentamerica.org/california/articles/using-parking-lots-and-highways-for-solar-power/, Jeff St. John, *How transmission along railroads and highways could break open clean energy growth*, Canary Media, Apr. 26, 2021, https://www.canarymedia.com/articles/transmission/how-transmission-along-railroads-and-highways-could-break-open-clean-energy-growth.

Finally, in order to minimize and mitigate adverse impacts, it is essential that DOE conduct appropriate environmental review of these projects in accordance with the National Environmental Policy Act (NEPA), 42 U.S.C. § 4321, *et seq.*, the Endangered Species Act (ESA), 16 U.S.C. § 5321, *et seq.*, and related statutes.[60] Indeed, DOE's failure to conduct appropriate environmental review led to a major setback the last time DOE tried to designate national interest transmission corridors.[61] Only through early and meaningful consultation and appropriate environmental review can DOE ensure that transmission projects that are actually necessary are timely built.[62]

C. DOE must engage in appropriate consultation before any transmission corridors are designated.

It is also vital that DOE take appropriate steps to consult with impacted communities in developing any plans related to transmission projects and mitigating their impacts. Mere solicitations for community feedback on any transmission corridors already designated in the Transmission Needs Report will erode trust, and squander opportunities to effectively use engagement to build consensus.[63] DOE must also provide necessary resources and technical expertise and capacity for meaningful engagement. Technical assistance is crucial as communities that have been subjected to many years of systemic disinvestment and neglect often

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[60] This list is not intended to be exhaustive, but other implicated statutes may include the Migratory Bird Treaty Act, 16 U.S.C. § 701, *et. seq.*; the Bald and Golden Eagle Protection Act, 16 U.S.C. § 668, *et seq.*, ; and, if transmission is associated with offshore energy generation such as wind turbines, the Marine Mammal Protection Act, 16 U.S.C. § 1361, *et seq.*.

[61] *See Cal. Wilderness Coalition v. Dep't of Energy*, 631 F.3d 1072 (9th Cir. 2011).

[62] We note that while these environmental review statutes are critical, they are not the reason that so many transmission projects have been delayed in recent years. As has been well-documented, other factors are responsible for these delays, including the right-of-first-refusal regime which has incentivized local transmission projects and state and local opposition. *See, e.g.,* Comment of United States Department of Justice and Federal Trade Commission to the Federal Energy Regulatory Commission in Docket No. RM21-17-000 (Aug. 17, 2022), https://www.ftc.gov/legal-library/browse/advocacy-filings/comment-united-states-department-justice-federal-trade-commission-federal-energy-regulatory; DOE, *Queued Up…But in Need of Transmission: Unleashing the Benefits of Clean Power with Grid Infrastructure* (2022), https://www.energy.gov/sites/default/files/2022-04/Queued%20Up%E2%80%A6But%20in%20Need%20of%20Transmission.pdf; Devin Hartman and Beth Garza, *Plenty of low-hanging fruit: How FERC can catalyze transmission infrastructure,* Utility Dive (Apr. 9, 2021), https://www.utilitydive.com/news/plenty-of-low-hanging-fruit-how-ferc-can-catalyze-transmission-infrastruct/598088/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202021-04-09%20Utility%20Dive%20Newsletter%20%5Bissue:33514%5D&utm_term=Utility%20Dive.

[63] Amanda Dewey, Jasmine Mah & Bryan Howard, *Ready to Go: State and Local Efforts Advancing Energy Efficiency*, American Council for an Energy-Efficient Economy, (Nov. 2021), https://connectedcommunities.lbl.gov/sites/default/files/2022-02/ACEEE%20ready_to_go_toolkit_final_11-8-21.pdf.

lack "the resources or infrastructure required for technical, complex, and time-consuming government grants."[64]

While there is a political push in both the Biden administration and Congress to hasten the rollout of clean energy development, the best way to achieve the desired speed is not to cut back community engagement or NEPA review—but rather to go the opposite direction and invest more resources in meaningful engagement.

To break down barriers to equitable community engagement, DOE should ensure involvement of trusted leaders and community-based organizations,[65] properly compensate those leaders for their work, and prioritize those that have demonstrated a previous history of positive community engagement. DOE should also make sure community members have meaningful engagement opportunities, and that meetings are planned at times and places that maximize the number of community members who can conveniently attend, with appropriate services like a translation and interpreting services, childcare, and possibility for virtual attendance.[66]

DOE's prior experience with trying to designate national transmission corridors demonstrates the need for this vital community engagement. In particular, a lack of community acceptance led to litigation, and a ruling that DOE had failed to undertake the process in a manner that appropriately engaged the public.[67]

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[64] The Greenlining Inst., *Fighting Redlining & Climate Change with Transformative Climate Communities* (Nov. 2021), https://greenlining.org/wp-content/uploads/2021/10/Fighting-Climate-Change-and-Redlining-with-Transformative-Climate-Communities-Final-Report.pdf.

[65] California Energy Commission, Disadvantaged Communities Advisory Group, Equity Framework, https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/disadvantaged-communities/dacag-equity-framework.pdf?sc_lang=en&hash=130F6FD0AEA89095CD0EAC455D0C60EE.

[66] *See* Initiative for Energy Justice, The Energy Justice Workbook, Section 1 – Defining Energy Justice: Connections to Environmental Justice, Climate Justice, and the Just Transition, https://iejusa.org/section-1-defining-energy-justice/.

[67] *Cal. Wilderness Coalition v. Dep't of Energy*, 631 F.3d 1072 (9th Cir. 2011).

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Conclusion

We are at a critical crossroad in addressing the climate emergency. The decisions we make in the next few years will determine whether we can keep climate change below 1.5 degrees and thereby avert the worse impacts of climate change. They will also determine how prepared our electricity grid is to sustain the impacts of climate change that are occurring and will continue to occur. And they will determine whether the necessary transition to clean energy uplifts low-income, Black, Brown, and Indigenous communities that bear the brunt of fossil fuel pollution as well as of climate change impacts.

It is therefore critical that DOE's Transmission Needs Report fully address the issues we have raised here, which are necessary to create an energy system that is not only clean, but which centers justice.

We appreciate the opportunity to submit these comments. Please contact us if there is any further information we can provide.

Respectfully submitted,

Center for Biological Diversity
1411 K Street N.W., Suite 1300
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U.S. Department of Energy's Grid Deployment Office
Draft National Transmission Needs Study
Comments of the Clean Energy Buyers Association

I. INTRODUCTION

The Clean Energy Buyers Association ("CEBA")[1], respectfully provides these comments on the request for feedback on the Draft National Transmission Needs Study ("Needs Study" or "Study").[2] CEBA thanks the Department of Energy's ("DOE") Grid Deployment Office ("GDO") for providing stakeholders with the opportunity to submit feedback on the Needs Study draft, which is integral to the designation of National Interest Electric Transmission Corridors ("NIETCs").

II. OVERVIEW OF CEBA

CEBA is a business association representing a diverse membership of nearly 400 members, which includes stakeholders from the commercial and industrial sector, non-profit organizations, as well as energy providers and service providers. CEBA's membership is comprised of 89 Fortune 500 companies, $7 trillion in revenue and employs 17 million domestic employees. CEBA's members account for over 90% of the nearly 65 GWs of new utility-scale wind and solar capacity voluntarily transacted by large energy customers since 2014, which is equivalent to roughly 40% of all wind, solar and battery capacity deployed in that time.[3] CEBA's members and other corporate and industrial energy customers are projected to drive demand for an additional 85 GW by 2030.[4] CEBA's aspiration is to achieve a 90% carbon-free U.S. electric system by 2030, and in furtherance of that goal, to cultivate a global community of energy customers driving expanded demand for clean energy. For CEBA and its members to access

[1] http://www.cebuyers.org/ the Clean Energy Buyers Association's aspiration is to achieve a 90% carbon-free U.S. electricity system by 2030 and to cultivate a global community of energy customers driving clean energy.
[2] https://www.energy.gov/gdo/national-transmission-needs-study
[3] Clean Energy Buyers Association. "CEBA Deal Tracker," 2023. https://cebuyers.org/deal-tracker/; Clean Energy Buyers Association.
[4] Wood Mackenzie. "Analysis of Commercial and Industrial Wind Energy Demand in the United States," 2019. https://www.woodmac.com/our-expertise/focus/Power--Renewables/corporates-usher-in-new-wave-of-u.s.-wind-and-solar-growth/

clean energy resources and achieve our decarbonization goals, a national buildout of regional and interregional electric transmission is required.

III. COMMENTS

CEBA supports DOE's findings in the Draft National Transmission Needs Study and believes with improvements to communication on the Study methods and key takeaways as well as dedication to continued stakeholder engagement, evaluation, and improvement to the process and methods of future need studies, the Study will serve as a fair, clear, and compelling foundation to implement DOE's authority under Section 216(a)(2) to designate NIETCs.

A. Recommendations on Draft Needs Study to Ensure a Strong Foundation for NIETC designation.

CEBA praises and supports GDO's efforts to implement DOE's authority and directives under the Federal Power Act ("FPA") Section 216(a) as amended by the Infrastructure and Investment Jobs Act ("IIJA") and looks forward to the final release of the National Transmission Needs Study. Given that the Needs Study will serve as a primary resource in DOE's authority to designate NIETCs, the Needs Study needs to provide clear rationale and direction in its methods and conclusions, in this regard, CEBA offers the following recommendations:

1. CEBA appreciates the inclusion of the geographical regional breakdown of transmission needs in the executive summary; given the length of the report, CEBA recommends that it may be beneficial to add the regional and interregional transfer tables as well as a summary on the national key takeaways of the report to the executive summary. The addition of these elements can save a reader time in deciphering the key takeaways, CEBA also suggests GDO provide more clear indication in the executive summary between whether a need is current or anticipated for easier prioritization.
2. CEBA supports the Study's findings and approves of GDO's method of grouping existing Capacity Expansion Modeling ("CEM") study results to uncover future needs; however, recommends GDO provide further reasoning on the Study's methods. In the current draft it is not very clear on why GDO chose to conduct the Study through a review of existing literature, therefore providing opportunity for doubt on the strength and importance of the report. GDO should consider inclusion of an additional section after *Section II: Legislative Language* that dives into an explanation on the overall method of the study

which includes (1) mention of limitations of the study, (2) why a literature review was the chosen method (3) how the Needs Study is different than the National Transmission Planning Study, and (4) how and why the Study may under project transmission needs. In this final point, CEBA wishes to draw particular attention to mentioning the need to account for large energy customer load and growth, which is often not included in transmission planning studies and can lead to under forecasting clean energy demand and load growth.[5] Additionally, the impact of recent events such as Winter Storm Eliott not included in the existing literature are further examples of the potential under projection of needs found in the Study.

3. Regarding the results of the Study, CEBA believes there are a couple additional details GDO could enhance to improve study key takeaways. More explanation on what the CEM scenario groups represent, such as whether the high/high scenario is equivalent to a roughly 100% decarbonized power system by 2035 would be helpful.
4. GDO should provide further explanation on how states and regional bodies can use the Study, by providing concrete examples. As GDO expressed in the Study and in reply to stakeholder public comments, the Study is not supposed to replace local and regional planning, so it may be helpful to further explain how the report can benefit regional and local entities.

B. Ensuring Future Iterations of the Needs Study Remain Relevant and Insightful

CEBA commends GDO on its comprehensive approach and consideration of multiple factors that affect transmission congestion and capacity constraint as a needed initial step in its expanded authority and recommends GDO to continue its expert work by further dedicating resources to continued evaluation and improvement of future needs studies. Since the Needs Study is to be released every three years, CEBA recommends GDO consider the following actions to improve future Needs Studies:

[5] Clean Energy Buyers Institute. "White Paper on Transmission Planning Reforms to Support Large Customer Clean Energy Demand and Investment", September 2022. https://cebi.org/wp-content/uploads/2022/08/Transmission-Planning-Reforms-to-Support-Large-Customer-Clean-Energy-Demand-and-Investment_White-paper_Oct-13th.pdf

1. Acknowledging the lack of and access to necessary data on local, regional, and interregional congestion and capacity constraints, specifically in non-RTO regions in the west and southeast, poses barriers to the robustness of the Study, GDO should explore opportunities to improve data collection for future iterations of the Needs Study. GDO could consider utilizing its technical and convening capabilities in setting up working groups to address concerns and how to overcome barriers in evaluating the nation's transmission needs.
2. In continuation of GDO's stakeholder engagement, GDO should collaborate with and illicit additional regional, state, and tribal entity feedback on how to improve the next Needs Study in developing recommendations for future reports. GDO should also consider convening stakeholder meetings with large energy customers, to ensure customer projected load and voluntary clean energy demand is accurately reflected. With an abundance of federal dollars flowing to manufacturing and electric vehicles, corporate and industrial (C&I) load profiles could drastically change over the next three-six years. Communication and inclusion of these activities could improve the industry and government utilization and credibility of the report.
3. CEBA recommends communication in the Study or on the Needs Study website on how the report is an iterative process and include identified lessons learned and recommendations on how to improve future iterations could improve stakeholder engagement and use of the Study. Such disclosure can make stakeholders feel heard and trustful of DOE and the Study. An additional section in the current Final Study that provides recommendations for future studies would be a welcome place to also communicate next steps for the use of the Study.

C. Need for Open, Fair, and Transparent NIETC Designation Process

CEBA encourages GDO to provide further transparency and communication on the NIETC designation process as well as robust opportunity for stakeholder and public input. Until now, communication regarding NIETC designation has been that this Study, in addition to other relevant information, will inform NIETC designation and it will be applicant driven. It is important for GDO to remain transparent and communicative on this process given the importance of transmission buildout and potentially affected entities and communities. CEBA encourages speed and timeliness in corridor designation while maintaining a robust and transparent stakeholder process that includes C&I customers. Lastly, GDO should ensure NIETC designation activities are complementary to FERC reforms on transmission planning[6] and backstop siting[7] so transmission planning and siting processes are coordinated and do not delay transmission development further.

IV. CONCLUSION

CEBA appreciates the opportunity to provide comments on the Draft National Transmission Needs Study and requests the GDO to consider CEBA's comments and adopt recommendations herein.

Respectfully Submitted,
/s/ Bryn Baker
Sr. Director, Market and Policy Innovation
Clean Energy Buyers Association
bbaker@cebuyers.org
1425 K Street, Suite 1110
Washington, DC 20005

Dated: 20 April 2023

[6] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022).
[7] *Applications for Permits to Site Interstate Electric Transmission Facilities*, Notice of Proposed Rulemaking, 181 FERC ¶ 61,205 (2022).

April 20, 2023

Maria Robinson
Director, Grid Deployment Office
U.S. Department of Energy
1000 Independence Ave SW
Washington, D.C. 20585

Comments submitted to NeedsStudy.Comments@hq.doe.gov

Re: Comments on the Department of Energy's draft *National Transmission Needs Study*

Dear Director Robinson:

The Columbia River Treaty Power Group (Power Group) appreciates the opportunity to comment on the Department of Energy's draft National Transmission Needs Study. The U.S. and Canada have been linked via transmission lines that facilitate international sales of electricity for decades, with most sales coming from Canada into the U.S. Currently, both countries are negotiating the future of the 1964 Columbia River Treaty, which facilitated the joint development of power generation and flood control in the Columbia River Basin. While both countries will be weighing power, flood control and ecosystem needs, the next phase of international partnership should also consider transmission expansion to support the exchange and delivery of renewable hydropower.

The Power Group represents more than 6 million electricity consumers and businesses across Pacific Northwest states who are served by hydroelectricity and the high voltage transmission grid operated by Bonneville Power Administration (BPA). Under the Treaty, BPA is obligated to provide Canada with one-half of the theoretical downstream power benefit created by Canadian storage dams. Today, this Canadian Entitlement (CE) amounts to returning 3.9 million MWh of clean, carbon-free, hydroelectric power each year. This is a commitment that both BPA and the Power Group agree vastly exceeds what should be returned to Canada going forward. This is because the methodology used to calculate the benefits was based on data and assumptions about the future that did not materialize.

Now, five decades after the Treaty's enactment, western power markets have seen major changes. Renewable energy has flourished, and coal plants have retired. Energy efficiency, customer demand response and energy storage all contribute to the modernized energy landscape. In 2014, the Bonneville Power Administration and the Army Corps of Engineers stated in their *Regional Recommendation for the Future of the Columbia River Treaty after 2024* that the United States "should pursue rebalancing the power benefits between the two countries to reflect the actual value of coordinated operations."[1]

With 2024 approaching, Congress created an opportunity for U.S. and Canadian negotiators to reduce the CE return while redirecting funds into transmission expansion. A provision[2] in the Infrastructure Investment and Jobs Act of 2021 (IIJA) establishes a new Treasury account, essentially equal to five years of CE value, to help increase bilateral transfers of renewable electric generation between the U.S. and Canada through the construction of electric power transmission facilitates. However, these activities cannot take place until after September 16, 2024 and are contingent upon the CE being reduced or terminated. In addition, the IIJA authorizes $10 million for BPA to "conduct a study considering the

[1] U.S. Entity Regional Recommendation for the Future of the Columbia River Treaty after 2024.
[2] IIJA Sec. 40113 (b). Columbia Basin Power Management. Public Law 117-58.

potential hydroelectric power value to the Pacific Northwest of increasing the coordination of the operation of hydroelectric and water storage facilities on rivers located in the United States and Canada."[3] This study would evaluate increased transmission capacity and provide insight into today's power system needs — rather than what the system of a half century ago required. Enactment of this IIJA provision indicates that U.S. policy makers recognize the importance of rebalancing and modernizing the Columbia River Treaty.

We encourage the Grid Deployment Office to review these IIJA provisions as it finalizes its *National Transmission Needs Study*. Further, U.S. and Canadian interests should work to reduce the CE so that funds authorized in the IIJA can be directed to better optimize the inter-regional – and international – transmission of emission-free hydropower. In addition, BPA should work expeditiously with British Columbia, the Department of Energy, the Bureau of Reclamation, and the Mid-Columbia Public Utility Districts to conduct the $10 million power coordination study authorized by Congress in the Infrastructure Investment and Jobs Act of 2021.

Again, thank you for the opportunity to comment. Please do not hesitate to contact Suzanne Grassell at suzanne.grassell@chelanpud.org with questions.

[3] IIJA Sec. 40113(d).

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conEdison
a conEdison, inc. company

April 20, 2023

VIA ELECTRONIC MAIL

United States Department of Energy
NeedsStudy.Comments@hq.doe.gov

RE: National Transmission Needs Study, New York Region Analyses

Dear Department of Energy:

Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") submits these comments in response to the United States Department of Energy's ("DOE") draft of the 2023 National Transmission Needs Study (the "Needs Study"). While these remarks are generally limited to the Needs Study's findings in the New York area, the Company commends the DOE's efforts to understand both historic and anticipated future capacity constraints and transmission congestion that could impact customers nationwide.

Development of new transmission will be the key to integrating new, clean energy resources, maintaining safe and reliable service as electrification drives increased demand for electricity, and providing resilience during extreme weather events. The clean energy transition cannot result in sacrificing reliability, particularly given the sometimes-inequitable impacts outages can have on disadvantaged communities. While significant advancements are being made in New York, much more transmission will be needed in the long-term, as the Needs Study notes. The DOE's efforts are helpful to understanding future system needs and prompting productive discussion on the important role of transmission, as a coordinated approach to planning is necessary to advance the integration of offshore wind and meet decarbonization goals.

Respectfully, the Company offers the following comments on the DOE's preliminary findings:

I. New York Needs Additional Electric Transmission Infrastructure, Particularly to Integrate Offshore Wind

The draft Needs Study analyzes the growth of new regional transmission needed to meet two scenario groupings: Moderate/Moderate and Moderate/High. The Moderate/Moderate scenario group is defined as a power system without the Infrastructure Investment and Jobs Act (IIJA) and Inflation Reduction Act (IRA) enacted.[1] The Moderate/High scenario attempts to capture the most likely power group sector future given the recently enacted laws. Based upon analysis of data collected by the North American Electric Reliability Council (NERC) as part of its annual Long-Term Assessment, the Needs Study concludes that current planned transmission in New York exceeds the DOE's anticipated transmission needs for both the Moderate/Moderate and Moderate/High scenarios.

While historic transmission investment in New York has indeed been quite robust, advancements in the policy landscape and evolving customer needs continue to signal that significantly more transmission will be needed in the near- to long-term to maintain reliability and resiliency and to meet

[1] *See* Needs Study at p. 90.

Consolidated Edison Company of New York, Inc.
4 Irving Place New York NY 10003

clean energy resource integration goals. Con Edison emphasizes that the DOE's above finding should not dampen transmission expansion efforts, including at the local level.

Presently, Con Edison is focused on executing upon initiatives undertaken pursuant to New York's Accelerated Renewable Energy Growth and Community Benefit Act (AREGBA)[2] and expanding the transmission system to facilitate achievement of the goals under New York's ambitious Climate Leadership and Community Protection Act (CLCPA).[3] The CLCPA requires 70 percent renewable energy by 2030, 100 percent carbon-free electricity by 2040, and 85 percent economy-wide decarbonization from 1990 levels by 2050. This includes goals of 6,000 MW of distributed solar installed by 2025, 3,000 MW of storage installed by 2030, and 9,000 MW of offshore wind installed by 2035.

In general, further transmission build-out can play a role in addressing intermittency by connecting geographically diverse resources. Additionally, as the impacts of climate change become increasingly apparent, a well-integrated, reinforced transmission system will be able to better withstand extreme weather events. As further technological advancements are made, cost allocation methodologies should also evolve and be broad enough to appropriately capture the vast benefits of meeting clean energy policies and goals. Applying economic beneficiary-based methods to clean energy- enabling transmission facilities could ultimately inhibit project development.

Planning for the integration of offshore wind is a high priority for Con Edison. Con Edison is developing the Brooklyn Clean Energy Hub project which will help enable the interconnection of offshore wind while also addressing local reliability needs.[4] Additional innovative solutions like this project will be needed to meet clean energy goals, along with coordinated transmission solutions to bring offshore wind to shore, often referred to as an "offshore grid." Therefore, when finalizing the Needs Study, the DOE should consider the need to expand New York's transmission system to accommodate offshore wind.

II. Interregional Transfer Capabilities Should be Increased

The draft Needs Study indicates the need to significantly expand interregional transfer capability. The DOE evaluates potential interregional transmission requirements under the Moderate/Moderate and Moderate/High scenarios in 2030, 2035, and 2040.[5] For the Moderate/High scenario, the DOE anticipates between 1.6 and 3.4 GW of new transfer capability needed between New York and the Mid-Atlantic region in 2035, a 122% increase relative to the 2020 system. Similarly, the DOE anticipates a 3.4 to 6.3 GW transfer need between New York and New England, a 255% increase relative to 2020 conditions.

Overall, Con Edison supports expanding and improving interregional capabilities. Like regional transmission, demand for interregional facilities will grow and evolve to meet changing system conditions and customer needs. Increased transfer capability, as noted by the Needs Study, has many benefits, including strengthening grid reliability and resilience by diversifying generation availability and creating

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[2] Chapter 58 (Part JJJ) of the New York laws of 2020.

[3] New York Public Service Law, § 66-p.

[4] *See* Case 20-E-0197, *Motion on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act,* Petition of Consolidated Edison Company of New York, Inc. for Approval to Recover Costs of Brooklyn Clean Energy Hub (April 15, 2022) and Consolidated Edison Company of New York, Inc. Petition Supplement to Propose an Alternative Brooklyn Clean Energy Hub (December 13, 2022).

[5] *See* Needs Study at p. 98.

access to clean energy sources.[6] Thoughtful cost allocation methodologies focused on the benefits of interregional ties during system emergencies must be developed to capture these vast and widespread system benefits.

There are many avenues to expanding interregional capabilities. One approach that should be considered is utilization of existing interregional facilities. Targeted use cases, such as reconductoring and re-energizing PSE&G's and Con Edison's B and C lines located on the seam between PJM and the NYISO, could provide widespread benefits. While these facilities had, from the 1970s through early 2018, provided resilience benefits to both the NYISO and PJM systems, they are currently out of service following damage caused by a pier collapse in New Jersey. To the extent possible, an obvious priority should be to restore inter-regional facilities that already exist.

Though not directly opposing the suggested GW increases, Con Edison would appreciate additional transparency regarding the DOE's underlying data to confirm whether it is the most up to date. This is an important step that should be taken before any GW figure recommendations are finalized to ensure that the proper amount of needed interregional transmission is captured. To that end, interregional planning processes must allow for collaboration between neighboring regions to productively identify the needed transmission. The DOE's Needs Study recommendations provide an informative basis for planning entities like the New York ISO (NYISO) to conduct further, more granular studies. Con Edison recommends that the DOE urge the NYISO to work with ISO-New England and PJM Interconnection to examine the needed interregional transfer requirements.

III. Further Engagement is Needed to Determine Whether a National Interest Electric Transmission Corridor is Needed in New York

Pursuant to Section 216(a)(1) and (3) of the Federal Power Act, the DOE may designate one or more National Interest Electric Transmission Corridors (NIETCs).[7] The DOE has indicated that the Needs Study will support the potential designation of NIETCs, following further engagement and collection of additional information.

While Con Edison takes no position on the declaration of a NIETC at this time, the Company is supportive of the DOE using its [ultimate] findings to encourage discussions between regions. Following verification of and/or updates to the data used as the basis for its findings, the DOE should engage with state public service commissions and stakeholders to review potential recommendations. Since significant transmission development is already underway in New York, through fruitful collaboration between the State, its utilities, and the NYISO, a NIETC in the state may not be needed at this time. The final Needs Study, however, will be useful to inform policymakers and other key stakeholders of transmission needs in the region.

IV. Conclusion

Con Edison appreciates the DOE's continued efforts to assess and identify high-priority national electric transmission requirements and agrees with many of the recommendations in the Needs Study. Before the report is finalized, the Company respectfully suggests that the DOE take the suggestions noted above into consideration.

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[6] *See* Needs Study at p. 96.
[7] *See* Needs Study at p. 1.

From: [redacted]
To: NeedsStudy.Comments
Subject: [EXTERNAL] Feedback on National Transmission Needs Study
Date: Wednesday, April 5, 2023 10:09:04 AM

Dear Members of the Grid Deployment Team,

I am a mom with two young kids and a climate change activist. Maintaining a climate suitable for human civilization is very important to me which means limiting warming to 1.5C and taking significant action by 2030 to lower our emissions. To me, this means decarbonizing our grid by 2035 or sooner.

I am concerned that the National Transmission Needs Study is not adequately capturing the need and priority of connecting the center of the country to PJM. I was listening to testimony from the PJM's Vice President Asim Haque to the Ohio state senate where he raised red flags about PJM's ability to provide reliable electricity in the medium term (from now into 2030). The main concerns raised were that new state policies in PJM's footprint, such as Maryland's Climate Solutions Now Act (passed in April of 2022), would drive thermal resources off of PJM's portion of the grid and reduce reliability properties of the grid in a timeframe that PJM had not planned for. Overall, I am very concerned that PJM is being reactive to state policies on decarbonization instead of having its own plan for how it will achieve full decarbonization in its operating region. This may be a function of PJM's charter, but given PJM's more reactive nature, the mix of new generation in PJM's queue (which is 94% wind, solar, batteries and 6% natural gas), and the retirement of thermal assets, PJM may have trouble meeting reliability requirements by 2030. This is even before considering that there will be considerable pressure from the public and from activists to push to decarbonize the grid entirely by 2035 in an effort to limit global warming to the civilization stabilizing temperature of 1.5C. Winter storm Elliott caused challenges to PJM's grid operations, and as the energy mix changes further, PJM may have even greater struggles in the future. If PJM were connected to the center of the country, PJM may have an easier time meeting its reliability requirements without resorting to keeping aging coal plants on line or building more natural gas assets which will need to be stranded before their natural end of life.

Vice President Asim Haque's testimony:

https://ohiochannel.org/video/ohio-senate-energy-and-public-utilities-committee-2-28-2023

https://search-prod.lis.state.oh.us/cm_pub_api/api/unwrap/chamber/135th_ga/ready_for_publication/committee_docs/cmte_s_energy_pu_1/submissions/cmte_s_energy_pu_1_2023-02-28-1000_137/asimhaquepjm.pdf

Sincerely,
Dana Siler

5890 Darlington Rd.
Pittsburgh, PA 15217
412-719-0030

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April 20, 2023

Maria Robinson
Director, Grid Deployment Office
United States Department of Energy
1000 Independence Ave. SW
Washington DC 20585

RE: U.S. Department of Energy's National Transmission Needs Study – Draft for Public Comment

Dear Ms. Robinson:

I am writing on behalf of the Data Center Coalition (DCC)[1] to provide comments on the U.S. Department of Energy's (DOE) draft National Transmission Needs Study (Study).

I. Introduction

DCC is the national membership organization for the data center industry, representing leading data center owners and operators who maintain data center infrastructure across the country and globe. DCC empowers and champions the data center community through public policy advocacy, thought leadership, community engagement, and education.

DCC appreciates this opportunity to offer comments on the Study. Building out critical transmission infrastructure quickly and strategically will help alleviate grid congestion, reduce interconnection queue delays, integrate more renewable resources, reduce carbon emissions, support economic growth, and maintain the nation's leadership and competitiveness in data center development.

In these comments, we outline the importance of proactive, thoughtful, and transparent transmission planning and investments to drive economic growth and advance clean energy transition. We also offer some recommendations to strengthen the Study, future studies, and other transmission planning efforts.

II. Data centers are leading the clean energy transition through aggressive sustainability goals, energy efficiency, cutting-edge technology, and clean energy procurement.

As DOE's Grid Deployment Office (GDO) works to identify capacity constraints and congestion on the nation's electric transmission grid – which will help address a range of challenges associated with the integration of additional renewable energy resources and increasing demand from electric vehicles

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[1] The Data Center Coalition (www.datacentercoalition.org) is a membership organization of leading data center owners and operators. Public testimony and written comments submitted by DCC do not necessarily reflect the views of each individual DCC member.

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(EVs) and building electrification – it is important to recognize that data center companies have led the way in advancing the clean energy transition through aggressive sustainability goals, which includes innovative energy efficiency strategies, cutting-edge technologies, and significant investment in renewable energy projects for all customers.

Data centers are the critical backbone to the global internet and modern economy, aggregating our collective computing demands – everything from supporting online education and remote work to storing important medical and financial information – efficiently and securely. By centralizing computing resources, data centers have been able to leverage innovations in design, equipment, and technology to maximize energy efficiency. From 2010 to 2018, computing output at data centers jumped sixfold, but energy consumption only rose 6 percent.[2]

Data center owners and operators have not stopped at energy efficiency; they are leading the charge locally and globally in developing and procuring carbon-free energy, now driving approximately two-thirds of all corporate renewable energy demand in the U.S.[3] This aggressive investment in clean energy is in line with the industry's sustainability goals: many companies have committed to achieving carbon neutrality and supporting their operations with 100 percent clean energy within the next 10 years. In fact, when compared to other industries, technology companies with data center operations routinely place in the top five companies committed to procuring clean energy, as determined by the Clean Energy Buyers Association.[4] Eight of DCC's member companies are now ranked in the U.S. Environmental Protection Agency's Green Power Partnership National Top 100.[5]

III. Businesses need reliable electricity and transmission infrastructure to support and drive economic growth.

While data center energy load is highly efficient and increasingly powered by renewable energy, it is significant, and the industry has never shied away from that fact. In the U.S. – which accounts for approximately 40 percent of the global data center market – energy demand from the data center industry is expected to top 35 gigawatts (GW) by 2030, more than double from the 17 GW in 2022.[6]

It is important to consider what data center energy demand represents: supporting mission critical operations (and businesses of all sizes) in a 24/7 environment, driving economic growth in our local communities, and maintaining the nation's competitiveness and leadership on the global stage. Data center investment catalyzes supply chain and service ecosystems, employs hundreds of construction professionals as facilities are built, and provides quality high wage jobs to support ongoing operations.

Moreover, data center investment also translates to significant economic benefits to states and local communities. One clear example is Virginia where data centers represented $6.8 billion of investment

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[2] The New York Times, "Cloud Computing Is Not the Energy Hog That Had Been Feared," February 27, 2020, https://www.nytimes.com/2020/02/27/technology/cloud-computing-energy-usage.html.

[3] S&P Global, "Datacenter companies continue renewable buying spree, surpassing 40 GW in US," March 28, 2023, https://www.spglobal.com/marketintelligence/en/news-insights/research/datacenter-companies-continue-renewable-buying-spree-surpassing-40-gw-in-us.

[4] Clean Energy Buyers Association (CEBA), Clean Energy Buyers Association Announces Top 10 U.S. Energy Customers in 2021, February 16, 2022, https://www.businesswire.com/news/home/20220216005453/en/Clean-Energy-Buyers-Association-Announces-Top-10-U.S.-Energy-Customers-in-2021.

[5] U.S. Environmental Protection Agency (EPA), Green Power Partnership National 100, January 23, 2023, https://www.epa.gov/greenpower/green-power-partnership-national-top-100.

[6] McKinsey & Company, "Investing in the rising data center economy," January 17, 2023, https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/investing-in-the-rising-data-center-economy.

in 2021 – nearly two-thirds of all economic investment in the Commonwealth – and directly and indirectly supported more than 45,000 jobs.[7] Data centers have also been a significant boon for local tax revenue, generating in some counties at least $13 in taxes for every $1 in services required to support the industry. This provides vital funding for schools, affordable housing, social services, and other community priorities.[8]

These important benefits are only possible with the necessary supporting energy infrastructure in place. For our members to deliver data center projects to customers and communities that stand to benefit from them, the industry needs access to reliable electricity, especially renewable energy and sufficient transmission infrastructure. Without sufficient energy infrastructure, the nation's leadership, and overall competitiveness in attracting data center investment is threatened.

The data center industry has experienced firsthand the real-world impact of inaccurate or under-forecasting of various energy demand growth drivers. It is critical to ensure that load forecasts accurately model a wide range of demand drivers including EV load growth,[9] broader electrification efforts, the onshoring of industrial manufacturing (such as semiconductor chip, solar, and battery manufacturing),[10] large customer growth (including data centers), and other industry trends. Inaccurate forecasting, coupled with exclusionary transmission planning processes, have had a detrimental effect, not only on the data center industry, but also with community investment, local tax revenue, and overall economic growth. The data center industry is currently facing substantial uncertainty and billions of dollars in stranded costs and investments due to transmission constraints in multiple markets. In some cases, completed facilities are sitting idle while awaiting access to power previously committed by utilities. These types of transmission constraints have a profound economic ripple effect that extends well beyond our industry, into our local communities: construction crews are sent home from project sites and local revenue projections are thrown into a state of flux.

For data centers to continue to effectively serve customers, maintain the integrity of the internet, and spur economic development across the country, our industry needs reliable access to electricity. The Study has a unique opportunity to help create a roadmap for the nation's buildout of transmission infrastructure and set a high standard for robust and transparent transmission planning processes.

IV. Recommendations

For the data center industry to meet its aggressive sustainability targets while maintaining its essential services, reliable electricity and sufficient transmission infrastructure are required.

The Study is a critical step in identifying the areas of highest constraint and most need for expanded and upgraded transmission infrastructure in the coming years. Furthermore, the Study is integral to DOE's consideration and execution of its authority under Section 216 of the Federal Power Act (FPA),

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[7] Northern Virginia Technology Council (NVTC), The Impact of Data Centers on the State and Local Economies of Virginia, March 2022, page 4, https://www.nvtc.org/NVTC/Workforce/Resource_Library_Docs/2022_NVTC_Data_Center_Report.aspx.
[8] NVTC, page 5.
[9] Utility Dive, "Data centers, EVs drive PJM's long-term load growth forecast, but it expects some utilities to see declines," January 4, 2022, https://www.utilitydive.com/news/data-centers-evs-drive-pjm-load-growth-forecast-capacity-market/616584/
[10] Bloomberg, "Chipmaking's Next Big Thing Guzzles as Much Power as Entire Countries," August 25, 2022, https://www.bloomberg.com/news/articles/2022-08-25/energy-efficient-computer-chips-need-lots-of-power-to-make.

which grants DOE the ability to designate national interest electric transmission corridors (NIETC) based on transmission capacity constraints or congestion.[11]

It is critical that DOE, the Federal Energy Regulatory Commission (FERC), grid operators, utilities, and other stakeholders act expeditiously, strategically, and transparently to address the growing transmission constraints across the nation's electricity grid to avoid further stalling economic development. Given the concerns discussed above and the importance of accelerating the construction of critical transmission infrastructure, we offer the following recommendations to help strengthen this Study, future studies, and the nation's transmission planning efforts. DCC respectfully recommends that the DOE:

1. Add a new section or subsection to *Section V: Review of Existing Studies: Current and Future Needs* that provides further detail on the overall study process and methodology, especially as it relates to incorporating source data and reports. While the Study notes it incorporates more than 50 different industry reports published over the past five years, we believe the Study would benefit from greater discussion on the potential issues and limitations of drawing data from other past/regional reports and how GDO considered the potential pitfalls of this approach. This new section or subsection could specifically discuss the expected load growth in large loads (including data centers, EVs, semiconductor chips, and solar panel manufacturing) that seems to be under-forecasted or missing in some of the reports and data GDO incorporated into the Study. We believe a similar concern regarding the speculative or inaccurate nature of certain industry forecasts was also provided by the Southeastern Regional Transmission Planning Process (SERTP).[12]

2. Continue to evaluate ways to strengthen and improve study processes and methodologies to ensure greater transparency and accuracy of future needs studies. DCC believes there is a clear opportunity to engage key stakeholders early in the consultative process (beyond the states, tribes, and regional grid entities required under statute), most notably large commercial and industrial customers. We encourage DOE to convene stakeholder meetings with large customers, including the data center industry, ahead of the development of the next study and other transmission planning activities to ensure that source data and reports accurately reflect growth plans, which could significantly impact study findings. Based on our experience, collaboration among utilities, grid operators, policymakers, and the data center industry can lead to improved planning and communication.

3. Provide actionable information on how utilities, grid operators, regulators, and other stakeholders should utilize this report, especially in relation to state and regional transmission planning activities. As the Study clearly notes in the Executive Summary, "This study prescribes no particular solutions to issues faced by the Nation's power sector. Rather, it establishes findings of need for industry and the public to suggest best possible solutions for alleviating them in a timely manner."[13] While DCC understands the informational nature of the Study, we also believe it is not clear how the Study's findings should be considered or utilized by stakeholders in state and

[11] Steptoe, FERC Proposes NOPR on Backstop Siting Authority: Has Congress Breathed New Life Into FERC's Transmission Siting Authority? December 19, 2022, https://www.steptoe.com/en/news-publications/ferc-proposes-nopr-on-backstop-siting-authority.html.
[12] U.S. Department of Energy, SERTP Feedback on Draft National Transmission Needs Study, Comment 126, page 146, https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf.
[13] U.S. Department of Energy, page ii.

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regional regulatory proceedings or planning processes. We recommend that GDO consider adding a section on best practices for incorporating the Study's findings into such planning activities.

4. Ensure DOE activities are aligned with ongoing FERC reforms aimed at improving transmission planning and generator interconnection processes as the nation progresses in the clean energy transition.[14] It is vital that DOE's activities are complementary to FERC's work on transmission planning, cost allocation, and generator interconnection reform to avoid any potential confusion, legal challenges, or further delays in the construction of needed transmission infrastructure.

5. Provide further transparency and opportunity for stakeholder and public input on the NIETC designation process. DCC is aware that this Study will inform NIETC designation but is unaware of DOE providing a clear explanation on exactly how the Study will inform the designation of such transmission corridors and how stakeholders will be engaged in the process. DCC believes similar questions were raised by the South Carolina Office of Regulatory Staff.[15] We encourage a timely, transparent, and robust stakeholder process for NIETC corridor designation, one that engages large commercial and industrial customers, including the data center industry.

V. Conclusion

DCC thanks the GDO for its significant work on this important topic and greatly appreciates the opportunity to provide comments on DOE's draft National Transmission Needs Study. We respectfully request that GDO consider DCC's comments and recommendations above. We look forward to continued collaboration with DOE, regional transmission organizations and independent system operators, utilities, and other stakeholders in advancing the nation's clean energy transition and buildout of transmission infrastructure in a strategic manner that supports and drives continued economic growth across the country.

Please do not hesitate to reach out to me at aaron@datacentercoalition.org should you have any questions about these comments or recommendations.

Respectfully,

Aaron Tinjum
Director, Energy Policy & Regulatory Affairs
Data Center Coalition

[14] Utility Dive, "FERC works 'feverishly' on transmission reform, with near-term focus on interconnection rule," March 17, 2023, https://www.utilitydive.com/news/ferc-transmission-planning-generator-interconnection-reform/645267/.

[15] U.S. Department of Energy, SC Office of Regulatory Staff, Comment 164, page 159.

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From: [redacted]
To: NeedsStudy.Comments; [redacted]
Subject: [EXTERNAL] Comments - Draft National Transmission Needs Study
Date: Sunday, March 26, 2023 12:21:18 PM

Hi DOE Team - thanks again for the webinar a few weeks back. I definitely enjoyed the results of the study and the direction team is headed. I am cc'ing my colleague Supriya w/ Oak Ridge National Labs to just keep her in the loop on some of my thoughts / comments that the team suggested the public provide. In this case, we (DataCapable) supports many of the largest IOU's in the country, so hopefully these comments provide some feedback direction:

Interoperability / Shareability - a major disconnect between utilities, vendors, and DERS manufacturers is the interop of both distribution and transmission data. Nearly all distribution utilities and transmission operators have a network model data but the shareability of this data (and associated asset details - congestion, age, upgrade plans, etc.) is not shared with those that support. Consider additional work related to the interop of this data and the shareability of this data. Please reference recent work related to ODIN (outage data interop. for inspiration)

Interconnectivity - future demand + future considerations related to generation is rapidly changing. How this data is shared between micro grid operations, utilities, and transmission operators needs additional research / alignment on how the interconnectivity process is standardized across the USA (please reference work in Hawaii and associated process can be streamlined to remove utility specific bottlenecks)

Zac Canders - cofounder

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ECONWERKS

April 20, 2023

US Department of Energy
Grid Development Office
Washington DC
by email to: NeedsStudy.Comments@hq.doe.gov

RE: Comments on the Draft 2023 National Transmission Needs Study

Thank you for the opportunity for the general public to comment on the US DOE Grid Development Office's draft 2023 national transmission needs study. Here are five comments to consider.

1) The draft report is not technology neutral. This can be easily seen by the number of references to the assorted resource adequacy technologies both on the supply and demand sides. As expected, transmission needs are addressed 1,623 times. In comparison, the use of wind 155 instances, solar 85 times, battery storage 70 mentions, natural gas 40 references, coal at 6 items, and nuclear power amazingly only 6 cites when allies like the United Kingdom are actively focusing on that technology as a resource for decarbonization goals per Bloomberg News reporting service. On the demand side of the equation, there are no mentions of energy efficiency, only 7 times is demand-side management discussed. The use of real-time pricing to ration demand is absent. Load modifying programs also appear absent. Even the value of lost load is not mentioned. These are crude measures, but the development of necessary resources to meet public policy goals needs much more attention and quantitative analysis than a copious literature review in the assessment, in which the literature itself apparently gives short shrift to the complexity of the resource adequacy subject as well. This draft assessment is just an analysis of prior work that already presumes the outcome. The report does not come across as objective, neutral, nor independent. Such a proper analysis might actually come to the same or similar conclusion as the draft assessment, but absent such an in-depth rigorous approach the general public will not be convinced that this effort was truly a "follow the science" approach as promised by President Biden. Perhaps buried in the many studies cited by the assessment there is more such discussion, but it should much more front and center in the current draft assessment and study, which will act as the cornerstone of national policy.

2) The report errors in making the presumption that all congestion is to be addressed, corrected, and likely eliminated. That is a failed interpretation of economic theory where some form of congestion is actually optimal and allocatively efficient. The congestion that is also depicted has an unreality about it as well. Clearly, there are many entities that want to build wind, solar, storage resources; but wanting to build, or wishing to build as seen in the various RTO queues is not the same as a measurement of the potential true

optimal economic expansion. Recent LBL work presents evidence from 2000-2017 that perhaps only 14-21 percent of what is in the queue will get built.[1] This is not surprising actually, when for instance in the MISO footprint the amount of generation in the current queue (1400+ projects totaling 244GW) far exceeds MISO's 2011 all-time system summer peak demand of 127GW.[2] To build that much generation in the queue would take an electrification of transportation even more aggressive than that contained in the draft assessment, a supernormal new inter-RTO dependency, or it reflects an impossible to attain number of new resources. When you factor in that policy subsidies to construct new renewable resource technologies are in place and sizeable, it would be expected that a group of folks wanting to undertake the development of such generation projects would occur. That does not mean all should be constructed. The report needs to make a clearer delineation of truly economic expansion of these technologies and their impact on the required grid. To use an analogy, there might be ten cars waiting on the on ramp for the traffic signal to go ahead onto the interstate, but that is by no means also a signal that the highway needs to be expanded from 3 lanes in each direction to five or six so as to eliminate the traffic congestion. Similarly, the existence of HOV lanes with significant enforcement penalties or fees is presently used in the US to reduce infrastructure use, congestion, and buildout. The analog of the HOV is not even discussed in the draft assessment. Therefore, the draft report needs to refine its use of congestion as a prime driver for grid expansion. Otherwise, this is just a report with a conclusion looking for analyses to support it, and one which could actually lead to an overbuilding of the necessary transmission. A more careful examination of resource adequacy needs to be performed independent of the Reliability coordinators as well as their RTOs and their consultants as well as the myriad number of policy purveyors who all have an economic interest in grid buildout. Following the science requires a more academic, peer-reviewed independent study of transmission needs and resource adequacy drivers. Such an approach may again actually lead to the same or similar conclusions as the draft assessment and study, but the general public requires that to have full confidence in an infrastructure build out that would far exceed any internal improvements undertaken in US History.

3) The draft report does not adequately address the existence of natural monopoly and cost non-linearities that exist in the electric industry. Specifically, that an RTO like MISO may have an expansion plan for transmission plan in place for its footprint, and likewise for all other RTOs performing the same, that does not mean the integration of each RTOs

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[1] See Linked-In posting of LBL Senior Scientist Dr. Ryan Wiser April 7, 2023 with the LBL report at https://emp.lbl.gov/queues

[2] See MISO document, "Generation Interconnection Queue: Overview," March 30, 2023. https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

transmission expansion plan is the proper plan for the nation at large. Prior to President Eisenhower's enactment of the interstate highway act, the US relied on the US highway system, a system that was not optimized for nationwide commerce nor national defense. The interstate I-system planning addressed that larger scale optimization, including the important political economy aspect supportive of fuel taxes. Rolling up the results from various individual electricity sector participants may be easy and politically pragmatic, but it again misses the mark of a true scientific inquiry of both resource adequacy and necessary transmission infrastructure. It is good that the draft report properly does addresses the need for improved inter-RTO transmission development. It is beyond the scope of this report, but the present patchwork of what look like gerrymandered RTOs can hardly be optimal as well. And it should be recalled as well that the individual states and RTOs by themselves, or aggregated, do not by definition represent the national interest nor a proper national economic optimization of the transmission grid. It is likely heresy to mention this point, but national authorities should examine this subject from a purer national interest perspective. The assessment need not be bothered by the parochial interests of the numerous stakeholders.

4) Fourth, the report is in myriad ways too predicated on the decarbonization without a transparent quantification of the monetization of the carbon externality. Specifically, it would be instructive to delineate what part of the upcoming transmission build out is due primarily for commerce and engineering reliability reasons versus that which is additionally required to address decarbonization including the electrification of transportation. In that way, the public would be able to see the implied price of carbon per ton that is being used so the general public can identify the clear cost of dealing with our most unfortunate present externality facing this generation.

5) Finally, the transmission assessment and its transmission grid build out completely ignores the fact that such transmission development itself has externalities with respect to land use, effects on the natural environment, farming, tourism, and even whether such a grid build out might make the system even more vulnerable to electro mechanical issues including geo-magnetic solar events. There may actually be merit in a grid that is not so interconnected. During the Summer 2003 US blackout the Northeast ISO was able to separate off fairly easily from the cascading disturbance that occurred in the MISO PJM and Canadian footprints. All these externalities should be put forth and discussed as well. We live in an imperfect situation; diagramming out all risks is a necessary component of any such transmission needs assessment and study.

In sum, it is with great irony that 100+ years of global industrialization has caused climate change, and now only further even more rapid industrialization of the rural US is needed to address the climate change issue. Before doing so and committing so much of the nation's precious financial resources, let's prepare as technologically neutral and objective a report that is

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as scientifically and academically peer reviewed as possible for the benefit of both this and future generations.[3]

Again, thank you for the opportunity to share some observations. As many folks have pointed out through time, no one has the monopoly on truth, including this author; but, given the circumstances let's try harder to pull the present effort to address climate change to a more solid scientific foundation, not one reflecting a simple panoply of economic interests with parochial goals. The report does do a commendable job in collecting up that knowledge, but so much more can be done in the name of more exacting science.

Sincerely,

Randel Pilo

Randel Pilo,
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[3] Do not take these comments to mean that the author does not believe in climate change. It is real. Newtonian mechanics alone predict that human activity influencing the abundance of CO_2 in the atmosphere will have consequences. Prudence requires as thoughtful and scientific an inquiry as possible to ferret out necessary policy programs attenuating such consequences. The current draft assessment report does not yet provide that robust assurance but leaves one the clear perception that substantial transmission infrastructure is the true panacea that will correct the issues at hand and return our realm back to Eden. The author has full confidence in the federal agencies to actually perform such an analysis with the rigor of the most precise scientific method. The current method in the assessment study too strongly only represents collective political and economic interests' opinion and preferences. Such a consensus may be important from a political economy perspective, it does not mean it is itself a firm scientific conclusion. To wit, before Copernicus and his depiction of the heavens, the broad consensus in its day was that Earth was the center of the universe; but, with math and science that supposed consensus did not hold up to the scrutiny of in-depth further inquiry. Moreover, it sadly took nearly a century for Copernicus' models to become the new consensus. That spirit of constant rigorous study should be at the base of this most important assessment and study. This is a very high standard, but one that is required to address our existential environmental issues appropriately.

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April 20, 2023

U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Submitted via email to NeedsStudy.Comments@hq.doe.gov

Re: Comments on the Public Draft of the National Transmission Needs Study (Entire Draft)

To whom it may concern:

I. INTRODUCTION

The Edison Electric Institute (EEI) appreciates the opportunity to submit comments in response to the U.S. Department of Energy's (DOE's) draft National Transmission Needs Study (Draft Study), released for public comment on February 24, 2023.[1]

EEI member companies' investments, undertaken on behalf of customers, make the energy grid smarter, cleaner, more dynamic, more flexible, more secure, and more reliable. As electric companies continue to deploy greater amounts of carbon-free technologies, transmission will play a critical role in ensuring clean, reliable energy is delivered cost effectively. Investment in electric transmission infrastructure will support a more reliable and resilient energy grid and our member companies are central to those efforts. To ensure that these investments are efficient and cost-effective, EEI members participate in ongoing processes with regional planners, state regulators, and other stakeholders to develop proactive and comprehensive transmission plans. These plans reflect the unique characteristics of the different planning regions and customers' needs.

[1] *See* https://www.energy.gov/gdo/articles/draft-doe-study-identifies-pressing-national-electric-transmission-needs?utm_medium=email&utm_source=govdelivery.

In aggregate, EEI member companies invested more than $150 billion in 2022 on the electric grid. In 2021 and 2022, roughly 20 percent of that was dedicated to investing in transmission infrastructure. While significant, this represents a fraction of the estimated investment needed over the coming decades. Building energy infrastructure, including new and upgraded transmission, is key to achieving economy-wide and industry-specific clean energy goals. A robust transmission system enables electric utilities to integrate new energy resources, including clean and renewable energy resources, and ensure reliable delivery to customers. Analysis indicates that achieving a carbon-free economy by 2050 will require significant transmission build out. Moreover, many of the benefits of the clean energy tax incentives included in the Inflation Reduction Act (IRA) will be lost without more rapid transmission expansion over the next decade. The Biden Administration recognizes that new transmission expansion and upgrades to existing facilities will create an array of new jobs, prevent power outages in the face of extreme weather, and can reduce electricity costs for customers.

II. COMMENTS

A. The Draft Study

While the Draft Study is not, as DOE notes, a long-term planning study,[2] it provides valuable information about capacity constraints and congestion on the nation's electric transmission grid. EEI is dedicated to improving transmission planning with the goal of resolving future needs by adding efficient and cost-effective transmission infrastructure. The Draft Study contributes to these efforts by comprehensively enumerating transmission needs outlined in studies and reports issued in the last few years. This may be helpful for stakeholders participating in local, regional, and interregional planning processes.

[2] *See* https://www.energy.gov/gdo/national-transmission-needs-study.

The Draft Study's broad conclusions are generally accurate. There is indeed an ongoing need to expand the transmission system to meet a variety of needs. The needs outlined in the Draft Study – to improve grid reliability, resilience, and resource adequacy, enhance renewable resource integration and access to clean energy, decrease energy burden, support electrification efforts, and reduce congestion and curtailment – are generally of interest to EEI members though they differ by region and are likely more acute in some regions than in others. The Draft Study makes this clear in listing an array of needs across different planning regions (see pages iv to xv in the Executive Summary). In the West, transmission will address reliability and resource adequacy concerns presented by extreme heat and wildfires; in the Delta and Florida regions, transmission can mitigate the effects of hurricanes; in New England, transmission can help with reliability challenges presented by a constrained natural gas system. The needs identified for specific regions are consistent with those identified by system planners and stakeholders in the regions.

The Draft Study rightly concludes that interregional transmission has the potential to produce significant benefits for electric customers, depending on myriad factors. Among other things, the Draft Study notes that expanding interregional transmission capacity will permit regions to take advantage of the geographic and temporal diversity of resources, which will support affordable, reliable energy while increasing operational flexibility. EEI supports efforts to consider the need for interregional transmission planning processes, and whether and how to increase interregional transfer capacity. However, determining transfer capability between regions is a complex task that must ultimately account for a variety of factors, including the trade-off with regional resource adequacy and the potential for interregional resource diversity, as further described below.

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B. Interaction Between Draft Study and Other DOE Work

The Draft Study is a helpful aggregation of recent studies; it provides important context and illustrative information from which trends may be observed. DOE notes that the results will be beneficial in terms of "informing" DOE's work implementing the Infrastructure Investment and Jobs Act (IIJA) and IRA as well as supporting implementation of existing programs, including DOE Loan Programs and potential designation of National Interest Electric Transmission Corridors (NIETC). However, the Draft Study alone is insufficient for the purposes of specific DOE action – it does not prescribe particular solutions for the nation's power sector, nor does it explain how DOE plans to use it going forward. Thus, DOE should finalize the Draft Study as quickly as possible, while also making clear how it will apply its determinations of transmission needs in utilizing its various federal statutory transmission authorities.

In the Building a Better Grid Initiative Notice of Intent, DOE indicated that it intends "to provide a process for the designation of National Corridors on a route-specific, applicant-driven basis" with the intent of facilitating efficient consideration of projects seeking a FERC-issued permit.[3] This would be a significant change in policy implementation and DOE should provide more detail as to how applicants can utilize the Needs Study in their applications (e.g., explaining when and how a project/NIETC application will be evaluated in terms of meeting customers' needs and cost-effectiveness).

[3] *See* Notice of Intent: Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization, U.S. Department of Energy, at 15 (Jan. 11, 2022).

C. Interaction Between Draft Study and Existing Planning Processes

The Draft Study states that many existing transmission planning processes "are primarily focused on compliance with NERC and local reliability standards with very limited scopes and planning horizons."[4] This is a broad statement that fails to recognize that the Federal Energy Regulatory Commission (FERC or the Commission) recently proposed reforms to existing transmission planning policy. Chief among them is the Notice of Proposed Rulemaking to change existing regional transmission planning and cost allocation requirements.[5] EEI member companies support a variety of the proposals put forward by FERC – long-term scenario planning, including new factors into those scenarios, ensuring existing process for reliability and economic projects continues to deliver for customers, and creation of new federal Right of First Refusal for jointly owned facilities and right-sized replacement transmission facilities. If adopted, these reforms will facilitate proactive transmission planning and reinstate rights necessary to an efficient, cost-effective build-out of necessary transmission.[6] As DOE evaluates transmission planning and needs, it cannot overlook the ongoing process of reforming transmission planning.

The Draft Study states, several times, that DOE does not intend to displace existing planning processes or reliability standards.[7] DOE should carefully assess whether its actions could adversely affect existing planning processes, delay decisions therein, and/or create paths to transmission development that allow a project proponent or particular class of developer to avoid

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[4] Draft Study at 2.

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

[6] Initial Comments of the Edison Electric Institute, Docket No. RM21-17-000, at 24-37 (Aug. 17, 2022) (explaining why a federal Right of First Refusal will enable construction of needed transmission in a timely and efficient manner).

[7] Draft Study at 2.

critical elements of existing planning processes. FERC has spent decades evaluating and reforming these processes to ensure coordinated, open, and transparent planning; these processes are the product of evolving policymaking over decades. Beginning with Order No. 888, issued in 1996,[8] to the pending Transmission Planning NOPR, FERC has periodically required changes to transmission planning on a national basis with the clear goal of ensuring efficient, open, and transparent transmission planning. In the years between national action, FERC has required or approved changes in individual regions on a case-by-case basis.

The FERC-approved planning processes should not be undermined or superseded by DOE action. The planning processes are open and transparent, require broad dissemination of planning information and permit wide participation for all stakeholders. Challenges and tensions in some of the existing planning processes exist precisely because they are structured to ensure that only projects with a compelling justification are approved for construction. DOE should avoid taking actions that remove projects from consideration in these processes. The potential exists to waste resources and produce inefficient transmission planning outcomes if safeguards and hurdles in the existing transmission planning processes are eliminated, explicitly or effectively.

D. Interregional Transfer Capacity

The Draft Study outlines anticipated transfer capacity needed between planning regions in 2030, 2035, and 2040. Determining interregional transfer capacity involves complex and technical analysis and the conversations across the industry continue to evolve. Below, we

[8] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Pub. Utils.; Recovery of Stranded Costs by Publ. Utils. & Transmitting Utils.*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080).

discuss important issues with interregional transfers between regions that DOE should consider in its actions.

In December 2022, FERC convened a workshop on establishing interregional transfer capability. Panelists at the workshop raised several key considerations for the Commission and other policymakers. First, several panelists noted that the definition of transfer capability must be clear. The Southwest Power Pool (SPP) representative emphasized that some entity would have to develop a common understanding of what transfer capability is and how to measure it.[9] Another panelist agreed, noting that it is "important to understand the complexity and the nuance of the requirement."[10] Second, panelists explained that determining transfer capability between regions is "not as simple as adding up the tie line capabilities between two entities, or two planning regions."[11] The representative from the Midcontinent Independent System Operator (MISO) explained that there are other factors to study, exemplified by times when transfers of power from PJM through MISO into SPP may be limited by elements on the TVA system.[12] Third, panelists noted that any facility planned and built to facilitate interregional transfers must have "clarity and consensus on the benefits that it provides, both to ensure appropriate cost allocation, and to enable the construction through state regulatory processes."[13] Finally, creating significant levels of new transfer capability between regions is also likely to require supporting upgrades to the existing transmission system to ensure that imports of electric energy can be

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[9] *Transcript of the December 6, 2022 Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*, Docket No. AD23-3-000, at 138 (filed Feb. 3, 2023) ("Transcript").

[10] Transcript at 141.

[11] Transcript at 138.

[12] Transcript at 140.

[13] Transcript at 122.

reliably transmitted within the recipient region.[14] The Draft Study does not appear to have taken these elements into account. DOE must ensure that these critical factors are evaluated when considering any action on interregional transmission.

E. Grid Enhancing Technologies

New technologies can support system reliability and produce benefits for customers, but many are most valuable in near-term operations and less so in the context of long-term transmission planning. EEI supports policies that recognize the value of—and support investments in—grid modernization that enhance reliability and resiliency as well as promote integration of cleaner energy resources. Some of the grid enhancing technologies (GETs) specifically referenced by DOE in the Draft Study – dynamic line ratings (DLR), power flow controllers, and topology optimization – currently provide operational flexibility to system operators in the short-term. These are not replacements for transmission; they should be encouraged but not required as part of a transmission project. For example, DLR technologies allow utilities to understand the real-time condition of assets by measuring and monitoring temperature, weather, wind, line sag, and other factors. These factors permit increased (or decreased) flow during certain conditions and enable prioritizing asset condition work on aging assets. However, DLRs have limited use in planning studies.

III. CONCLUSION

EEI appreciates the opportunity to provide these comments in response to the Draft Study. EEI looks forward to continuing the dialogue with DOE on efforts to facilitate

[14] A 2020 ISO-NE study of offshore wind integration found that roughly 6,000 MW of offshore wind could be connected to the existing New England system without additional reinforcements. However, after that point, considerable transmission upgrades would be necessary to accommodate quantities of offshore wind.

investment and development of needed transmission to meet emerging challenges and fundamental changes to the energy grid.

Respectfully Submitted,

/s/Kevin Huyler

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April 20, 2023

Sent via email to NeedsStudy.Comments@hq.doe.gov

Dr. Adria Brooks
Transmission Engineer
U.S. Department of Energy
Grid Deployment Office
1000 Independence Ave., SW
Washington, DC 20585

Re: National Transmission Needs Study

Dear Dr. Brooks:

Electric Reliability Council of Texas, Inc. (ERCOT) appreciates the opportunity to provide comment on the public draft of the Department of Energy's National Transmission Needs Study. As the entity responsible for overseeing the planning of the transmission system that serves the majority of the State of Texas, ERCOT understands the critical importance of identifying transmission projects to meet future system needs and the related challenge of forecasting long-range load and generation scenarios many years out. Under ERCOT's oversight of the regional transmission planning process, transmission utilities serving the ERCOT region have constructed over 52,700 miles of transmission lines to reliably and cost-effectively serve the needs of Texas consumers.

Given our deep experience with transmission planning, I commend you and others at DOE for your ample efforts in this study to identify transmission needs across the United States. We appreciate DOE providing ERCOT an opportunity to comment on the discussion draft of this study, and we also appreciate the changes DOE made to the study based on those comments. However, my staff and I still have several concerns with this study. We therefore offer the following comments for your consideration:

Consideration of Relevant Costs

As ERCOT noted in its original comments, DOE's analysis of the economic benefits of new transmission does not give appropriate attention to the substantial cost associated with the transmission additions for which benefits have been identified. Established planning principles dictate that a transmission project may be justified under economic criteria only if the estimated benefits of the project exceed a measure of its estimated costs. If a project's benefits don't exceed that measure, the project cannot be justified under economic criteria. The study identifies substantial economic benefits of a number of new transmission facilities across the country, and

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in particular, projects linking Texas to the western United States and the "Plains" region.[1] However, the study does not address the cost of these projects, which in many cases is likely to be very substantial, given the contemplated scale. ERCOT therefore recommends that the DOE provide a more robust cost-benefit analysis with estimates of project costs so that the net benefit of these additions can be fully understood. Without such an analysis, this study does not establish that an independent economic "need" exists to support the construction of expansive and costly new interregional transmission lines.

In the updated public version of the study, DOE responds to ERCOT's concern by noting that "[t]he National Transmission Needs Study is not meant to displace the transmission reliability or planning responsibilities" of regional entities. See study at 156. ERCOT does not read this to address the stated concern. Cost considerations are relevant in any case where new transmission is proposed based on economic principles; they are not limited to traditional regional planning processes.

In evaluating project costs, DOE should consider that adding substantial capacity between ERCOT and other regions (such as the 9.8 GW [median] recommended for connecting ERCOT to the Plains region by 2035[2]) would require a number of new separate transmission lines, each limited to approximately 1.5 GW. This is because relying on a single point of interconnection to provide this transfer capability would result in a material increase in ERCOT's single largest contingency, which would in turn require a substantial increase in ERCOT's costs of ancillary services to counter the operational risk of losing the facility while it is importing or exporting. The costs of building these separate points of interconnection should be considered.

Increasing transfer capability between ERCOT and other regions would also result in the need for additional transmission facilities to address stability and voltage limits that would be encountered for each of the new injection points. Voltage and stability limits often dictate the limits for interregional transfer capability. The study does not adequately consider the limitations imposed by these constraints or the additional costs associated with the facilities needed to mitigate the constraints. The cost of these upgrades could be significant and, in some cases, could exceed the costs of the proposed lines.

In addition to the costs of the identified transmission facilities and the land on which they would be built, DOE's assessment should include consideration of other costs attributable to the proposed changes to the grid, which would include the following:

- Additional transmission upgrades that may be needed to ensure sufficient grid strength and inertia

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[1] Study at viii-ix.
[2] Study at ix, 156.

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- Changes in dispatch costs due to retirements of older or less efficient generation caused by the increased transfer capability
- Changes the increased transfer capability will have on the regional dispatch costs due to intermittency of renewable resources
- Changes to operating reserve requirements due to increased reliance on intermittent resources
- Potential changes to existing market designs and Texas state rules to manage interregional transfers

Interdependency of Transmission Benefits

The study identifies a number of benefits associated with additional connections between Texas and other regions of the country. For example, the study notes that the increased transfer capability would help address capacity shortages under emergency conditions like those that occurred during the February 2021 cold weather event.[3] The study also identifies Texas as one of the regions in greatest need of cost-effective transmission growth.[4] However, the economic, reliability, and resiliency benefits identified in the study for Texas cannot be achieved by implementing only certain projects identified as providing the highest value. Rather, the benefits depend on additional proposed transfer capability being built between other regions. As the study notes, "the coinciden[t] scarcity of generation resources among ERCOT's immediate neighbors during [the February 2021 cold weather event] calls into question the value of increased transfer capability limits without an accompanying increase [in] multiregional transfer capability . . . ."[5] Any analysis of improvements would therefore need to consider the costs of building all of these facilities—not just a select few facilities that the study identifies as having the highest value.

Reliance on Anomalous 2021 Data

The study explores historical trends since 2012 to identify a need for transmission investment. The study uses several metrics to highlight the regional market price differences and congestion. However, the study still fails to fully account for data that may skew the overall historical trend. The most obvious example is the use of 2021 price data for ERCOT and SPP.[6] The February 2021 winter storm was a statistical outlier by any metric. Some analyses suggest this storm was a 1 in 100 or even a 1 in 130-year event for the Texas region.[7] The extreme weather produced equally extreme market pricing outcomes, as energy costs in ERCOT in 2021 were six

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[3] Study at 51.
[4] Study at 106.
[5] Study at 51.
[6] Study at 29.
[7] *See Reliability and Resilience in the Balance*, Texas Section of the American Society of Civil Engineers at 46, available at https://www.texasce.org/wp-content/uploads/2022/02/Reliability-Resilience-in-the-Balance-REPORT.pdf ("Winter Storms Uri . . . appears to be a 1 in 100- or 130+-year risk event.").

times higher than in 2020 due to the February 2021 winter storm.[8] Such anomalous results should not be expected to reoccur with any regularity. While ERCOT appreciates DOE's efforts to reduce the report's emphasis on the anomalous 2021 data by introducing data from additional time periods, continued reliance on 2021 data would still tend to overestimate the benefits of increased interregional transmission connections between ERCOT and other regions because of reforms undertaken since 2021 that would reasonably be expected to reduce the likelihood and the financial impact of a similar event.[9]

For example, the Public Utility Commission of Texas (PUCT) has adopted market pricing changes, including a $4,000/MWh reduction in the system-wide offer cap, that would alter the value of transmission between ERCOT and other regions if a similar loss of generation were to occur today.[10] Additionally, the PUCT has adopted rules requiring a number of important reforms, such as requiring weatherization of generators, transmission facilities, and critical gas infrastructure,[11] creating new market products that ensure the availability of alternative on-site fuel supplies in the event of gas curtailments or shortages that impact generators,[12] requiring operators of gas supply infrastructure to register with transmission utilities as critical loads,[13] and mapping the natural gas supply chain to enable identification of critical gas infrastructure needed to support power generation.[14] These changes should be accounted for in estimating the economic benefits of new interregional transmission projects. Furthermore, an ongoing market re-design will alter future market outcomes and therefore impact many of the conclusions found in the study.

Consideration of Generator Retirements

Building more transfer capability between regions could reduce the total reserves available to all regions because the increased competition from other regions could lead some generators to retire. As ERCOT noted in its previous comments, these retirements would impact the economic benefits cited in the study and should therefore be considered as part of the study.

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[8] *See 2021 State of the Market Report for the ERCOT Electricity Markets*, Potomac Economics (May 2022) at 11, available at https://ftp.puc.texas.gov/public/puct-info/industry/electric/reports/ERCOT_annual_reports/2021annualreport.pdf ("Average real-time prices rose to $167.88 per MWh in 2021, more than 6 times higher than in 2020, due almost entirely to the effects of Winter Storm Uri.").
[9] *See* Study at 128-129.
[10] *Review of the ERCOT Scarcity Pricing Mechanism*, Public Utility Commission of Texas, Order (Dec. 2, 2021) https://interchange.puc.texas.gov/Documents/52631_47_1171647.PDF. DOE did note that "[t]he high prices found in ERCOT in 2021 may also have been reduced had certain regulatory changes already been implemented, including requirements for weatherization for generation resources and lower peak price limits." Study at 29. However, as discussed above, ERCOT believes that the establishment of the price cap and other reforms would need to be considered in any cost-benefit analysis.
[11] *See* Tex. Util. Code § 35.0021; Tex. Nat. Res. Code § 86.044; 16 Tex. Admin. Code § 25.55.
[12] *See* Nodal Protocol Revision Request 1120, Create Firm Fuel Supply Service; ERCOT Firm Fuel Supply Service Request for Proposals, https://www.ercot.com/services/programs/firmfuelsupply.
[13] *See* 16 Tex. Admin. Code § 25.52(h).
[14] Tex. Util. Code § 38.201. As required by section 38.201(c), the supply chain map was jointly developed by the PUCT, the Railroad Commission of Texas, the Texas Department of Energy Management, and ERCOT.

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For ERCOT's operational purposes, this additional transfer capability also means that adding 10 GW of transfer capability between ERCOT and the Plains region, for example, would not equate to an increase of 10 GW in ERCOT's reserves. These retirements could result in ERCOT becoming more reliant on sources of generation located outside of Texas to serve load during certain peak hours. And ERCOT could be put at an operational disadvantage if market designs in neighboring regions lead generators to develop in those areas and both regions end up needing the capacity to serve their load during peak days.

Reliability Risks of More Interconnections

Increasing connections between regions can increase some reliability risks. Generally, more connections to geographically diverse areas would help in slow events, such as the February 2021 winter storm. On the other hand, more connections would make ERCOT more susceptible to fast events like the January 2019 Eastern Interconnection event, which arguably put the entire Eastern Interconnection on the brink of a collapse.[15] DOE should address these risks in the study. In response to ERCOT's comment raising this concern on the initial draft of the study, DOE points to language added in the public study stating that transmission can help to reduce congestion and losses and to address resource adequacy concerns in certain cases. *See* Study at 151, comment 28. That language does not appear to be relevant to the concern ERCOT is addressing here, which is that greater interdependency between regions increases the risk that more of the country will be affected by large-scale, fast-moving disturbances, and that fewer regions will remain energized and available to help those affected by the disturbance.

Historical Transmission Investment Figures

The study states that transmission investment and transmission construction in the ERCOT region have experienced a "sharp decrease" from 2016 through 2020.[16] However, as noted in the report, transmission investment is "inherently lumpy," and large investments should be considered when determining trends in transmission investment.[17] In ERCOT's case, the PUCT's Competitive Renewable Energy Zone (CREZ) initiative, which resulted in a number of major transmission projects that connected wind-rich areas in West Texas to population centers, yielded significant new transmission investment from 2013 to 2016. When transmission investment over the past decade is considered, ERCOT has actually seen a steady increase in the transmission investment (see figure below).

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[15] https://www.nerc.com/pa/rrm/ea/Documents/January_11_Oscillation_Event_Report.pdf.
[16] Study at 22.
[17] Study at 19.

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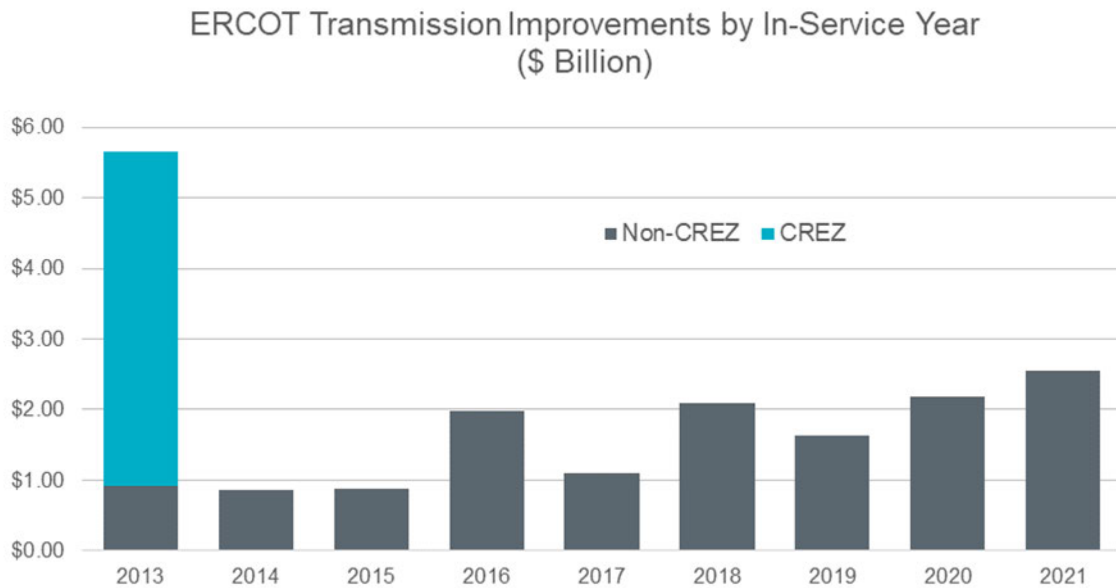

Also, as shown in Table IV-1 in the study, Texas's average Load-Weighted Circuit-Miles is the highest compared to all other regions and more than twice the regional average. ERCOT appreciates DOE's acknowledgment on page 20 that Texas built more transmission than other regions. Study at 20. However, the report's suggestion that transmission investment and construction has experienced a "sharp decrease" from 2016 through 2020 remains inaccurate.

We appreciate the opportunity to review the study and your consideration of these comments. Please feel free to contact me if you would like to discuss these comments further.

Respectfully,

/s/ Woody Rickerson

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Environmental Defense Fund

Grid Deployment Office
United States Department of Energy
Submitted via email

Re: Draft National Transmission Needs Study

Driving and supporting the development of a safe and reliable electric system that cost-effectively meets America's energy needs is a core responsibility of the Department of Energy ("DOE"). As we face increasingly frequent and severe extreme weather events that cause harmful blackouts and high utility bills, as well as changing baseline temperatures and conditions, it is crucial that the electric system be improved to meet those challenges. At the same time, the electric system is undergoing a massive transformation as solar, wind, storage and a variety of other distributed energy resources are interconnected. While this transformation will usher in generational opportunities, it also poses unique challenges. While new laws and policies, including the Inflation Reduction Act ("IRA") and the Infrastructure Investment and Jobs Act ("IIJA"), as well as state and local laws and policies supporting and requiring decarbonization, offer critical support for this electric system evolution, careful planning and responsible development of the electric system is needed take advantage of the opportunities and respond to any challenges.

The Department of Energy's National Transmission Needs Study is a key tool for examining current system conditions for the existence of present or expected electric transmission capacity constraints or congestion that can potentially be mitigated through new or upgraded transmission facilities, including through non-wire alternatives. As the Draft National Transmission Needs Study ("Transmission Needs Study" or "Draft Study") issued in February 2023 explains, several basic factors indicate a substantial need for additional transmission capacity: (1) declining investment in transmission infrastructure; (2) significant wholesale market price differentials across Regional Transmission Organizations/Independent System Operators ("RTOs"); (3) evidence of periods of extreme weather and other unusual system conditions driving particularly high prices in a limited number of hours; and (4) substantial interconnection queues of wind, solar, and storage process demonstrating the need to plan the electric system for the evolving resource mix.

Against this backdrop, the Transmission Needs Study effectively demonstrates, through a review of recently published power systems studies, the substantial benefits of expanded electric transmission investment. The Draft Study's focus on improving interregional connections and addressing regional needs for enhanced reliability and upgrades in response to and in preparation for demand growth and generation buildout is appropriate and consistent with the DOE finding that there are significant transmission constraints throughout the country, which involve unique and individualized regional needs that RTOs and utilities must address in local and regional planning processes and system development.

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The Environmental Defense Fund ("EDF")[1] appreciates the opportunity to offer feedback on the Draft National Transmission Needs Study. Our comments explain that the Draft Study identifies significant transmission needs, including capacity constraints and congestion, consistent with the requirements of the Energy Policy Act of 2005 and subsequent amendments, as well as meeting requirements to consult with affected States and Indian Tribes. However, we encourage the DOE to go beyond these requirements and conduct additional outreach to ensure that a broader range of community voices, particularly from environmental justice communities, are reflected in the Study. We also recommend that in the final version of the Transmission Needs Study DOE provide additional clarity in its discussions of Transmission Value. In addition, we share a number of recommendations regarding how DOE can build on the important work done in the Transmission Needs Study with the development and issuance of the National Transmission Planning Study.

EDF offers the following specific recommendations:

Purpose of the Study

1. The Transmission Needs Study Meets the Requirements of the Federal Power Act.

The DOE has fulfilled its longstanding mandate in conducting a study of congestion and capacity constraints.[2] Consistent with section 216 of the Federal Power Act ("FPA") as enacted in the Energy Policy Act of 2005 and subsequently amended, the Draft Study appropriately considers both current *and* future capacity constraints.[3] Read as a whole, Section 216 requires that the study consider both current conditions and potential developments. Section 216(a)(1) of the FPA directs DOE to conduct a study of electric transmission capacity constraints and congestion, while section 216(a)(2), mandates that the study "or other information relating to electric transmission capacity constraints and congestion" form the basis for a report – wherein the DOE has the authority to designate national interest transmission corridor(s) ("NIETC") in "any geographic area that (i) *is experiencing* electric energy transmission capacity constraints or congestion that adversely affects consumers; or (ii) *is expected to experience* such energy transmission capacity constraints or congestion."[4] For DOE to appropriately consider the designation of a NIETC where capacity constraints or congestion are "expected," the underlying basis must include a study of those expectations. As a result, a study that only looks at historical conditions to analyze the present system would be contrary to congressional directive. Comments suggesting that DOE has exceeded the scope of authority by evaluating the drivers of future needs, such as the anticipated generation mix,[5] ignore the Department's statutory

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1 EDF is a membership organization whose mission is to preserve the natural systems on which all life depends. Guided by science and economics, EDF seeks practical solutions to resolve environmental problems. EDF uses the power of markets to speed the transition to clean energy resources, and consistent with its organizational purpose engages in activities to encourage policies that will drive cost-effective and efficient investment to modernize the energy grid so that it can support the ongoing deployment of clean energy resources.

2 Federal Power Act § 216(a).

3 Department of Energy, *National Transmission Needs Study*, Draft for Public Comment, 80 (Feb. 2023) [hereinafter "Transmission Needs Study"].

4 Federal Power Act § 216(a)(2) (emphasis added).

5 Transmission Needs Study at 151, Comment 147.

obligation to prepare a study which encompasses expected transmission congestion and constraints.

DOE also appropriately structured the Transmission Needs Study to consider transmission needs in a holistic manner, rather than limiting the Draft Study to a narrow view of congestion. Congress has, as DOE explains, imbued the agency with substantial "grid-related research and development" responsibilities, such that it is wholly appropriate for the Department to broadly analyze system needs.[6] The DOE's definition of a "transmission need" as "the existence of present or expected electric transmission capacity constraints or congestion in a geographic area" is appropriate and aligns with the statutory contours of FPA Section 216(a).[7] DOE defines transmission capacity constraints as "a suboptimal limit of transfer of electric power on the grid, including those that reduce operational reliability of the power system; power transfer capability or capacity limits between neighboring regions that reduce resilience or increase production costs; and limits on the ability of cost-effective generation to be delivered to high-priced demand."[8] This definition algins with the Department's role in preparing a study designed to identify NIETCs as well as in administering research and development, loan, and grant programs supporting transmission buildout and other electric system improvements. Commenters suggesting that DOE should leave analysis of issues like projections of future demand and generation to "NERC-registered transmission planners and transmission owners"[9] would have DOE abdicate these responsibilities, which Congress specifically assigned to DOE and expanded in recent legislation.

2. The Transmission Needs Study Complements FERC and Regional Planner Activities.

The DOE's congressionally mandated Transmission Needs Study is not in conflict, nor does it supplant regional transmission planning processes required under FERC Order No. 1000. Order No. 1000 requires "each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan."[10] The purpose of this is "to plan for regional needs and identify regional transmission projects that would meet regional and local needs more cost-effectively or efficiently."[11] In contrast, DOE's Transmission Needs Study is far broader, serving a supporting role – "intend[ing] to help inform and drive effective regional and interregional planning to properly assess the multiple values of transmission and the ability of robust transmission plans to improve reliability and resilience and lower overall delivered energy prices to consumers under a broader and more diverse set of factors impacting the current and expected future electricity system, as well help guide the Department in the execution of its transmission-related authorities."[12]

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6 Transmission Needs Study at 5. *See* Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 429 (2021); *see also* Energy Policy Act of 2005, § 925, § 936; Energy Independence and Security Act of 2005, Title XIII; and Energy Act of 2020, § 8001–8004; and the America Recovery and Reinvestment Act of 2009, § 402.

7 Transmission Needs Study at 1.

8 Transmission Needs Study at 10-11.

9 Transmissions Needs Study at 152, Comment 148.

10 Order No. 1000, 136 FERC ¶61,051, July 21, 2011.

11 Transmission Needs Study at 2.

12 Transmission Needs Study at 2.

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3. The DOE Has Congressional Authority to Use the Transmission Needs Study, in Addition to "Other Information Relating to Electric Transmission Capacity Constraints and Congestion," for NIETC Designation.

Section 216(a)(2) of the FPA is unequivocal that DOE has the authority to designate National Interest Electric Transmission Corridors. In doing so, the DOE must first issue a report based on the Transmission Needs Study "or other information relating to electric transmission capacity constraints and congestion," and where appropriate designate NIETC(s) in each geographic area that either (1) is experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers; or (2) is expected to experience such energy transmission capacity constraints or congestion.[13] This authority is broad and does not limit DOE to the use of information captured in the Transmission Needs Study in designating such corridors, but instead allows DOE to build upon the Study as needed. This allows the Department to consider supplemental or updated information in designating NIETCs.

<u>Consultation with Stakeholders</u>

While the DOE has met its statutory obligation to consult with affected States, Indian Tribes and regional organizations in preparing the draft Transmission Needs Study, the DOE should endeavor to do more than merely meeting the statutory minimum and should consult with potentially affected communities as well as nongovernmental organizations with expertise in transmission capacity and congestion. In addition, the Department must continue to consult with affected States, Indian Tribes and other relevant voices as it moves forward with issuing a final Transmission Needs Study, developing the subsequent report, and considering NIETC designations.

1. The Transmission Needs Study Was Based on Appropriate Consultation.

DOE has undoubtedly met the obligation to consult with affected States, Indian Tribes and regional organizations in preparing the Transmission Needs Study as set out in Section 216(a) of the FPA. In *California Wilderness Coalition v. United States DOE,*[14] the Ninth Circuit held that under Section 216(a) of the FPA "consultation with affected States and Indian Tribes"[15] must be made directly to such entities and begin "before an agency makes a decision"[16] and that information "critical to DOE's preparation of the . . . Study" including "technical studies and data upon which [DOE] bases a ruling" must be disclosed.[17] This is to ensure that affected States and Tribes are "able to critique the DOE's preliminary findings and analyses as they are evolving."[18] Accordingly, the Court found that in preparing its 2006 transmission study the DOE failed to meet its statutory consultation obligation when it published a notice in the Federal Register disclosing that the agency had begun work on the study, failed to provide affected States and Indian Tribes with studies and data relevant to DOE's decision, held one technical

[13] Federal Power Act 216(a)(2).

[14] 631 F.3d 1072 (9th Cir. 2011).

[15] Federal Power Act 216(a)(1).

[16] *Cal. Wilderness Coal.* at 1093.

[17] *Cal. Wilderness Coal.* at 1089.

[18] *Cal. Wilderness Coal.* at 1086.

conference in Chicago, and held an "invitation-only" meeting that did not include representatives of any States or Indian Tribes.[19]

In contrast, the DOE's consultation process in developing the Draft Transmission Needs Study began far earlier and was more comprehensive and inclusive than the previous effort. First, DOE directly reached out to affected States, Indian Tribes and regional entities, providing a notification letter with at least "30 days notice that the "consultation draft" would be sent to them for review and feedback."[20] Following that, the consultation draft of the Transmission Needs Study was sent to "each state (including points of contact from state energy offices, Governors offices, utility commissions chairs, and state public utility commission groups for multi-state ISOs), Tribes, and regional entities (including transmission reliability and planning entities) in the continental US, along with an invitation to provide written comment on the draft or to meet with DOE staff, in person or by phone, to convey comments."[21] Further, the DOE then provided six webinars on the consultation draft – one open to all recipients of the consultation draft – while the remaining five were targeted towards "each entity type in partnership with a convening group to help with amplification of the webinar (e.g., DOE partnered with the National Association of State Energy Offices for the webinar targeted at state energy offices)."[22] In addition, DOE included a summary of all comments received from these stakeholders in the Draft Study and responded to each comment either with changes to the text or with an explanation of why changes were not needed.

Providing such early notice, with opportunities to speak directly with DOE officers and several information webinars, as well as the accepting and responding to comments, is a reasonable and workable consultation process that must be continued as the process moves forward.

2. DOE Should Conduct Broader Outreach to Ensure the Inclusion of Energy and Environmental Justice Voices.

While we greatly appreciate the DOE's improved consultation process in conducting the Transmission Needs Study, we encourage the DOE to consult with entities and communities beyond the four corners of the statute that can provide the DOE with critically important perspectives. Pointedly and appropriately, the Transmission Needs Study draws attention to the issue of energy justice and the role that transmission siting can play in exacerbating historic inequalities.[23] In determining what transmission is "needed," the DOE should more thoroughly examine communities that have historically been deprived of access to affordable and reliable energy, as well as to clean energy technologies. By consulting with energy justice organizations and communities, the DOE can better contextualize transmission needs. This consultation will also lay the groundwork for working with impacted and potentially impacted communities in identifying NIETCs as well as in preparing the DOE's Transmission Planning Study.

To ensure that this consultation is made in such a way that communities are able to adequately participate, the DOE should be mindful of the principles outlined by DOE Director of the Office of Economic Impact and Diversity Shalanda Baker during the Federal Energy Regulatory Commission's March 2023 Environmental Justice Roundtable – that agencies must "engage

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19 *Cal. Wilderness Coal.* at 1080-1081.

20 Transmission Needs Study at 108.

21 Transmission Needs Study at 108.

22 Transmission Needs Study at 108.

23 Transmission Needs Study at 41-42.

with [communities] at every step" coming to them, rather than expecting communities to be able to come to the DOE.[24] Director Baker also acknowledged the "remarkable and extraordinary" convening power of the federal government to create spaces for communities to talk through the issues.[25] We therefore encourage the DOE, in further development of the Transmission Needs Study, subsequent report and NIETC designations as well as in conducting the Transmission Planning Study, to develop and implement a strategy for consultation with potentially impacted and historically disadvantaged communities consistent with Director Baker's principles and in a manner that is appropriate for the individual community where consultation is sought.

Discussion of Transmission Value

1. DOE Should Ensure that the Study Clearly Defines the Term "Transmission Value."

A key benefit of the Transmission Needs Study is its ability to demonstrate that substantial transmission expansion would result in significant cost savings for ratepayers, as well as reliability and environmental benefits, even after taking into account the costs of transmission buildout. To ensure that this finding is clearly communicated, the Department should ensure that unambiguous language is used in its discussion of the benefits and costs of transmission. Currently, the Transmission Needs Study regularly uses the terms "transmission value" and "value of transmission" without clearly defining either term. In particular, it is not clear across usages whether the terms are intended to describe a net "value" after costs are deducted as benefits or only the gross benefit value; in addition, it is unclear in some cases whether the terms are being used to refer strictly to the economic value that would be created by reducing interregional price differentials or whether they include other benefits, including increased reliability and reduced outages as well as environmental benefits. Given the Draft Study's significant findings of transmission value opportunities in different regions, such as the finding that "[t]he greatest transmission value is found by connecting regions in the middle of the continent with their more eastern or western neighbors," this lack of clarity could significantly limit the usefulness and persuasive power of this Study.[26]

While certain sections hint at the derivation of transmission value, they do not offer sufficient detail to determine whether a consistent definition is used throughout the document or what that definition is. The Transmission Needs Study refers to a report from Lawrence Berkeley Labs that argues for consideration of "Locational Marginal Prices" which calculates transmission value as an average $/MWh,[27] but stops short of making clear that this is what is meant by transmission value. Page 19 of the Draft Study, however, states that "Section IV.c analyzes differences in simultaneous wholesale market prices between neighboring regions to quantify the value of interregional transmission", seeming to indicate that the value of interregional transmission is the "difference[] in simultaneous wholesale market prices between neighboring regions."[28] Even if so, the Draft Study indicates that such analysis is only a part of the value assessment, stating that "[e]xamining differences in simultaneous market prices across the

24 Federal Energy Regulatory Commission, Environmental Justice Roundtable (Mar. 29, 2023).

25 Federal Energy Regulatory Commission, Environmental Justice Roundtable (Mar. 29, 2023).

26 Transmission Needs Study at 40.

27 Transmission Needs Study at 30 (referencing Millstein et al., *Empirical Estimates of Transmission Value using Locational Marginal Prices* (2022).

28 Transmission Needs Study at 19.

United States provides *additional* insight into the value of transmission during real-time operations."

Further complicating this issue is that one of the stated purposes of the Transmission Needs Study is to "help inform and drive effective regional and interregional planning to properly assess the *multiple values* of transmission."[29] This presumably intends to suggest that multiple benefits of transmission, rather than purely price alignment benefits, are considered in the Draft Study, but offers no additional clarity. Looking to sources beyond the Transmission Needs Study, PJM's 2019 Whitepaper "The Benefits of the PJM Transmission System" appears to move away from this concept of a single stated transmission value metric and towards a look at the multiple benefits that transmission development would provide – including ensuring reliability, access to low cost power, supporting public policy including economic growth and access to clean and renewable energy.[30]

DOE's lack of clarity on this issue could undermine the conclusions reached in the Draft Study. As a result, DOE should provide a clear definition for use of the term transmission value and, if it currently refers to different things in different parts of the Draft Study, instead use different language to make it clear what is being referred to in each case. EDF also encourages the DOE to ensure that a broad range of benefits are considered wherever possible, as benefits like increased reliability, reduced blackout risks, and environmental improvements are important to capture as well as reductions in price differentials.

<u>Transmission Planning Study</u>

EDF looks forward to the DOE's continued study of the national transmission system and to engaging in the National Transmission Planning Study process. EDF supports DOE's suggestion that not only will the Transmission Needs Study inform the Transmission Planning Study but that the Planning Study can help inform the next Transmission Needs Study. This iterative approach to studying the transmission system is much appreciated as it will help ensure that areas not included in a Transmission Needs Study, due to its appropriate scope or as the system and forecasts continue to develop, can be studied in the Planning Study and vice versa. EDF offers several recommendations here for how the Transmission Planning Study can build upon the important work done in the Transmission Needs Study.

1. **EDF Supports a DOE National Transmission Planning Study with a Long-Term Planning Horizon of Not Less Than Twenty Years.**

The stated intention of the National Transmission Planning Study is to "identify transmission solutions that will provide broad-scale benefits to electric customers; inform regional and interregional transmission planning processes; and identify interregional and national strategies to accelerate decarbonization while maintaining system reliability."[31] Meeting these goals will require long-term planning that recognizes that developing new transmission assets often takes 5-15 years and that the federal government and state and local governments have decarbonization goals stretching through 2050 and beyond, with many having interim goals at

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29 Transmission Needs Study at 2.

30 PJM Interconnection, The Benefits of the PJM Transmission System (April 16, 2019), https://www.pjm.com/-/media/library/reports-notices/special-reports/2019/the-benefits-of-the-pjm-transmission-system.pdf.

31 Building a Better Grid Initiative to Upgrade and Expand the Nation's Electric Transmission Grid to Support Resilience, Reliability, and Decarbonization, 87 FR 2769 (Jan. 19, 2022).

2030. A robust Transmission Planning Study will consider how the system must start developing now to cost-effectively support achievement of those goals, addressing shifts in both demand and generation, as well as new capabilities and new challenges associated with a modernizing and decarbonizing system.

EDF suggests that the DOE look to existing and relevant, Federal, regional and State planning processes to ensure that the DOE National Transmission Planning Study is at least consistent with these existing plans. Currently, several Federal, State and regional entities are currently engaged in long-term grid planning. For example, the New York Public Service Commission currently has a proceeding open to design a coordinated grid plan[32] with a proposal by participating utilities of a twenty year horizon.[33] Implementation of such a plan would likely have ripple effects on subsequent regional plans and as a result should be reflected in the DOE's Planning Study. Failure to consider the full twenty years of the NY PSC's plan and other long-term state and regional plans would limit the relevance of DOE's National Transmission Planning Study. The National Transmission Planning Study must therefore consider system evolution, anticipated needs, and potential solutions for *at least* twenty years into the future.

2. The DOE's National Transmission Planning Study Should Include a Number of Scenarios Sufficient to Reflect the Range of Possible National Electric System Futures.

The range of scenarios considered in the DOE's National Transmission Planning Study should be consistent with the range of possible electric system futures and reflective of the inherent uncertainty in designing such a plan. DOE should instead look to existing policies, proceedings and actions undertaken at the State, Federal and regional level to determine the number and details of the scenarios to be considered. A limited or narrow consideration of possible future scenarios could have far-reaching consequences in DOE's stated effort to "bridge the gap between national, long-term capacity expansion modeling studies and regional, near-term transmission planning studies."[34]

In determining appropriate scenarios to study DOE should ensure that any conclusions drawn from the Transmission Needs Study are updated according to new information, not limited to State and Federal legislation and State and regional forecasts and studies. As a result, the Transmission Planning Study must consider the impacts that the IRA and the IIJA will likely have on increased electrification and should consider materials such as NYISO's annual Gold Book, which includes forecasts of peak and total energy demand from EVs and building electrification.[35] Such information should be duly considered in scenario planning.

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32 Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals (Sep. 9. 2021).

33 Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, The Utilities' Coordinated Grid Planning Process and Revised Benefit Cost Analysis Proposals (Dec. 17, 2021).

34 Transmission Needs Study at 81.

35 NYISO, 2022 Load and Capacity Gold Book (Apr. 2022) https://www.nyiso.com/documents/20142/2226333/2022-Gold-Book-Final-Public.pdf.

Further, the DOE should continue its prudent approach of not only looking at extreme weather events in determining resource adequacy but also to "milder versions of these events."[36] DOE should endeavor to resolve the disconnect in considering "extreme weather events" as isolated occurrences and the lived reality that such episodes are happening with increased regularity. Data collected by NOAA shows that from 1984 to 1993 there were an average of 3.9 "billion-dollar" natural disaster events per year costing on average $21.7 billion dollars, while from 2013 to 2022 there were an average of 15.4 billion-dollar natural disaster events per year costing on average $81 billion dollars.[37] This data demonstrates a steep increase in extreme weather events with no statistical indication that the number and severity of these weather events will decrease in the coming years. DOE should therefore ensure that every planning scenario considered includes margins for incremental increases in such extreme "billion-dollar weather and climate disasters."[38]

3. The DOE Must Include a Thorough Analysis of Non-Wire Alternatives in the National Transmission Planning Study.

Consideration of Non-Wire Alternatives ("NWAs"), as well as grid-enhancing technologies, should be a priority in preparing the National Transmission Planning Study. A study of national transmission plans absent adequate consideration of NWAs could lead to inconsistent proposals that fail to find the least cost solutions. While the Transmission Needs Study does discuss NWAs, the analysis is limited, as acknowledged by the drafters.[39] Further, grid-enhancing technologies were "not explicitly modeled in the studies considered here."[40]

We therefore agree with and support the DOE's assessment that "[a]dditional engineering analysis performed by planners is needed to determine the best technologies and locations of the available transmission solutions to meet the needs identified here."[41] Further, NWAs should not be treated as a special case, but should be fully and consistently integrated into DOE's study of the grid. More than thirteen years ago, the DOE commissioned a report by the National Council on Electricity Policy on "Non-Transmission Alternatives."[42] The report acknowledged, "[i]n considering the *need* for new transmission . . . *it may be important to consider alternative, non-transmission methods or technologies that bring energy services to customers and*

36 Transmission Needs Study at 70.

37 National Oceanic and Atmospheric Administration, National Centers for Environmental Information, Billion-Dollar Weather and Climate Disasters, https://www.ncei.noaa.gov/access/billions/ (last accessed Apr. 19, 2023).

38 National Oceanic and Atmospheric Administration, National Centers for Environmental Information, Billion-Dollar Weather and Climate Disasters, https://www.ncei.noaa.gov/access/billions/ (last accessed Apr. 19, 2023).

39 Transmission Needs Study at 85 ("There is some inclusion of these solutions in the capacity expansion modeling results analyzed here. Notably, the grid reliability services provided by NWAs are not captured in capacity expansion modeling, but their value in reducing overall system costs are captured.")

40 Transmission Needs Study at 85.

41 Transmission Needs Study at 85.

42 National Council on Electricity Policy, Updating the Electric Grid: An Introduction to Non-Transmission Alternatives for Policymakers (2009).

moderate transmission congestion."[43] DOE was correct to have commissioned this report and to have offered this information to policymakers to help spur policies that would reduce congestion. It, however, appears that few of the recommendations or considerations in the report made its way into the Transmission Needs Study, despite there being far more congestion in 2023 than there was in 2009.[44]

Thirteen years is sufficient time for the DOE to have duly integrated consideration of NWAs into its work, and we are hopeful that the DOE, mindful of its past consideration of NWAs, will make consideration of NWAs central to its work on the National Transmission Planning Study as well as in future Transmission Needs Studies. As discussed above, NWAs also have the potential to reduce cumulative burdens to energy justice communities. Given DOE's commitment to energy justice and Justice40, due consideration of NWAs must be included in subsequent studies.

4. The DOE Should Continue and Expand Stakeholder Consultation in Preparing the National Transmission Planning Study.

As discussed above, the DOE should continue to consult with affected States, Indian Tribes, and regional entities in preparing the National Transmission Planning Study. A process which is at least as inclusive as the process used in conducting the Transmission Needs Study will help to ensure consistency between reports as they will help inform one another. The DOE, however, must intentionally and thoughtfully engage with energy justice, environmental justice, tribal, historically disadvantaged and low-income communities in its efforts to study national transmission plans and identify "transmission solutions."[45]

EDF is encouraged by the DOE's stated intention of "[r]obust stakeholder engagement [to] help define new scenarios for analysis to reach grid decarbonization goals cost effectively and under new high-stress conditions"[46] and its commitment "to advance energy justice goals in transmission planning."[47] EDF also supports the DOE's suggestion that "studies could prioritize renewable energy in areas that have had greater cumulative burdens associated with fossil dependence, energy burden, environmental and climate hazards and socio-economic vulnerabilities" and that "[e]xpanded transmission should mitigate existing harms and increase benefits to frontline communities facing high energy burden, longer-duration outages, and higher levels of environmental hazards."[48] Moreover, "[e]xpanded transmission along with storage and other non-wire alternatives could create avenues for frontline communities to have

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43 National Council on Electricity Policy, Updating the Electric Grid: An Introduction to Non-Transmission Alternatives for Policymakers, 1 (2009). (emphasis added).

44 *Compare* Department of Energy, National Electric Transmission Congestion Study (Dec. 2009) https://www.energy.gov/sites/default/files/Congestion_Study_2009.pdf *with* Transmission Needs Study.

45 Building a Better Grid Initiative To Upgrade and Expand the Nation's Electric Transmission Grid To Support Resilience, Reliability, and Decarbonization, 87 FR 2769 (Jan. 19, 2022).

46 Building a Better Grid Initiative To Upgrade and Expand the Nation's Electric Transmission Grid To Support Resilience, Reliability, and Decarbonization, 87 FR 2769 (Jan. 19, 2022).

47 Transmission Needs Study at 41.

48 Transmission Needs Study at 41.

access to community-owned renewable generation projects which could decrease costs, reduce air pollutants that cause adverse health impacts, and advance energy democracy."[49]

In order to understand the precise burdens and harms that communities currently face, the types of projects which could cumulate burdens, and the types of benefits that would support an individual community's interest, the DOE should adhere to the recommendations for community outreach discussed above as outlined by DOE Director of the Office of Economic Impact and Diversity Shalanda Baker during the Federal Energy Regulatory Commission's March 2023 Environmental Justice Roundtable. Director Baker stated that agencies must engage with the communities where they are, and not expect communities to be able to come to them and to "engage with them at every step."[50] As a result, in preparing the DOE for the Transmission Planning Study process, the DOE should put together a strategy of how it intends to engage with community members to ensure that the community voices are heard by the agency. Such a strategy should be shared with environmental and energy justice organizations for feedback as to whether the processes will ensure the greatest opportunity for community engagement. EDF recommends that the DOE engage as early as possible and to provide as many forums as possible to support community involvement, including in-person and virtual-online meetings at times that would encourage the greatest participation. The information should be provided in as many languages as is relevant for that particular community.

Conclusion

The Department of Energy can and should be a thought leader in identifying and supporting the solutions that our grid needs to meet modern challenges and opportunities. The Draft National Transmission Needs Study is a key first step in determining how to best meet those challenges. EDF respectfully requests that the Department of Energy issue a final Transmission Needs Study consistent with the recommendations above, take further appropriate action to prepare for the designation of NIETCs, and conduct the Transmission Planning Study as recommended above.

Thank you,

/s/ Ted Kelly
Ted Kelly
Senior Attorney, Federal Energy
Adam Kurland
Fellow, Federal Energy
Michael Panfil
Senior Director & Lead Counsel, Climate Risk & Clean Power
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[49] Transmission Needs Study at 41.

[50] Federal Energy Regulatory Commission, Environmental Justice Roundtable (Mar. 29, 2023).

Federation of American Scientists
1112 16th Street NW
Washington D.C. 20036

April 20th, 2023

Grid Deployment Office, Enhanced Transmission Planning Team
Department of Energy
1000 Independence Ave. SW
Washington DC 20585

Re: National Transmission Needs Study, Section V: Review of Existing Studies: Current and Future Needs and Section VI: Capacity Expansion Modeling: Anticipated Future Need

Dear Members of the Grid Deployment Office, Enhanced Transmission Planning Team,

The Federation of American Scientists (FAS) is a catalytic, non-partisan, and nonprofit organization committed to using science and technology to benefit humanity by delivering on the promise of equitable and impactful policy. FAS believes that society benefits from a federal government that harnesses science, technology, and innovation to meet ambitious policy goals that serve the public's common good. I am writing in my capacity as a Policy Entrepreneurship Fellow at FAS to provide comments on sections V and VI within the DOE's National Transmission Needs Study.

I am submitting this comment to 1) express my strong support for the DOE's decision to emphasize the nation's anticipated future transmission needs for the first time in its regular triannual Transmission Needs Study, 2) provide comments on how the DOE can improve the RAPID toolkit discussed in Section V to improve its utility to transmission developers, and 3) to suggest that the phrasing used to describe the relationship between the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) and the scenarios used in Section VI's meta-analysis needs to be clarified.

Many publications, including the Transmission Needs Study, have highlighted that the United States needs to increase investment in its transmission network to improve system reliability and resilience, to lower electricity costs in congested areas, and to support the growth in renewable energy production necessary for a net-zero economy. However, despite the need for increased investment, significant barriers impede the construction of the transmission necessary to address these reliability, resilience, cost, and climate concerns. These barriers include negotiating leases with landowners with understandable concerns about how transmission projects could alter their properties, increasing wait times in interconnection queues, varying local and state regulatory regimes for projects that cross multiple jurisdictions, and maintaining investor confidence throughout the complex and time-consuming permitting and leasing process.

As mentioned in the Transmission Needs Study, one promising approach to bypass these challenges is to co-locate new transmission with existing rail, highway, or pipeline infrastructure. Unlike aboveground transmission built through a mosaic of thousands of stakeholders' holdings, these solutions would require negotiations with far fewer stakeholders - possibly only the rail companies, highway authorities, pipeline owners, and relevant state and local governments. In addition, co-location takes advantage of the proximity of these types of infrastructure to many areas with high renewable energy potential, would not disturb undeveloped land, and if the transmission were buried underground would not add visual pollution to the above ground landscape. As a result, co-location offers the possibility of reducing the time and effort required for transmission developers to acquire leases, increasing investor confidence through the siting process, and increasing the speed at which new transmission can be brought online.

However, co-location by itself does not help developers negotiate complex and varying local and state regulations for interstate transmission projects. The Regulatory and Permitting Information Desktop (RAPID) toolkit developed by the DOE is a valuable resource to address this issue; however, in exploring through its Transmission Reference Library I noticed that while this resource included many state specific resources for building transmission in highway right of ways it did not include resources for building in railroad right of ways. Rail co-location with HVDC transmission is technically viable since HVDC lines would not interfere with railway signaling equipment. In addition, such an approach is already being pursued by Minneapolis-based Direct Connect Inc.'s SOO Green renewable rail line. **As a result of this approach's technical feasibility and demonstrated industry interest, it would greatly help future transmission developers who are interested in this approach if the DOE included information on the pertinent permitting and regulatory requirements for rail co-located HVDC in its Regulatory and Permitting Information Desktop (RAPID) toolkit.**

As mentioned in the National Transmission Needs Study, the IRA and the IIJA are transformative pieces of legislation for the United States' power grid. However, the phrases and wordings used to describe these pieces of legislation's relationship to the future scenarios of Section VI's meta-analysis are misleading and should be clarified. For example, on pages 84-85 this relationship is described as:

"The Moderate/Moderate scenario group most closely represents the evolution of the power system had IIJA and IRA not been enacted. The Moderate/High group best represents the future power system that will be enabled by current (as of the publication date of this Needs Study) utility, local, state, and federal policies, including the large advances in generation technologies enabled by the IRA. The High/High group represents the future power system where new clean energy and electrification of demand-side energy policies are enacted."

Although I understand this was not the DOE's intent, the current wording can plausibly be read as stating that the moderate transmission expansion / high renewable penetration future scenario is now an inevitable real-world result due to the IRA and IIJA. This is not the case, as can be seen most clearly in Figure VI-6, which shows that all regions except New York, New England, California, and Florida have levels of planned transmission that fall well below the interquartile range of the transmission required to achieve a high (>80%) degree of renewable energy penetration. In some cases, this discrepancy is on the order of thousands of GW. Such a large difference between the estimated need and projected construction is a serious impediment to simultaneously meeting the United States' need for a reliable, low-cost, secure, and resilient grid while achieving the Biden administration's climate goals. While the IRA and IIJA likely increase our ability to overcome this gap, such an outcome must be chosen by multiple actors across all levels of government, industry, and society.

In order to clarify this important point I suggest that the DOE change the wording used to describe the IRA and IIJA's relationship to the moderate / high scenario throughout section VI to emphasize that these pieces of legislation allow the moderate / high scenario to enter the realm of possibility, but that such a future is not inevitable. One example of how to achieve this is below:

"The Moderate/Moderate scenario group most closely represents the evolution of the power system had IIJA and IRA not been enacted. The Moderate/High group best represents a future power system, now within the range of possibility due to the IRA and IIJA, but still requiring significant action from public, private, and community actors. The High/High group represents a future power system where new clean energy and electrification of demand-side energy policies are enacted."

In conclusion, I am grateful for the opportunity to comment on this important study and its implications for the United States' energy, transmission, power, and climate policies. I am happy to provide further information or to continue discussing my suggestions above via email or through a zoom meeting.

Yours truly,

John Tracey

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GALLATIN POWER

Dear Department of Energy Grid Deployment Office,

Gallatin Power Partners, LLC (Gallatin) is a privately held and funded company focused on the development of utility-scale solar, battery storage and transmission projects. Gallatin is primarily focused on development in the western United States, with projects currently under development in Montana, Nevada, Oregon and California. The principals of Gallatin have extensive experience in solar and battery storage project development, financing and construction, having developed over 13,000-MW of solar and battery storage projects across the United States.

Gallatin agrees that for our nation to integrate and access clean energy our transmission system needs extensive upgrades and expansion. We appreciate all of the work done to date by the GDO on the Draft National Transmission Needs Study (NTNS) to help bring attention and focus on this matter.

We primarily focused on the western region within the draft NTNS since all of our development efforts are in that region. We would like to suggest that additional research be completed on a WECC Path basis to evaluate the significant transmission constraints being experienced in the West. Specifically, there are known constraints on Path 46 and Path 66 that do not appear to be recognized in the Draft NTNS. Although released after the Draft NTNS, the Draft CAISO 2022-2023 Transmission Plan (released 4/3/23) would be informative to review and include as supplemental material. The Plan mentions the congestion on Paths 46 and 66 in Section 4.6.

Please do not hesitate to contact me if you have any questions, and thank you in advance for considering Gallatin's comments.

Sincerely,

Kirsten Eliassen

Kirsten Eliassen
VP of Development

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Grid United LLC

Comments to Draft National Transmission Needs Study

April 20, 2023

Grid United commends DOE staff on the tremendous effort that has gone into studying and analyzing transmission needs from close to 300 scenarios of our complex and ever evolving grid.

We particularly appreciate the study's evaluation of the benefits of inter-regional transmission, in addition to regional transmission. Our internal studies of interregional lines have also reached similar conclusions – the largest congestion value of new transmission lines is across the interconnects and during extreme weather events.

While the impacts of extreme weather on the grid have become very apparent in recent years, conventional transmission planning methodologies are not set up to simulate the wide range of extreme weather impacts. We would suggest DOE continue to explore study methodologies to assess extreme weather events like LOLE studies, incorporating more rigorous modeling of weather volatility. If this approach is too quantitatively rigorous, a qualitative assessment of historic extreme weather events like storm Uri, Elliot, California heat wave etc. to identify transmission needs that manifested itself during those events, both regional and interregional, would be beneficial.

In addition, we would also suggest an evaluation of regional networked transmission buildout required for deliverability of resources from large energy zones, closely mimicking the study methodology used by RTOs and utilities in their generation interconnection process.

Respectfully submitted.

Michael Skelly, CEO

Grid United

Houston, Texas

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April 20, 2023

Via Email: *NeedsStudy.Comments@hq.doe.gov*

Re: National Transmission Needs Study

Hydro-Québec ("HQ") through its U.S. subsidiary H.Q. Energy Services (U.S.) Inc. ("HQUS"), appreciates the opportunity to submit comments on the Department of Energy ("DOE") Draft National Transmission Needs Study ("The Study"). The Study highlights the pressing need for additional electric transmission infrastructure investment throughout the country, including markets in the Northeast which have experienced a long-standing clean energy partnership with Québec. HQ submits the following recommendations designed to supplement the results of The Study and assist policy makers in prioritizing strategic deployment of transmission and identify and overcome key challenges:

1. The Study should expand on the value recognition of international transmission investments in enabling two-way trade of electricity.

2. There are unique elements which should be considered in The Study pertaining to the value of new transmission in New York and New England.

3. The Study should identify the need for new market mechanisms and commercial models as a barrier to transmission development.

Introduction

HQ is one of the largest clean energy supply companies in the world, with a generation portfolio comprised of close to 37,000 MW (nearly 100% of which is renewable energy) and operates a system with the ability to store up to 176 million MWh of energy. HQ is committed to the goal of deep decarbonization, with a corporate commitment to sustainably developing renewable energy resources in the Province of Québec and to pursuing cooperation with neighboring markets to achieve GHG reduction and decarbonization goals.

This commitment is demonstrated through HQ's extensive history in providing clean and reliable electricity supply to the Northeast, delivering an average of nearly 8 million MWh to New York and 16 million MWh to New England each year (representing 5% and 12% of each region's total 2021 electricity demand respectively). HQ is actively working to develop two new interregional HVDC transmission projects designed to deliver substantial volumes of additional clean energy into the U.S. through long-term contracts awarded in response to serving the clean energy needs in the Northeast. The Champlain Hudson Power Express Project ("CHPE)[1] in New York, and the New England Clean Energy Connect ("NECEC")[2] in New England will expand HQ's ability to support decarbonization throughout the region.

Looking forward, HQ remains uniquely positioned to provide the clean dispatchable operating characteristic and long-duration storage services necessary to enable a clean energy transition (both within Québec and in neighboring markets). HQ's controllable and flexible generation can respond rapidly to precisely balance supply and demand, with the ability to ramp between zero and over 1,000 MW within minutes. With new bidirectional transmission, HQ's ramping capability is able to operate in both directions, offering the capability to increase and decrease clean energy deliveries to reliably serve the needs of an increasingly complex electricity system. HQ's controllable and long-duration storage can operate at various timescales from minutes to days, weeks, seasons, or even longer. This service is crucial in preserving reliable electricity supply in Northeastern markets to shift excess renewable production across extended time periods and maintaining grid flexibility.

While variable renewable technologies and short-duration storage will play a significant role in achieving zero-emission electricity systems in the Northeast, the region will require clean resources that are able to generate on a continuous basis and provide a large-scale solution to balance the variability of certain types of renewable generation. Reservoir hydropower is a low-carbon energy source that can provide the flexibility and long-duration storage required to ensure adequate supply remains available across rapidly changing weather and operating conditions, replacing the services currently provided by fossil-fuel resources. Without clean dispatchable alternatives such as HQ hydropower, the region will continue to rely on emitting fossil-fuel generation to serve demand during the prolonged periods of low renewable production and higher energy demand that are expected to occur as a result of beneficial electrification of other sectors of the economy.

There is a tremendous opportunity for Québec and the Northeastern States to work collaboratively toward a full clean energy transition, which takes advantage of both region's resources to achieve decarbonization more affordably. This approach will require increased interconnectivity through new and expanded bidirectional transmission designed to facilitate two-way trade of electricity.

The Study should expand on the value recognition of international transmission investments in enabling two-way trade of electricity.

The role of HQ in supporting decarbonization in the U.S. markets will expand and evolve, as the Northeast region accelerates their transition to a clean energy economy. The

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[1] The CHPE project is a collaboration between HQ and TDI to develop a new intertie between the HQ and New York transmission systems. It creates a new transmission facility into New York City, using a fully underground/underwater 1,250 MW high-voltage direct current ("HVDC") transmission line spanning 375- miles from the Hertel substation in Québec to a converter station located in the Astoria Annex substation in Queens, New York, delivering renewable generation directly in New York's Zone J.
[2] NECEC will be a 1,200 MW 345 kV HVDC transmission line that will deliver clean energy from HQ and interconnect to the ISO-NE transmission system at Lewiston, Maine.

dispatchable characteristics of HQ hydropower will complement the integration of renewables into the U.S. grid and provide a clean replacement source of the operating services currently provided by fossil-fuel resources. And linking the Northeastern markets with the extensive storage capability of the HQ system through bidirectional transmission will enable greater two-way trading of electricity, maximizing the benefits and reducing the cost of deep decarbonization. The Study represents a foundation which can enable comprehensive planning to fully harness the benefits of greater interregional collaboration between Québec and the Northeast.

The Study recognizes the value of interregional transmission in several areas, including the benefit of increased transfer capability between the U.S. and Canada to address the need in New England to meet future load and generation growth.[3] Interconnections between the U.S. and Canada have provided significant benefits to both regions for decades, and increasing these interconnections represents a unique advantage available to help achieve domestic clean energy goals and more broadly share benefits across regions by leveraging the unique resources across control areas.

Facilitating greater two-way trading of electricity between Québec and the U.S. is the best way forward for decarbonization: the unique advantages offered by each region can be more broadly shared in order to maximize benefits for both Québec and the regions in the Northeast and keep costs as low as possible. For example, surplus renewable energy from New York and New England can be imported into the HQ system during periods of high production. This can help to accelerate the renewable development and foster the offshore wind industry in the United States by creating an additional market for clean generation and preventing potential curtailments. Further, the highly controllable features of the HQ system can ensure that adequate clean supply remains available to serve demand in the Northeast, reducing the need to dispatch expensive and high emitting resources.

The Study references multiple studies which conclude that new bidirectional transmission between Québec and the Northeast will play an essential role in achieving State climate policies. According to the Dimanchev et al. (2020)[4] study, in a low-carbon future it is optimal to shift the utilization of the existing hydropower and transmission assets away from facilitating one-way export of electricity from Canada to the U.S. and toward a two-way trading of electricity to balance intermittent U.S. wind and solar generation. They find doing so can reduce power system cost by 5-6% depending on the level of decarbonization. The cost-optimal use of Canadian hydropower is as a complement, rather than a substitute, to deploying low-carbon technologies in the U.S. Expanding transmission capacity enables greater utilization of existing hydropower reservoirs as a balancing resource, which facilitates a greater and more efficient use of wind and solar energy.[5]

Jones et al. (2020) similarly note that Canadian hydropower is an essential element of regional balancing, and bidirectional flow of electricity enables Québec hydropower system to

[3] Department of Energy National Transmission Needs Study Draft for Public Comment, February 2023, page xv.
[4] Dimanchev E, Hodge J, Parsons J. 2020. Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower. Boston, MA: Massachusetts Institute of Technology Center for Energy and Environmental Policy Research. https://ceepr.mit.edu/wp-content/uploads/ 2021/09/2020-003.pdf.
[5] Department of Energy National Transmission Needs Study Draft for Public Comment, February 2023, page 56.

transition into the role of a 'battery' storing excess wind and solar generation for the New England region. Modelling in the study suggested that an additional 4.1 to 7.1 GW of capacity between Québec and New England would be required to achieve Massachusetts' net-zero emission target.[6]

New interregional transmission will also provide significant reliability benefits. FERC (2020) reports that high-voltage transmission enhances the stability of existing transmission system, aiding with restoration and recovery after an event, and improving frequency response and ancillary services.[7] And the most recent NYISO Reliability Needs Assessment[8] highlighted the vital contribution the Champlain Hudson Power Express project will provide in addressing diminishing reliability margins and the importance of the project entering into service in 2026 in order to avoid reliability problems in New York City and elsewhere.

The proximity of the Northeast markets to Québec, and HQ's experience as a clean energy supplier in these markets creates a unique opportunity to further leverage the capability of HQ to serve the unique needs in these regions. Expanding this clean energy partnership will require additional HVDC transmission lines, which in turn will provide a host of additional benefits.

There are unique elements which should be considered in The Study pertaining to the value of new transmission in New York and New England.

While The Study identifies a need for additional electric transmission infrastructure across all regions, there are features of the Northeast region that are unique and warrant consideration in accommodating the shifting needs of the future power grid. These features include aggressive State climate goals, the need for new transmission to help address persistent electricity sector challenges, and the geographic and technical potential for expanding interconnections with Québec.

New York and New England have extremely ambitious clean energy targets. The Climate Leadership and Community Protection Act mandates that New York obtains 70% renewable energy by 2030, a fully decarbonized electricity system by 2040, and a net zero economy by 2050. In New England, there are multiple clean energy targets designed to increase renewable energy and reduce emissions to nearly zero by 2050, with five of the six New England States mandating economy wide GHG reductions by at least 80% by 2050. Achieving these goals will entail a massive shift in the time and location electricity is generated and consumed, as the regions transition their electricity supply mix toward renewable generation and act to electrify the heating and transportation sectors.

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[6] Jones R, Haley B, Williams J, Farbes J, Kwok G, Hargreaves J. 2020. Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study. Evolved Energy Research for the Commonwealth of Massachusetts as part of the Decarbonization Roadmap Study. https://www.mass.gov/doc/energy-pathways-for-deep-decarbonization-report/download.

[7] FERC. 2020. Report on barriers and opportunities for high voltage transmission. Washington, DC: Federal Energy Regulatory Commission. https://www.congress.gov/116/ meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf.

[8] NYISO Reliability Needs Assessment November 2022.

There is an acute need for increased deliverability of clean energy in both the New York and New England market. In New York, this need is often characterized as the “tale of two grids”, which describes the fact that the Upstate portion of the New York electricity system is predominantly sourced from clean energy, while the downstate area is served primarily from fossil-fuel.[9] New England’s overreliance on natural gas represents a significant challenge to the region, especially in winter periods where limited natural gas supply is needed to serve both electricity generation and consumer heating demand.[10] While new transmission and renewable generation projects are in development to resolve these issues, additional action will be needed to deliver clean energy to load centers as electricity demand increases in response to electrification, and clean dispatchable resources are required to balance greater penetrations of offshore wind.

As noted previously, both regions will also require dispatchable emission free resources to preserve reliable operation of the electricity system as the supply mix increasingly shifts toward renewable generation. The Study references MISO’s Renewable Integration Impact Assessment which concludes that the effort required to plan for, support, and operate new resources reliably as they are integrated into the grid substantially increases at renewable penetration levels beyond 30 percent of annual load served.[11]

The existing academic literature is clear on the value and need for interregional transmission in meeting current and future electricity system needs in the Northeast. The benefits of new transmission that connect load centers, variable renewables, and dispatchable clean generation will continue to grow as the Northeastern economies are increasingly electrified and powered from renewable energy. And supporting investments in these infrastructure projects will be essential.

The Study should identify the need for new market mechanisms and commercial models as a barrier to transmission development.

Despite the multiple benefits transmission investments provide, there remain several barriers identified in The Study which must be overcome for these projects to reach commercial operation. The issue of cost allocation and determination of benefits is specifically referenced[12]; but new challenges are emerging related to mechanisms to fund transmission investments which are required to achieve regional and national goals. New transmission projects will be developed and operated in a manner to match the evolving needs of the future clean energy systems, which may be different than how this infrastructure has been utilized in the past. While these projects will provide a host of new benefits to stakeholders, the investments will require adaptable funding mechanisms which reflect more dynamic performance of the resource.

Historically, HVDC transmission projects have been funded through regulatory processes or long-term baseload energy supply contracts. Under a long-term baseload contract,

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[9] NYISO Power Trends 2022, page 8.
[10] Natural gas represented 53% of New England generation in 2021 (https://www.iso-ne.com/about/keystats/resource-mix/).
[11] Department of Energy National Transmission Needs Study Draft for Public Comment, February 2023, page 47-48.
[12] Department of Energy National Transmission Needs Study Draft for Public Comment, February 2023, page 78.

transmission costs can be distributed across millions of MWh delivered over decades in order to minimize cost impact to consumers. Future projects designed to facilitate two-way trading of electricity between regions will likely require a new approach, as the flow of electricity changes directions and capacity on the line is kept in reserve in order to rapidly respond to balance changes in supply and demand.

Interregional transmission projects will deliver significant net benefits to stakeholders, reducing the total cost of decarbonization, reducing curtailments of domestic renewables, and lowering dependence on fossil-fuel resources. Therefore, viable funding mechanisms can be created to support these investments. Through formally identifying the need for new funding mechanisms as a barrier to transmission development, The Study will advance the procedures and discussions necessary to resolve this challenge and enable more large-scale developments to occur sooner and through a more efficient process.

Conclusion

Investment in additional transmission infrastructure and increasing interregional transfer capability are essential components of achieving regional and national clean energy objectives. The clean dispatchable characteristics provided from the Québec system will operate in concert with domestic renewables and battery storage as part of a portfolio delivering a complete solution to decarbonization, leveraging resources that are proven to be effective and affordable at scale.

Findings from The Study provide guidance for policy makers on how to best undertake the actions necessary to overcome the barriers which have traditionally challenged new transmission development. As stated above, identifying regions where transmission can connect clean energy with demand centers and deliver effective solutions to electricity system challenges will enhance this effort. Prudent and comprehensive planning can be enabled by simultaneously working to accurately value the benefits that transmission can provide in meeting the future needs of the electricity system and working to create funding structures to support these investments.

HQ stands ready to collaborate with national and regional stakeholders to develop and implement the policies and actions necessary to fully capture HQ's unique operational capabilities and expand the clean energy partnership between Québec and the United States.

Serge Abergel
Chief Operating Officer
H.Q. Energy Services (U.S.) Inc.

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COMMENTS OF INTERNATIONAL TRANSMISSION COMPANY d/b/a ITC*TRANSMISSION*, MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC, ITC MIDWEST LLC, AND ITC GREAT PLAINS, LLC – U.S. DEPARTMENT OF ENERGY DRAFT NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY

International Transmission Company d/b/a ITC*Transmission*, Michigan Electric Transmission Company, LLC ("Michigan Electric Transmission Company"), ITC Midwest LLC ("ITC Midwest"), and ITC Great Plains, LLC ("ITC Great Plains") (collectively, "ITC") respectfully submit the following comments in response to the Draft National Electric Transmission Congestion Study ("Needs Study") prepared by the U.S. Department of Energy's ("DOE") Grid Deployment Office as made available for public comment on March 6, 2023.[1]

As the nation's largest independent transmission company, ITC provides transmission grid solutions to improve reliability, expand access to markets, allow new generating resources to interconnect to its systems, and lower the overall cost of delivered energy. ITC owns and operates high-voltage transmission infrastructure in Michigan, Iowa, Minnesota, Illinois, Missouri, Kansas, and Oklahoma, and in development in Wisconsin. These systems serve a combined peak load exceeding 26,000 MW along 16,000 circuit miles of transmission line, supported by approximately 700 employees and 1,000 contractors. Due to its sole focus on electric transmission, and corresponding lack of ownership of any generation facilities or participation in energy markets, ITC has a unique, neutral view of the electric grid and its current and future needs. ITC also has extensive experience participating in Regional Transmission Organization ("RTO") stakeholder processes through which the vast majority of the U.S. transmission system is planned and operated.

[1] U.S. Department of Energy, Grid Deployment Office, Notice of Availability of National Transmission Needs Study and Request for Comment, 88 Fed. Reg. 13,811 (March 6, 2023).

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ITC commends DOE for its hard work and dedication in developing the Needs Study. ITC further appreciates the extensive consultation with various entities in support of this effort.[2] The examination of both historic and anticipated future capacity constraints has allowed DOE to effectively highlight the significant and pressing need for regional and interregional transmission buildout to ensure a reliable and affordable energy transition. With this in mind, ITC believes that DOE should support and draw guidance from the Midcontinent Independent System Operator, Inc.'s ("MISO") Long Range Transmission Planning ("LRTP") process, as well as the MISO-Southwest Power Pool, Inc. ("SPP") Joint Targeted Interconnection Queue ("JTIQ") joint study as it considers the Needs Study in the implementation of the agency's broader mandates. ITC further urges DOE to, in its analysis, advocacy, and statutory implementation, be particularly cognizant of the clear benefits that accrue when incumbent utilities are allowed a right of first refusal ("ROFR") to construct new transmission facilities in their particular service areas – as evidenced by the recent successful approval of the LRTP Tranche 1 portfolio in MISO, as well as the ongoing progress towards a second Tranche of broadly beneficial regional projects in the MISO North region.

I. COMMENTS

a. <u>The Needs Study Supports DOE Looking to the LRTP and the JTIQ As It Implements the Infrastructure Investment and Jobs Act ("IIJA") and Inflation Reduction Act ("IRA")</u>

ITC agrees with the Needs Study's thoroughly-supported conclusion that there is a "pressing need to expand electric transmission—driven by the need to improve grid reliability,

[2] *See* Needs Study, Appendix A-1 and A-2. For example, we note the Minnesota Department of Commerce and the Minnesota Public Utilities Commission's request to add "the MISO LRTP study to your evaluation of transmission needs", and the DOE's decision to do so throughout Chapter V. *Id.* at p. 133.

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resilience, and resource adequacy, enhance renewable resource integration and access to clean energy, decrease energy burden, support electrification efforts, and reduce congestion and curtailment."[3] ITC believes that MISO's LRTP is exactly the type of "holistic and comprehensive planning assessment[] that consider[s] a range of scenarios of the future of the bulk power system" that the Needs Study calls attention to, and which will be required to accomplish the tremendously beneficial and urgently-needed buildout it identifies.[4] Consistent with the Needs Study's analysis, the LRTP "help[s] ensure a more robust and cost-effective bulk power system that will address future needs and ensure that expected transmission constraints and congestion are identified and mitigated before they harm consumers."[5] As such, the foundational, most-conservative Future 1 projects identified in LRTP Tranche 1 represent a crucial down payment on the high level of transmission investment that will be required in the years to come.

The current LRTP process is the result of extensive, long-running stakeholder collaboration, and has the support of customers, transmission owners, generators, public power entities, and state regulators. Ultimately, Tranche 1 of the LRTP projects, as recently approved by MISO, is projected to deliver between \$23.2 and \$52.2 billion in net benefits compared with \$10.3 billion in projected costs.[6] It must be noted, though, that while a huge step forward, this portfolio includes projects which are sorely needed *today* that are nonetheless set to be placed in-service seven to ten years from now.[7] And there is much more to be done. Luckily, the LRTP Tranche 2

[3] *Id.* at p. 78.

[4] *Id.* at p. 3.

[5] *Id.* at p. 3.

[6] See MISO, MTEP21 Report Addendum: Long Range Transmission Planning Tranche 1 Portfolio Report at pp. 4, 47 (2021), available here: https://cdn.misoenergy.org/MTEP21%20LRTP%20Tranche%201%20Portfolio626133.zip.

[7] *Id.* at Section 3.

study process is underway, and is intended to build upon foundational Future 1 projects and address MISO's Future 2A, which posits more realistic projections of generation fleet transformation and load growth through electrification in MISO North.[8] Further, MISO plans for an LRTP Tranche 3 and Tranche 4 in subsequent years. ITC believes that DOE would be well served by supporting these efforts as it advocates for the development of crucial regional and interregional transmission infrastructure. By the same token, ITC urges DOE to avoid pursuing actions which may slow down or otherwise complicate this groundbreaking regional planning effort, which relies upon delicate stakeholder consensus to succeed.

Beyond LRTP, the recent MISO-SPP JTIQ is a further example of holistic, comprehensive joint planning that DOE should look to and support as it takes actions informed by the Needs Study. ITC believes that efforts such as this help to address the need for greater collaboration between RTOs, as the Midwestern Governors Association Chair, Illinois Governor J.B. Pritzker, recently called for.[9] To this end, the Needs Study observes, "[t]he JTIQ Portfolio resolves constraints that enable MISO to interconnect over 28 GW of additional generation near the seam, and SPP estimates it could interconnect over 53 GW of additional generation near the seam."[10] Significantly, the MISO-SPP JTIQ joint planning study has identified more comprehensive, cost effective and efficient upgrades than would otherwise be identified in the current interconnection queue process. It has also identified solutions that provide multiple values capable of meeting

[8] *See* Midcontinent Independent System Operator, Long Range Transmission Planning (LRTP) Tranche 2- Frequently Asked Questions, available here: https://cdn.misoenergy.org/MISO%20LongRange%20Transmission%20Planning%20LRTP%20Tranche%202%20FAQs627648.pdf

[9] *See* Governor Pritzker Announces His MGA Chair's Agenda – Better Connections Between RTOs – Improving Transmission Seams Reliability in the Midwest, available here: https://midwesterngovernors.org/pritzker-chair-announcement/.

[10] Needs Study at p. 55.

both the needs of interconnection customers and providing benefits to load in both SPP and MISO.[11]

Although ITC recognizes that the Needs Study does not prescribe any particular solutions to issues faced by the power sector,[12] we ask DOE to support effective ongoing planning efforts such as the LRTP and MISO-SPP JTIQ.

b. <u>DOE Should Recognize the Value of and Actively Support ROFRs Including Reinstatement of a Federal ROFR</u>

ITC believes DOE is well positioned to promote successful planning processes. ITC urges DOE to, in its analysis, advocacy, and statutory implementation, be particularly cognizant of the clear benefits that accrue when incumbent utilities are allowed a ROFR to construct new transmission facilities in their particular service areas. The lack of certainty driven by the removal of a federal ROFR by the Federal Energy Regulatory Commission ("FERC") is the most pressing issue hindering regional and interregional transmission development. Recent research on the cost impacts of the now-mandated solicitation processes on planned and completed transmission projects conclusively shows that such solicitations are almost wholly unable to deliver any appreciable cost savings to customers.[13] In many instances solicitations have resulted in substantial delays, cost overruns, and less than expected project benefits relative to what would have resulted under the prior federal ROFR regime.[14]

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[11] Comments of MISO, p. 4, FERC Docket No. AD21-15-000 (filed Sept. 2, 2022). Materials related to the JTIQ effort are available here: https://www.misoenergy.org/stakeholder-engagement/committees/miso-spp-joint-targeted-interconnection-queue-study/.

[12] Needs Study at p. ii.

[13] Concentric Energy Advisors, Competitive Transmission Experience to Date (Aug. 2022), available here: https://ceadvisors.com/publication/competitive-transmission-experience-to-date-shows-order-no-1000-solicitations-fail-to-show-benefits/.

[14] *Id.*

In a separate proceeding, FERC has recognized its mistake in removing federal ROFR and has proposed its partial reinstatement.[15] However, there is an urgent need for final action. The Needs Study's median model result suggests that a staggering 57 percent growth in today's transmission system will be needed over the next dozen years.[16] Though that may seem a far-off date, in the world of large-scale transmission development it certainly is not, even *with* the benefits of a federal ROFR. Allowed to stand as they are today, mandated developer solicitations will continue to take tremendous amounts of time and scarce RTO resources to conduct. It will be absolutely infeasible to apply them to the portfolios of major transmission projects which the Needs Study indicates are required.[17]

Here again LRTP Tranche 1 provides a useful example for DOE to consider. Many MISO North states have opted out of forced developer solicitation by adopting state ROFR laws, recreating the environment of trust and collaboration stakeholders require to align around regional portfolio development. The results speak for themselves. The approval of LRTP Tranche 1 and the ongoing development of Tranche 2 indicate that ROFR is a pro-transmission policy that results in the most beneficial outcomes for the vast majority of stakeholders. Wherever it has the opportunity, DOE should promote the recreation of this pro-transmission environment nationally by supporting the reinstatement of the federal ROFR in all regions. This, more than any other reform, would pave the way for the rapid increase in regional and interregional transmission development called for by the Needs Study.

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[15] Federal Energy Regulatory Commission, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* 179 FERC ¶ 61,028 (2022)

[16] Needs Study at p. 106.

[17] *See* Concentric Energy Advisors, Building New Transmission: Experience To-Date Does Not Support Expanding Solicitations, at pg. 27 (Jun. 2019), available here: https://ceadvisors.com/wp-content/uploads/2019/06/CEA_Order1000report_final.pdf.

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II. CONCLUSION

ITC appreciates the opportunity to respond to Needs Study. We look forward to collaborating with DOE as it moves forward with the Needs Study and in the implementation of its IIJA and IRA authorities.

Respectfully submitted,

/s/ Kyle Hall Henne
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Counsel for ITC

April 20, 2023

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UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

COMMENTS OF ISO NEW ENGLAND INC.
ON PUBLIC DRAFT OF THE NATIONAL TRANSMISSION NEEDS STUDY

Pursuant to the "Notice of Availability of National Transmission Needs Study and Request for Comments" that the Grid Deployment Office of the U.S. Department of Energy ("DOE") issued on March 6, 2023, ISO New England Inc. ("ISO-NE") respectfully submit these limited comments on Section V.b of the Public Draft of the National Transmission Needs Study released on February 24, 2023 ("Draft Study").

ISO-NE appreciates the addition of information on the ISO-NE Future Grid Reliability Study ("FGRS"), which was added since the consultation draft was published. However, ISO-NE notes that the first sentence of the fourth paragraph in Section V.b of the Draft Study regarding the FGRS may be misleading. To address this, ISO-NE suggests changing that sentence to clarify as follows:

> ISO-NE (2022) similarly found in their Future Grid Reliability Scenarios (FGRS) that <u>even in a</u> mild weather <u>year, such as the 2019 weather year used in the FGRS, weather</u> events can pose significant challenges to maintaining electrical grid reliability under a high variable energy future.

ISO-NE believes these limited changes will help improve the study's accuracy, and respectfully requests that DOE incorporate them in the final study.

Respectfully submitted,

/s/ Monica Gonzalez

Monica Gonzalez
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ISO New England Inc.
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Counsel for ISO New England Inc.

Dated: April 20, 2023

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From: [redacted]
To: NeedsStudy.Comments
Subject: [EXTERNAL] Comments on the Public Draft
Date: Friday, April 21, 2023 5:18:11 AM

In reference to the entire study:

The draft National Transmission Needs Study is flawed. The Department of Energy's transmission studies are not based on data and science.

There is no pressing need for additional electric transmission infrastructure.

Janice Cooper

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March 3, 2023

Maria Duaime Robinson, Director
Grid Deployment Office
US Department of Energy *Sent electronically via email: needsstudy.comments@hq.doe.gov*

RE: Comments of Feb 2023 National Transmission Needs Study

Dear Ms. Duaime Robinson,

We appreciate the invitation to comment on the 2023 National Transmission Needs Study draft. We want to share our comments with you and ask for your consideration and concurrence of our critical comments for incorporation into the final report.

Juneau Hydropower, Inc. (JHI) is an Alaska-registered corporation and is a fish-friendly hydropower energy developer in Alaska. JHI is the license holder of a 19.8 FERC-licensed hydropower project that will bring clean and lower-cost energy to the Southeast region of Alaska. JHI is working on adding 40.29 miles of a new, high-voltage transmission line to Alaska and our nation's grid network. We comment on the draft report as a stakeholder in this report, where decision-makers in DOE and Congress will use this report as a basis for allocating future federal planning and funding resources. The concern is acute since the current draft report does not address Alaska's transmission needs or the transmission impact/benefits/needs for our national or regional hydropower and hydrokinetic resource potential. It would be fairer and more beneficial if this final national report included all geographical regions, all 50 states, and our nation's hydropower and hydrokinetic resources. We appreciate the opportunity to provide value-added comments to improve GDO's final report document.

While the draft report is primarily focused on the lower 48 contiguous states, we suggest an improvement that GDO's final report to include an Alaska Annex or chapter. We also find that the final report would have material gain by incorporating our nation's hydropower and hydrokinetic resources, their potential, or their associated beneficial enhancement to our nation's transmission grid and future needs.

JHI would recommend incorporating hydropower and hydrokinetic resources, and their beneficial enhancements to the national transmission need analysis in the final study. In 2021, hydroelectricity accounted for about 6.3% of the US utility-scale electricity generation and 31.5% of the entire utility-scale renewable electricity generation[1]. Roughly 1,450 conventional and 40 pumped-storage hydropower plants operate in the United States[2]. Unlike other renewable energy resources, hydropower infrastructure has a longer working life and, therefore, a long time value of carbon displacement compared to other renewable energy sources of similar capacity and generation. Consider that a 100-year-old dam is still displacing fossil fuel sources that would have been burned and emitted into the atmosphere for over a century. The

[1] US Energy Information Administration. https://www.eia.gov/energyexplained/hydropower/
[2] Ibid

differentiation of the time value of carbon displacement elevates the hydropower status in the portfolio of our nation's renewable energy resources required to meet net zero goals and objectives.

Comparatively, wind power is prominently identified and mentioned in the draft report over 150 times, and solar resources are mentioned over 80 times in the draft report. Our word search of the draft document found the report did not mention hydrokinetic energy and only made a scant mention of hydropower as a national energy resource. The draft report's hydropower discussed importing hydropower from Canada. We ask that American-developed and produced hydropower and hydrokinetic resources receive additional consideration on parity with other American renewable energy resources discussed in the report. We are a hydropower nation, and any National Transmission Needs study would be incomplete without addressing the beneficial enhancements, implications, and projected economic and environmental benefits that firm hydropower capacity and energy bring to our nation's grid.

Below are two specific comment areas to assist the authors.

Hydropower and Hydrokinetic Resources addition in the final report-

The natural placement of American hydropower resources is uniquely riverine or waterways near mountains or valley riverways and determined by geological time and nature. Optimized hydropower and hydrokinetic locations are sometimes distantly located from existing grid infrastructure leading to complex financing or not immediately viable project economics due to the significant transmission infrastructure investment required to interconnect the project. Our national grid becomes increasingly strained and needs new tranches of firm hydropower to bolster and strengthen the firm capacity of our grid. Collectively, we seek overarching decarbonization goals for our nation's grid; these potential hydropower projects and interconnected transmission lines take on a new national value and value proposition in that they deliver firm power to back up intermittent forms of energy.

Additionally, the time value of carbon displacement plays well with the increasing discussions of decarbonization. These new realities create value propositions for supporting hydropower developers and their high-voltage interconnections to the existing grid. JHI would ask the DOE to consider and provide more weight and support to large and small fish-friendly hydropower development in supporting and strengthening the nation's grid system. Such reporting would require a more robust consideration of the need to unlock stranded hydropower and the second-order effect of transmission requirements, which the final report should mention.

The Federal Energy Regulatory Commission (FERC) hydropower licenses typically identify and include transmission sections required to interconnect new hydropower projects. Additionally, the receiving grid may be constrained and congested with the pre-existing generation, which can pre-empt the minimal viability screening for these firm power hydropower projects. The report can mention that analysis should be considered to expose potentially constrained hydropower projects that would otherwise become viable should additional transmission assets be located to unleash potential hydropower and hydrokinetic resources.

This DOE Hydrovision Report 2016, Chapter 3: Assessment of National Hydropower Potential, contains a useful link identifying America's untapped hydropower resources. https://www.energy.gov/node/1922621/

Please consider that water is 832 times denser than air and is a powerful energy source for our nation. Therefore our tides, waves, ocean currents, and free-flowing rivers equipped with fish-friendly technologies represent an untapped, powerful, highly-concentrated, and clean energy resource. These resources and their impacts on transmission needs are essential in the portfolio mix of energy planning and opportunities required for our nation to meet our economic, energy, and national security objectives. JHI suggests that the final report include hydropower and hydrokinetic energy as growing national energy resources. Recognize their potential, firm power, national security, and decarbonization enhancements on our national transmission need assessment.

Alaska Centric Comments for consideration in the final report-

We understand that Alaska does not fall into a National Interest Electric Transmission Corridor (NIETC). The draft report does not address substantive basic Alaska transmission needs that we believe the DOE GDO should identify and address as this is a national-level and title report. As stated in the draft report, the purpose and underlying authority of this Needs Study is broad, the scope of this study is not constrained solely to the authority set forth in Section 216(a) of the FPA.

If Alaska's transmission needs cannot be addressed and added directly to the final report. In that case, JHI requests consideration that the Grid Deployment Office fund, draft, and develop an Alaska Annex for this critical report. Please consider in your decision-making and report data inclusion process the dire transmission need for Alaska, which is crucial for our national security needs. Our Alaska transmission grid infrastructure is representative of a 2nd world nation, and the rest of the nation's geographical regions are working on transmission improvements, efficiencies, and decongestion. Comparatively, Alaska is in the transmission dark ages. The needs assessment helps identify that more is required to provide and build acceptable transmission and reliability to lower energy costs for our job creation industries, citizens, military installations, and collective energy security.

Ironically, since 2009 China has built 18,000 miles of ultrahigh voltage transmission[3][4], and the US has built few transmission lines extensions of any voltage size for Alaska. Compared to China and the contiguous US, Alaska, and its leadership are focused on lowering the cost of energy by removing expensive and heavily transported diesel and diesel generation to obsolescence. A further priority is creating minimum transmission reliability and redundancy for Alaska population centers and opening Alaska up for renewable energy development. Alaska has 1697 miles of high and low voltage transmission lines for the entire State of Alaska[5] , which encompasses 17.5% of our nation's land mass. The contiguous United States has over 700,000 circuitous miles of high and low-voltage transmission lines[6], and ***Alaska transmission infrastructure represents less ¼ than 1% of our Nations transmission infrastructure***. Regardless of any metric, to state that there is a transmission need in Alaska is an understatement.

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[3] IEEE Spectrum, Peter Fairley, China's Ambitious Plan to Build the World's Biggest Supergrid 2019 https://spectrum.ieee.org/chinas-ambitious-plan-to-build-the-worlds-biggest-supergrid

[4] The Atlantic. America is bad at building power lines lets fix that transmission climate.Robinson Meyer 2021 https://www.theatlantic.com/science/archive/2021/07/america-is-bad-at-building-power-lines-lets-fix-that-transmission-climate/619591/

[5]US DOE State of Alaska Energy Security Risk Profile 2021 https://www.energy.gov/sites/default/files/2021-09/Alaska%20Energy%20Sector%20Risk%20Profile.pdf

[6] US Energy Information Administration 2018, EIA study examines the role of high-voltage power lines in integrating renewables https://www.eia.gov/todayinenergy/detail.php?id=36393

S. Rept. 106-405 - SOUTHEASTERN ALASKA INTERTIE SYSTEM in 2000[7] and Public Law 106-511 Title IV [8] federally authorized a Southeast Alaska Intertie in 2000 to interconnect the Southeast Alaska region of the state with high voltage transmission lines have not been appropriated by Congress. The Southeast Alaska intertie is an essential national transmission potential corridor not identified in the draft report. Alaska has other needs in our Alaska Railbelt region to remove decongestion, improve redundancy and add capacity for current and future electrical generation. Since the National Transmission Needs final report is used to provide future federal assistance and allocation of resources, Alaska transmission needs should be identified and incorporated into the final report.

Aside from the economic and national security layers of need, the environmental and social justice perspectives for understanding and assessing Alaska's transmission needs through a national perspective and lens are equally compelling. Alaska has untapped potential as a renewable energy resource state that can serve our nation's needs with planned interconnecting transmission corridors. While this report does not grade geographical location needs, Alaska's transmission needs are an incomplete grade and require federal recognition of the magnitude of the problem of insufficient transmission. This recognition in your final report will assist decision-makers in understanding the severity of the need and begin directing federal assistance to bring Alaska's transmission system on par with the rest of the nation. Please consider adding an Alaska Annex to the final report to address Alaska's salient and crucial transmission needs as they intersect national transmission and energy security interests.

JHI appreciates the GDO inviting comments on the draft study report. We intend and hope the GDO office finds our Alaska and Hydropower/Hydrokinetic comments and perspectives constructive and helpful in adding value to the 2023 final report.

Kindest regards,

Duff Mitchell
Managing Director

CC: Governor Mike Dunleavy
Senator Dan Sullivan
Senator Lisa Murkowski
Representative Mary Peltola
Curtis Thayer, Executive Director, Alaska Energy Authority
Malcolm Woolf, President and CEO, National Hydropower Association
Joel Groves, President, Alaska Independent Power Producers Association

[7] S. Rept. 106-405 - SOUTHEASTERN ALASKA INTERTIE SYSTEM 2000 https://www.congress.gov/congressional-report/106th-congress/senate-report/405/1
[8] Public Law 106-511 Title IV https://uscode.ecfr.io/statutes/pl/106/511.pdf

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Source- Bells Travel Guide

National Transmission Needs Study Draft

Comments of Keryn Newman, 6 Ella Dr., Shepherdstown, WV 25443
April 20, 2023

The Law of the Instrument is a cognitive bias that is often expressed with the phrase, "If the only tool you have is a hammer, every problem looks like a nail." The draft National Transmission Needs Study epitomizes the Law of the Instrument because it prioritizes transmission as the only possible solution. Three years ago, DOE's last congestion study concluded, "…the Department has not identified transmission congestion conditions that would merit proposing the designation of National Corridors."[1] Now the Department has found terrible congestion in an area so vast that if the DOE were to designate corridors to solve it, the entire continental U.S. would be one gigantic "corridor." The only conclusion that can be drawn by these drastically different findings is that the DOE's transmission studies are not based on data and science, but on political goals. This does not benefit the citizens the Department exists to serve. Although politics produces a vast supply of hot air, it cannot keep the lights on.

The National Transmission Planning Study ("Study") relies on cherry-picked studies funded by special interests to make its findings. FERC's "Report on barriers and opportunities for high voltage transmission"[2] that the DOE relied upon for its Study was also created using special interest studies and not upon any information from or about the human barriers themselves. Although landowner concerns about new transmission easements across their properties is mentioned in DOE's Study, no one thought to consult these "barriers" to find workable solutions. It is interesting to note, but not surprising, that DOE's Technical Review Committee does not include any actual landowner representatives. The citizens who would bear the brunt of new transmission's devastating impacts have been barred from meaningful participation in this Study.

Perhaps the biggest failing of this report is its quick dismissal of co-locating new high-voltage electric transmission on existing federal highway rights-of-way, or other transportation corridors. The study uses old information and tired excuses to brush aside the best chance for successfully building new transmission today. The study incorrectly claims that, "high voltage lines can also affect railroad signaling systems" but fails to recognize transmission projects such as SOO Green HVDC Link,[3] which is proposed to be buried on existing railroad right-of-way for hundreds of miles. If it would cause issues with signaling, would Canadian Pacific be a willing partner on this project? The Study's findings just don't make sense. Another excuse used by the Study is "electrical interference can affect the protection systems of oil and gas pipelines and accelerate corrosion," which is another "problem" that has been solved by modern technology.

[1] National Electric Transmission Congestion Study, page vi, September 2020.
[2] FERC. 2020. Report on barriers and opportunities for high voltage transmission. Washington, DC: Federal Energy Regulatory Commission. https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf.
[3] https://soogreen.com/

Selecting another corridor easily solves the claim that transportation corridors may not run in a direction compatible with the project. It's not as if there's a shortage of transportation corridors running in any direction. The idea that co-location can cause safety concerns is entirely solved by burying the transmission in a shallow trench on the edge of the highway right-of-way. We've been burying utilities alongside transportation corridors for decades and I haven't seen one report of a buried line jumping out of the ground to cause an accident. Security would actually be increased if electric transmission was buried alongside busy transportation corridors, instead of strung on metal towers across remote locations. Any and all excuses against an effort to use existing linear infrastructure corridors for siting new infrastructure can be easily dispelled with up-to-date studies and a will to implement the latest technology. A better place to get modern information and recent studies on co-locating transmission on transportation corridors can be found at The Ray.[4] The current administration has ordered that the use of highway corridors to site new electric transmission be encouraged,[5] therefore DOE would be remiss if it did not give adequate consideration to this policy and put its full effort toward accomplishing this goal.

The Study notes, "Transmission projects also frequently face public opposition or "not-in-my-backyard" concerns for various reasons. These challenges can lead to increased costs, schedule delays, or even project cancellations."[6] But yet the Study plows ahead without any practical solution to this dilemma. Perhaps DOE personnel concocting this Study lack the awareness and empathy simply because it is not *their* "backyard." The DOE also seems to be unaware that dismissing opposition to transmission using derogatory motives for opponents like "not-in-my-backyard" is name-calling at its worst. The only way to solve these "NIMBY" challenges is by siting new transmission buried on existing transportation corridors, which are not in anyone's "backyard."

The Study has an impossible goal to eliminate all transmission congestion. Transmission congestion can never be completely eliminated; it can only be shifted from place to place. Relieving economic congestion attempts to levelize prices between different geographic areas. Like a seesaw, the lowering of prices in one area raises them in others. An area with adequate, competitive generation enjoys the benefits of that competition with lower electric prices, while an area without enough competitive generators pays higher prices. It's simple supply and demand, which is something the DOE can never "fix", nor should it even try. There is more than one solution for economic congestion. New generation in high priced load pockets can also solve economic congestion but is ignored in the Study because of DOE's Law of the Instrument approach. Congestion that is "solved" with new transmission before competitive generation markets can work to incite the building of new generation is a market failure. High electricity prices are a demand for new generation, not just transmission.

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[4] https://theray.org/technology/transmission/

[5] https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/27/fact-sheet-biden-administration-advances-expansion-modernization-of-the-electric-grid/

[6] Draft Study at page 9.

The Study used the following example to tout the value of transmission, "During the Texas heat wave of 2019, the study found that an additional 1 GW transmission tie to the Southeast could have saved Texas consumers nearly $75 million."[7] However, it fails to note how much constructing that transmission tie would cost consumers. Based on the huge costs of constructing new transmission, it is likely that the cost of the tie would be a lot more than the $75 million. How many heat wave events would be needed before the new transmission tie actually saved consumers money? Would new peaking generation in Texas actually cost less? This is more an example of the Study's Law of the Instrument thinking than a demonstration of the value of new transmission.

The idea that we can expand the transmission system so that every electron generated anywhere can be used by anyone is not only prohibitively expensive, it is patently absurd. A true apples-to-apples comparison of the cost of new transmission vs. the cost of new generation near load is avoided in the Study. This comparison must be made before saddling consumers with new transmission costs to connect with remote generators. It is more likely that transmission is not cost-effective, even with vague claims of "economies of scale" factored in. What are the "economies of scale", exactly, and how are they calculated? The report doesn't say. It seems like this term is used to avoid true scientific study.

An inability to import generation from other regions cannot always be solved with new transmission when the excess generation is just not there in the other regions. If a region without adequate generation (or variable generation that cannot reliably serve load) can "borrow" from other regions using new transmission, what happens when the neighboring regions also lack sufficient generation? Insufficient generation events are spreading across the country. Soon, no region may have sufficient generation, or enough to share with others. Placing average capacity factors on a spreadsheet to determine that "there's always power to be had somewhere" only works on paper. In real time, capacity factors can tank over a wide area all at once, such as overnight, when solar is not producing. Transmission does not produce electricity. Only generators can do that, and they must be reliable all the time, not just some of the time at the whim of Mother Nature. As bulk power system reliability engineer George Loehr once testified, "Reliability is not a function of the amount of wire in the air."[8]

The Study touts bidirectional trading of power between regions, but does not recognize the nature of interregional merchant transmission, where dedicated capacity is sold to generators and/or load serving entities. Merchant transmission is paid for by contracted customers, not captive ratepayers. If merchant transmission does not have firm customers, it has no revenue stream and is uneconomic to build. If an eastern load serving entity has purchased dedicated capacity on a merchant transmission line to serve its load from contracted generators in other regions, how could this capacity be commandeered to reverse flow when needed? The eastern city may not be able to serve its load that depends on the power imports. The city would have to offer its capacity for re-sale in order for others to use it. Bidirectional power trading between regions depends

[7] Study at page 71.
[8] Testimony available at https://earthjustice.org/wp-content/uploads/loehr-testimony.pdf

on the availability of capacity. The Study needs to explore this concept further and explain exactly how this would work. If it does, would it discourage load-serving entities from purchasing merchant transmission capacity to serve load if that capacity could suddenly become unavailable? Why would anyone purchase something that can be taken from them at any time without repercussion?

The DOE has not sufficiently answered the question of its authority and jurisdiction to plan the transmission system. The idea that DOE's Study could help inform and drive planning at regional transmission organizations is perhaps a bit ambitious and naive. Regional transmission planners use their own data and assumptions to plan their systems to meet reliability standards and projected demand growth, or to solve necessary historic congestion within their region. They have been doing this for decades and it is questionable whether or not they need help from the Department of Energy to perform a job they seem rather capable of doing. The Study creates a completely separate and ambitious plan to build transmission, whether it is actually needed by RTO planning criteria or not. The DOE Study is not bound by reliability standards, instead it seems to be focused on political goals. As a consumer, I'd much rather have experienced engineers and planners keeping my lights on, instead of a bunch of policy wonks planning the grid to meet the goals of people who have no idea how it works. DOE does not have authority to plan the transmission system, or allocate the costs of transmission to consumers in the corridors it designates. Those are responsibilities of existing planning authorities. DOE only has authority to designate corridors that shift transmission permitting from states to federal regulators. If DOE's Study is even remotely useful for transmission planning, why are we paying billions of dollars every year for the planning services of RTOs? It seems like DOE is duplicating the efforts of others by usurping their authority to plan the transmission system and allocate costs to captive ratepayers. System reliability, resilience, and congestion relief are the reasons DOE gives for the necessity of all the new transmission in its Study, however existing planning authorities already have that covered.

The Study relies too much on the number of generation projects in interconnection queues without the realization that only a small fraction of these projects are ever built. Until interconnection agreements are signed, the projects in the queue are nothing more than ideas. A transmission system built to allow the interconnection of all projects in the queue is an overbuilt and unnecessary transmission system.

The Study's data is inaccurate by presuming all congestion can be solved with new transmission. For instance, the Study found that congestion in PJM could be solved by new transmission, such as the Independence Energy Connection (IEC) in Pennsylvania and Maryland, a project that was proposed more than 5 years ago by PJM to solve economic congestion in the Washington/Baltimore metro area. The Pennsylvania PUC has subsequently rejected IEC because it is too costly to the state's electric consumers. The historic congestion that was the basis for this project has evaporated. DOE breathing new life into this project with a corridor designation is a complete waste of consumer dollars. New congestion in PJM is caused by temporary outages due to transmission work. DOE could not have actually studied the facts of this congestion before deciding that new transmission to alleviate it should be built. The IEC project would open new avenues for cheap coal and gas-fired generation from the Ohio Valley to reach Washington and Baltimore. This new generation would supposedly lower electric prices; making planned renewable projects closer to load uncompetitive and uneconomic to build. This hardly helps the renewable transition that supposedly underlies everything in DOE's Study. Without the IEC, Washington and Baltimore would build new renewable generators that are economic. With IEC, they would continue to rely on fossil-fuel generators in other states. Building transmission to levelize prices within a region, or between regions, does not always result in less carbon emissions.

The Study posits that additional long-distance transmission can act as insurance against weather-related blackouts. Aboveground transmission lines strung through remote areas only adds risk to the system from wildfires, hurricanes, tornados, sabotage and other grid failure events. A smaller system where load and generation are closer together decreases risk simply because there are less points of possible failure. Only buried transmission can protect against these types of outages because it is not exposed to weather and opportunity for destruction. If we're going to make progress in this country we must stop using transmission technology from the 1880's: aerial wires strung on invasive metal structures. Why not spend some of the money dedicated to improving our energy systems on modernizing transmission so that it doesn't cause burden, doesn't take private property, and doesn't foment loud and long opposition?

Transmission opposition to aerial projects on new rights-of-way will definitely happen. It can delay actually building transmission for decades, and will certainly increase its cost. The Study notes, "Large amounts of low-cost generation potential exist in the middle of the country and accessing this generation through increased transmission is cost effective for neighboring regions." This "low-cost" generation is only low-cost because it relies on taxpayer-funded subsidies and because it has "…prioritized placement in low-cost lands"[9]. The Study admits, "…high cumulative burden should be an indicator to avoid those areas."[10] Midwestern landowners and farm businesses are already losing vast amounts of land from numerous energy-related projects such as liquid petroleum, natural gas, anhydrous ammonia, crude oil, highly volatile liquids and CO2 pipelines. They are also being surrounded by wind and solar "farms" (a term at which real farmers scoff). Just because turning rural America into an energy serfdom to provide power to far-away cities who don't want to build all that nasty infrastructure in their own backyard is "cost effective" for the cities doesn't mean rural areas should be turned into the nation's powerhouse. This smacks of cultural and political elitism. Building long distance transmission means you don't have to build new generation in your own neighborhood.

The DOE's Law of the Instrument Study makes several findings that suit its pre-determined agenda, such as:

[9] Study at page 41.
[10] *Id*

"Because generation resources are usually located far from load centers, transmission infrastructure is required to connect those resources to the larger system." and "New transmission advances clean energy goals by enabling greater access to clean energy resources, which can be in remote areas, far from load and the existing transmission system." Clean generation can be everywhere and anywhere if there is the will to do it. It's just not true that generation has to be located far from load and the existing transmission system. Before destroying the American farm industry that supplies our food, we need to put on our thinking caps and revolutionize the way we produce and deliver energy.

Perhaps this much-ignored passage from the Study is a place to start: "There are several different combinations of solutions to meet regional electricity demands, for example, co-locating generation and storage units, [or] siting generation close to load..." Another idea is to site new nuclear generation at shuttered fossil fuel power plants that already have sufficient transmission to serve local or regional load. The Study does not "…make the least cost choice among these combinations." It does nothing more than provide a not-very-believable backstory for a political choice the DOE seems to have already made. Transmission is a band-aid being used to hide the fact that intermittent renewables alone cannot power our country. How much money will be wasted before we are finally forced to admit it? And will it be too late?

When the only tool you have is a hammer, everything looks like a nail.

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April 20, 2023

LineVision Comments Re: Draft National Transmission Needs Study

Introduction:

LineVision is pleased to provide comments regarding the Department of Energy's (DOE) draft National Transmission Needs Study. LineVision is a Grid-Enhancing Technology (GET) company that has developed an advanced non-contact sensor and analytics platform that continuously monitors the behavior of overhead transmission line conductors, detecting anomalies and issuing real-time alerts on risks, while unlocking as much as 40% additional capacity on existing lines through dynamic line ratings (DLR).

LineVision believes that utilizing GETs such as DLR can help address the challenges that arise from the conclusion of the 50+ industry reports that were analyzed in this study process, and that collectively highlight a pressing need for an optimized, expanded transmission grid. GETs play a key role in optimizing the existing grid by creating critically needed transmission capacity, improving grid reliability, and reducing congestion and curtailments.

LineVision provides utilities with three applications that address these needs, all of which are enabled by the company's non-contact equipment, which has no limitations on the line voltage, conductor size, type, or bundle configurations as a light detection and ranging technology (LiDAR) sensor is mounted to the tower structure, eliminating the need to schedule line outages and requiring no live line working techniques. The three solutions are: LineAware, LineRate, and LineHealth, each of which addresses a specific need of operators:

- LineAware® provides utility and grid operators with situational awareness, which helps to inform operators with sag and horizontal motion data, triggering alerts on exceedances, a source of wildfire ignition
- LineRate® provides Dynamic Line Ratings (DLR) and AmbientAdjusted Ratings (AAR) which increase the capacity on transmission lines
- LineHealth® provides planners and risk management teams with Asset Health Monitoring, which improves maintenance strategies by creating a digital twin to determine conductor health

GENERAL COMMENTS:

1. GETs represent a "least regrets" option for adding transmission capacity quickly and addressing increasing congestion costs

Historically, utilities, system operators, and regulators assumed the transmission grid was essentially "fixed" in capacity and configuration. This assumption ignores the capabilities offered by GETs like DLR, which allow physical transmission assets to be actively managed to provide more transmission capacity, reduce grid congestion, provide higher reliability and resilience, and improve the integration of renewable generation.

One recommendation for meeting the needs of a grid that enables electrification and decarbonization at a national scale and that withstands increasingly severe extreme weather events would be to consider a transmission loading order approach where optimization of the grid (via the utilization of low-cost tools such as GETs) is considered first, then grid reinforcement, and then grid expansion. This is a sequential way to create an expanded, flexible, dynamic grid with customer affordability as a guiding principle. Such

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transmission planning loading order principles have been used internationally: Germany's NOVA principle emphasizes "grid optimization first, then grid strengthening before any further grid expansion."[1]

This theme of grid optimization can be found in New York, a state working to meet the goals of the landmark state Climate Leadership and Community Protection Act (CLCPA), which requires 70% clean energy on the grid by 2030. The New York Public Service Commission has recognized the key benefit of advanced transmission technologies like DLR and found that "utilities could implement well-established advanced technologies in the near term, specifically those that have advanced beyond the R&D and pilot phase and have been deployed in New York and other jurisdictions" recognizing that "such established technologies can offer significant benefits by expanding the CLCPA benefits of the projects."[2]

Furthermore, DOE's "Next-Generation Grid Technologies" report notes that GET's like DLR and topology optimization can be applied concurrently as solutions to optimize the utilization of the current electricity delivery system, reduce the frequency and duration of outages, and generally improve the reliability of the system.[3]

The flexible nature of GETs hardware and corresponding software applications can also provide relief during planned or unplanned outages associated with new generation-driven construction or planned maintenance, which can increase grid congestion. For example, in a situation when the grid is in an irregular operating state, use of DLR can provide additional capacity on existing transmission pathways enabling operating flexibility that will help mitigate some of the impacts to the grid and reduce the amount of required generation re-dispatch or curtailment needed to alleviate the short-term constraint. This need to implement congestion relief solutions like GETs is key as 2021 was a record year for transmission congestion. Consulting firm Grid Strategies LLC estimates that U.S. consumers paid for $13 billion in congestion costs as extreme weather took generators offline for extended periods - nearly double the five-year average.[4]

2. LineVision DLR projects showing immediate benefit

According to a moderate load growth, high clean energy growth scenario, the DOE's draft study finds that the US will likely need 47,000 GW-miles of new transmission by 2035. That finding represents 57% growth over the current level of transmission. A key conclusion of the draft study is that regardless of which load growth or clean energy scenario is ultimately reached, we will need to build significantly more transmission in the next decade than occurred in the past. A key benefit of DLR technology is its ability to increase transmission capacity quickly, thereby serving as a reinforcement to existing grid infrastructure as new transmission is built while also providing future benefits such as reducing congestion and expanding flexible capacity.

Several indicators that point to an immediate need for more transmission infrastructure are highlighted in the draft study. Because planning and building new transmission typically takes five to ten years (if not longer), GETs like DLR play a key role in being able to quickly alleviate congestion and create critically needed transmission capacity while new projects are put in place over a longer-term timeline. LineVision is proud to be showcasing these timely benefits in the following regions:

[1] https://www.transnetbw.com/en/world-of-energy/nova-principle

[2] Order on Phase 1 Local Transmission and Distribution Project Proposals, at 18, Case No. 20-E-0197 (February 11, 2021)

[3] https://www.energy.gov/sites/default/files/2022-05/Next%20Generation%20Grid%20Technologies%20Report%20051222.pdf

[4] https://gridprogress.files.wordpress.com/2023/04/transmission-congestion-costs-in-the-us-2021-update.pdf

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New York

- Working with National Grid, LineVision has deployed sensors in the western region, which along with five miles of circuit rebuilds, is projected to reduce curtailments by over 350 megawatts while increasing capacity by 190 megawatts. This will provide enough capacity to existing power lines to power some 80,000-100,000 homes.[5]

PJM

- LineVision has been able to increase capacity by up to 25% in southwestern Pennsylvania[6], part of the PJM footprint, which has seen DLR become operationalized on three historically congested lines, saving customers $23 million annually in congestion costs.[7]

MISO/West

- LineVision sensors were installed in Xcel's Minnesota, Wisconsin, and Colorado territory to investigate the capacity provided by DLR. Average DLR exceeded static reference ratings by 9-33% in winter months and 26-36% in summer months. Overall, increased capacity was available 85% of the time.[8]

As LineVision projects are actively demonstrating, DLR can substantially increase the amount of renewable energy that can be integrated and, thus, enhance the capability of the existing grid as well as increase the cost-effectiveness of new transmission projects that are being evaluated through the local and regional planning process.

3. Use of GETs is key before, during, and after new transmission is built

As clean energy demand increases due to improved economics and implementation of the Inflation Reduction Act (IRA), the role of transmission in delivering the IRA's goals has become of paramount importance: it is estimated that 80% of projected IRA emissions reductions will be lost if the current, stagnant rate of transmission expansion continues. Failing to accelerate transmission expansion beyond the historical pace of roughly 1% per year will increase 2030 US greenhouse gas emissions by ~ 800 million tons per year, relative to estimated reductions in an unconstrained IRA case.[9]

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[5]https://www.linevisioninc.com/news/national-grid-and-linevision-deploy-largest-dynamic-line-rating-project-in-the-united-states

[6]https://www.utilitydive.com/news/duquesne-light-expands-linevision-partnership-after-dynamic-ratings-boost-t/631112/

[7] https://insidelines.pjm.com/dynamic-line-rating-activated-by-ppl-electric-utilities/

[8] https://www.energy.gov/sites/default/files/2022-05/DOE_OE_TRAC_Peer_Review_Project%20-%20LineVision.pdf

[9] Electricity Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act, Princeton University, Sept 2022

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Beyond meeting IRA goals, transmission is also key to addressing the existing transmission grid interconnection queue, which has grown from 1.4 TW at the end of 2021 to 2 TW of generation and storage capacity now actively seeking grid interconnection.[10]

GETs can be a key solution to these challenges as DLR facilitates the integration of a higher share of renewable generation by increasing the effective transmission network capacity. While additional new transmission infrastructure is needed to meet our nation's net-zero goals, the optimization of the existing grid can reduce or defer the need for investment in transmission network reinforcements in the short to medium term.

As highlighted in a recent white paper by The Brattle Group, "*Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts*," GETs play a key role at various stages of transmission expansion.[11] GETs provide benefits that start *before* traditional transmission projects are being developed (by addressing/alleviating congestion), *during* the construction of the transmission projects (by preventing congestion caused by transmission outages that occur while interconnecting new projects) , and *after* the newly developed transmission projects are put in service, primarily by increasing the utilization of both the new line(s) and the existing system, which increases the Benefit to Cost ratio of any given transmission project. As noted in the white paper, these benefits are significant to the corresponding timeframes:

- Before construction, GETs can reduce congestion by 40% or more.
- During construction, outages can be avoided or ameliorated, with similar reductions in congestion costs of 40% or more.
- And after construction, utilization on new lines can increase by 16%, improving the Benefit to Cost ratio of the new lines.

CONCLUSION

LineVision appreciates the opportunity to highlight the key role of GETs as the Department looks to address historic and anticipated transmission capacity constraints and congestion and consider the transmission grid infrastructure necessary to meet the nation's clean energy goals. Thank you for consideration of these comments.

Sincerely,

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[10] https://emp.lbl.gov/queues

[11] https://www.brattle.com/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

National Transmission Needs Study and "Additionality"

April 17, 2023
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Summary: *It is unclear whether in this Study the total demand for clean electricity has been comprehensively assessed, to incorporate the potential grid load from indirect uses of electricity such as the production of green hydrogen and low carbon fuels and the operation of carbon removal systems in addition to direct delivery. The impact of the production of green hydrogen via electrolysis at the level of tens of millions of metric tons per year would consume substantial quantities of clean electricity (45-50 TWh per million tons). This demand raises significant questions about the allocations of grid electricity between direct grid delivery and other potentially substantial indirect uses, and hence the transmission networks needed to deliver the future total grid load.*

Issues which need to be addressed include:

- *Will there be competition between the use of clean electricity generation resources (a) delivered directly over the grid to support increasing electrification, which is the most effective and most widely applicable method for reducing anthropogenic emissions, and (b) to support other non-electric methods for reducing emissions which require clean electricity at one or more stages in their supply chain?*
- *If so, how should clean electricity be allocated over time so that the reduction of anthropogenic emissions is maximized, and not compromised by diverting clean electricity in large amounts from direct delivery over the grid?*
- *Specifically, how much public funding should be provided to the producers of clean hydrogen and what rules should be applied to ensure that hydrogen production projects awarded subsidies are truly clean, and not dirty such as blue hydrogen projects which fossil fuel interests may try to wrap in a cloak of purity?*
- *Should subsidies be provided to hydrogen production projects whose target markets include the supply of this gas to uses or applications where electrification is demonstrably a much superior solution, especially if the use of hydrogen is inconsistent with goals for reductions in anthropogenic emissions and would perpetuate or increase risks to safety and human health[1]?*

[1] The most notable example of an unjustified and stupid use of green hydrogen is the proposal by gas utilities for this gas to replace methane in leaky pipelines as a fuel for heating and other purposes in buildings, burning it in air with NOx as a byproduct. This proposal would open the door to hijacking green hydrogen, a scarce resource, from applications in industry and transport where it can contribute to decarbonization. Counterintuitively this use of hydrogen in buildings would increase the demand for electricity compared to the direct use of electricity to power heat pumps. This outcome has been proved beyond a reasonable doubt by publicly available analyses based on the laws of physics and chemistry, whose findings gas utilities nevertheless persist in denying or ignoring.

The imperative for clean electricity is to replace and substantially augment the capacity of existing polluting power plants so that the grid is fully decarbonized as rapidly as possible to eliminate anthropogenic emissions attributable to existing and future applications or activities powered by electricity. The generation capacity we will need to achieve this goal will be much greater than the current capacity of dispatchable grid-connected generators, although this increase can be moderated somewhat by a range of techniques such as demand management and energy storage systems replenishable during periods of surplus (compared to demand) generation. Nevertheless we will have to deploy resources with much higher nameplate capacity in total than are deployed today to ensure grid reliability and resilience despite large fluctuations in demand (hourly, daily, and seasonally) because of the combination of the impact of new electrification (such as but not limited to EVs) and the inherent variability or weather-dependence of the major sources of clean electricity, wind and solar. The capacity factors of wind and solar and hence the amounts of electricity they can generate during a year are much lower than those of dispatchable generators such as fossil fuel power plants with the same nameplate capacities.

But as with new and expanded transmission facilities, there are significant bureaucratic, siting and permitting obstacles to the deployment of new clean electricity generators. The challenge of deploying enough clean sources of electricity to achieve the goal of full grid decarbonization on the schedule we have targeted is already daunting. It will become even more daunting if clean electricity must satisfy large demands for applications in addition to those fulfilled by direct delivery over the grid. Other indirect uses of clean electricity risk hijacking substantial amounts of clean electricity from the grid, inhibiting, and potentially blocking or slowing progress in progressively increasing the proportion of grid electricity that is clean or green. Reductions in anthropogenic emissions attributable to electrified applications will be lower. Well-defined and enforced rules for the sources of clean electricity consumed by indirect uses are required to avoid this outcome.

Indirect uses of clean electricity include the production of green hydrogen, which has powerful advocates among fossil fuel interests as a carbon-free fuel and has some, but limited roles to play in decarbonizing economic activities where electrification is not a feasible option. Regrettably gas utilities are also strong advocates of the use of hydrogen as a decarbonizing replacement for methane where there are much more efficient electric alternatives, notably for heating buildings. There is an incessant drumbeat of propaganda and misinformation about "The Hydrogen Economy," as if the backbone of the non- or minimally emitting energy future will be hydrogen and not electricity, "The Clean Electricity Economy." This electricity will have to be supplemented by various lower carbon fuels which will themselves require electricity for their production or upgrading/purification. These fuels do have targeted roles to play in decarbonizing or depolluting selected applications, for example in industry and heavy duty transport, that cannot be electrified directly. But although essential, these fuels can only achieve much smaller reductions in emissions compared to new and expanded applications of electrification in the sectors responsible for most greenhouse gas emissions, namely transport, residential and commercial buildings, and the replacement of fossil fuel power plants in the power sector by clean sources of electricity. Combined these sectors account for about two thirds of total emissions. In addition, we will have to compensate for residual anthropogenic emissions by scaled up emissions removal methods (notably CDR (Carbon Dioxide Removal)) to achieve Net Zero and ultimately Net Negative if we wish to reduce the concentrations of emissions in the atmosphere and the oceans, which will increase significantly over the next two to three decades, to lower levels that are healthier and more sustainable for humans. The operation of some CDR methods will be another significant source of demand for clean electricity.

The production of green hydrogen via electrolysis is very electricity intensive. Conservatively this production, were it only to replace the gray hydrogen currently used in the US, would consume some 450- 500 TWh annually. Production of 50 million tonnes of green hydrogen would consume up to 2,500 TWh. This consumption can be compared with the total consumption of electricity in the US in 2021 of about 4,000 TWh.

My assumption (or should it be a question?) is that the scenarios covered in the Draft Transmission Needs Study of future grid loads of 7,000 TWh or maybe higher up to 8,000 TWh by the 2040s do not incorporate significant demands for clean grid-connected electricity to produce green hydrogen or power CDR systems. The anticipated large Increases in total annual grid load in the scenarios covered in the Study appear to be driven predominantly by the electrification of transport, e.g., EVs, and the increasing electrification of buildings.

The principle of additionality being pursued in the European Union requires that clean electricity for producing green hydrogen – or for powering other electricity-intensive systems such as Direct Air Capture (DAC) for carbon dioxide removal (CDR) – must be additional to and not absorb a sizable proportion of the clean electricity needed to meet the grid decarbonization target with respect to final electricity consumption. Application of this principle means that electrolysers producing renewable hydrogen must likely be supplied mostly with electricity from dedicated sources of clean electricity, not needed or suitable for contributing to grid decarbonization.

The inflation reduction Act (IRA) referred to in this Study includes large subsidies for producing green hydrogen. One example of forecast demand for green hydrogen in the US lies in the range of 22-41 million tonnes annually - https://www.nrel.gov/news/program/2020/study-shows-abundant-opportunities-forhydrogen-in-a-future-integrated-energy-system.html. The production of this amount of green hydrogen would consume between 1,000-2,000 TWh of clean electricity. This finding suggests two questions:

1. Do the scenarios in the Transmission Needs Study include a substantial grid load for producing hydrogen or do they assume that other dedicated sources of clean electricity not connected to the grid will be used to power the electrolysers?
2. If alternatively clean electricity from the grid is used in significant quantities to produce green hydrogen, and/or for any other purpose than direct delivery to electrified applications, what will be the impact on the pace and extent of grid decarbonization over time, and hence on progressively eliminating anthropogenic emissions to achieve growing reductions in annual emissions in 2030, 2040, 2050 and subsequently[1]?

The Transmission Needs Study should address these questions using scenarios for future transmission (and distribution) facilities that are derived from credible integrated, coordinated energy planning at the federal, regional, and state levels. This planning must consider the demand for electricity both for direct delivery to end uses over the grid, and for other purposes, as well as the roles of lower carbon fuels where electric solutions are not practical. Indirect uses for electricity include the production of some fuels with roles to play in decarbonizing selected applications and in the longer term to deliver power to various schemes for the removal of legacy emissions. Removal of legacy emissions will be needed to compensate for remaining anthropogenic emissions (to achieve Net Zero) and to reduce the concentrations of carbon dioxide (Net Negative) in the atmosphere and oceans to more sustainable and healthy levels if they exceed environmentally safe limits.

Perhaps the Draft Study and its future grid load scenarios are based on analyses which already include these considerations. If so, this is not evident from the Draft as it is currently presented and should be made explicit. If not, the Final Study should incorporate them and address the question of how public funds should be awarded to subsidize projects for clean hydrogen production, specifying that this hydrogen, a scarce resource, must not be diverted to applications for which it is not an effective solution for decarbonization. Hydrogen proposed as a replacement for methane in the natural gas distribution infrastructure to heat and meet other needs for energy in residential and commercial buildings is demonstrably unsuited for this purpose, both economically and because of its likely life cycle emissions including leaks of hydrogen itself (an indirect green house gas) and its emissions byproducts when burned in air, as well as for safety reasons given its high flammability. Public funding that subsidizes this application of hydrogen would be a waste of the resources needed to develop and support real solutions, not the interests of powerful organizations seeking to preserve their traditional business model at all costs to consumers, rejecting evidence proving the falsehoods of their claims about the benefits of hydrogen for heating buildings and refusing to plan cooperatively

[1] The elimination of increasing amounts of today's anthropogenic emissions are necessary to curb the substantial cumulative contributions that will otherwise be added to the concentrations, notably of CO2, in the atmosphere, before we reach Net Zero. Future generations will have to deal with this legacy in the second half of this century and beyond.

transitions to new business models for themselves and their workforces while there is still time to do so.

Projects to produce clean hydrogen must adhere to strict conditions initially and subsequently as appropriate to be eligible for public subsidies:

- Verification by independent sources that the subsidized hydrogen is genuinely clean on a life cycle basis.
- Satisfaction of additionality requirements for the consumption of clean electricity.
- Verification that all contracts for uses of the subsidized clean hydrogen are for applications where electrification is not feasible, and this gas is competitive with other potential solutions.

Thank you for the opportunity to submit these comments.

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VIA EMAIL

April 20, 2023

Office of Electricity
U.S. Department of Energy
1000 Independence Avenue, SW
Washington DC 20585

Re: National Transmission Needs Study

Dear DOE:

On February 24, 2023, the U.S. Department of Energy ("DOE") issued a draft report, National Transmission Needs Study ("NTN Study"). Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM ("Market Monitor"), provides this letter in response to DOE's solicitation of comments.[1] The Market Monitor's comments emphasize transmission development in the organized wholesale energy markets like the one operated by PJM Interconnection, L.L.C. ("PJM"). PJM markets and other regional transmission organization markets (RTOs/ISOs) use locational marginal pricing ("LMP") to price energy. The operation of LMP markets makes congestion transparent, creates congestion revenues, and requires a method to return congestion revenues to load.

The goal of PJM and RTO market design should be to enhance competition and to ensure that competition is the core element of all PJM and RTO markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require or even permit direct competition between transmission and generation to meet loads in the affected area. In addition, despite FERC Order No. 1000, there is not yet a transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide a clearly defined and enforceable total project cost cap, or to require that transmission owners obtain least cost financing through the capital markets.

Rules for competitive transmission development through the RTEP should build upon FERC Order No. 1000 to create real competition between incumbent transmission providers and nonincumbent transmission providers. The ability of transmission owners to block competition

1 *See* U.S Department of Energy, "*National Transmission Needs Study*," Draft for Public Comment (Feb. 2023)<*https://www.energy.gov/gdo/national-transmission-needs-study*> .

for supplemental projects and end of life projects and the reasons for that policy should be reevaluated. The rules should enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission.

Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base, paid for by customers. PJM now has the responsibility for planning the development of the grid under its RTEP process. Property bought to facilitate future expansion should be a part of the RTEP process and be made available to all providers on equal terms.

The process for determining the reasonableness or purpose of supplemental transmission projects that are asserted to be not needed for reliability, economic efficiency or operational performance as defined under the RTEP process needs additional oversight and transparency. If there is a need for a supplemental project, that need should be clearly defined within the RTEP process and there should be a transparent, robust and clearly defined mechanism to permit competition to build the project. If there is no defined need for a supplemental project for reliability, economic efficiency or operational performance then the project should not be included in rates.

The Commission should require that RTOs enhance the transparency and queue management process for nonincumbent transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from nonincumbent transmission. Nonincumbent transmission should also be held to clearly defined, enforceable standards to ensure that nonincumbent transmission costs are also consistent with a least cost, competitive outcome.

The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly, whether there is more risk associated with the generation or transmission alternatives, or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of RTO market design.

The current market efficiency process does exactly the opposite by permitting transmission projects to be approved without competition from generation. The broader issue is that the market efficiency project approach explicitly allows transmission projects to compete against future generation projects, but without allowing the generation projects to compete. Projecting speculative transmission related benefits for 15 years based on the existing generation fleet and existing patterns of congestion eliminates the potential for new generation to respond to market signals. The market efficiency process in PJM allows assets built under the cost of service regulatory paradigm to displace generation assets built under the competitive market paradigm. In addition, there are significant issues with PJM's current cost/benefit analysis which cause it to consistently overstate the potential benefits of market efficiency projects. The market efficiency process is misnamed. The Market Monitor recommends that the market efficiency process in PJM, and any similar processes in other RTOs, be eliminated. If it is retained, there are significant issues with PJM's cost/benefit analysis that should be addressed prior to approval of additional projects. The current cost/benefit analysis for a regional project, for example, explicitly and incorrectly ignores the increased congestion in zones that results from an RTEP project when calculating the energy market benefits. All costs should be included in all zones and LDAs. The definition of benefits should also be reevaluated.

The cost/benefit analysis should also account for the fact that the transmission project costs are not subject to cost caps and may exceed the estimated costs by a wide margin. When actual costs exceed estimated costs, the cost/benefit analysis is effectively meaningless and low estimated costs may result in inappropriately favoring transmission projects over market generation projects. The risk of cost increases for transmission projects should be incorporated in the cost/benefit analysis.

As an example of the complexities of defining the benefits of transmission investments, the reduction in congestion is frequently and incorrectly cited as a metric of benefits.

Congestion is frequently misunderstood. Congestion is not static. Congestion exhibits dynamic intertemporal variability and dynamic locational variability. More importantly, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid.

There is not a secular trend towards increasing congestion in PJM. Congestion is volatile on a monthly basis. Congestion is also volatile on an hourly and daily basis. For example, higher congestion can result from changes in seasonal and daily/hourly fuel costs.

The level and distribution of congestion at a point in time is a function of the location and size of generating units, the relative costs of the fuels burned and the associated marginal costs of generating units, the location and size of load and the locational capability of the transmission grid. Each of these factors changes over time.

The geographic distribution of congestion is dynamic. The nature and location of congestion in the PJM system has changed significantly over the last 10 years and continues to change. The nature and location of congestion in PJM can also change from one day to the next as a result of changes in relative fuel costs. As a result, building transmission to address a specific pattern of congestion does not make sense, unless the technology can be easily moved to new locations as

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conditions change. The transmission system is only one of many reasons that congestion exists. The dynamic nature of congestion and the multiple, interactive causes of congestion make it virtually impossible to identify the standalone impacts of an individual transmission investment on future congestion. It is possible, for example, that congestion occurring during a period of a few days in the winter as a result of very high fuel prices, significantly increases the reported level of congestion for the entire year. This has occurred in PJM. It would be a mistake to consider that level of congestion to be a signal to build transmission.

At a more fundamental level, congestion is not the correct metric for evaluating the potential benefits of enhancing the transmission grid. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. Congestion is neither good nor bad, but is a direct measure of the extent to which there are multiple marginal generating units with different offers dispatched to serve load as a result of transmission constraints. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load. The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area. Load in the constrained area pays the higher price for all energy including energy from low cost generation and energy from high cost generation, while only high cost generators are paid the high price at their bus and low cost generators are paid only the low price at their bus.

If FTRs worked perfectly and were assigned directly to load, FTRs would return all congestion to the load that paid the congestion. Congestion is not a cost, it is an accounting result of a market based on locational energy prices in which all load in a constrained area pays the higher single market clearing locational price, resulting in excess payments by load that are not paid to generation, which should be returned to load.

Counterintuitively, congestion actually increases when the transmission capacity between areas with lower cost generation and areas with higher cost generation increases but does not fully eliminate the need for some higher cost local generation. The smaller the amount of higher cost local generation needed to meet load, the more of the local load is met via low cost generation delivered over the transmission system and therefore the higher is the difference between what load pays and generation receives, congestion.

The PJM Regional Transmission Expansion Plan (RTEP) successfully addresses the need for transmission investment to reliably meet load. Together with the requirement that new generation pay interconnection costs, the RTEP process has resulted in the appropriate level of new transmission investment in PJM. There is no evidence that the PJM planning process is not adequate to meet the requirements of the PJM markets. Additional transmission investment is not a panacea. Transmission investment is expensive and long lived and it is essential that

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transmission investments be carefully planned for clearly identified needs in order to ensure that power markets can continue to provide reliable service at a competitive price.[2]

The Market Monitor issues comprehensive quarterly state of the market reports on PJM markets. The state of the market reports include data and analysis supporting the basic points made in this letter. The reports, and other information, including filings with the Federal Energy Regulatory Commission concerning transmission issues, can be accessed on our website at *www.monitoringanalytics.com*.

Sincerely,

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General Counsel

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2 Starting in the third quarter of 2019, the cost of transmission per MWh of wholesale power in PJM has been higher than the cost of capacity. See Monitoring Analytics, LLC, *2022 State of the Market Report for PJM*, Vol 2. Section 1: Introduction, p19, Table 1-10.

National Electrical Manufacturers Association
The association of electrical equipment
and medical imaging manufacturers
www.nema.org

April 20, 2023

U.S. Department of Energy
Grid Deployment Office
1000 Independence Ave., SW
Washington, DC 20585

RE: Comments on Draft 2023 National Transmission Needs Study

Submitted via: needsstudy.comments@hq.doe.gov

To whom it may concern:

The National Electrical Manufacturers Association ("NEMA") submits the following comments in general support of the Department of Energy's ("DOE") draft *National Transmission Needs Study* ("Study"). As our organization has voiced in previous editions of this study (formerly known as the *National Electric Transmission Congestion Study*),[1] we believe such exercises prove useful for all parties involved in transmission development to properly identify and frame the challenges to the buildout of this vital grid component. Further, with the recent historic investments in clean energy through the Infrastructure Investment and Jobs Act ("IIJA") and the Inflation Reduction Act ("IRA") on both the demand and supply sides of the electric grid, the Study is timely and can help ensure that the benefits sought through electrification are maximized.

NEMA represents nearly 325 electrical equipment and medical imaging manufacturers that make safe, reliable, and efficient products serving building systems, building infrastructure, lighting systems, industrial products and systems, utility products and systems, transportation systems, and medical imaging. Our combined industries account for roughly 370,000 American jobs in more than 6,100 facilities located in every state. These industries produce $124 billion in shipments and $42 billion in exports of electrical equipment and medical imaging technologies per year.

The electroindustry fully understands that the clean energy transition and modern economy cannot be realized without resilient, reliable, and adequate high voltage direct

[1] https://www.energy.gov/oe/articles/2020-national-electric-transmission-congestion-study

current ("HVDC") transmission investment. NEMA supports processes which makes HVDC more plentiful, including through the application of grid enhancing technologies which make existing lines 'smarter' and more efficient to physical upgrades to components, such as updating wire cores from steel to composite. Modernization of existing HVDC lines alone, however, will only produce marginal benefits for the grid as a whole. The development and installation of new HVDC transmission lines in the near-term and throughout the country is necessary for this transition to be holistically successful.

Therefore, NEMA has aligned with other organizations to encourage DOE, the Federal Energy Regulatory Commission ("FERC"), and other relevant agencies to bring fresh and creative perspective and insight to how transmission projects can progress in fair, efficient, and effective ways. These coalition partners include the Rail Electrification Council ("REC") and NextGen Highways to encourage and incentivize the use of existing rights of ways for transmission siting along railroads and highways. Additionally, NEMA supports the position taken by Americans for a Clean Energy Grid to identify ways for greater cooperation among regional grid interconnections as well as permitting and other institutional reforms necessary for national grid development.

For decades, America's electroindustry has been an active participant in the development and deployment of innovative and reliable grid products across the transmission spectrum. In many ways, the nation's current electric grid exists due to the enabling strategies made capable by these technologies. As transmission developers, siting authorities, regulatory agencies, and other interested parties consider how best to address transmission needs, it is important they consult with manufacturers to better understand the art-of-the-possible which current technologies can offer.

The Study defines an electric transmission need as the "present or expected electric transmission capacity constraints or congestion in a geographic area."[2] Furthermore, "geographic areas where a transmission need exists could benefit from an upgraded or new transmission facility—including non-wire alternatives—to improve reliability and resilience of the power system." NEMA appreciates DOE's continued acknowledgment that there is not one need regarding transmission and, therefore, not a one-size-fits-all solution to satisfy those needs. The current and future energy requirements of the thirteen geographic regions identified in the Study vary due to a variety of factors, including changes in population, topographical barriers, political and cultural norms and traditions, property rights, and other market- and policy-based issues. Thus, the answers to a region's electric energy needs will rely on a blend of cooperation, opportunity, creativity, and technological prowess.

[2] https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf

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Just as the Study is neutral in its analysis and simply identifies the needs of each region based on DOE's review of publicly available data and industry studies, NEMA wishes to generally emphasize available technological opportunities and recommend potential policy considerations which could help address those needs.

Technological Opportunities

- Continued Consideration and Adoption of Grid Enhancement / Dynamic Line Rating Technologies

  The needs of the various energy regions and the states within them vary dramatically; investment in new transmission lines and infrastructure alone will not solve their immediate and short-term load needs given the lengthy process to build and implement such projects. Grid enhancement technologies ("GET"), such as dynamic line ratings which enable constant measuring and adjusting of transmission load based on immediate operating conditions, allow current infrastructure to become as efficient as possible. As the Study makes clear, non-wires alternatives need to be considered on par with new transmission investment if the goals of electrification are to be realized and needs adequately met.

  Other federal entities have already begun to support these alternatives. To improve the accuracy, transparency, and effectiveness of transmission line ratings, FERC issued Order 881, a policy aimed at maximizing available transmission capacity. The order will require independent system operators, transmission owners, and regional transmission owners to implement ambient-adjusted ratings ("AAR") on the transmission lines over which they provide transmission service. AAR technologies are products which frequently, some hourly, calculate the variables of a transmission line, enabling more timely and accurate information to be relayed to transmission system operators and managers. NEMA encourages DOE to continue encouraging an 'all-of-the-above' philosophy when it comes to grid enhancement technologies as viable solutions to regional transmission needs.

- Grid Component Modernization

  The deployment of modernized grid components can effectively bridge many capacity and line-efficiency needs in every energy region. For example, the replacement of legacy steel-core wires with high-temperature, low sag conductors can allow for more power to be pushed through a transmission corridor and over a longer distance. Such products made with composite cores versus steel are able to transport more load capacity with reduced expanding and sagging of the wires themselves. Combine hardware upgrades such as these with the software technologies described above, transmission needs can be met much more quickly.

The IIJA provided ample funds for grid resilience and reliability upgrades. As NEMA suggested in its comments to DOE on the implementation of the Grid Resilience and Innovative Partnership ("GRIP") program last year, a proactive approach to grid resilience planning will help ensure cost effective IIJA investment. As envisioned, it will also invite more capital and creativity into this space, allowing for the potential of even greater and more effective solutions to transmission needs.

The GRIP program encourages grid operators to lean into the value of data-driven, automated decision-making technologies; smart tools which further identify risks and opportunities for planning purposes and needs identification. GET, dynamic line ratings systems, stationary battery technologies, distributed energy resource aggregators, and other advanced power flow control devices are proven, innovative tools which have helped the grid modernize. Such technologies likewise serve as a practical bridge between legacy equipment, designed to achieve output goals, and contemporary systems, designed with cybersecurity, digital connectivity, and efficiency in mind.

Policy Considerations

- Utilization of Rights of Way

NEMA advocates strongly for siting authorities on the federal, state, and local levels to encourage the use of rights of ways ("ROWs") along existing highways, railroads, brownfields, and other corridors for transmission development. The benefits of such utilization are many, particularly for the communities transmission projects are expected to navigate through. Such benefits include minimal or low environmental impact by running alongside, above, or below existing transportation corridors. These avenues already run close to or directly through populated regions which require higher energy loads; utilizing ROWs thereby increases distribution efficiency and reduces property-rights issues. Existing ROWs provide project developers a ready-made option to run new transmission lines.

Providing the correct incentives for owners of ROWs is a necessary component in order for this recommendation to effectively address transmission needs. For example, most railroad ROWs are privately owned, and the industry is already heavily regulated by the Federal Railroad Administration ("FRA"), which sets safety standards and approves rail research and improvement strategies. Collaboration with railroad companies and the FRA along with transmission developers, FERC, the REC, and other interested parties is strongly suggested. Doing so will allow the best incentives to be identified and encourage these entities to become partners in the electrification of America's economy.[3]

Highway ROWs provide similar benefits for electrification but require different incentives in order to be utilized for transmission development. Primarily owned by states and managed by state transportation authorities, existing highway ROWs can allow for transmission to be developed with mitigated impact and increased societal benefits. However, many states have dated rule or regulations that currently disallow for transmission development to occur on such corridors, enacted decades before in part because of safety concerns. Modern day grid technologies allow the safe implementation and flow of transmission along highways; modernizing these laws to compliment technological advancements will help provide transmission benefits sooner.

Similar to railroads, greater collaboration and leadership between and among federal agencies can allow for highway ROWs to be utilized more quickly. The DOE, FERC, the Federal Highway Administration ("FHWA"), the Department of Interior, and others all play an important role in the development of this transmission solution. For example, the FHWA allows for highway transmission projects to be given a "utility accommodation" or receive approval as an "alternative use" of the highway ROW to overcome dated statutes. Likewise, in its backstop siting notice of proposed rulemaking,[4] NEMA and the REC encourage FERC to consider and prioritize ROWs as it considers new authorities in order to advance transmission development.

- Identify Lack of Transformer Ability as a 'Need'

  While the Study is mainly concerned with transmission needs, grid development must be looked at in a wholistic way and include variables concerning electricity distribution. The availability of critical products necessary for the grid's functionality at the state and local level, meaning consumer end-users, must be considered as part of transmission planning: the timing and ability to deliver electricity to the end user are paramount when planning future transmission load usage, rate setting, and return on investment.

  The Study does mention, albeit as an example, that power flow could be constrained due to the technical limitations of transformers themselves and be a cause of transmission constraint.[5] This is true; a transformer itself can only step-up or step-down a certain capacity of electricity, based on its technical design. However, the document stops short of identifying that the lack of available transformers is in itself a

[3] https://www.utilitydive.com/news/4-transmission-technologies-to-watch/617945/
[4] https://www.federalregister.gov/documents/2023/01/17/2022-27716/applications-for-permits-to-site-interstate-electric-transmission-facilities
[5] https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf

much greater cause of transmission congestion. NEMA argues that the larger issue confronting transmission development is less the technical limits of a transformer and more the inability to obtain one.

Large power and distribution transformers are key to the grid's distribution operations. Without them, transmission loads have nowhere to go as electricity cannot be delivered to the end user. Production timelines for these products have extended exponentially over the past few years for a variety of reasons. In 2020, the expected delivery time for a distribution transformer once it was ordered was about six months; now it is more than 16 months on average. For large power transformers, the wait time can be as high as 38 months.[6]

DOE conducts transmission needs studies on a triennial basis. If the ability to obtain transformers, or any other grid component, takes roughly half or even longer than the scope of these studies, NEMA argues that this is a significant 'need' which much be considered and presented as a study criterion. NEMA has submitted to DOE numerous comments within the past six months on what policies should be pursued by government in order to help reduce the production timeline of these products.[7] [8] We urge the department to include and acknowledge this situation as part of its final document.

NEMA once again appreciates the opportunity to provide these comments on the Study. If there are questions regarding these comments, please do not hesitate to contact me.

Sincerely,

Spencer Pederson
Vice President, Public Affairs

[6] https://www.tdworld.com/utility-business/article/21243198/transformative-times-update-on-the-us-transformer-supply-chain
[7] https://www.nema.org/docs/default-source/advocacy-document-library/nema-comments-on-distribution-transformers-nopr-march-27-2023.pdf?sfvrsn=b64b63fe_3
[8] https://www.nema.org/docs/default-source/advocacy-document-library/nema-gridwise-comments-doe-dpa-rfi-11.30.22.pdf?sfvrsn=2969fc7b_4

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Submitted via email to NeedsStudy.Comments@hq.doe.gov.

nationalgrid

April 20, 2023
Grid Deployment Office
Office of the Under Secretary for Infrastructure
Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

RE: Request for Feedback on the draft DOE National Transmission Needs Study

National Grid is pleased to submit these comments on the Draft National Transmission Needs Study, published in the federal register for public review and comment by the U.S. Department of Energy (DOE) on March 6, 2023. National Grid also supports the responses from the Edison Electric Institute (EEI), the American Clean Power Association (ACP), the Advanced Energy Group (AEG), and the New York Transmission Owners (NYTO).

National Grid is a gas and electric utility delivering power and heat to more than 20 million people in New York and Massachusetts. With almost 9,000 miles of electric transmission lines, 70,000 miles of electric distribution circuits, and 36,000 miles of gas pipelines in the US, we help heat and power homes and businesses and connect communities to the energy they need. Our 17,000 employees, two-thirds of whom belong to a union, are at the heart of transforming our electricity and natural gas networks with smarter, cleaner, and more resilient energy solutions to achieve our net-zero by 2050 ambition.

In addition to our core regulated business, National Grid also owns and operates National Grid Ventures. National Grid Ventures is our competitive business that operates outside of National Grid's core regulated businesses in the UK and US where it develops, operates, and invests in energy projects, technologies, and partnerships to accelerate the development of our clean energy future. Such projects in the US include investment in transmission through regulated venues or ISO system planning, as well as competitive transmission projects and development of offshore wind generation in the region.

Last year, National Grid and National Grid Ventures each announced plans to further our net-zero ambition. National Grid's Clean Energy Vision positions our communities to become clean energy capitals. Our aim is to fully eliminate fossil fuels from our U.S. gas and electric networks no later than 2050.

National Grid agrees with the study's conclusion that interregional transmission ties between New York and New England will be significant for economic security and the region's clean energy vision. As both regions set ambitious climate goals, the electrification of large swathes of the Northeastern economy will depend on a robust and reliable electric grid to provide reliable and affordable access to clean electricity.

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The Northeast also faces unique challenges. Cold winters make access to heating a priority for the region. Electric heating will increase demands on the grid on the coldest (overnight) hours of the coldest days of the year—by the end of this decade, Upstate New York is expected to become winter-peaking. At the same time, the region faces gas supply constraints, and New England has faced substantial commodity price increases due to reliance on imported LNG. Both regions also anticipate interconnecting large amounts of onshore solar and offshore wind in the next decade.

As such, we have expanded upon the below themes in our attached comments:

- The value of interregional transmission to enable the clean energy transition in the Northeast;
- Lessons from the Northeast's transmission and clean energy efforts to date;
- Insights from National Grid's unique position as operator of existing interregional ties and as distribution utility / transmission owner in neighboring regions; and
- How National Grid can support the DOE through the Planning Study or other efforts to advance interregional transmission.

Thank you for the opportunity to provide comments, and please do not hesitate to contact us with questions. We thank the Department in advance for considering our and others' comments on the Draft National Transmission Needs Study.

Respectfully submitted,

/s/ Michael C. Calviou
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National Grid – Draft National Transmission Needs Study Comments

I. Interregional Transmission Will Play a Crucial Role for the Northeast's Economy

National Grid affirms that interregional transmission will be critical to enabling clean energy growth and economic security in regions like the Northeast. The Northeast's progressive climate goals and grid planning experience positions National Grid to offer unique learnings for our peers across the US, including the DOE's National Transmission Planning Study. We believe that the DOE Needs Study identifies potentially valuable opportunities based on congestion pricing. National Grid has experience and capability to help the DOE and partner agencies take this analysis a level deeper such as including operational (production cost) and resource (capacity expansion) modeling across regions, while also evaluating interface impacts on resilience and reliability. We also believe that the DOE and the federal government have a valuable role in determining how to quantify and value these interregional benefits, e.g. economic or national security.

As the clean energy transition progresses, the Northeastern transmission grid will increasingly become the backbone of the region's economy. Therefore, it is critical to manage the transition to not only meet climate goals but also to allow for clean economic growth and preserve energy security. The colder weather of the Northeast region paired with natural gas constraints, electric heating, and dependence on foreign fuels in New England are unique challenges the region faces. Interregional ties can bring down the cost of the energy transition in the region, help ensure energy security and access to vital services during adverse events, and support the region's continued growth as electricity powers more of the Northeastern economy. Having a strong, inter-regional transmission grid will ensure the region's economic security yet barriers found in the current, suboptimal inter-regional planning process and ex-ante cost allocation inhibit the region's ability to develop inter-regional projects.

II. Lessons from an Accelerating Clean Energy Transition in the Northeast

Since the conclusion of the study period, the Northeast has made significant progress in intraregional transmission development to support clean energy that can be leveraged to develop national policy and processes.

New York's 2020 Accelerated Renewable Energy Growth and Community Benefit Act (AREGCBA) spurred substantial investments, including over $5B announced to date for local transmission "on-ramps" and "off-ramps" to deliver renewable energy across the state. New bulk transmission projects have also progressed over the past two years, including Smart Path Connect (a partnership between National Grid and the New York Power Authority) and two projects increasing renewable energy deliverability downstate, the Champlain Hudson Power Express (which will deliver hydropower from Quebec) and the Clean Path New York. New York utilities have also proposed a new integrated planning framework, the Coordinated Grid Planning Process[1], which seeks to effectuate T&D planning to enable the state's clean energy goals. New York has also successfully utilized its Public Policy Transmission Needs process to solicit competitive transmission solutions to unbottle and prepare for renewable generation. The lessons learned from New York policy and process development, particularly around development of transmission for renewable deliverability, would provide valuable insights to national leaders pursuing a clean energy supply.

Even with the long history of investments directed towards reducing congestion in New England, there are still gaps and opportunities for the New England electric market in its transition to net zero. New England's unique position in the country means that there are limited

[1] A Coordinated Grid Planning Process proposal was filed by a group of utilities, including National Grid, in response to the New York Public Service Commission proceeding to develop and consider proposals for implementing the provisions of the Accelerated Renewable Energy Growth and Community Benefit Act with respect to distribution and transmission upgrades, capital expenditures and planning.

clean energy resources for the region to tap into locally. National Grid recognizes that future investments into the region also need to take into consideration a holistic view of the diverse needs of customers and system at large such as reducing transmission curtailments, bolstering grid resiliency, enabling a clean fuel mix, and access to low-cost resources. National Grid is exploring the *Twin States Clean Energy Link* project that would provide multi-faceted value to the region by increasing interregional (HVDC) energy flow between New England and Quebec, Canada while increasing the flexibility of the transmission system in times of low or high customer demand. Although the project directly addresses the Canadian transfer capacity need as identified in the DOE Needs Study, the project will need the support of DOE and other partner agencies. The support of DOE in both advocacy and financial partnering are key to stewarding in the needed interregional transmission investments (like *Twin States Clean Energy Link*) for the clean energy future. While ISO-NE is undergoing a series of studies to reform planning to enable its region's climate goals, the DOE's National Transmission Planning Study could guide and influence how regional planning in New England integrates interregional ties to meet future load and generation growth and optimal design of offshore/onshore wind networks.

The Inflation Reduction Act will further accelerate clean energy deployment and economy wide electrification in the Northeast. National Grid's experience in Northeastern states', pressing an aggressive clean energy agenda that leads to an increased need for large scale transmission across the region, can provide insights for the entire country – not only as it pertains to interregional transmission, but transmission planning and development writ large. As a distribution utility and transmission owner who serves these neighboring regions, National Grid looks forward to sharing its experience with DOE and other federal agencies.

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III. Insights from National Grid's Experience Across These Neighboring Regions

National Grid has a unique position operating transmission assets which connect the NY and NE regions, while also operating thousands of miles of transmission within NYISO and ISO-NE planning regions. From that experience, we offer these high-level comments about the benefits of interregional ties identified in the Needs Study, particularly in the Northeast:

1. **Considering *project-specific* benefits is critical.**

   Needs assessments are a critical first step to any engineering process, identifying regions where additional capacity provides value, but results become more meaningful when applied to specific projects, considering the unique attributes, benefits, and challenges associated with a transmission upgrade. For example, evaluating how transmission upgrades will impact interregional transmission capacity requires complex modeling and collaboration on both sides of the interface, including potentially unique planning criteria, to identify contingencies and conditions limiting the new interface and its capability. National Grid, as one of the largest transmission owners in the Northeast, is also uniquely positioned to assess both the NY and NE system needs and benefits of owning and operating expansive contiguous transmission networks in NY and NE.

2. **Evaluating *multiple value streams* is also imperative.**

   The congestion mitigation opportunities identified by the Needs Study are valuable. We expect that the Needs Study would benefit from results from a more granular regional production cost modeling and better quantify the operational cost benefits of an interregional intertie across New York and New England, provide further insight into how an interregional transmission upgrade might reduce wholesale market volatility, and provide key generator dispatch insights.

In addition to operational benefits of interregional coordination, capital investment decisions are being made right now based on state policy mandates. Interregional capacity can potentially reduce total investment cost by providing a more optimal distribution of renewable resources, allowing more efficient achievement of the clean energy transition. Capacity expansion modeling performed in the Transmission Planning Study would provide insights into this benefit under different scenarios. The federal government (including DOE and FERC) may have a role beyond evaluating this benefit, in improving inter-state planning (both at the regulator and ISO level) to ensuring each region reaps maximum benefits from additional interregional capacity through with co-optimized solutions. .

Lastly, it is critical to consider planning synergies that transmission investments can provide by supporting traditional planning needs as well as renewable deliverability. This includes consideration of Multi-Value opportunities, particularly related to Asset Condition (i.e. projects to replace end-of-life assets), as the average transmission asset in much of National Grid's territory is at least 50 years old. National Grid appreciates the opportunity to explore these considerations along with the DOE and PNNL in the Transmission Planning Study.

3. **Resiliency and reliability can be substantially improved with interregional transmission in the face of climate change, though quantifying this benefit is a challenge.**

Though some tools exist or are under development to assess resilience and reliability benefits – such as the Interruption Cost Estimator 2.0[2] -- quantifying these types of benefits

[2] National Grid has joined LBNL and other utilities to develop the ICE Tool 2.0, a tool designed to quantify energy user tradeoffs and costs associated with power delivery interruptions, which may provide insights into a portion of the reliability

is a challenge. One thing that is clear is that the value of interregional transmission in providing resiliency benefits will only increase in the coming decades. Climate change will drive weather volatility and likely increase the number of transmission-level outages requiring mitigation. As generation supply in the region becomes more dependent on intermittent renewables, a robust interregional network can take advantage of generation diversity and help mitigate curtailments of surplus renewable energy. These are important economic and environmental considerations that are becoming more valuable to Environmental Justice Communities and individual energy consumers dependent on the electric grid, for example to charge their cars or heat their homes. Interregional transmission can also provide resiliency benefits to the gas delivery and supply system, enabling flexible reallocation of thermal generation resources to mitigate gas constraints[3].

4. **Actively examine *both* on-shore and off-shore resources to holistically perform interregional planning.**

The Northeast is positioned to deliver most of the federal '30GW of Offshore Wind by 2030' goal between New England interconnection sites like Brayton Point and New York's development to the south including the New York Bight. These seismic shifts in supply profiles can cause challenges throughout the grid (far from the interconnection sites), particularly given the intermittent nature of these resources. Interregional transmission can help smooth out intermittency and reduce load center dependence of offshore resources, maximizing the value of offshore resources by complementing them. The DOE-funded NREL Atlantic Offshore Wind Transmission Study has begun to look at pathways for

[3] National Grid believes this is particularly salient in the Northeast, where New York generation may have the opportunity to offset thermal generation during New England's impending and growing winter peaks, mitigating New England gas constraints.

deploying wind energy through assessing different transmission topologies and their impacts, including offshore connections between regions. With such a large amount of offshore wind anticipated in the Northeast[4] and the challenges this brings both on and offshore, the DOE should consider how the results of the Needs Study and the Atlantic Offshore Wind Transmission Study interact, particularly when it comes to interregional transfers. National Grid's *Twin States Clean Energy Link* project can play a significant role in getting ahead of these issues through its proposed bi-directional, 1200 MW HVDC line. However, the project is ultimately one potential piece of the future interregional transmission system in the Northeast.

IV. Conclusion

In conclusion, National Grid offers its expertise to the DOE & partner agencies through direct engagement or participation in the National Transmission Planning Study**.** Our involvement in NE-ISO and NYISO regional studies puts us in a unique position to see the planning processes of neighboring regions.

We have identified points of contact below who look forward to engaging with DOE and partner agencies on these efforts:

Tom Vaccaro	Director, Clean Energy Development – Transmission for Renewables in New York	Thomas.vaccaro@nationalgrid.com
Terron Hill	Director, Clean Energy Development – Transmission for Renewables in New England	Terron.hill@nationalgrid.com

[4] New England, New York, and New Jersey have targets totaling 29GWs by 2040; 65-95GW are estimated to be needed to meet decarbonization targets.

The National Hydropower Association, Inc.
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March 6, 2023

Re: Comments on the Public Draft National Transmission Needs Study

The National Hydropower Association ("NHA") is a non-profit national association dedicated to securing hydropower as a clean, carbon-free, renewable, and reliable energy source that provides power to an estimated 30 million Americans. Its membership consists of more than 300 organizations, including public and investor-owned utilities, independent power producers, equipment manufacturers, and professional organizations that provide legal, environmental, and engineering services to the hydropower industry. NHA promotes innovation and investment in all waterpower technologies, including conventional hydropower, marine and hydrokinetic power systems, and pumped storage hydropower to integrate other clean power sources, such as wind and solar.

NHA appreciates the opportunity to respond to the Department of Energy (DOE) Grid Deployment Office (GDO) Draft National Transmission Needs Study ("Report") issued January 19th, 2023, to provide information about present and anticipated future capacity restraints and congestion on the nation's electric transmission grid.

DOE states in the Executive Summary:

> …study prescribes no particular solutions to issues faced by the Nation's power sector. Rather, it establishes findings of need in order for industry and the public to suggest best possible solutions for alleviating them in a timely manner. As used in this study, an electric transmission need refers to the existence of present or expected electric transmission capacity constraints or congestion in a geographic area. Geographic areas where a transmission need exists could benefit from an upgraded or new transmission facility—including non-wire alternatives—to improve reliability and resilience of the power system; alleviate transmission congestion on an annual basis; alleviate transmission congestion during real-time operations; alleviate power transfer capacity limits between neighboring regions; deliver cost-effective generation to high-priced demand; or meet projected future generation, electricity demand, or reliability requirements.

Within this scope and purpose of this Transmission Needs Study, the NHA would like the DOE and authors of this report to consider the following comments:

1. **NHA asks the DOE to consider and provide more emphasis to both large and small hydropower development in supporting and strengthening the nation's grid system.**

    a. Such support would require a more robust consideration of the need to unlock stranded hydropower. The placement of hydropower is uniquely riverine near mountains which in some cases make traditional transmission financing impractical or not immediately viable. However, as our nation's grid becomes increasingly

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strained and requires new tranches of firm hydropower, these potential transmission lines take on an energy security role that focuses less on financing and more on reliability. NHA also recognizes the value of energy security and the discussions of decarbonization create new value propositions for supporting hydropower developers and their interconnections to the existing grid.

2. **NHA recommends the DOE consider an analysis to uncover potentially constrained hydropower projects that would otherwise be minimally viable should additional transmission assets be located to unleash potential hydropower resources.**

    a. There are more than 90,000 dams in the United States and approximately 3% generate electricity.[1] These dams are a large and untapped source of energy from *existing* infrastructure. DOE should consider non-powered dams that could be electrified to unlock clean energy potential. Depending on the location, these dams could be an alternative that could be a cost beneficial alternative to new transmission lines.

3. **NHA recommends the DOE Transmission Needs Study consider conducting an Alaska appendix to address the transmission needs for Alaska, considering its geological area.**

    a. Within the National Transmission Needs Study, there is no reference that Alaska could export hydropower to the Yukon or British Columbia should these transmission links occur. Hydropower development requires markets and transmission. There are instances where transmission costs limit viability without federal or other subsidy assistance. Alaska represents 17% of our nation's land mass and represents a large percentage of our nation's untapped renewable energy sources yet represents less than 1% of our nation's high voltage and low voltage circuitous transmission miles.

4. **NHA recommends the DOE National Transmission Needs Study include pumped storage in its analysis.**

    a. DOE analyzes the impact of storage technologies as a non-wires alternative and recognizes it as a grid enhancing technology. Much of DOE's study analyzes reports that discuss the beneficial impact of battery storage technologies. NHA recommends DOE include pumped storage as an alternative. Most of the installed capacity for storage technologies in the United States is pumped storage. For pumped storage alone, there are approximately 40,000 MWs of proposed projects for permits and licenses at the Federal Energy Regulatory Commission. There are studies available to DOE including from the National Renewable Energy Laboratory.[2]

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[1] FEMA, *National Inventory of Dams*, Available at https://www.fema.gov/emergency-managers/risk-management/dam-safety/national-inventory-dams

[2] One such study is from Hydrowires called the Closed-Loop Pumped Storage Hydropower Resource Assessment for the United States. It was published May 2022 and is available at https://www.nrel.gov/docs/fy22osti/81277.pdf.

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5. **NHA recommends the DOE National Transmission Needs Study include marine energy as a growing and highly potential energy source.**

    a. NHA finds that the study does not address the potential impacts of emerging hydrokinetic energy resources such as marine energy as a potential alternative to new transmission. Marine energy technologies are defined as those that are powered by currents, tides, and waves.[3] Although a developing industry, a recent DOE study analyzed the technical and theoretical potential of marine energy in the United States.[4] The report found that there is a technical potential of upwards of 2,300 Terawatt-hours for marine energy (approximately 57% of electricity generated in the United States in 2019).[5]

Thank you for your time to review NHA comments on the DOE Transmission Needs Study. We look forward to reviewing the final report.

Respectfully submitted,

Anthony Laurita, Program Manager
National Hydropower Association

[3] Marine energy is defined in the Energy Act of 2020 as energy from waves, tides, ocean currents, free-flowing rivers and man-made channels, as well as from differentials in salinity, temperature, and pressure.
[4] U.S. Department of Energy. Marine Energy in the United States: An Overview of Opportunities (February 2021). https://www.energy.gov/sites/prod/files/2021/02/f82/78773_3.pdf.
[5] Id. at vii.

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COMMENTS OF PUBLIC INTEREST ORGANIZATIONS

Natural Resources Defense Council, Sustainable FERC Project, RMI, Earthjustice, Sierra Club, National Wildlife Federation, Southern Environmental Law Center, Western Resource Advocates, Montana Environmental Information Center, National Audubon Society, and Alliance for Affordable Energy (together "Public Interest Organizations" or "PIOs") submit these comments in response to the March 6, 2023 Draft Transmission Needs Study issued by the Department of Energy ("Needs Study" or "Study").[1]

I. PIOs Agree with the Needs Study's Conclusions Regarding the Need to Expand Transmission Planning

PIOs strongly agree with the Needs Study's conclusions regarding the need to expand transmission planning, particularly interregional and cross-interconnection transmission, to enhance reliability, support electrification efforts, and to reduce costs for consumers. As the Study notes, "studies reviewed signify a pressing need to expand electric transmission—driven by the need to improve grid reliability, resilience, and resource adequacy, enhance renewable resource integration and access to clean energy, decrease energy burden, support electrification efforts, and reduce congestion and curtailment."[2] Emphasizing the importance of regional and interregional transmission planning to ensure reliability in the face of increasingly common severe weather events, the Study finds that "[r]ecent experience with extreme weather events demonstrates that planning for the bulk power system needs to extend beyond the footprint of individual utilities or regions to provide assurance that energy can be delivered from where it is available to where it is needed to mitigate risks associated with common mode failures."[3] Highlighting the importance of

[1] Department of Energy, *Draft Transmission Needs Study*, 88 Fed. Reg. 13811 (March 6, 2023).
[2] Needs Study at ii.
[3] *Id*. at 3.

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scenario-based multi-value transmission planning in reducing costs for consumers, the Study finds that "holistic, scenario-based, multi-value transmission expansion planning can also provide energy price benefits to consumers, and this Needs Study seeks to assess opportunities to lower consumer energy costs through such coordinated transmission planning and development efforts to meet expected future conditions."[4]

PIOs have long advocated for scenario-based, multi-value transmission planning because of the multiple benefits it provides. As we stated in our comments in response to the Federal Energy Regulatory Commission's recent proposals to address systemic problems with existing regional and interconnection planning, the "failure to conduct transmission planning across a regional and interregional portfolio using a multi-value and scenario-based methodology produces an inefficient patchwork of incremental transmission projects that limit the planning processes' ability to identify more cost-effective investments that meet both current and rapidly changing future system needs, address uncertainties, and reduce system-wide costs and risks that systematically results in inefficient infrastructure and excessive electricity costs."[5] As a result, current transmission planning processes across the nation result in inefficient investments that foreclose meaningful competition, miss out on economies of scale, and result in consumers paying considerably more for significantly less—less choice, less capacity, less flexibility, less resiliency, and ultimately less reliability.[6]

A. The Study Establishes a Sufficient Basis for Future Action but Could Benefit from Additional Clarification

[4] *Id*.
[5] *Comments of Public Interest Organizations* at 51 (Oct. 12, 2021), Accession No. 20211012-5519 ("PIOs' Initial ANOPR Comments"), *citing* Brattle Report at 4 (internal quotations omitted).
[6] *Id*. at 53.

In compiling the Needs Study, DOE examined 50 sophisticated transmission modelling studies that highlight the historical and anticipated drivers, benefits, and challenges of transmission expansion. These studies include reports from the National Labs, industry, academia, and consultants that incorporate quantitative and qualitative analysis of transmission needs, including increased reliability, cost savings, and other benefits. The studies have a wide geographic diversity, subject matter expertise, and cover a wide range of issues faced by the nation's transmission system today. Given DOE's review of these studies, it was not necessary to replicate these already existing studies with its own qualitative or quantitative study where the cited studies provide sufficient and reliable information to identify transmission needs. Conducting a systematic review or meta-analysis of transmission studies is a routine and scientifically appropriate means of research and grounds for policymaking.

That being said, greater clarity from DOE around this point would be beneficial, including the scope of its research and its own criteria for assessing whether a present or future transmission need exists in the first place. One critical area for clarification is DOE's position regarding its own criteria for comprehensive identification of a transmission need. Numerous studies, and the Federal Energy Regulatory Commission's recent regional transmission NOPR, have indicated that to adequately address future needs, planners must evaluate transmission needs under multiple reasonably anticipated scenarios that incorporate several drivers—including expected generation changes, shifting trends in demand, and extreme weather patterns—and assess all the potential benefits of proposed solutions instead of only focusing on one or two limited types.[7]

[7] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028, 87 Fed. Reg. 27,504 (May 4, 2022) ("Long-Range Transmission Planning NOPR"); *see also* The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Cost* (Oct. 2021); Rob Gramlich & Jay Caspary, *Planning for the Future: FERC's Opportunity to Spur More Cost-Effective Transmission Infrastructure*, at App. A, ACEG (Jan. 2021) (citing numerous studies demonstrating the value of forward-looking, multi-value transmission planning).

Clarifying DOE's own criteria is helpful in identifying the relative value of the studies that DOE relies upon in its analysis, and whether an identified transmission need is potentially even greater than existing analysis has indicated. For example, where DOE relies on studies that have identified transmission needs based on a more limited analysis, it would be valuable to note those limitations both to denote the likelihood that identified needs are actually more pressing than indicated and also to ensure that where less comprehensive studies have not identified transmission needs, DOE's imprimatur of such a study does not indicate that further transmission needs do not exist. This is especially important for regions where comprehensive, scenario-based, and multi-benefit transmission planning and analysis have not occurred. DOE's indication of such limitations and indication of where additional studies should occur in the future would be especially valuable in guiding the use of this document not only in the future designation of NIETCs but in assisting relevant stakeholders with focusing their own future analyses.

B. Comments from Some Parties Concerning the Needs Study are Misplaced

PIOs note that most of the comments of DOE's prior draft Transmissions Needs Study as set forth in the Appendix A-2 are generally supportive of DOE's framework and assessed needs. PIOs note, however, that certain parties would inappropriately limit the scope of the Needs Assessment. For example, Southeast Regional Transmission Planning (SERTP) asserts repeatedly that the Draft Study is an overly broad analysis of transmission needs that exceeds the statutory mandate set forth in Section 216 of the Federal Power Act.[8] SERTP objects in particular to DOE's inclusion of future generation as part of its analysis.[9] These objections misread Section 216's mandate.

[8] *See, e.g.,* Appendix A-2, Comments 43, 147-148.
[9] *Id.,* Comment 147.

By definition, an analysis of transmission congestion and constraints examines the systemic limitations on delivering generation to load. Nor does Section 216(a)(1) limit DOE's analysis to existing or historical conditions. To the contrary, Section 216(a)(2) requires the issuance of a NIETC report based upon the Needs Study that may designate a NIETC where there is existing *or future* transmission congestion or constraints. As further discussed in Section II, *infra*, Section 216(a)(4) of the Federal Power Act sets forth numerous factors that may be considered in designating a NIETC, including national energy policy and security interests, economic growth, diversification of resources, as well as enhancing the ability of generators to the electric grid. Because the Needs Study serves a primary role in in NIETC designation, it is necessary for DOE to broadly assess the multiple drivers of existing and future transmission needs.

Additionally, both SERTP and PJM assert that its planning processes have adequately addressed its transmission needs and object to a "top-down" assessment of interregional needs.[10] SERTP also objects to interregional transmission needs identified by the Study on a number of grounds, primarily that the benefits of transmission needs identified in the Study would not justify the costs.[11] These objections are belied by the current state of regional and interregional transmission planning which, as multiple transmission stakeholders have noted, has resulted in unjust, unreasonable, and unduly discriminatory rates and practices.[12]

Since its passage a decade ago, the problems with regional and interregional transmission planning that Order No. 1000 was designed to address remain. Despite spending increasing amounts of money on transmission, the vast majority of transmission investments in RTO regions

[10] *Id.*, Comments 11, 148, 156, 157, 158.
[11] *Id.*, Comments 55, 83, 97, 148.
[12] *See, e.g.,* Federal Energy Regulatory Commission, *Building the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Comments of Public Interest Organizations, Sec. V, Docket No. RM21-17-000, Accession No. 20211012-5519 ("PIOs' ANOPR Comments"), *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211012-5519&optimized=false.

fall outside the Order No. 1000 regional planning process and in non-RTO regions such planning is functionally nonexistent.[13] Transmission owners have every incentive to avoid competition and prudence review by building local projects, and empirical data shows that regional and interregional projects have largely or entirely failed to materialize in either RTO or non-RTO regions—including PJM and SERTP.[14] This is primarily a result of the failure of current transmission planning efforts to accurately account for the multiple benefits of transmission or allocate costs.[15] The failure to properly plan for regional and interregional transmission needs has led to excessive costs for consumers and a failure to meet system demands that has already jeopardized reliability, resulted in interconnection queue delays, and caused catastrophic harm.[16] PIOs agree with the April 20, 2023 comments regarding the scope and jurisdiction of the Needs Study filed in this docket by the Southern Renewable Energy Association. In particular, PIOs agree that the Needs Study provides a necessary objective perspective, especially with regard to interregional and intra-regional transmission needs that are not currently represented in existing transmission planning processes across the country, including in the SERTP transmission planning process.

C. Studies Examined by the Needs Study Uniformly Show an Urgent Need to Expand Transmission

As explained in more detail in the Needs Study, the authors reviewed 50 recent reports to highlight both the historical and anticipated drivers, benefits, and challenges of expanding the

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[13] *Id.* at 30.
[14] *Id.* at 30-49; *see also* Federal Energy Regulatory Commission, *Building the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Reply Comments of Public Interest Orgs., 24-25 Docket No. RM21-17-000 (Nov. 30, 2021), *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211130-5284&optimized=false ("PIOs' Reply Comments"). *See also* Johannes P. Pfeifenberger et al., *A Roadmap to Improved Interregional Transmission Planning*, (Nov. 30, 2021) at https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf ("Roadmap").
[15] PIOs' ANOPR Comments at 49-51.
[16] *Id.* at 53-57; PIOs' Reply Comments at 5-7; *Roadmap* at 24-29.

nation's electric grid. Together, these studies demonstrate a pressing need to expand transmission for multiple reasons, including to enhance renewable energy integration and access to lower cost resources, support electrification efforts, improve resource adequacy, reduce congestion and curtailment, and most importantly to ensure grid reliability and resilience.[17] The Study cites several indicators that point to an immediate need for more transmission infrastructure, including removing or reducing the variation in prices caused by congestion by allowing lower-cost energy to reach high demand areas. The Study also notes that over the last several years, installation of new generation, the vast majority of which is renewable, has been delayed because of longer wait times for interconnection agreements and increased costs to connect to the grid, demonstrating that a "piecemeal" approach to transmission deployment through the interconnection process is less effective than a full regional transmission planning process.[18]

Moreover, the Study demonstrates that transmission investment in lines greater than 100-kV has declined since 2011, noting "[a] review of historical transmission system data from 2011 to 2020 provides insight into key indicators that demonstrate the need for increased transmission capacity. These indicators include an overall decrease in historical transmission investment in higher voltage lines, regional and interregional wholesale electricity price differentials, and a record amount of new generation and storage capacity in interconnection queues across the county. Regional entities spent between $0.19 and $5.29 per MWh of annual load on new transmission in the past decade, on average. Most of these investments were made in the first half of the decade, with transmission investments steadily declining since 2015."[19] Not only has the pace of high-

[17] Needs Study at 19. Other relevant studies that should be considered as part of the Needs Study include Rob Gramlich, Enabling Low-cost Clean Energy and Reliable Service Through Better Transmission Benefits Analysis, Aug. 9, 2022, *available at* https://acore.org/wp-content/uploads/2022/08/ACORE-Enabling-Low-Cost-Clean-Energy-and-Reliable-Service-Through-Better-Transmission-Analysis.pdf.
[18] *See id*.
[19] *See id*. at ii.

voltage transmission buildout slowed, but public utility transmission operators have also largely sought to avoid the regional planning process. As PIOs pointed out in our comments to the FERC transmission and cost allocation rulemaking, the loopholes that exist in Order No. 1000 to avoid regional planning and competition have led to the vast majority of projects approved in RTOs to be excluded from the competitive process for rulemaking.[20] The result has been the buildout of replacement or local transmission projects (i.e., lower voltage lines) that are built without effective oversight and need not be competitively bid. It is thus not surprising that higher-voltage transmission buildout has slowed since Order No. 1000 went into effect, with a corresponding rise in congestion and constraints.

D. The Needs Study Demonstrates the Value of Interregional Transmission

The Needs Study states that "[i]nterregional transmission investments will help improve system resilience by enabling access to diverse generation resources across different climatic zones, which is becoming increasingly important as climate change drives more frequent extreme weather events that damage the power system."[21] It further states that "[r]ecent experience with extreme weather events demonstrates that planning for the bulk power system needs to extend beyond the footprint of individual utilities or regions to provide assurance that energy can be delivered from where it is available to where it is needed to mitigate risks associated with common mode failures."[22]

Based on the plethora of existing studies, PIOs strongly agree with DOE that expanded transmission capacity – especially between the three interconnections, between different regions of the country, and between different utility service territories – is essential for a reliable,

[20] PIOs' Initial ANOPR Comments at 18 *et seq*.
[21] Needs Study at iii.
[22] *Id*. at 3.

affordable, and clean energy system. "Expanding interregional transmission capacity enables the system to take advantage of the geographic and temporal diversity of energy resources, so that abundant production in one region can help compensate for low production in other areas, which improves the electric system's ability to produce affordable, reliable energy while increasing the operational flexibility of the grid."[23] As DOE further notes, interregional transmission is also key for grid resilience: "Several authors mention the benefits of transmission in reducing weather risks by allowing utilities to share generating resources, enhancing the stability of the existing transmission system, aiding with restoration and recovery after an event, and improving frequency response and ancillary services. One case in which transmission likely would have improved grid resilience was during the severe cold weather event that occurred in February 2021 in Texas and the South Central United States (FERC et al. (2021)."[24] NREL's Interconnections Seam Study shows that increased intercontinental transmission helps balance generation and load with less total system installed capacity across each of the generation scenarios, due to load and generation diversity, and increased operating flexibility, with "benefit-to-cost ratios ranging from 1.2 to 2.9, indicating significant value to increasing the transmission capacity between the interconnections and sharing generation resources for of all the cost futures studied."[25] MIT researchers Patrick R. Brown and Audun Botterud have found that "inter-state coordination and transmission expansion [including across regions and interconnections] reduce the system cost of electricity in a 100%-renewable US power system by 46% compared with a state-by-state approach, from 135 $/MWh to 73 $/MWh."[26] LBNL recently showed that "[i]nterregional and regional transmission links reduce congestion and expand opportunities for trade" and that while "[m]any links have hourly

[23] *Id*. at 79.
[24] *Id*.
[25] NREL Interconnections Seam Study at 7 (preprint).
[26] Brown & Botterud, Joule 5, January 20, 2021, at 115.

average pricing differences that exceed $15/MWh – equivalent to $130 million per year for a 1000 MW link," "[i]nterregional links ($24/MWh in the median case in 2021) have greater value than regional links ($11/MWh in the median case in 2021) – though many high-value regional links exist."[27]

However, despite these myriad benefits, and as PIOs have noted in our comments to FERC's rulemaking on transmission planning and cost allocation, the interregional coordination process required by Order No. 1000 is effectively broken. For virtually all planning regions, this process has essentially become a paperwork exercise, has failed to identify or implement needed projects, and consequently has failed to alleviate unlawful rates and practices identified by the Commission as requiring an expeditious remedy over 10 years ago, while the need for interregional transmission has only grown more pressing since.[28]

While eliminating existing barriers to interregional transmission projects can maximize net consumer benefits across regions and improve reliability and resilience in the face of increasing extreme weather events, barriers to interregional planning make it virtually impossible to maximize net consumer benefits and have created a gap in investments near and across market seams as regional planning authorities have shifted away from development along seams with neighboring regions and instead have focused primarily on local and regional investments and generator interconnection requests.[29]

DOE summarizes these barriers in the Study as follows: "Multiple studies specify siting of high-voltage lines as one major challenge, indicating that developers often must navigate multiple state processes and local and federal government requirements. […] Criteria used to make

[27] LBNL Empirical Estimates of Transmission Value using Locational Marginal Prices (August 2022) at 3.
[28] *Comments of Pub. Interest Orgs.* at 75 (Aug. 17, 2022), Accession Nos. 20220817-5270 ("PIOs' NOPR Comments").
[29] *See id*. at 75-76.

determinations may differ in each state and may even be inconsistent. For example, some states may focus on intrastate benefits and costs only, while others may also take into account or even require interstate, regional, or national benefits and costs. Further, some states may require broad environmental and economic benefits and costs, while others may consider specific policy goals. […] FERC (2020) and Breakthrough Energy Sciences (2021) further indicate that obtaining approvals in each state also may be difficult because many states focus on intrastate burdens and benefits. A line that does not directly connect resources within a state might not receive permits required to traverse the state."[30]

E. DOE Should Adopt High Load and High Clean Energy Assumptions as the Base Case for the Needs Study

While the Needs Study reviewed public data and over 50 different studies to determine national transmission needs, none of the studies incorporated the passage of the IRA[31] or the recent EPA proposed rulemakings on vehicle emissions.[32] Switching to the high load and high clean energy assumption means the baseline case requires a doubling of the U.S transmission system by 2040.[33] The IRA and EPA vehicle emissions proposed rulemaking provide significant incentives for vehicle electrification. The IRA also provides incentives for residential electrification and clean energy deployment, all of which are not currently accounted for in the Study. DOE has already identified in the Study that the high clean energy assumptions are "in line with the future power sector enabled" by the IIJA and IRA.[34] Other analysis since the passage of the IRA confirms the acceleration of clean energy deployment in the U.S. For example, BloombergNEF estimates solar

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[30] Needs Study at 77.
[31] *Id*. at 84.
[32] U.S. Environmental Protection Agency, "Proposed Rule: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles," April 12, 2023, https://www.epa.gov/regulations-emissions-vehicles-and-engines/proposed-rule-multi-pollutant-emissions-standards-model.
[33] Needs Study at 106.
[34] *Id*.

deployment will increase 21 percent and wind deployment will increase 36 percent over pre-IRA forecasts.[35] The IRA also included $9 billion for residential energy efficiency and electrification financial assistance programs.[36] In addition, before EPA released its most recent proposed rulemaking, BloombergNEF found that IRA incentives increased their projections for EV sales in 2030 by 9 percent, estimating that EVs would increase from 43 percent of the U.S. market to 52 percent,[37] and the EPA has estimated that its new rulemaking could potentially require nearly 70 percent of new vehicles sold in 2032 to be EVs.[38] Given the ample evidence presented in these studies as well as the amount of clean energy necessary given the passage of the IRA and the EPA's recent vehicle emissions rulemaking, PIOs recommend that the Study adopt the high load and high clean energy assumptions as the base case.

F. The Needs Study Should Incorporate the Potential for Offshore Wind in the Pacific, Gulf of Mexico, and Great Lakes Regions

While transmission issues relating to the significant amount of expected offshore wind development is mentioned briefly in the Needs Study, this discussion is primarily limited to discussion of Atlantic Offshore Wind with a brief mention of development along the Pacific Coast.[39] The Study discusses in detail studies relating to offshore wind development in New England, New York, and Oregon and notes that DOE is conducting its own study for Atlantic Offshore Wind.[40] While that work is ongoing, DOE should include in its Needs Study the findings

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[35] David R Baker and Angel Adegbesan, "US Renewable Power Set to Get More Than 20% Boost From New Climate Law," Bloomberg, October 19, 2022, https://www.bloomberg.com/news/articles/2022-10-19/us-renewable-power-set-to-get-more-than-20-boost-from-new-climate-law.
[36] Congressional Research Service, "The Inflation Reduction Act: Financial Incentives for Residential Energy Efficiency and Electrification Projects," November 28, 2022, https://crsreports.congress.gov/product/pdf/IF/IF12258/2?itid=lk_inline_enhanced-template.
[37] Ira Boudway, "More Than Half of US Car Sales Will Be Electric by 2030," Bloomberg, September 20, 2022, https://www.bloomberg.com/news/articles/2022-09-20/more-than-half-of-us-car-sales-will-be-electric-by-2030.
[38] U.S. Environmental Protection Agency, "Fact Sheet: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles," 5, April 12, 2023, https://www.epa.gov/system/files/documents/2023-04/420f23009.pdf.
[39] Needs Study at 57-58, 86.
[40] *See id*.

of its 2021 Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis along with other relevant studies,[41] including findings from Phase I of PJM's Offshore Wind Transmission Study.[42] In addition, PIOs recommend that the Study recognize the potential for offshore wind in the Pacific, Gulf of Mexico, and the Great Lakes and suggest that DOE initiate studies to analyze how different coordinated transmission solutions would enable offshore wind in these regions. In this regard, PIOs recommend that DOE perform an interim needs study as soon as studies regarding these areas are available.

Moreover, PIOs were surprised to see the lack of offshore wind-related transmission needs identified in the list of identified projects in the Study. While DOE is conducting its own analysis of offshore wind needs in the Atlantic, to the extent that existing studies have identified existing and future transmission congestion or constraints associated with current and future offshore wind development, those needs should be included in the Study.

II. DOE Needs to Align the Transmission Needs Study with Statutory Requirements for the Future Designation of Any National Interest Electricity Transmission Corridor

As noted by DOE, the Needs Study arises in part from Section 216(a) of the Federal Power Act, which directs it to conduct an assessment of national electric transmission capacity constraints and congestion no less than once every three years.[43] The Study plays two unique and essential roles in ensuring the reliability and affordability of the nation's electric grid. First, it relies on

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[41] Department of Energy, Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis, Oct. 2021, *available at* https://www.energy.gov/sites/default/files/2021-10/atlantic-offshore-wind-transmission-literature-review-gaps-analysis.pdf.2021. *See also* Johannes Pfeifenberger et al., The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals (Jan. 24, 2023), *available at* https://www.brattle.com/wp-content/uploads/2023/01/Brattle-OSW-Transmission-Report_Jan-24-2023.pdf; Kelly Smith et al., Offshore Wind Transmission and Grid Interconnection Across U.S. Northeast Markets, *available at* https://createsolutions.tufts.edu/wp-content/uploads/2021/08/OSW-Transmission-and-Grid-NE.pdf.

[42] This study is available at https://www.pjm.com/-/media/library/reports-notices/special-reports/2021/20211019-offshore-wind-transmission-study-phase-1-results.ashx.

[43] 16 U.S.C. 824p(a)(1); Transmission Needs Study at 1.

DOE's experience and expertise in providing an independent assessment of the nation's transmission system as a whole, including the identification of interregional needs that are often absent from existing regional and local planning processes but are increasingly critical to ensuring grid reliability in the face of changing weather patterns and resource transition. Second, the Study serves as the foundation for implementing a number of DOE's statutory authorities, primary among them the requirement under Section 216(a)(2) that DOE issue a report every three years that may designate any geographic area that has existing or expected transmission constraints or congestion as a NIETC — designations that will be essential to resolving transmission bottlenecks that compromise the stability and affordability of the nation's electric grid.[44]

While the NIETC designation process allows DOE to consider any relevant information, it is clear from both the statutory language of Section 216(a)(2) and from the Study itself that the final National Transmission Needs Study ("Final Study") is intended to serve as a primary resource for making a NIETC designation.[45] The Federal Power Act also establishes specific factors the Secretary may consider in such a designation, namely:

- the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
- economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy and a diversification of supply is warranted;
- the energy independence or energy security of the United States would be served by the designation;
- the designation would be in the interest of national energy policy;
- the designation would enhance national defense and homeland security;

[44] *Id*. at 1; 16 U.S.C. 824p(a)(2).
[45] *Id.*

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- the designation would enhance the ability of facilities that generate or transmit firm or intermittent energy to connect to the electric grid;

- the designation—(i) maximizes existing rights-of-way; and (ii) avoids and minimizes, to the maximum extent practicable, and offsets to the extent appropriate and practicable, sensitive environmental areas and cultural heritage sites; and

- the designation would result in a reduction in the cost to purchase electric energy for consumers.[46]

Because the Final Study will serve as a primary resource in the designation of NIETCs not only for DOE but also for regional planning authorities, governmental decisionmakers, affected communities, generation developers, consumers, and other stakeholders, information in the Final Study must provide the clarity needed to support the NIETC decisionmaking process. Additionally, since DOE has expressed an intent to have a participant-driven process for the designation of NIETCs, it is imperative that DOE provide as much clarity, specification, and justification for transmission needs identified by the Study. Consequently, the Final Study needs to explain whether and how each transmission need identified therein also implicates any of the factors set forth in Section 216(a)(4) in order to enable DOE and stakeholders to better understand, justify, and prioritize NIETC decisionmaking.

Providing this kind of information at the outset is necessary for DOE to rely on the Final Study (as statutorily intended) in setting clear, rational, and fair criteria for NIETC designation that allow participants to understand who is best suited to apply for NIETC designation and why. These criteria could include, for example, categories such as Extra-High Voltage projects or HVDC projects that connect at least two of the three U.S. interconnections or at least two Order No. 1000 transmission planning regions, Extra High-Voltage projects or HVDC projects that connect at least two different states or at least two different balancing authorities, or projects that

[46] 16 U.S.C. § 824p(a)(4).

are at least 1 GW and 100 miles. If clear, comprehensive, and compelling information regarding what specific transmission is needed, where it is needed, and all the reasons why it is needed is not provided in the Final Study, addressing those needs – whether part of local and regional planning processes or as part of the NIETC designation – becomes more challenging.

III. In Reducing Congestion and Constraints in MISO, PIOs Recommend that DOE Consider Market Boundaries in Addition to the Grid Topology when Identifying Potential Solutions

The Needs Study recommends that to alleviate congestion between the Midwest (MISO North) and the Delta (MISO South), it is more efficient to develop a solution connecting the Midwest to the Plains (SPP) and then connecting the Plains to the Delta, i.e., to route electricity flows through SPP rather than directly between MISO North and MISO South.[47] DOE's finding was based on the following:

- Differentials in wholesale price differentials, with DOE noting that "Transmission between ISOs was generally more valuable than transmission within ISOs;"[48]
- Capacity expansion models indicated the highest needs in the country between the Midwest and Plains regions as well as between the Mid-Atlantic and the Midwest regions. The next highest level of need was identified between the Delta and Plains regions;[49] and
- Congestion between the Midwest and Delta regions.[50]

While flows from MISO North to SPP and from SPP to MISO South would be useful for many reasons, the Study should recognize the benefits of unifying the MISO market between

[47] "The historic wholesale price (§ IV.b) and anticipated future capacity expansions model (§ VI.c) analyses suggest congestion between the Midwest and the Delta regions is alleviated most cost effectively by increased transfer capacity between the Midwest and Plains and between the Plains and Delta, instead of between the Midwest and Delta directly." Needs Study at xi.
[48] *Id*. at 28.
[49] *See id*. at § VI.c.
[50] *See id*. at § V.d.4.

MISO North (Midwest) and MISO South (Delta) through increasing the direct transfers between these two regions. When the Illinois Commerce Commission raised the same concern,[51] DOE did not provide a meaningful response. The FPA specifically states that NIETCs can be designated when "the end markets served by the corridor may be constrained by lack of adequate or reasonably priced electricity"[52] or "the end markets served by the corridor may be jeopardized by reliance on limited sources of energy."[53] Hence, DOE is statutorily authorized to recognize the impacts on the "end markets" and question whether market-to-market implications were considered when recommending against connecting the end markets of MISO North and MISO South.

Additionally, while PIOs recognize (and highlight above) that interregional projects are more difficult to build and should be a primary focus of the Study, DOE should not ignore regions that have had difficulty building transmission within their own market boundaries. Development within MISO South and the connection between MISO North and MISO South has been elusive and is only one example of major transmission needs of potentially national importance occurring within regional market boundaries that should not be ignored in the Study.

Respectfully submitted,

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[51] *See id*. at 114, cmt 5.
[52] 16 U.S.C. § 824p(a)(4)(A).
[53] 16 U.S.C. § 824p(a)(4)(B)(I).

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UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY

National Transmission Needs Study	)
Draft for Public Comment	)
	)

COMMENTS OF THE NEW JERSEY BOARD OF PUBLIC UTILITIES ON THE NATIONAL TRANSMISSION NEEDS STUDY

In February 2023, the Department of Energy ("DOE"), released a draft of the National Transmission Needs Study ("Needs Study") for public comment, and invited feedback on potential analysis gaps or any other matter pertaining to the study. The New Jersey Board of Public Utilities ("Board") files these comments both to express its support for the holistic approach to transmission planning the Needs Study adopted and to suggest ways DOE could further improve this effort. Specifically, the Board believes the Needs Study properly complements traditional planning processes by proactively identifying various broad-scale needs that multi-value regional or interregional projects could address more cost-effectively than traditional planning processes. Given New Jersey's clean energy goals, the Board also appreciates the analysis of national transmission needs in scenarios with very high levels of renewable energy. However, the Board believes that DOE could make the Needs Study even more useful, especially for state policymakers, if it also analyzed scenarios and clearly identified transmission needs that must be met in order to produce a reliable, resilient, and least cost electricity system.

I. The Board Supports DOE's Holistic Approach to Transmission Planning and Identifying Transmission Needs

The Board fully endorses the DOE's approach to examining transmission needs at the regional and interregional scale, as this is a necessary complement to traditional planning processes that all too often myopically focus on local needs. DOE correctly notes that most utilities' and Regional Planning Authorities' transmission planning processes "primarily focus[] on compliance with NERC and local reliability standards with very limited scopes" and tend to result in "siloed consideration of the multiple benefits of transmission."[1] This approach stymies multi-value transmission projects that could simultaneously deliver significant cost savings to consumers, improve reliability and/or resiliency, and support accelerated deployment of clean energy.[2] DOE's efforts to identify transmission needs from a holistic, broader-scale perspective are therefore necessary.

The Board thus disagrees with some commentators' implicit suggestion that the Needs Study should defer or take a back seat to traditional "bottom up" transmission planning processes.[3] In the Board's view, the main function of the Study is to identify the gaps that would otherwise be left unaddressed by existing planning processes. Consequently, limiting the scope of the study to the standard planning framework would defeat its purpose. Though DOE's transmission studies should not displace the planning work performed by transmission providers,

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[1] U.S. Dep't of Energy, *National Transmission Needs Study* 2, 77-78 (2023), https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf ("Needs Study").

[2] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Comments of the N.J. Bd. of Pub. Utils., FERC Docket No. RM21-17-000, at 3-14 (filed Aug. 17, 2022) (discussing the multiple benefits of proactive, multi-value, and portfolio-based transmission planning).

[3] *See, e.g.*, Needs Study at 157 (noting that PJM cautioned against "a 'top down analysis" because "[t]he planning process is and always has been more of a 'bottom up' exercise").

the Study makes it clear that DOE is merely seeking to complement and help inform rather than replace that planning work.[4] DOE thus struck the appropriate balance in this Needs Study, and it should maintain that balance in both this and future transmission studies.

II. The Board Recommends that DOE Focus On Identifying Transmission Investments that Provide Net Benefits from a Reliability and Economic Perspective While Also Facilitating the Energy Transition.

Nonetheless, the Board recommends that the DOE clarify which of the transmission needs identified in this Study correspond to scenarios that will ultimately minimize total system costs. Specifically, the Board believes that highlighting investments that will more efficiently expand transmission under the assumption that existing policy mandates are the only constraints on the allowable generation mix will emphasize the need for specific projects. In its present form, the Needs Study primarily characterizes scenarios and corresponding needs by the amount of clean generation deployed in each scenario.[5] The underlying studies that DOE drew upon also appear to have used a mix of scenarios that were constrained to support a certain level of clean and/or renewable generation and those that were not.[6] As a result, it is hard for the reader to tell which identified needs correspond to transmission investments needed to provide reliability at the lowest possible cost and which are solely needed to support a given level of clean energy deployment. This also means the study does not clearly identify transmissions needs that must be addressed to *both* ensure a least-cost reliable system and enable higher levels of clean generation. The Board believes the Needs Study would have significantly greater utility, particularly to state policymakers, if it instead clearly identified general areas where additional

[4] *See id.* at 2 ("This Needs Study is not meant to displace these planning processes, the reliability standards they address, or the planning efforts of utilities and Regional Planning Authorities. Rather, this Study is intended to help inform and drive effective regional and interregional planning . . . .").

[5] *See, e.g.*, Needs Study at 84, 86-87, 89-90, 96-98.

[6] *See id.* at 82-83.

transmission investment would serve to both reduce overall system costs and facilitate more clean energy.

Granted, the DOE notes that "[t]he Moderate/High group best represents the future power system that will be enabled by current (as of the publication date of this Needs Study) utility, local, state, and federal policies, including the large advances in generation technologies enabled by IRA."[7] DOE describes these scenarios as generally involving "moderate load growth" and "high clean energy penetration above 80% in 2040."[8] This appears to be a reasonable if somewhat rough estimate of future clean energy generation, as DOE cites studies projecting that the IRA and other policies could lead to the U.S. sourcing 80% of its electricity from clean sources as soon as 2030 (assuming that various interconnection, transmission, and supply chain constraints are resolved).[9] However, the transmission needs identified using these scenarios may not correspond to transmission investment needed to maintain reliability and/or minimize total system costs. The problem is that the actual moderate/high scenarios DOE used appear to be ones that include additional policy assumptions that effectively mandate clean energy

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[7] *Id.* at 84-85.

[8] *Id.* at 84.

[9] *See id.* at 85, n.51 (citing John Larsen et al., Rhodium Grp., *A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act* (2022), https://rhg.com/wp-content/uploads/2022/08/A-Turning-Point-for-US-Climate-Progress_Inflation-Reduction-Act.pdf; Megan Mahajan et al., *Updated Inflation Reduction Act Modeling Using the Energy Policy Simulator* (2022), https://energyinnovation.org/wp-content/uploads/2022/08/Updated-Inflation-Reduction-Act-Modeling-Using-the-Energy-Policy-Simulator.pdf). Specifically, Larsen et al. project that the IRA will result in the U.S. sourcing 60% to 81% of its electricity from clean energy in 2030, while Mahajan et al. project that the IRA will lead to clean energy sources providing 72% to 85% of U.S. electricity in 2030. Larsen et al. at 5; Mahajan et al. at 7. Mahajan et al. explicitly note that their "modeling assumes that necessary transmission will be built, interconnection delays are addressed, supply chains provide the necessary materials to deploy these levels of clean electricity, and a sufficient workforce can supply the labor." Mahajan et al. at 7.

penetrations in the 90% to 100% range by 2040.[10] Consequently, these scenarios likely include some combination of "no regrets" transmission *and* transmission that is necessitated solely by deep decarbonization efforts. While the Board finds these scenarios to be useful, especially in light of New Jersey's ambitious clean energy goals, the Board also believes the study could be further improved by including scenarios that concentrate on "no regrets" transmission solutions that both reduce costs and facilitate greater clean energy deployment.

Indeed, the Needs Study's apparent focus on transmission needed to support the clean energy transition and de-emphasis of other factors might fail to capitalize on an opportunity to help forge the consensus needed to facilitate a cost-effective transition. Specifically, the Board is concerned the Needs Study may be viewed skeptically due to a perception that it is focused near-exclusively on deploying clean energy.[11] This is unfortunate, as the Board believes that development of long-distance, high-voltage transmission infrastructure will be needed to both contain electricity costs for consumers and allow for the reliable deployment of clean energy. Such transmission development will almost certainly require multiple States with diverse interests to agree on its purpose, scope, necessity, and ultimate desirability. The Board believes that forging this consensus will require rigorously demonstrating and ideally quantifying the myriad non-clean-energy benefits of such transmission infrastructure in order to demonstrate its full value to all stakeholders.

[10] *See* Needs Study at 82-83 (providing an overview of scenarios); *id.* at 86 (showing in Figure VI-1 that in nearly all moderate/high scenarios clean energy accounts for 90% to 100% of 2040 U.S. electricity generation).

[11] Other stakeholders appear to have similar perceptions of the Needs Study. *See, e.g.*, *id.* at 157 (noting PJM's comments that the Needs Study's analysis "appears to be an attempt at optimizing the deployment of renewables across the nation" and that "it is difficult to determine" any basis for finding a "need for increased interregional transfer capability" besides optimizing the deployment of renewables nationwide).

Fortunately, a substantial number of potential transmission projects could both reduce costs for consumers *and* accelerate clean energy deployment. A September 2022 Study from Princeton University found that at present rates of transmission development nuclear and renewables would supply only 56% of the Nation's electricity in 2035 even with the IRA.[12] However, if the economically optimal amount of transmission could be built, total electricity costs would be lower and nuclear and renewables would supply 74% of the Nation's electricity in 2035.[13] MISO similarly found that its planned Long Range Transmission Planning ("LRTP") Tranche 1 portfolio will more than pay for itself while also enabling significant deployment of new renewable and storage resources. Specifically, the LRTP Tranche 1 Portfolio will support up to 53 gigawatts of additional renewable and storage capacity,[14] save consumers $32.0 to $39.4 billion,[15] and cost only $14.2 to $16.9 billion over its lifetime.[16] In short, there are likely

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[12] *See* Jesse D. Jenkins et al., Princeton Univ., *Electricity Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act* 4, 13 (2022), https://repeatproject.org/docs/REPEAT_IRA_Transmission_2022-09-22.pdf (noting that recently the rate of transmission expansion has been 1% per year in the U.S. and at this rate solar, wind, and nuclear resources would only provide about 3,500 terawatt-hours out of roughly 6,200 terawatt-hours' worth of total annual electricity generation in 2035).

[13] *See id.* at 3, 13 (noting that a significant increase in transmission development is economic and that the unconstrained and economically optimal level of transmission deployment would lead to solar, wind, and nuclear resources providing 5,300 terawatt-hours out of roughly 7,200 terawatt-hours' worth of total annual electricity generation in 2035).

[14] Ethan Howland, *MISO Finds Broad Benefits to Building $10.4B of Transmission Projects to Support 53 GW of Clean Energy*, Util. Dive (Apr. 7, 2022), https://www.utilitydive.com/news/miso-benefits-transmission-projects-renewable/621729/.

[15] *See* MISO, *LRTP Tranche 1 Portfolio Detailed Business Case* 16 (Mar. 29, 2022), https://cdn.misoenergy.org/20220329%20LRTP%20Workshop%20Item%2002%20Detailed%20Business%20Case623671.pdf (reporting that the portfolio will save $13.0 to $19.0 billion in avoided congestion and fuel costs, $17.0 billion in avoided capital costs for local resource investments, $1.4 to $2.0 billion by obviating the need for other transmission investments, and $0.6 to $0.7 billion in avoided resource adequacy costs).

[16] *Id.*

numerous regional and interregional transmission projects that could potentially provide the diverse set of benefits needed to drive stakeholder consensus on project desirability.

The issue is identifying what kind of transmission projects will deliver this combination of benefits and where they need to be built. The Board believes this is the type of information that future iterations of the Needs Study should focus on providing, even if the outputs are just "zonal estimates of the amount and general geographic location of future transmission need."[17] When paired with rigorous and quantitative data on candidate transmission projects from the upcoming National Transmission Planning Study,[18] this could demonstrate the wide ranging benefits of such major new infrastructure to all stakeholders. It will be critical to have data along these lines to build multi-state consensus on the need to develop and pay for significant new regional and interregional transmission infrastructure.

III. Conclusion

The Board appreciates the DOE's work to proactively identify a holistic set of transmission needs, and this opportunity to offer advice on how the DOE can improve both the current and future Needs Studies. The Board further respectfully requests that DOE consider providing additional data and analysis that could be used to identify broadly beneficial, "no regrets" transmission projects that would reduce costs for consumers, improve reliability, and accelerate the deployment of clean energy.

[17] Needs Study at 80.

[18] *See id.* at 81 (noting that "the National Transmission Planning Study" will "identify transmission solutions that will provide broad-scale benefits to electric customers" and include "downstream engineering analysis of candidate transmission projects" to help "bridge the gap between national, long-term capacity expansion modeling studies and regional, near-term transmission planning studies").

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April 20, 2023

VIA E-MAIL

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RE: COMMENTS ON THE PUBLIC DRAFT, NEW YORK REGION ANALYSES
MEETING REQUEST
COMMENTS AND MEETING REQUEST OF THE NEW YORK TRANSMISSION OWNERS

Dear Department of Energy:

The New York Transmission Owners[1] appreciate this opportunity to provide these comments to the United States Department of Energy's ("DOE") draft for public comment of its National Transmission Needs Study dated February 2023 (the "Draft Study"). The NYTOs' comments focus primarily on the New York-related aspects of the Draft Study and seek to improve the accuracy of not only the final Transmission Needs Study that will result from this proceeding ("Final Transmission Needs Study"), but also any future reports that DOE may issue in accordance with the Federal Power Act ("FPA") Section 216.[2]

I. Executive Summary

The development of new transmission will be key in the coming decades as the grid continues to transition to clean energy resources, expands to support dramatic increases in electric demand resulting from electrification of key sectors, and is reinforced to withstand extreme

[1] The New York Transmission Owners (or "NYTOs") are: Central Hudson Gas & Electric Corporation ("Central Hudson"), Consolidated Edison Company of New York, Inc. ("Consolidated Edison"), Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), New York Power Authority ("NYPA"), New York State Electric & Gas Corporation ("NYSEG"), Orange and Rockland Utilities, Inc. ("O&R"), Long Island Power Authority ("LIPA"), and Rochester Gas and Electric Corporation ("RG&E").

[2] 16 U.S. C. § 824p (2018); *See* Draft Study at 5 (stating that DOE intends to issue such a report in accordance with that statute, and that prior to doing so, DOE "intends to engage in further process and collect additional information for purposes of potential NIETC designations.")

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weather events. In this context, the Draft Study is a useful tool towards informing key stakeholders and regulators on nationwide transmission developments and future needs.

As explained herein, New York State continues to advance transmission projects needed to attain the state's climate goals established in its Climate Leadership and Community Protection Act ("CLCPA").[3] The Draft Study appears to recognize the significant progress that has been made to date in New York.[4] To help improve the accuracy and relevancy of the Draft Report, the NYTOs through these comments provide updates on several significant recent and soon-to-occur transmission planning development activities/projects that may not be reflected in the Draft Study's underlying data for New York.[5] These activities should be included both in the Final Transmission Needs Study anticipated to be released this summer and in any future report that DOE issues under FPA Section 216 upon which one or more National Interest Electric Transmission Corridors ("NIETCs") may be designated.[6]

Specifically, the following transmission projects may not be considered in the Draft Study and/or the transmission-related studies upon which the Draft Study relies. The following are significant efforts that, if included, would address many of the within New York concerns identified in the Draft Study:[7]

- The AC Transmission Project
- Smart Path Connect[8]
- The "Tier 4" HVDC Projects:
  - The Champlain Hudson Power Express ("CHPE")
  - The Clean Path New York ("CPNY")

[3] 2019 N.Y. Sess. Laws, ch. 106. New York is attaining these ambitious CLCPA goals through the current resource procurement/Renewable Energy Credit programs administered by the New York State Energy Research & Development Authority ("NYSERDA"), the local transmission and distribution planning ("LT&D") performed by the NYTOs under the auspices of the New York Public Service Commission ("NYPSC"), and the local and bulk transmission planning performed under the NYISO's administered processes as part of NYISO's Comprehensive System Planning Process ("CSPP").

[4] Draft Study at 91 ("The planned transmission development of many regions – including … New York… – exceeds the range of anticipated transmission needs in both scenario groups in 2030…."); *see also id.*, at 106.

[5] With the Draft Study largely being a compilation of several existing transmission-related studies, it is unclear what specific transmission planning assumptions that the Draft Study makes for New York.

[6] *See* Draft Study at 5.

[7] *See id.* at xv, 26-27, 40, 63.

[8] The Draft Study references outages associated with the construction of the Smart Path Connect project, so that project may be included in at least some of the Draft Study's analyses. *See id.* at 63. As the Smart Path Connect will go far to address the upstate to Long Island price disparity and access to renewables issues raised by the Draft Study, the NYTOs have included the Smart Path Connect in this list of recent transmission projects that should be incorporated into DOE's studies and reports.

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- The Long Island Offshore Wind Export Public Policy Transmission Need Project(s) ("Long Island PPTN"), once selected[9]

Regarding the Draft Study's projections of interregional transmission needs, the NYTOs support establishing appropriate levels of interregional transmission capability that are determined to provide net benefits for the neighboring regions. The addition of interregional transmission capability can provide numerous benefits, including access to clean energy resources, leveraging of resource and load diversity between the regions, and providing resilience and reliability benefits. While supporting the addition of appropriate amounts of interregional capability, the NYTOs are concerned that the Draft Study is not clear on the basis for its projections of a need for significant amounts of new interregional capabilities between New York and its neighboring Mid-Atlantic and New England regions. The NYTOs suggest that DOE coordinate with the New York Independent System Operator, Inc. ("NYISO"), the PJM Interconnection, L.L.C. ("PJM"), and ISO New England Inc. ("ISO-NE") on further studies of the three regions before considering any NIETC designation (if appropriate). These ISOs/RTOs are the ideal parties to conduct such studies as they are closest to recent developments with respect to transmission, generation, and load in their respective regions.

II. Discussion

A. New York's "Within Region" Transmission Needs

Within New York, the Draft Study identifies the transmission need to address price disparities between upstate New York and Long Island and the need for transmission to access low-cost generation to address Long Island's consistently high prices.[10] However, the modeling that the Draft Study references for "within region" transmission projections concludes that the planned transmission development in New York exceeds the range of anticipated 2030 transmission need.[11]

The NYTOs agree that New York is making great progress in developing the transmission required to address New York's projected transmission needs, including the ambitious clean energy requirements adopted under the CLCPA and New York's other environmental requirements. The CLCPA, for example, requires:

- 6,000 MW of distributed solar installed by 2025;
- 185 trillion BTU reduction in total energy consumption including electrification to reduce fossil fuel use by 2025;

[9] *See infra* at 5-6 (explaining that the NYISO Board is expected to announce the winning bidder(s) for the Long Island PPTN in the second or third quarter of 2023).

[10] *Id.* at xv, 26, 40, and 63.

[11] *Id.*, at 91, 106.

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- 3,000 MW of storage installed by 2030;[12]
- 9,000 MW of offshore wind installed by 2035;
- 70% of load served by renewable resources by 2030 ("70 x 30"); and
- 100% emissions-free grid by 2040 ("100 x 40").[13]

To facilitate achievement of the CLCPA's requirements, New York's Accelerated Renewable Energy Growth and Community Benefit Act ("AREGCBA")[14] directs the NYPSC and the Department of Public Service ("DPS") to establish LT&D transmission capital plans for utilities to implement local system upgrades to meet New York's objectives, which are well underway.[15] At the bulk transmission level, several regional transmission projects have also been solicited and selected for development under the NYISO's public policy transmission planning processes ("PPTPP") provided under its Open Access Transmission Tariff ("OATT"). Over the past five years, the NYISO, acting to address Public Policy Transmission Needs ("PPTNs") identified by the NYPSC through open proceedings, has undertaken several competitive solicitations to select the more efficient or cost-effective transmission projects to relieve or avoid constraints on the bulk transmission system to access existing and future renewable resources. These solicitations have resulted in the selection of a variety of authorized regional transmission projects that are presently in operation or in mature stages of construction.

Given these on-going transmission planning developments, it is imperative that DOE incorporate the latest NYISO transmission planning models into its analyses to avoid significant omissions that would change the Draft Study's conclusions. While it is not completely clear what load, resource, and transmission project assumptions the Draft Study included in its analyses, the NYTOs are concerned that the analyses may not include several recent, significant transmission developments in New York. In addition, the Final Transmission Needs Study and future reports should incorporate an important transmission award expected to be made in the second or third quarter of 2023. Specifically, DOE's analyses should include the following transmission projects

[12] On December 28, 2022, Governor Hochul announced the doubling of this requirement to 6,000 MW in her State of the State speech. *See* https://www.governor.ny.gov/news/governor-hochul-announces-new-framework-achieve-nation-leading-six-gigawatts-energy-storage#:~:text=Governor%20Kathy%20Hochul%20today%20announced,load%20of%20New%20York%20State; *see also In the Matter of Energy Storage Deployment Program*, NYPSC Case 18-E-0130, New York's 6 GW Energy Storage Roadmap: Policy Options for Continued Growth in Energy Storage (Dec. 28, 2022).

[13] The CLCPA is not the only relevant supply-side public policy requirement enacted in New York. Others include New York's "Peaker Rule" requiring a reduction in ozone-contributing pollutants associated with New York's peaking unit generation. *See* N.Y. Comp. Codes R. & Regs. tit. 6 § 227-3.

[14] 2020 N.Y. Sess. Laws, ch. 58, Part JJJ.

[15] *See, e.g., Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, NYPSC Case 20-E-0197, Order Approving Phase 2 Areas of Concern Transmission Upgrades (Feb. 16, 2023) (accepting with certain modifications the NYTOs' proposed LT&D projects necessary to integrate and deliver electricity generated by new zero-emission energy with the utilities' systems); *see also, e.g., Consol. Edison. Co. of New York, Inc.*, 180 FERC ¶ 61,106 (2022) (accepting the NYTOs' filing of their Cost Sharing and Recovery Agreement and a new Rate Schedule 19 to the NYISO OATT that provides for the participant funding and statewide cost allocation of these projects).

that have recently been included in NYISO's transmission planning or soon expected to be included.

- The AC Transmission Project: This is a 150-mile upgrade that will increase delivery of clean power generated in northern and western New York to downstate customers through transmission improvements made in the Hudson Valley, Capital Regions, and other nearby regions. Construction began in 2021 and is planned to be in-service December 2023.[16]

- The Smart Path Connect Project:[17] This consists of upgrading approximately 100 miles of existing 230kV lines in northern New York to 345 kV, along with substation construction and upgrades. Construction began in October 2022, and is planned to be in-service Fall 2025.

    - Creates a continuous 345 kV transmission path from northern New York to New York's "backbone" transmission system.[18]

    - Provides an incremental 1,000 MW of transfer capability from northern New York and Québec to the rest of the State

- The Tier 4[19] HVDC Projects[20]

    - CHPE
        - Consists of a 1,250 MW/339-mile HVDC transmission project that will run from Hydro-Québec's system at the Canadian border to NYPA's Astoria Annex 345 kV Substation in Astoria, Queens, New York.

    - CPNY
        - Comprised of more than 20 renewable energy generation projects (3,800 MW) and an approximate 175-mile, underground transmission line from Delaware County, New York to New York City.

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[16] *See* NYISO, *Power Trends 2022, The Path to a Reliable Geener Grid for New York*, at 42 (2022).

[17] *See supra* at n. 8.

[18] *See* www.nypa.gov/power/transmission/transmission-projects/smart-path-connect (providing details regarding Smart Path Connect).

[19] The Tier 4 was a solicitation by NYSERDA for transmission projects to increase the penetration of renewable resources into New York City, with the CHPE and CPNY projects being the winning bidders.

[20] The Tier 4 HVDC projects having been recently added to NYISO's Road to 2040 Policy Base Case and having received certain approvals by the NYPSC: *See* NYISO, *2021-2040 System & Resource Outlook*, at 26-27 (Sept. 22, 2022), *available at*: https://www.nyiso.com/documents/20142/33384099/2021-2040-Outlook-Report.pdf/a6ed272a-bc16-110b-c3f8-0e0910129ade?t=1663848567361.

- The Long Island PPTN: Transmission planning in New York to attain the CLCPA's requirements is on-going. Accordingly, in addition to the foregoing significant transmission projects that have recently been included in NYISO's transmission planning models, it is expected that in either the second or third quarter of 2023, the NYISO Board is expected to announce the selected transmission project(s) to NYISO's solicitation for solutions to the Long Island PPTN.
    - On March 19, 2021, recognizing the CLCPA's requirement for 9,000 MW of offshore wind by 2035, the NYPSC issued an Order identifying the Long Island PPTN, consisting of:
        - Adding at least one bulk intertie cable to increase the export capability of the LIPA-Con Edison interface, allowing for the delivery of at least 3,000 MW of offshore wind from Long Island to the rest of New York;
        - Upgrading associated local transmission facilities.[21]
    - NYISO initiated a solicitation process, and on October 11, 2021, received 19 proposals by four developers.

DOE's website states that the Final Transmission Needs Study is to be issued in summer 2023.[22] Given the significant impact that the selected project of the Long Island PPTN will surely have, the NYTOs submit that it should be included in the Final Transmission Needs Study. Should the timing of the award and the finalization of the Transmission Needs Study preclude such inclusion, then the Selected Long Island PPTN transmission project should be included in the future report that DOE states it will be issuing that may result in the designation of NIETCs.[23]

The foregoing transmission projects will significantly address many of the Draft Study's concerns identified for New York, including the large price disparities between upstate New York and Long Island and the consistently high prices experienced in Long Island for at least the past five years.

B. New York's Interregional Needs

Before turning to the Draft Study's conclusions regarding New York's interregional needs, the NYTOs first want to emphasize their general support for appropriate additions to interregional transmission capacity. The addition of interregional transmission capacity can increase access to both economic and/or clean energy resources, take advantage of load and resource diversity between the regions, and provide numerous reliability and resilience benefits. While the NYTOs support the addition of appropriate interregional capacity, the NYTOs are concerned that the Draft Study's basis for its projections of the need to make significant expansions to the transfer capacity between New York and both of its neighboring regions, the Mid-Atlantic and New England, is

[21] *In the Matter of New York Independent System Operator, Inc.'s Proposed Public Policy Transmission Needs for Consideration for 2020*, NYPSC Case 20-E-0497 *et al.*, Order Addressing Public Policy Requirements for Transmission Planning Purposes (Mar. 19, 2021).

[22] https://www.energy.gov/gdo/national-transmission-needs-study (last visited April 1, 2023).

[23] *See* Draft Study at 5.

unclear.[24] Given this ambiguity, the NYTOs request that DOE coordinate with the NYISO, PJM, and ISO-NE on further studies of the three regions before considering any NIETC designation. These ISOs/RTOs are the ideal parties to conduct such studies, as they are closest to the most recent transmission, generation, and load developments in their respective regions.

The Draft Study references the potential creation of an offshore transmission system to support wind generation that may allow the New England and Mid-Atlantic regions to share direct transfers without transferring through terrestrial New York.[25] Several studies conducted by New York have likewise indicated the benefits of building out a meshed offshore transmission network rather than just a series of radial lines to the existing transmission system.[26] Coordinating transmission development for offshore wind is key to optimizing use of constrained waterways in the New York Harbor and on-shore facilities in dense, urban areas. Further, the NYPSC has noted that a meshed network could facilitate beneficial linkages to both New Jersey and New England.[27] Given these and other considerations, the NYPSC has instructed NYSERDA to include eligibility criteria in its future offshore wind procurements to require developers' proposals to be "mesh-ready."[28] In addition, the NYPSC is currently considering proposals to establish a new PPTN, which could include, among other features, an offshore grid.[29] These first steps could help enable the creation of a meshed system serving New York that could also be potentially connected to other regions in the future.

C. New York's International Needs

The Draft Study states that the "[a]ppreciable international transfer capacities between Canada and New York and New England do not arise until 2040 in Brinkman et al. (2021)."[30] However, as previously explained, the CHPE will consist of a 1,250 MW/339-mile HVDC transmission project that will run from Hydro-Québec's system at the Canadian border to NYPA's

[24] *Id.* at xv, 99, and 103.

[25] *Id.*, at 96.

[26] *See* DPS and NYSERDA, *Initial Report on the New York Power Grid Study*, at 69, 75 (Jan. 10, 2021), *available at*: https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/NY-Power-Grid/full-report-NY-power-grid.pdf; *see also* Pfeifenberger *et al.*, *The Benefits and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York*, at 8 (Nov. 9, 2021), *available at*: https://www.brattle.com/wp-content/uploads/2021/12/The-Benefit-and-Cost-of-Preserving-the-Option-to-Create-a-Meshed-Offshore-Grid-for-New-York.pdf.

[27] *See Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, NYPSC Case 20-E-0197, *et al.* Order on Power Grid Study Recommendations, at 11 (Jan. 20, 2022).

[28] *Id.* at 14.

[29] *See* NYISO Notice: Request for Proposed Transmission Needs Being Driven by Public Policy Requirements for the 2022-2023 Transmission Planning Cycle (Aug. 31, 2022), available at: https://www.nyiso.com/documents/20142/1406936/2022-2023-Notice-Requesting-Proposed-PPTNs.pdf/248b1c15-d54f-cb81-0ae5-ce153e5b8e84 (last visited April 19, 2023).

[30] Draft Study at 103.

Astoria Annex 345 kV Substation in Astoria, Queens, New York. The CHPE is permitted and expected to be operational in the spring of 2026.[31] Also noted above is Smart Path Connect's projected increase in transfer capability from Québec.

III. Meeting Request

DOE's website for the National Transmission Needs Study allows commenters to request a meeting with DOE.[32] As noted in the subject line to these comments, the NYTOs request to have such a meeting. The NYTOs would appreciate the opportunity to discuss with DOE these New York-related aspects of the Draft Study and underlying assumptions that DOE made to reach its New York-related conclusions.

IV. CONCLUSION

The NYTOs appreciate and support DOE's efforts to develop and prepare the Draft Study. The NYTOs encourage DOE to consider the more recent New York developments noted in these comments to update its analyses when it prepares the Final Transmission Needs Study and future reports. In addition, while the NYTOs support appropriate additions of interregional transfer capability, the Draft Study's basis is unclear for concluding that significant additional transfer capacity additions are needed for New York's interfaces with both the Mid-Atlantic and New England. To address this ambiguity, the NYTOs recommend that DOE coordinate with the NYISO, PJM, and ISO-NE to conduct further studies of the three regions before considering any NIETC designation. These ISOs/RTOs are the ideal parties to conduct such studies, as they are most knowledgeable of recent developments impacting transmission, generation, and load in their respective regions.

[31] *See* https://chpexpress.com/

[32] *See* National Transmission Needs Study | Department of Energy

Should additional information be required, please contact the undersigned so that such information can be supplied expeditiously.

Respectfully submitted,

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Dated: April 20, 2023

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State of North Carolina
Utilities Commission

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April 20, 2023

Maria Robinson
Director, Grid Deployment Office
U.S. Department of Energy
1000 independence Avenue SW
Washington, DC 20585
(Via email to needsstudy.comments@hq.doe.gov)

Re: Comments on the Public Draft, National Transmission Needs Study

Director Robinson:

The North Carolina Utilities Commission (NCUC) appreciates the opportunity to comment on the U.S. Department of Energy's February 2023 Draft for Public Comment of the National Transmission Needs Study (Draft Needs Study). The NCUC is the state agency with authority to regulate the retail rates and services of North Carolina's public utilities. We have dedicated considerable effort to understanding the transmission needs of our state and employing our regulatory authority to support a cost-effective build-out of our transmission system to meet the challenges of rapid simultaneous changes in the generation mix and the load profile in North Carolina.

The NCUC would like to call to your attention one point of disagreement. The Draft Needs Study states that the Southeast region requires an increase in transmission of between 5,400 and 8,000 GW-mi in 2035. Executive Summary, p xiii. The Draft Needs Study goes on to say that "Current utility plans for transmission development in the Southeast do not meet this anticipated need." Executive Summary, p xiii. From our review of the Draft Needs Study, we have not been able to determine the basis of the conclusion that current utility transmission plans in the Southeast do not meet the anticipated need.

While the NCUC cannot speak for all of the states in the region, we do not find this statement to be accurate as to North Carolina's public utilities, which engage in several long-term transmission planning processes. In addition to the local and regional transmission planning processes required by the Federal Energy

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Regulatory Commission, state law also requires public utilities to engage in long-term transmission planning.

North Carolina statutory law requires the NCUC to develop and keep current an analysis of the long-range needs for electric generation facilities in North Carolina, i.e., an integrated resource plan (IRP).[1] North Carolina's public electric utilities are required to develop and maintain a 15-year forecast of native load requirements as well as all supply and demand-side resource options available to meet that load.[2] Their IRP reports must include a list of transmission lines with capacity equal to or exceeding 161 kV and associated facilities, plans for the construction of any such transmission assets, and a discussion of the adequacy of the utility's transmission system.[3] In recent years, with the encouragement and direction of the NCUC, the utilities' IRPs have placed a greater emphasis on transmission planning. In the 2020 IRP, Duke Energy Progress LLC and Duke Energy Carolinas LLC reported on their Integrated System and Operations Planning (ISOP) project, which utilizes advanced planning tools to identify transmission and distribution infrastructure opportunities from a more holistic perspective.[4]

In 2021, North Carolina enacted a law titled Energy Solutions for North Carolina, codified at N.C.G.S. § 62-110.9, which requires the NCUC to develop a Carbon Plan by the end of 2022 that meets carbon emission reduction goals of 70% reductions by 2030 and carbon neutrality by 2050. The statute specifically requires the Carbon Plan to consider transmission and grid modernization in connection with meeting the carbon reduction goals.[5] The NCUC has issued its initial Carbon Plan Order, which included approval of specific transmission projects needed to interconnect new solar generation as well as directives involving improving the transmission planning process overall.[6]

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[1] N.C. Gen. Stat. § 62-110.1(c).

[2] NCUC Rule R8-60(c).

[3] *Id.* at (i)(5).

[4] Order Scheduling Technical Conference and Requiring Filing of Report, *2020 Biennial Integrated Resource Plans and Related 2020 REPS Compliance Plans*, No. E-100, Sub 165, at 1 (N.C.U.C. Jan. 12, 2021).

[5] N.C. Gen. Stat. § 62-110.9(1).

[6] Order Adopting Initial Carbon Plan and Providing Direction for Future Planning (Carbon Plan Order), *Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial*

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For these reasons, the NCUC suggests that when DOE finalizes the 2023 National Transmission Needs Study it exclude North Carolina from the statement regarding the utilities in the Southeast lacking sufficient plans to meet anticipated 2035 needs or, in the alternative, provide additional context to explain the basis for the statement. While the NCUC understands that the study analyzes the anticipated transmission results of more than 200 scenarios from six capacity expansion modeling studies that have been published since 2020, these studies are separate and distinct from the work on-going in North Carolina specific to the electric system in North Carolina and, therefore, could produce results that are distinct from the work on-going in North Carolina.

In addition, we are concerned that the benefits of alleviating transmission needs listed on pages 1-2 of the Study Report exceed the specific considerations for National Interest Electric Transmission Corridors set out in the Federal Power Act, 16 U.S.C. § 824p(a)(4). We note that DOE states that "[p]rior to issuing the next report, DOE intends to engage in further process and collect additional information for purposes of potential NIETC designations." We look forward to further engagement with DOE on these matters."

The NCUC has appreciated the DOE's recent workshops and listening sessions on various transmission issues and is looking forward to continuing to partner with the DOE to better understand issues related to the transmission system. North Carolina stands ready and willing to serve as a resource for the DOE on the retail utility regulatory environment and on matters specific to the electric system in North Carolina and the Southeast.

Sincerely,

Charlotte A. Mitchell
Chair, North Carolina Utilities Commission

Integrated Resource Plans and Carbon Plan, No. E-100, Sub 179 (N.C.U.C. Dec. 30, 2022), which can be accessed at this link: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=7b947adf-b340-4c20-9368-9780dd88107a.

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NCTCA

NORTHERN CALIFORNIA TRIBAL CHAIRPERSONS ASSOCIATION

Bear River Band Rohnerville
Elk Valley Rancheria
Karuk Tribe
Tolowa Dee-ni' Nation
Wiyot Tribe
Resighini Rancheria
Big Lagoon Rancheria
Pitt River Tribe
Bue Lake Rancheria
Hoopa Valley Tribe
Redding Rancheria
Trinidad Rancheria
Yurok Tribe
Quartz Valley
Susanville Rancheria

May 12, 2023

Sent via Email to: NeedsStudy.Comments@hq.doe.gov

Re: Northern California Tribal Chairpersons Association Comments on the Public Draft of the National Transmission Need Study February 2023

To All This May Concern,

The Northern California Tribal Chairpersons Association (NCTCA), a consortium of fifteen (15) Native American tribal nations in Northern California, is pleased to submit the following comments on the February 2023 Public Draft of the National Transmission Need Study ("Draft").

General Comments
The transmission needs in Tribal lands are severe. The Rural Electrification Act of 1936 and subsequent efforts to electrify rural and remote areas of the U.S., have largely excluded Tribal Nations. The Climate Crisis and related impacts (wildfires, flooding, extreme heat, extended drought, landslides, weather volatility) have created cascading effects on electric transmission serving Tribal lands.

Currently transmission and distribution grids providing electrical service to Tribal Nations are at capacity, which constrains clean-energy-based economic development and other kinds of growth. Further, ~threefold increases in load and related hosting capacity are needed for clean energy transitions, additions of distributed energy resources (DERs), and full electrification of buildings and transportation.

The NCTCA recommends focused outreach to Tribal Nations regarding the National Transmission Needs Study before it is finalized, to incorporate input from a variety of Tribal Nations with transmission needs. In Northern California for example, the Big Lagoon Rancheria, Hoopa Valley Tribe, the Karuk Tribe, and the Yurok Tribe have experienced several multiple-day and multiple-week extended outages in the last three years due to wildfires, storms, earthquakes, and other disasters. Since building its microgrids in 2017, the Blue Lake Rancheria Tribe has experienced over 30 grid outages that required extended islanding of its systems. These conditions must be improved, and part of the solution is transmission upgrades to and within Tribal lands.

<u>California Section</u>
To the section on California in the Draft, the NCTCA agrees with the needs statements, and adds the following to the need to improve system reliability and resilience:

- Seismic activity – in coastal Humboldt and Del Norte counties, and Tribal Nations within those areas, all energy transmission lines and pipelines (electric and natural gas) run through areas with extreme seismic risk.
- Transmission in Humboldt County has a single point of failure due to over-reliance on a single natural gas-powered electrical plant. As a recent example, during a 6.4 earthquake on December 20, 2022 the entire region lost power due to the immediate outage of that one power plant.
- The Humboldt County area is transmission capacity constrained where it cannot import more than 70 MW, roughly half its base electricity use. Transmission upgrades to the single 115kV line serving the region should be a top priority, with or without the addition of offshore wind generation transport needs (see below).

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- Tribal Nations along transmission routes need upgrades to substations and distribution grids, as many areas are rural, remote, and subject to multiple hazards.
- Sea level rise – Humboldt Bay in Northern California has the fastest rate of sea level rise on the Pacific Coast, and this threatens the region's sole anchor natural gas-to-electricity power plant. Sea level rise also threatens transmission infrastructure to and within several Tribal Nations on or near the coast.
- Grid capacity shortfalls – California is already experiencing capacity shortfalls. In southern Humboldt County, a hospital cannot be built today, and several Tribes seeking to build DERs cannot connect to the grid, because of grid capacity constraints.

Offshore Wind Section

To the section on Offshore Wind in the Draft, the NCTCA adds the following needs: Off the Northern California / Southern Oregon coasts, there is potential for ~15-45 GW (or more) of offshore wind generation, due to demonstrated resource potential. To deliver the offshore wind power to load centers to the east, south, and north, new high voltage transmission lines must be built. Tribal Nations must be included in planning and design activities - and deployment investments - with state and federal counterparts. Including Tribal Nations early and designing transmission to also solve for Tribal energy needs will ensure energy benefits to Tribal Nations are delivered, and impacts from construction and operation of these corridors are minimized or avoided. Activities such as new substations for Tribal communities, undergrounding or otherwise hardening transmission infrastructure for the regional risks noted above, in addition to full engagement on cultural resources and environmental review, are crucial. Tribal Nations may also pursue building, owning, and operating transmission infrastructure, and need frameworks for collaboration and coordination in development and regulatory spaces.

Clean Energy on Tribal Lands

To the section on Clean energy on Tribal lands, the NCTCA adds the following needs: The majority of Tribal Nations are actively seeking to build electrical infrastructure at various scales. The inadequacy of transmission capacity, and poor quality of electricity delivery, is creating a chilling effect on adoption of electrified transportation, building electrification, and development of DERs in Tribal lands. Lack of transmission is also constraining Tribal economies, e.g., high-quality, resilient power is required for digitally-connected economies of today and the immediate future, and crossing the digital divide requires crossing the clean energy divide. As noted above, due to historic lack of infrastructure builds in Tribal lands and subsequent divestments, Tribal Nations are currently capacity constrained.

The Tribal clean energy and economic potential statistics cited in the Draft are dated. With future-proofed transmission capacity, Tribal Nations, and particularly those in markets where energy costs and constraints have increased in the past few years, can develop greater amounts of clean energy, both as economic enterprises, and as economy-enabling infrastructure. The NCTCA recommends updating the studies referenced with new research and data.

Thank you in advance for your close attention and time-sensitive review. For further information, please contact Amy Atkins at aatkins@trinidadrancheria.com.

Respectfully,

Garth Sundberg
NCTCA Chairman

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PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403

April 20, 2023

Honorable Jennifer M. Granholm, Secretary of Energy
Department of Energy
Forrestal Building
1000 Independence Ave SW
Washington DC, 20585

Re: Comments of PJM Interconnection, L.L.C. on the U.S. Department of Energy Draft National Transmission Needs Study

Dear Secretary Granholm:

PJM Interconnection, L.L.C. ("PJM") appreciates this opportunity to comment on the United States Department of Energy's ("DOE" or "Secretary") draft National Transmission Needs Study ("Needs Study").[1] Over the past decade, increasing focus by federal and state governments, corporations and other organizations on climate change, energy independence and other policy areas continues to make clear the critical role of the transmission system. PJM agrees with the fundamental premise underlying the Needs Study, *i.e.*, that the facilitation of transmission investment will help enhance reliability, reduce power costs, ensure a more resilient grid and address our nation's aging transmission system and changing generation resource mix. PJM further supports the Needs Study's overall determination that additional transmission, if appropriately planned and sited, can significantly enhance the reliability, resilience and efficiency of the power grid, promote state and federal public policies, and ultimately lower costs to consumers. PJM generally agrees with many of the Needs Study's findings specific to the PJM Region (referred to in the Needs Study as the Mid-Atlantic region).

[1] The draft National Transmission Needs Study is available at: https://www.energy.gov/gdo/national-transmission-needs-study.

As discussed below, however, PJM believes that the Needs Study is incomplete in certain respects.[2] Specifically, pursuant to section 216 of the Federal Power Act ("FPA"), the DOE must conduct a study and issue a report on electric transmission capacity constraints and congestion on a triennial basis.[3] Based on that triennial review, the DOE Secretary may designate certain transmission-constrained or congested geographic areas as national interest electric transmission corridors ("National Corridors").[4] Congress made clear that this study is a key component in the process of designating National Corridors.[5]

PJM is concerned that, although the draft Needs Study makes observations at a high level about a number of factors affecting the future grid nationwide, the Needs Study does not provide any guidance to the Secretary or to the public as to what criteria should be utilized in determining whether a National Corridor designation is appropriate to address the current or expected congestion and capacity constraints described in the Needs Study. Nor does the study undertake any analysis as to whether National Corridor designation would be helpful to address the identified congestion and capacity constraints. As such, PJM believes the Needs Study, as currently drafted, does not provide a sufficient record upon which the DOE can designate any National Corridors – which is an important and necessary next step towards the construction of needed transmission facilities for a robust transmission system.

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[2] *See* Section II.A, *infra*.

[3] 16 U.S.C. § 824p(a).

[4] 16 U.S.C. § 824p(a). In November 2021, through the bipartisan Infrastructure Investment and Jobs Act ("IIJA"), Congress amended FPA section 216(a)(2) to expand the circumstances under which DOE may designate a National Corridor. In addition to geographic areas currently experiencing transmission capacity constraints or congestion that adversely affects consumers, DOE may designate National Corridors in geographic areas expected to experience such constraints or congestion. The IIJA also amended section 216(a)(4) to expand the factors that DOE may consider in determining whether to designate a National Corridor. *See* Pub. L. 117-58, § 40105, 135 Stat. 429 (2021).

[5] Although Congress indicated that "other information" may also be utilized by the Secretary, that information is, per the statute, related to transmission capacity constraints and congestion—the very topics that Congress sought the study to address as part of the corridor designation process.

Additionally, PJM proposes below additional factors that should be considered in finalizing the National Transmission Needs Study for use in setting a record to support National Corridor designations.[6] PJM describes below those additional factors that the DOE should consider in its analysis of transmission system needs with respect to the PJM Region, and corrects or clarifies certain factual statements contained in the draft Needs Study.

PJM respectfully requests that the DOE consider these comments in order to improve the National Transmission Needs Study and as additional information it should consider in deciding whether and where to designate National Corridors. In addition, PJM suggests that these additional factors be considered in revisions to the Needs Study as outlined herein.

I. DESCRIPTION OF PJM

Pursuant to the Federal Energy Regulatory Commission's ("Commission" or "FERC") Order Nos. 2000,[7] 890,[8] and 1000,[9] PJM is the independent regional transmission planner for the PJM Region. In that capacity, PJM is responsible for identifying transmission system enhancements and expansions needed to keep electricity flowing to 65 million people throughout

[6] *See* Section II.B, *infra*.

[7] *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), *affirmed sub nom. Public Utility District No. 1 Snohomish County Washington, et al., v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) (Order No. 2000).

[8] *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 73 Fed. Reg. 2,984 (Jan. 16, 2008), 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 74 Fed. Reg. 12,540 (Mar. 25, 2009), 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[9] *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 77 Fed. Reg. 32,184 (May 31, 2012), 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000 -B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014).

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13 states and the District of Columbia.[10] PJM directs the operation of more than 88,115 miles of transmission lines across 368,906 square miles of territory, interconnecting with more than 180,000 megawatts ("MW") of power generation. Within the PJM Region, 325 transmission tie lines connect each Transmission Owner Zone to adjacent Zones within the PJM Region, thereby permitting the flow of power between the 21 PJM Zones.[11] This essential aspect of the PJM grid gives rise to the benefits of shared capacity, power markets and mutual support under stressed system conditions – extreme weather, for example. While PJM coordinates the flow of electricity on its transmission system, PJM also works cooperatively with the transmission-owning utilities that operate and maintain the equipment that makes up the Transmission System in their respective Zones.[12]

II. COMMENTS

A. Congress Gave the DOE Authority to Designate National Corridors, But the Needs Study May Not Provide a Sufficient Record Upon Which the DOE Can Base a Finding Related to the Need for National Corridors

Section 216(a) of the Federal Power Act ("FPA") requires the DOE to undertake a triennial review of "electric transmission capacity constraints and congestion."[13] The Secretary is then required, after considering alternatives and recommendations from interested parties, to issue a report, "*based on the study* … or other information *relating to electric transmission capacity constraints and congestion*" to designate a National Interest Electric Transmission Corridor.[14]

[10] The PJM Region encompasses all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

[11] *See* PJM Open Access Transmission Tariff, Attachment J.

[12] PJM's relationship with the PJM Transmission Owners ("TOs") is codified in the following PJM Governing Documents: the Consolidated Transmission Owners Agreement ("CTOA"), Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. ("Operating Agreement") and PJM Open Access Transmission Tariff ("OATT" or "Tariff"). These Governing Documents can be found on the PJM website, https://pjm.com/library.

[13] 16 U.S.C. § 824p(a)(1).

[14] 16 U.S.C. § 824p(a)(2) (emphasis added).

Although FPA section 216(a)(4) was expanded in the IIJA to include additional factors the Secretary "may consider" in her designation, Congress made clear that the Needs Study, as well as information "related to electric transmission capacity constraints and congestion" *remains,* per the IIJA, the basis for any such designation.

Although the Needs Study makes observations at a high level about a number of factors affecting the future grid nationwide, it is completely silent on even mentioning, let alone providing, guidance to the Secretary as to what would be appropriate National Corridor designations to address the observed capacity constraints or congestion. This is a marked departure from prior studies. By simply being silent and not providing any observations let alone recommendations on what criteria would be appropriate for the Secretary to apply to address the identified capacity constraints or congestion, the Needs Study does not provide the Secretary with a clear record to undertake her responsibility to designate National Corridors. Indeed the Needs Study's observations are so broad that one could use the study as the basis for either designating the entire country as a corridor on the one hand or, on the other hand, not designating any particular area as one where corridor designation is appropriate. In this way, the sweeping conclusions of the Needs Study may not be helpful in providing the degree of specificity and record support for the designation of National Corridors that Congress intended.

Although PJM recognizes that the Secretary's proposed designation of National Corridors is a subsequent step in the process, and that the DOE is in parallel conducting the Transmission Planning Study,[15] the Needs Study's lack of even broaching the subject or providing *any* guidance on the size of the area that could be considered to address the identified capacity constraints or congestion, leaves the Secretary with little in the way of guidance and support, and the public with

[15] *See* https://www.energy.gov/gdo/national-transmission-planning-study.

little information, to assess whether the Secretary's eventual designation is actually grounded in specific conclusions that can be found in the draft Needs Study. For example, the Needs Study identifies areas of historic congestion within PJM but does not link any of its *other much broader findings* (such as those related to the value of interregional transfer capability or emerging renewable integration) to alleviating those specific areas of congestion within discrete zones within the PJM Region. As a result, the draft Needs Study, as written, does not provide the required information to the public to support any particular transmission corridor designation as the means to resolve the identified capacity constraints or congestion. And, although Congress in the bipartisan IIJA expanded the Secretary's ability to utilize "other information" than just the Needs Study, the specific information outside of the Needs Study that the Secretary is to consider was, according to Congress, information "relating to electric transmission capacity constraints and congestion," the exact topic that Congress sought this study to address. As a result, more generalized observations about the future energy mix not linked to particular regions, although helpful, cannot form the basis of a corridor designation.

The designation of National Corridors has been, and most likely will remain, controversial. PJM believes that, if properly done and with sufficient consultation with the states and affected parties, a National Corridor designation *could* be helpful to moving forward on needed transmission development that takes into account regional as well as state needs. PJM further believes that a regional identification of needs (which would include congestion) undertaken by a RTO through its independent transmission planning process developed with stakeholder input and consultation, should take precedence over individual state or local disagreements with that regional need once identified.[16]

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[16] PJM identified a regional need to address congestion in the eastern MAAC region of PJM through a multi-state transmission facility that included Maryland and Pennsylvania. The Maryland Commission accepted PJM's need

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PJM's concern remains that the Needs Study, which does not contain any discussion of what could constitute an appropriate geographic corridor to remedy the congestion the draft identifies, leaves the Secretary with essentially a "jump ball" with no specific guidance or recommendations upon which to base its decisions regarding National Corridors. Such action could then lead to legal challenges regarding whether the decision was arbitrary and capricious and followed, once again, by litigation effectively thwarting the very process that Congress crafted through FPA section 216. For this reason, PJM urges the DOE to supplement the Needs Study with additional discussion and explanation of how geographic corridors may (or may not) remedy the issues identified in each region.

The Final Needs Study need not (and should not) actually designate the National Corridors. But, the Needs Study's studious silence on the topic does little to advance Congress' goal or provide the Secretary with a strong record to support its upcoming decision. For this reason, PJM urges that the Final Needs Study provide this necessary analysis and linkages as outlined above.

determination while the state of Pennsylvania rejected that determination on the basis that it did not provide sufficient benefits to the state of Pennsylvania. AEP has recently challenged Pennsylvania's second-guessing of PJM's regional need determination in litigation now pending before the United States District Court for the Middle District of Pennsylvania. *Transource Pennsylvania, LLC v. PA PUC*, PJM's Brief in support of its motion for leave to file *amicus curiae* brief, Case No. 1:21-cv-01101-JPW (M.D. Pa. Apr. 5, 2023). This east-west transmission corridor need remains current and has since evolved to require much higher transfer capacity requirements as reflected in PJM's most recent New Jersey offshore wind competitive solicitation and through PJM's 2022 Regional Transmission Expansion Plan ("RTEP") competitive window #3 for transmission solutions.

B. There are Additional Factors That Should be Included in the Needs Study for DOE Consideration With Respect to PJM

1. Although PJM Supports an Examination of the Need for Increased Interregional Transfer Capability, the Report Does Not Make Clear the Criteria or Metrics to Gauge the Level of Increased Interregional Transfer Capability. The Needs Study Should Defer to Work Underway at FERC and Within the Eastern Interconnection Planning Collaborative to Develop Appropriate Metrics

The Needs Study identifies a need for greater interregional transmission investments to "help improve system resilience by enabling access to diverse generation resources across different climatic zones, which is becoming increasingly important as climate change drives more frequent extreme weather events that damage the power system."[17] For the Mid-Atlantic region, the Needs Study identifies the need for large amounts of increased interregional transfer capability between PJM and the Midwest region, and, to a lesser but still considerable degree between PJM and New York and PJM and the Southeast region.[18]

PJM agrees that it is important to develop interregional transfer capability and other measures to strengthen interregional coordination. Indeed, PJM has advocated for the need for increased interregional transfer capability among regions in various FERC proceedings, both individually[19] and as a member of the Eastern Interconnection Planning Collaborative ("EIPC"),[20]

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[17] Needs Study at iii.

[18] Needs Study at xiv.

[19] *See, e.g.*, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Initial Comments of PJM Interconnection, L.L.C., Docket No. RM21-17-000, at 69 ("PJM Initial ANOPR Comments" or "PJM's Initial ANOPR Comments") (Oct. 12, 2021); *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Initial Comments of PJM Interconnection, L.L.C., Docket No. RM21-17-000, at 123-126 (Aug. 17, 2022) ("PJM Initial NOPR Comments" or "PJM's Initial NOPR Comments").

[20] *See Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*, Testimony of David W. Souder on behalf of EIPC, AD23-3-000 (Dec. 9, 2022) ("Souder Testimony"). The EIPC is an organization that was formed in 2009 by North American Electric Reliability Corporation ("NERC")-registered Planning Coordinators in the Eastern Interconnection ("EI") to perform coordinated interconnection-wide transmission analysis. The EIPC is a "Technical Organization" pursuant to its Mission Statement, which provides a forum for interregional coordination of the combined plans of its regional members (representing both ISO/RTO and non-ISO/RTO regions) to evaluate how well the regional plans mesh to maintain the reliability of the bulk electric

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including the ongoing FERC proceeding that was initiated to address how FERC could establish a minimum requirement for interregional transfer capability.[21] In those dockets, however, PJM urged FERC to take a multi-step approach to develop metrics and a methodology that would be informative to transmission planners to facilitate their determination of the appropriate level of interregional transfer capability (*i.e.*, minimum interregional transfer criteria) between regions under extreme conditions.[22] It is critical that increased interregional transfer capability not become a substitute for each region ensuring resource adequacy to meet its own reliability requirements. The draft Needs Study unfortunately does not appear to note this appropriate limitation nor propose a specific metric or criteria to analyze an appropriate level of interregional transfer capability. It is for these reasons that the EIPC recommended that, given the complexity of the analyses that would have to be undertaken to establish such a metric and methodology, as an initial first step, FERC should work with the industry, the DOE's National Laboratories and Technology Centers, and the National Oceanic and Atmospheric Administration to help develop a metric to quantify the necessary interregional transfer capability for extreme events covering a wide area.[23]

Contrary to the deliberative process that PJM and the other EIPC members recommended be used to establish interregional transfer capability metrics and methodologies, the Needs Study

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system. The EIPC develops transmission system models and performs interregional scenario analysis to identify stress points on the EI-wide system, providing feedback to enhance the regional plans of our members. The EIPC also publishes periodic reports to assess the state of the Eastern Interconnection, the most recent of which was the 2021 "State of the Grid" Report ("2021 Grid Report"). *See* EIPC State of the Grid Report – 2021, *available at*: https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/61b8f9ae4172c60bdd3a72ad/1639512495712/2021+EIPC+State+of+the+Grid+12-7-21.pdf.

[21] *See Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*, Notice of Staff-Led Workshop, Docket No. AD23-3-000 (Oct. 6, 2022) (held on Dec. 5-6, 2022); *Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*, Notice Requesting Post-Workshop Comments, Docket No. AD23-3-000 (Feb. 28, 2023) (establishing an initial comment deadline of May 15, 2023 and a reply comment deadline of June 28, 2023) ("Interregional Transfer Capability Proceeding").

[22] *See* Souder Testimony at 5.

[23] *Id.*

merely estimates the transfer capability needs for each region without identifying any metric upon which the estimates are based. It is unclear whether the estimates are based on a "top down" optimization of renewables across the country and, if so, whether the approach adequately considers state renewable portfolio standard requirements and desires of states to locate renewables in their state. The Needs Study also does not make clear that each region needs to be responsible for resource adequacy in its region. Although generation from neighboring systems can help to provide that resource adequacy, interregional transfer capability should not allow neighboring regions to simply "lean" on their neighbors who otherwise would be bearing the costs of maintaining resource adequacy.

PJM recommends that, in determining the extent to which interregional transfer capability is needed between various regions, the DOE defer to the ongoing Interregional Transfer Capability Proceeding, where FERC, the DOE, EIPC members and other interested parties will have the opportunity to develop metrics and a methodology to determine the appropriate level of interregional transfer capability between regions. The Needs Study should factor in the detailed analysis and complexity associated with determining the appropriate level of interregional transfer capability – work which the EIPC is presently undertaking for the Eastern Interconnection.

2. The Needs Study Identifies Reliability and Resiliency Needs for Other Regions, but Fails to do so for PJM

The Needs Study identifies four main reasons that transmission should be built in the Mid-Atlantic (PJM) region, focusing on congestion and economics, as well as on the need to increase interregional transfer capability between PJM and its neighboring regions to support new clean energy resources and increased electrification. However, unlike other regions,[24] the Needs Study

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[24] *See* Needs Study at iv – xv (identifying the need to improve system reliability and resilience due to increased renewable penetration and/or to address extreme weather events for the following regions: Northwest; Mountain; California; Southwest; Texas; Plains; Midwest; Delta; Florida; and New England).

does not recognize PJM's actions to date to improve the transmission system resilience, or PJM's request for the identification of a planning driver to focus on resilience of the transmission system.

PJM's RTEP process continues to manage an unprecedented capacity shift driven by federal and state public policy and broader fuel economics. PJM recently released the third phase of its ongoing study of impacts associated with this energy transition in the PJM Region.[25] Specifically, in the Energy Transition Report, PJM analyzed the impact of industry trends and state and federal decarbonization policies within the PJM Region. The Energy Transition Report highlights four trends that, in combination, present increasing reliability risks during the transition, due to a potential timing mismatch between generation retirements, load growth and the pace of new generation entry:

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region.[26]
- Thermal generators are retiring at a rapid pace due to government and private sector policies as well as economics.[27]
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, the long-term impacts of which are not fully known.[28]

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[25] Energy Transition in PJM: Resource Retirements, Replacements and Risks, *available at*: https://www.pjm.com/-/media/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx ("Energy Transition Report").

[26] Due to the expansion of highly concentrated clusters of data centers, combined with overall electrification, certain individual zones exhibit more significant demand growth – as high as 7% annually. Energy Transition Report at 2.

[27] PJM's analysis shows that 40 GW of existing generation are at risk of retirement by 2030. This figure is composed of: 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity. *Id.* And, PJM's long-term load forecast shows demand growth of 1.4% per year for the PJM footprint over the next 10 years. *Id.*

[28] The projections in the Energy Transition Report indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. *Id.*

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- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources.[29] Given the operating characteristics of these resources, PJM will need multiple MW of these resources to replace 1 MW of thermal generation.

Each of these factors could have an impact on the PJM transmission system. Generator deactivations alter power flows that can cause transmission line overloads and, given reductions in system reactive support from those generators, can reduce voltage support. PJM may need to order transmission upgrades or additions built by transmission owners to accommodate the generation loss. Concentrated load growth associated with increased electrification and the proliferation of data centers also drives the need for transmission system reinforcements. And, the shift to intermittent and limited-duration resources will alter how power flows across the PJM Region and will drive future grid expansion to ensure reliable power delivery to load centers. PJM urges the DOE to consider the impact of these factors on the PJM transmission system as it finalizes the Needs Study.

In addition to these future reliability-related concerns, PJM has also stressed the need to consider resilience in intermediate- and long-term regional planning processes.[30] A number of emerging system conditions already present challenges to reliable system operations, including, for example: (i) extreme weather; (ii) cyber and physical attacks; and (iii) generation fleet shift driven by natural gas and increased deployment of renewable resources. Such challenges will continue to stress future grid resilience, which enhanced reliability criteria must address. For decades, planning criteria have been developed and applied to power systems across the country to ascertain the need for grid enhancement, so that system operators can meet the operating

[29] PJM's New Services Queue consists primarily of renewable resources (94%) with the remaining 6% consisting of gas units. Despite the sizable nameplate capacity of renewable resources in the interconnection queue (290 GW), the historical rate of completion for renewable projects has been approximately 5%.

[30] PJM's Initial NOPR Comments at 11-25.

conditions they encounter on any given day. Planners test the system under simulated stressed conditions, such as extreme weather, to understand where reinforcements may be warranted to make the grid reliable. Clear and focused resilience reliability criteria are needed to address more extreme system events. This is particularly true for a transmission grid with: (1) higher penetration of variable and duration-limited resources reliant on sun and wind to operate; and (2) an end-use sector with growing reliance on electrification.

PJM's ongoing efforts are taking a forward-looking, holistic and proactive approach to plan for future transmission needs with respect to extreme events, which may become a more significant grid expansion driver under higher levels of renewable penetration. The scope of planning studies will support efforts to assess how extreme events can be analytically evaluated and how consequential impacts to system reliability are identified. This may lead to new reliability criteria and planning tests.[31] PJM respectfully requests that the DOE factor into its analysis the impact that considering resilience in intermediate- and long-term regional planning processes will have on the transmission system as it finalizes the Needs Study and decides whether and where to designate National Corridors.[32]

C. Clarification or Correction Regarding Certain Facts Contained in the Needs Study

1. Findings Regarding Interregional Transfers During the February 2021 Extreme Weather Event are Misleading

The DOE discusses the importance of expanding transmission as it relates to ensuring resource adequacy in some regions, in that it would allow access to diverse resources from around

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[31] PJM has urged FERC to adopt a common definition of resilience and a specific resilience planning driver for grid enhancements, applicable to all planning entities. *See* PJM's Initial NOPR Comments at 11-26.

[32] As discussed above, the IIJA expanded the circumstances under which DOE may designate a National Corridor such that in addition to geographic areas currently experiencing transmission capacity constraints or congestion that adversely affects consumers, DOE may also designate National Corridors in geographic areas expected to experience such constraints or congestion. *See supra,* n.4.

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the country.[33] As part of this discussion, the DOE references the February 2021 freeze in Texas and the Midwest (the "February 2021 Cold Snap") and the fact that the Electric Reliability Council of Texas' ("ERCOT") "limited interconnections with its neighbors significantly affected its ability to make up for the capacity shortage experienced during the severe cold weather event of February 2021."[34] Although the DOE acknowledges that the Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP") regions were less impacted than ERCOT due to their strong connections with adjacent neighbors that were not affected by the storm, the DOE further states the MISO and SPP would have been limited in their ability to increase imports to ERCOT "without increased import capability with *their* adjacent neighbors in the Eastern Interconnection."[35]

PJM wishes to clarify that during the February 2021 Cold Snap, much of the Eastern Interconnection experienced cold weather that resulted in PJM exporting an unprecedented amount of electricity into neighboring systems. The February 2021 Cold Snap established a completely new top 10 list of peak winter interchange hours in PJM.[36] During those peak hours, net exports were three times higher than the 2020/2021 winter average, with a high of over 15,700 MW on February 15, 2021.[37] Overall, the grid performed reliably. PJM was able to supply power to

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[33] *See* Needs Study at 50-51.

[34] Needs Study at 50.

[35] *Id.* (emphasis original).

[36] *See* PJM Interconnection, L.L.C., *Winter Operations of the PJM Grid: December 1, 2020 – February 28, 2021*, at 26–30 (Apr. 8, 2021), https://pjm.com/-/media/committees-groups/committees/oc/2021/20210408/20210408-item-14-winter-operations-review.ashx.

[37] *Id.*

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neighboring systems during the winter storms that occurred during the February 2021 Cold Snap, when those systems were experiencing more severe weather conditions than PJM as a whole.[38]

Notwithstanding the fact that congestion management along the border served an important role during the February 2021 Cold Snap, PJM's ability to transfer power between regions was often limited by facilities internal to the neighboring region receiving the electricity, and not necessarily by facilities along the seam. That is, PJM had additional energy available to be transferred, but could not do so due to internal constraints in neighboring systems. The Needs Study should recognize this reality in its conclusions so as to ensure a full picture of the drivers of limits of transfer capability during the February 2021 Cold Snap.

2. Findings Regarding Potential Savings that Could Have Been Realized During the December 2017 / January 2018 "Bomb Cyclone" Event May Not Tell the Whole Story

The Needs Study discusses recent extreme weather events to determine "what, if any, value additional transmission would have provided to the power grid during such events."[39] Among other reports, the DOE summarizes a study that claims that "[d]uring the 'Bomb Cyclone' cold snap across the Northeast in December 2017-January 2018, the affected regions—New England, New York, and the Mid-Atlantic region—could have saved $30-40 million for each GW of stronger transmission ties among themselves or to other regions."[40] The findings of this study, however, may not tell the whole story. Although building strong transmission ties may benefit some regions, it may come at a significant cost to others. Given the complexity of the analysis required to evaluate the benefits of strong transmission ties, PJM recommends that the DOE rely

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[38] PJM has relied on the same strong transmission ties to import energy of approximately 10,000 MW during the 2014 Polar Vortex.

[39] Needs Study at 70.

[40] *Id.*

on the ongoing Interregional Transfer Capability Proceeding as discussed above.[41]

III. CORRESPONDENCE AND COMMUNICATION

Correspondence and communications with respect to these comments should be sent to the following persons:

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[41] *See supra*, n.21.

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IV. CONCLUSION

PJM respectfully requests that the Needs Study authors consider the comments set forth above as they finalizes the study. PJM stands ready to continue to serve as a resource to the Department and the Study's authors to ensure that the Needs Study remains thorough and factually accurate and provides a strong record for future decision-making by the Secretary of Energy.

Respectfully submitted,

/s/ Jessica M. Lynch

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UNITED STATES DEPARTMENT OF ENERGY

COMMENTS OF THE PSEG COMPANIES ON THE DRAFT 2023 NATIONAL TRANSMISSION NEEDS STUDY

The PSEG Companies[1] respectfully submit the following comments in response to the Department of Energy's (the "Department" or "DOE") solicitation for feedback from the public about analysis gaps or any other comments or suggestions relating to the Draft 2023 National Transmission Needs Study (the "Needs Study" or "Study") that was issued on February 24, 2023.[2]

I. INTRODUCTION

The U.S. faces significant challenges to meet the needs of the clean energy grid and the rapidly changing resource mix. PSEG provides these comments to highlight these challenges and draw attention to important issues that must be addressed to ensure that transmission investments are being made in a cost-effective manner and where they are most needed for a cleaner, more sustainable and more resilient grid. As a general

[1] The PSEG Companies are Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC, and are each wholly-owned, direct or indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG").
[2] U.S. Department of Energy, *National Transmission Needs Study: Draft for Public Comment* (February 2023) ("Needs Study").

matter, PSEG supports the National Transmission Needs Study's (the "Study") conclusion that there is a "pressing need to expand electric transmission to improve grid reliability, resilience, and resource adequacy, enhance renewable resource integration and access to clean energy … [and to] support electrification efforts..."[3] However, PSEG will also highlight additional issues that the Study should consider to paint a clearer picture of the challenges at hand. For example, the Study should take into account that:

1. There is a significant need but also significant challenges to long-term regional planning - particularly in multi-state RTOs- because of divergent state policies;

2. Physical and cybersecurity is an essential transmission need;

3. The Federal Energy Regulatory Commission's ("FERC") Order No. 1000-driven elimination of a federal Right of First Refusal ("ROFR") has had the negative effect of producing narrowly-scoped projects to address the short-term needs of the system rather than incorporating a comprehensive, holistic evaluation that reflects and anticipates future system needs; this in turn has discouraged the planning of regional and interregional projects; and

[3] Needs Study at ii-iii.

4. A fully networked transmission system is necessary to support offshore wind generation in the Mid-Atlantic, as well as in New England and New York.

The Study finds that "[a] more robust transmission system—along with associated upgrades to the distribution system—supports the electrification of end-use devices which presently rely on fossil fuel combustion, resulting in environmental benefits in the form of improved air quality and avoided adverse health effects."[4] At a state level, New Jersey has recognized the need for significant new transmission investment in the state and the region to achieve the state's ambitious clean energy goals, including a target of 11,000 MW for offshore wind generation.[5] New Jersey also set an electrification target to install electric space heating and cooling systems in 400,000 homes and 20,000 commercial properties, and make 10 percent of all low-to-moderate income (LMI) properties electrification-ready by 2030.[6] In comparison with other states, New Jersey is at the forefront of the clean energy transition.

PSEG is aligned with New Jersey's clean energy goals, and has been, and is continuing to be, deeply engaged in the critical work of addressing the impacts of climate change for the benefit of our customers, the community at large and the region. PSEG is

[4] Needs Study at 8.
[5] On January 23, 2023, New Jersey Governor Philip Murphy announced planning for the development of a new Energy Master Plan for release in 2024. *See e.g.*, 2019 New Jersey Energy Master Plan. *See also* N.J. Stat. Ann. 48:3-87.1 *et seq*. ("New Jersey Offshore Wind Economic Development Act"); N.J. Exec. Order 307 (2022) (increasing offshore wind target by over 50% to 11,000 megawatts); N.J. Exec. Order 315 (2023) (accelerating New Jersey's 100% clean energy target from 2050 to 2035).
[6] N.J. Exec. Order 316 (2023).

engaged at all levels of government from federal to the state and local levels, and through the Company's own evolution to focus on cost-consciously powering a future where people use less energy that is cleaner, safer and delivered more reliably than ever. PSEG continues to be a leader in addressing climate change and modernizing the grid.

Within PJM,[7] however, there are 13 states that all have vastly different state public policies. Although there is a significant need for new transmission within PJM, there are also significant challenges to getting transmission planned and built due in part to the divergent public policies and needs in the various states. For example, how will the New Jersey offshore wind and electrification targets be factored into long-range regional transmission planning to ensure no gaps in reliability?

There is a significant need for regional and interregional coordination in order to facilitate long-term scenario-based planning, strengthen the physical and cybersecurity of the transmission system, and to ensure the effective integration and interconnection of renewable resources to achieve clean energy goals.

In addition, regulatory certainty is a key component to addressing transmission need. Regulatory actions and policies play a significant role and provide signals to the industry and to the investment community. For example, for transmission being planned and built in RTO regions, FERC's proposal to remove the RTO adder incentive[8] provides

[7] PJM refers to PJM Interconnection, LLC. PSEG is a member of PJM.
[8] *See Electric Transmission Incentives Policy under Section 219 of the Federal Power Act*, 175 FERC ¶ 61,035 (2021).

a negative signal and undermines regulatory certainty, which will have a chilling effect on future transmission development in those regions.

II. DISCUSSION

A. There are significant challenges associated with planning in multi-state RTOs with divergent state public policies. Scenario planning will be necessary, but will be difficult to accomplish under these circumstances.

As recognized in the Study, long-range and robust scenario planning is essential, but PSEG believes that this will be very challenging to achieve across states and in multi-state RTOs where there will be no consensus on the planning scenarios to be utilized.[9] This may ultimately threaten grid reliability. FERC has recognized the need for scenario planning and has proposed that long-term transmission plans be based on scenario planning, with multiple scenarios used to estimate the most likely range of outcomes and to gauge the level of uncertainty of the resulting projections.[10] Many companies including PSEG supported scenario-based planning and provided comments in that proceeding.[11]

With regard to regional planning, the Study recognizes that many regional plans have "very limited scopes and planning horizons."[12] Our experience in PJM is somewhat different in that PJM plans for both 5-year and 15-year planning horizons, but there are

[9] Needs Study at 3 (The Needs Study concludes that "more holistic and comprehensive planning assessments that consider a wide range of scenarios of the future of the bulk power system . . . will address future needs and ensure that expected transmission constraints and congestion are identified and mitigated.")
[10] *Bldg. for the Future Through Elec. Reg'l Transmission Planning & Cost Allocation & Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022) (proposing to require that transmission providers develop and use Long-Term Scenarios as part of Long-Term Regional Transmission Planning).
[11] *Id.*
[12] Needs Study at 2.

limitations with PJM's regional planning because it is not true scenario planning. Without a robust form of scenario planning, we are not reliably planning the grid for long-term reliability and resilience. In 2019, the Organization of PJM States, Inc. ("OPSI") requested that PJM engage in scenario planning that considered, among other things, how to incorporate state public policy goals for renewables into the PJM transmission planning process. In 2021, PJM provided a preliminary update on these scenarios, in which it explained that it had identified significant benefits across the PJM footprint associated with the onshore network upgrades that had been studied. These benefits include congestion relief, reduced emissions, and decrease in load payments due to LMP changes and decrease in renewable generation curtailments. This type of scenario-based planning evaluation provides a useful tool in ensuring that regional plans are using the best available information regarding future system conditions. Therefore, rather than serving simply as an informational tool for a limited purpose and a discrete audience, RTOs and ISOs should incorporate detailed scenario-based planning procedures in their governing documents.

As noted in these comments, however, the challenge with scenario planning is how to effectively conduct and engage in scenario planning across a 13-state footprint where planning assumptions may be widely divergent and there will be no agreement on which scenarios to select. The stakeholder process, which is a key component of the RTOs, adds yet another layer that impedes regional and interregional coordination. Divergent views among stakeholders in multi-state RTOs reflects itself in flawed stakeholder processes where parties are unable to reach consensus on important issues and rules needed to move transmission investment forward. Further, accurate load forecasting, which is an essential underpinning of effective scenario planning, is difficult to conduct in a multi-state RTO given the lack of agreement on how public policy goals/targets/requirements will translate into concrete load forecast assumptions.

Another challenge in a large RTO is how to accurately create a load forecast that captures anticipated load and future demand in the various states. Although PJM reviews the region's transmission system as a whole, PJM's forecast assumptions are not able to capture trends that are evolving rapidly, which could lead to understated load forecasts. Specifically, this may occur with load forecasting for electric vehicles and data centers, which are both developing at a very high rate. To address this challenge, RTOs need the ability to model more scenarios and account for a greater variety of changes in the transmission system. In addition, enhanced coordination and collaboration between RTOs and members companies is beneficial since member companies may be better equipped to capture trends on the ground that would lead to more accurate planning at the regional level.

Another obstacle to expanding transmission is interregional coordination, which is an underutilized means of ensuring grid resilience. The current interregional planning rules make it very difficult for interregional projects to be developed because the proposed project must satisfy the criteria and be selected in the planning processes of both of the neighboring regions. This challenge is evidenced by the fact that there has only been one interregional market efficiency transmission project approved through the PJM RTEP long-term proposal window and Midcontinent Independent System Operator's ("MISO") planning process.

Multi-regional scenario planning would be particularly appropriate for addressing the build-out of renewable generation sources and storage. The transmission grid will face the problem of connecting concentrations of new renewable resources to load centers given that the geographical and meteorological considerations that drive the siting of renewable resources such as wind turbines and solar panel farms are entirely independent of the historical boundaries of electrical control areas. Creating artificial hurdles through RTO/ISO planning rules for transmission construction to meet these needs will result in greater costs and lower efficiencies.

PSEG notes that it has particular knowledge of the difficulties associated with potential interregional transmission. As the largest electric utility in the state of New Jersey and with a service territory that adjoins New York City, PSEG has considered the possibility of transmission projects that would strengthen ties between PJM and the New York Independent System Operator, Inc. ("NYISO"). However, the current PJM/NYISO rules around transmission planning and allocation severely limit the realistic options available.

B. Proactive resilience planning is necessary to protect the grid from physical and cyber threats that are constantly evolving, not just extreme weather events.

PSEG strongly supports the Study's finding that transmission "can increase grid reliability in the face of risks posed by future weather events."[13] However, resilience planning is also necessary to protect the grid from physical and cyber threats, and the Study lacks analysis on this need. Physical and cybersecurity is important for transmission systems because—as the FERC's Cybersecurity Incentives Policy White Paper recognized—the electric grid is an interconnected network and there are significant interdependencies between systems.[14] As such, efforts to enhance security have far-reaching consequences.

Resilience planning for physical and cybersecurity is essential at all levels of grid planning due to the interdependence of transmission systems. At the federal level, FERC has implemented a number of initiatives in the past few years aimed at enhancing physical and cyber security. In late 2022, FERC ordered NERC to review the Physical Security Reliability Standard applicable to transmission stations and substations following several physical attacks on electric infrastructure.[15] FERC Acting Chair Willie Phillips identified physical security as one of this top priorities, and discussed physical security at length during a recent meeting of the Joint Federal-State Task Force on

[13] Needs Study at 70.
[14] Cybersecurity Incentives Policy White Paper, Docket No. AD20-19 (June 18, 2020).
[15] *Incentives for Advanced Cybersecurity Investment; Cybersecurity Incentives, Notice of Proposed Rulemaking*, 180 FERC ¶ 61,189, Docket No. RM22-19 (2022); This NOPR supersedes the Commission's December 2020 Cybersecurity Incentives NOPR. *Cybersecurity Incentives*, Notice of Proposed Rulemaking, 173 FERC ¶ 61,240, Docket No. RM21-3 (2020).

Electric Transmission.[16] In his opening remarks, Phillips stated that the number of attacks on the physical transmission infrastructure has increased significantly in recent years. Specifically, he remarked that in the first eight months of 2022, there were 107 attacks, including the recent planned attack in Baltimore on BG&G's transmission system by a white supremacist group.[17]

PJM's Attachment M-4 process is another example of resilience planning that was developed to eliminate the criticality of a select number of transmission substations within the PJM footprint.[18] Attachment M-4 was limited in scope, but it is a first step and a component of overall resilience planning that will be increasingly necessary to mitigate threats to the grid.

At the state level, PSEG has worked closely with state regulators and lawmakers to provide guidance on the threats affecting utilities, collaborate in grid security planning, and update regulators of PSEG's ongoing efforts. Recently, PSEG testified before the Assembly Telecommunications and Utilities Committee of the New Jersey Legislature, with other New Jersey utilities, to provide information related to increasing resiliency of electric distribution and transmission infrastructure including methods of assessment, hardening, monitoring, and rapid repair and replacement.[19] Specifically, PSEG highlighted: (1) physical grid security measures that PSEG has taken; (2) the continued

[16] *Joint Federal-State Task Force on Electric Transmission*, Docket No. AD21-15-000 (February 15, 2023).
[17] *Id.*
[18] PJM Open Access Transmission Tariff, Attachment M-4.
[19] New Jersey Assembly Telecommunications and Utilities Committee, March 20, 2023.

vitality and increasing importance of public-private collaboration; (3) critical infrastructure mitigation efforts; (4) the need to continue strategic investments to ensure future resiliency and protect reliability; and (5) supply chain threats.

An attack on the transmission system, no matter how small or how isolated, can have a far-reaching impact beyond one substation or even one company. Therefore, PSEG believes that planning for physical and cybersecurity is of utmost priority, and this is a significant transmission need across the country.

C. The Order No. 1000 solicitation framework works directly counter to the robust, multi-value transmission planning that is needed.

According to the Study, states need to "properly assess the multiple values of transmission and the ability of robust transmission plans to improve reliability and resilience … under a broader and more diverse set of factors impacting the current and expected future electricity system …." However, this type of robust planning does not occur when RTOs run competitive solicitations; rather, the Order No. 1000 framework encourages narrowly-scoped projects to address the short-term needs of the system rather than reflecting a more comprehensive, holistic evaluation that reflects and anticipates future system needs.[20] Moreover, data demonstrates that Order No. 1000 solicitation processes have not been successful in achieving more cost effective and efficient transmission projects.[21] As the Needs Study confirms, transmission investment has

[20] *See also* Needs Study at 2 (recognizing that under FERC Order No. 1000, "plans are primarily focused on compliance with NERC and local reliability standards with very limited scopes and planning horizons").
[21] *See e.g.*, Concentric Energy Advisors, *Competitive Transmission: Experience To Date Shows Order 1000 Solicitations Fail to Show Benefits*, (August 2022) https://ceadvisors.com/publication/competitive-

declined across the country and in nearly all regions, and PSEG believes that the elimination of federal ROFR effectuated by Order No. 1000 is a significant reason for declining investment.[22]

An August 2022 study performed by Concentric Energy Advisors evaluated six competitive transmission projects that were awarded to non-incumbent developers under Order No. 1000 solicitation processes.[23] The Concentric Report found that, in several cases, project costs increased significantly relative to initial estimates due to the fact that the project developers relied upon exceptions to cost caps to recover higher than expected costs.[24] For example, according to the Concentric Study, in NYISO, the winning bid cost estimate for the Empire State Line project was $181 million, but the final project cost was $249 million, representing a 38% increase over the initial bid estimate.[25] The Concentric Report also found that transmission projects awarded to non-incumbents have

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transmission-experience-to-date-shows-order-no-1000-solicitations-fail-to-show-benefits/ (last visited Apr. 17, 2023).

[22] *See* Needs Study at Section IV.a. Indeed, PJM itself has commented that the Order No. 1000 solicitation framework has not worked. PJM stated that over the past decade or so, out of 163 reliability projects, the PJM Board designated only two projects to non-incumbent transmission developers. PJM stated that "even when nonincumbuent developers have had the opportunity to submit project proposals . . . in almost all instances, the nonincumbents' proposals were not found to be more efficient for cost effective. PJM has explained that, among other reasons, nonincumbent developers lack knowledge and familiarity with the transmission owners' system, which caused their proposed solutions to be more expansive than necessary. *See Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, PJM Interconnection, L.L.C., Docket No. RM21-17 at 34-35(Aug. 17, 2022).

[23] August 22 Concentric Report.

[24] August 2022 Concentric Report at 3 (noting that several projects experienced significant cost overruns due to factors that could have been avoided by experienced incumbent transmission owners, such as regulatory delays, re-routing, and other environmental challenges).

[25] August 2022 Concentric Study at 2. Similarly, in CAISO, the Delaney to Colorado project had a winning bid estimate of $300 million; however, the final cost was $389 million, representing a 30 percent increase vis-à-vis the initial bid estimate.

experienced major scoping issues and schedule difficulties, with the average delay in the project completion being approximately one year beyond the required in-service date.[26]

Based on available data over the past ten years since the issuance of Order No. 1000, it is clear that ROFR elimination has not achieved its intended objectives and will only further impede cost-effective and forward-looking transmission investments as the country transitions to a clean energy grid.

D. PSEG strongly supports the Study's finding that there is a need for an offshore backbone grid to support state policies for offshore wind generation, but the Study should provide more detailed analysis of the transmission needed to do so.

PSEG is aligned with the Study's recognition of the need to plan for a backbone meshed grid to support offshore wind generation, but believes the Needs Study should go a step further to recognize the need to develop a fully networked system rather than a network-ready system. According to the Needs Study, "an offshore grid designed and built with the capability of a networked system will provide more benefits and will better facilitate the integration of offshore wind ("OSW") resources compared with each OSW resource connecting to the onshore grid through a dedicated generator lead line."[27] However, a network-ready system will only delay implementation and lead to increased costs later on, as technologies developed today will be obsolete or require upgrades. Transmission facilities will likely need to be updated or replaced to be compatible with the networked system in the future, and this will create additional costs.

[26] *Id.*
[27] Needs Study at 57.

There are significant benefits to a networked system – or meshed grid – and there is an immediate need to implement this system. A meshed grid approach to support offshore wind generation provides economic, reliability, and resiliency benefits. Some of the specific benefits of a meshed grid system are as follows:

i. Avoiding hourly curtailment during peak wind conditions, thereby ensuring that the most clean MWhs are delivered to the transmission system;

ii. Allowing for congestion control between points of interconnection, thereby further reducing costs to customers;

iii. Ensuring power is rerouted immediately without needing time to reconfigure the transmission system to utilize the interlink systems without interruption; and

iv. Maintaining generation supply during routine HVDC maintenance or onshore substation outages.

In addition, a meshed grid provides significant economic benefits. For example, the New York State Research and Development Authority ("NYSERDA") conducted a meshed grid study, which identified approximately $60 million in annual savings for New York ratepayers and found savings that were attributable to reduced curtailment and congestion benefits associated with multiple points of interconnection.[28]

[28] *See* Pfeifenberger J, Newell S, Tsoukalis J., The Brattle Group, "The Benefits and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York," prepared for NYSERDA (2021).

Although the Study recognizes the "unique transmission challenges associated with offshore wind," the Study should provide greater detail on specific needs and challenges.[29] For example, the Study should address or refer to the need for high-voltage direct current ("HVDC") networks - which are discussed elsewhere in the Study, HVDC standardization, and interoperability requirements of HVDC offshore systems.[30]

In addition, the Needs Study refers to the Atlantic Offshore Wind Transmission Study initiated by the Department, but the Offshore Wind Study was underway during this Study.[31] However, the Department recently released an update on Offshore Wind Transmission Study with 40 recommendations.[32] PSEG is currently reviewing the update, and believes that the Needs Study should be updated to analyze those recommendations.

Another limitation of the Needs Study is that it identifies offshore wind transmission as needed specifically in the New England region,[33] but PSEG believes the Mid-Atlantic must also be included in order to achieve New Jersey's ambitious goal of producing 11 Gigawatts of offshore generation by 2040. As the Needs Study informs the future designation of National Interest Electricity Transmission Corridors ("NIETC") and

[29] Needs Study at 57.
[30] HVDC networks are recognized elsewhere in the needs study. See Needs Study, Sections V.a and V.c.
[31] Needs Study at 57 (noting that the Atlantic Offshore Wind Transmission Study "evaluates multiple pathways to reach offshore wind goals through coordinated transmission solutions along the U.S. Atlantic Coast under various combinations of electricity supply and demand while supporting grid reliability and resilience and ocean co-use").
[32] Atlantic Offshore Wind Transmission Stakeholder Workshop presentation, slides 30-58 (March 22, 2023).
[33] Needs Study at xv ("A well-designed offshore transmission system can integrate offshore wind generation without compromising reliability of the onshore transmission system; designing and building the offshore grid with the capability of a networked system will improve reliability and reduce curtailments when transmission outages occur").

due to the complexity of offshore wind development, regions with significant offshore wind targets, such as the Mid-Atlantic region, should not be overlooked.

III. CONCLUSION

PSEG agrees with the DOE that there is a "pressing need to expand electric transmission—driven by the need to improve grid reliability, resilience, and resource adequacy, enhance renewable resource integration and access to clean energy, decrease energy burden, support electrification efforts, and reduce congestion and curtailment."[34] The Study, however, has not fully addressed all of the system needs that underlie the need for new transmission build, including physical security threats and governmental targets for renewable generation, such as offshore wind generation. To portray a full and accurate picture of the need for transmission, the Department must identify and analyze all drivers for new transmission. The Study is one important piece of the puzzle, but there remain significant challenges to getting needed transmission built. For example, differing state policies reflected in multi-state RTOs, load forecasting challenges, elimination of the federal ROFR, and lack of regulatory certainty all represent obstacles to the construction of new transmission and must be evaluated in the Needs Study.

Respectfully submitted,

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[34] Needs Study at 78.

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National Transmission Needs Study
Comments on the Public Draft-Northwest Area

Two areas appear to have been considered inadequately for the Pacific Northwest.

1. The Canadian Entitlement Return and other flows between Canada (BC) and Pacific Northwest create transmission challenges that have not been included in this Needs Study. BC also serves as a resource provider to CA during many hours of the year. Regional flows have been challenging since the first PSANI curtailments occurred in the early 2000s. Canada to Northwest solutions should be added as a "need".
2. With passage of the Clean Energy Transformation Act (CETA) in WA state, past operations and practices will no longer be a good predictor or future flows. CETA impacts have not been fully studied yet, although a new study is underway by NorthernGrid that may shed more light on transmission impacts of this legislation. Intra-regional Northwest challenges should be included as a "need".

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COMMENTS OF THE SOUTHEAST PUBLIC INTEREST GROUPS

Southern Environmental Law Center, Appalachian Voices, Energy Alabama, South Carolina Coastal Conservation League, North Carolina Sustainable Energy Association, and Southern Alliance for Clean Energy (together, Southeast Public Interest Groups) submit these comments in response to the United States Department of Energy's (Department) March 6, 2023 National Transmission Needs Study: Draft for Public Comment (Draft Study).[1]

Southeast Public Interest Groups appreciate the opportunity to comment on the Draft Study, which appropriately recognizes the pressing need for additional transmission infrastructure, both at the present moment and in the not-so-distant future. As organizations dedicated to facilitating the clean energy transition in a prudent but expeditious manner, Southeast Public Interest Groups place significant importance on the role of transmission in its success. They accordingly recognize the gravity of this process, as the final National Transmission Needs Study (Final Study) that emerges will establish a foundation for the federal government's approach to transmission expansion going forward. Through these comments, Southeast Public Interest Groups seek to ensure that the Final Study accurately captures the Southeast's glaring transmission needs so that the region may fully avail itself of the federal opportunities on offer. Only by marshalling all available resources can the Southeast encourage—rather than impede—the budding clean energy economy.

I. INTRODUCTION

Southeast Public Interest Groups commend the Department for the thorough examination of transmission needs contained in the Draft Study. Synthesizing dozens of power systems studies,

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[1] National Transmission Needs Study: Draft for Public Comment, 88 Fed. Reg. 13811 (Dept. of Energy Mar. 6, 2023) (Draft Study).

the Draft Study fittingly finds a "pressing need to expand electric transmission—driven by the need to improve grid reliability, resilience, and resource adequacy, enhance renewable resource integration and access to clean energy, decrease energy burden, support electrification efforts, and reduce congestion and curtailment."[2] Given the tremendous benefits transmission can provide, the many needs it can satisfy,[3] and the federal funding opportunities that depend on its expansion,[4] the modest pace of transmission investment in recent years presents a dire threat if not promptly accelerated.

With respect to the Southeast, the Draft Study finds a pronounced lack of recent transmission investment,[5] as well as some of the most substantial anticipated needs in the country.[6] Yet one of the primary metrics by which the Draft Study assesses current transmission needs—market price differential—excludes the region entirely. This is not a failing of the Department's process but a defining characteristic of the Southeast's utility model. Vertically integrated utilities dominate electricity service in the region and dictate all generation and transmission planning activities. There are no Regional Transmission Organizations (RTO), Independent System Operators (ISO), or independent wholesale energy markets that could provide transparent pricing information. Nor does any independent entity conduct transmission planning that accounts for the myriad benefits of intra- and interregional transmission facilities. As such, neither market price

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[2] *Id*. at 78.

[3] *See id*. at 46-76.

[4] *See* Jesse D. Jenkins et al., *Electricity Transmission is Key to Unlock the Full Potential of the Inflation Reduction Act*, REPEAT Project, 3-4 (Sept. 2022), https://repeatproject.org/docs/REPEAT_IRA_Transmission_2022-09-22.pdf.

[5] *See* Draft Study at 20.

[6] *See id*. at 90.

differential nor utility transmission plans can provide meaningful insight into the region's current transmission needs.

That does not mean there are no such needs. Recent proceedings before the Southeast's state utility commissions depict a region limited by its current transmission infrastructure. Winter Storm Elliott dramatically emphasized these needs late last year, causing multiple Southeast utilities to resort to rolling blackouts and, in the process, exposing a need for additional connections to neighboring regions. The Draft Study's omission of this event is undoubtedly a function of its relatively recent occurrence, but Southeast Public Interest Groups urge the Department to account for its effects in the Final Study. Additionally, activities to develop offshore wind resources in the Southeast have begun in earnest and have presented unique transmission needs that the Draft Study does not fully explore. Despite the structural impediments to assessing existing transmission needs in the region, the Final Report should reflect these various drivers currently affecting generation decisions and reliability, in addition those looming on the horizon.

Southeast Public Interest Groups also take this opportunity to address and contextualize the Southeastern Regional Transmission Planning (SERTP) Sponsors' comments included in the Draft Study. As the utilities tasked with transmission planning in the Southeast, the SERTP Sponsors are in large part responsible for the needs identified in the Draft Study and these comments. Their attempts to discredit the Draft Study's findings and diminish the Department's authority to catalogue the region's transmission needs must be viewed in the context of their historic underinvestment in regional and interregional transmission. Contrary to the assertions of the SERTP Sponsors, the Department's mandates under the Federal Power Act (FPA), the Inflation Reduction Act (IRA), and the Infrastructure Investment and Jobs Act (IIJA) are sufficiently broad to encompass the scope of this Draft Study, with room to spare. The SERTP Sponsors' unfounded criticisms should not deter the Department from releasing a fulsome assessment of the transmission system's existing deficiencies, however poorly that may reflect on the planning processes that produced them.

Southeast Public Interest Groups offer these comments in order to aid the Department in that effort. As currently constituted, the Draft Study presents an accurate and concerning portrait of the Southeast's future anticipated transmission needs. Acknowledging the equally severe transmission needs that currently limit the region's evolving resource mix will complete the picture and reflect the appropriate urgency in addressing them.

II. COMMENTS

A. Existing Transmission Needs in the Southeast

Looking backward, the Draft Study notes that the Southeast has "made consistent and relatively low [transmission] investments throughout the decade."[7] Looking forward to "anticipated future transmission and transfer capacity need," the Draft Study finds that "the largest growth of transmission will be needed in the . . . Southeast," among a few other regions.[8] Southeast Public Interest Groups concur with these characterizations, particularly the magnitude of future needs. However, given the Draft Study's substantial reliance on market price differentials to identify current needs and its consultation with regional transmission planning entities, it risks understating the significant existing transmission needs in the Southeast.

Southeast Public Interest Groups support the Department looking to quantitative means of identifying existing transmission needs. Market price differentials provide a solid basis for doing so in most instances. No such data exists in the Southeast, however, due to the lack of an

7 *Id*. at 20.

8 *Id*. at iii.

independent wholesale energy market and the price transparency that comes with it. The Southeast-size holes in Figures IV-4 though IV-6[9] demonstrate this unfortunate deficit. Rather than participating in an organized market, the region's utilities predominantly deploy their own generation resources and procure the modest remainder from long-term power purchases or spot-market transactions. The nascent Southeast Energy Exchange Market (SEEM) began operations late last year, but has seen only meager activity to this point and provides no public pricing or trade information that could offer meaningful insight.[10] This electric service model results in a total lack of price transparency, making market price differential an unsuitable metric for identifying transmission needs in the region.

The Southeast's transmission planning processes likewise do not provide a useful resource for assessing transmission needs. Instead, they erect an additional barrier to regional and interregional transmission development by obscuring such needs. Unlike the top-down transmission planning conducted by independent planners in RTO/ISO regions, transmission planning in the Southeast is carried out by the transmission-owning utilities themselves, whose financial incentives favor investment in local transmission facilities rather than regional or interregional development.[11] To this end, rather than providing a forum for collaboratively

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9 *See id*. at 25, 27, 30.

10 *See, e.g.*, *Monthly Audit Report on the Southeast Energy Exchange Market: December 2022*, Potomac Economics: Independent Market Auditor, 5-12 (Jan 31, 2023), https://southeastenergymarket.com/wp-content/uploads/SEEM-Audit-Report-2022_12-Final.pdf (SEEM December 2022 Report).

11 *See* Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 Energy L.J. 1, 33-34 (2021) ("A congestion-relieving project, even one that would reduce rates paid by its own captive consumers, might harm the [Investor-Owned Utility (IOU)] if it owns generation that benefits from the congestion or holds financial instruments tied to the congestion. Similarly, an IOU might have an incentive to block transmission projects that would enable competing retailers to access low-cost generation that the IOU may already be able to access through a long-term agreement. . . .

"Apart from their interests in wholesale power, IOUs might also seek to block projects in order to maintain their monopolies over local transmission. A New York ISO white paper posits that 'utilities will protect their franchise areas, a valuable and exclusive asset, and are loathe to allow competitors' [transmission] projects through their areas considering regional and interregional transmission facilities as the Federal Energy Regulatory Commission (FERC) intended,[12] SERTP and the South Carolina Regional Transmission Planning (SCRTP) processes approach regional transmission facilities in a manner that guarantees they will never be selected.[13] In SERTP, the utilities annually roll up the ten-year transmission plans for their own local utility systems, which typically only address immediate reliability needs, to create a regional powerflow model. They then use this model to confirm the simultaneous feasibility of their individual transmission plans under applicable reliability standards.[14] In other words, the utilities individually conduct their own local planning processes, submit their plans for inclusion in the regional expansion plan, confirm they do not conflict with each other, and then proceed to carry out their individual plans. Regional "planning" realistically begins and ends at this stage. There is no long-term prospective consideration of varying load and resource scenarios. Nor is

without some control and participation.' AAI claims that because the development of one transmission project may foreclose alternatives, an IOU may attempt to block a competing project in order to boost its own alternative. IOUs also compete with non-IOU developers in 'more subtle ways' by providing 'yardstick competition.' A non-IOU project that is less expensive than IOU projects may put pressure on a utility by alerting regulators that the IOU is not the least-expensive transmission developer . . .

"In addition, as the resource mix evolves, new types of transmission projects—regional and perhaps even continental in scale, and utilizing direct current technology—may be the optimal means for cost-effectively integrating wind and solar generation. IOUs' incentives to prioritize development in their state-protected service territories bias them against large-scale projects, particularly high-efficiency direct current lines that don't neatly integrate with existing alternating current infrastructure.").

12 *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils*., Order No. 1000, 136 FERC ¶ 61,051, at PP 147-148 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) ("Through the regional transmission planning process, public utility transmission providers will be required to evaluate, in consultation with stakeholders, alternative transmission solutions that might meet the needs of the transmission planning region more efficiently or cost-effectively than solutions identified by individual public utility transmission providers in their local transmission planning process.").

13 *See* Att. 1, Comments of the Southeast Public Interest Groups, Fed. Energy Regulatory Comm'n, Docket No. RM21-17-000, 11-21 (Aug. 17, 2022).

14 *See id*. at 12; Joseph H. Eto & Giulia Gallo, *Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000*, Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, 13 (Nov. 2017), https://emp.lbl.gov/publications/regional-transmission-planning-review.

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there a formal adoption process for the regional plan, largely because no regional projects that would require multi-utility concurrence ever emerge.

Fittingly, since its inception, SERTP has never resulted in a regional transmission facility being included in the regional transmission plan. This owes primarily to the narrow evaluation process applied to proposed regional facilities, which examines only "whether there may be more efficient or cost effective transmission projects to address transmission needs than transmission projects included in the latest regional transmission plan."[15] To start, the local plans that form the basis of the regional plan typically only address reliability needs; SERTP does not conduct multi-value planning, which limits the benefits that inform the analysis from the outset. From there, the SERTP Sponsors consider whether the regional project would address identified transmission needs and could therefore displace any local projects currently included in the regional plan. If not, the inquiry ends there, as has occurred in the vast majority of cases.[16] When the rare regional project progresses to the next stage of the analysis, the SERTP Sponsors compare its projected costs to those of the identified local project(s) it would displace. In every case, the larger regional project's costs far exceeded the small local project's costs and none of the regional projects has been selected.[17] Instead of analyzing production cost savings or any other quantifiable benefits, this process amounts to a straight cost comparison between the regional project and the applicable

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[15] Alabama Power Company, Open Access Transmission Tariff, Att. K, The Southeastern Regional Transmission Planning Process, § 11.1.1 (5.0.0).

[16] *See, e.g.*, *2014 Regional Transmission Planning Analyses*, SERTP, 10 (2014), http://www.southeasternrtp.com/docs/general/2014/SERTP%20Regional%20Transmission%20Planning%20Analyses%20Summary.pdf.

[17] *See id.* at 12, 18; *2015 Regional Transmission Planning Analyses*, SERTP, 11 (2015), http://www.southeasternrtp.com/docs/general/2015/2015%20Regional%20Transmission%20Planning%20Analyses%20Summary.pdf; *2016 Regional Transmission Planning Analyses*, SERTP, 11, 15, 17, 19 (2016), http://www.southeasternrtp.com/docs/general/2016/2016%20SERTP%20Regional%20Transmission%20Planning%20Analyses%20Summary.pdf; *2017 Regional Transmission Planning Analyses*, SERTP, 19 (2017), http://www.southeasternrtp.com/docs/general/2017/2017-Regional-Transmission-Planning-Analyses-Summary.pdf.

local projects. Without considering a more comprehensive suite of benefits provided by the regional project over a longer period of time, this rubric will never result in the selection of a regional project.[18]

The limitations of these regional planning processes carry over to the interregional transmission planning process. Per FERC requirements, an interregional transmission facility must secure approval from (1) each of the planning processes for the regions it would connect, acting individually, and (2) a joint evaluation involving both regional planning processes, acting together.[19] As such, any proposed interregional facility in the Southeast must pass SERTP's cost comparison screens twice, once individually and again as part of a joint evaluation, in addition to the adjoining region's planning process. Given the nearly insurmountable burden the SERTP Sponsors place on regional facilities and the limited benefits they consider, the prospects for both regional and interregional transmission development in the Southeast are slim under the current planning paradigm. For the purposes of this Department's effort to identify transmission needs, the region's planning processes can provide only minimal assistance, as they focus almost exclusively on local reliability concerns and do not present a comprehensive portrait of the drivers creating current transmission needs.

Despite the region's endemic lack of transparency in pricing and transmission planning, transmission needs have nevertheless become apparent through state regulatory processes. Specifically, Integrated Resource Plan (IRP) and equivalent proceedings involving the utilities' long-term generation plans have shed light on the existing deficiencies in the region's transmission system. For example, in North Carolina, Duke Energy (Duke) must abide by a "Carbon Plan"

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18 In South Carolina, the SCRTP process considers potential regional facilities in a nearly identical manner and has produced similar results. *See* Att. 1 at 20-21.

19 *See* Order No. 1000 at P 436.

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established by the North Carolina Utilities Commission (NCUC) that enforces decarbonization benchmarks codified in state law.[20] In Duke's own words, meeting the Carbon Plan's milestones "requires transformation of the [Duke] transmission system in the near-term and long-term".[21] Interconnecting the sheer number of new renewable resources required while retiring all remaining coal units necessitates "significant investment in the transmission system on an aggressive timeline."[22] Most immediately, these needs include certain transmission upgrades known collectively as the "Red Zone" Transmission Expansion Project (RZEP), which have arisen in numerous solar generator interconnection studies but whose costs have consistently caused interconnection customers to withdraw.[23] Following the initial cycle of Carbon Plan proceedings, the NCUC found the need for the 14 RZEP projects,[24] paving the way for Duke to include them in its next transmission plan, but meeting the Carbon Plan's requirements will require additional transmission upgrades in the Red Zone and elsewhere.[25] To aid this effort, the NCUC directed Duke to overhaul its local transmission planning process to more proactively plan transmission expansion and to engage more vigilantly in SERTP.[26]

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20 *See* 2021 N.C. Sess. Laws 165.

21 Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, Carolinas Carbon Plan, App. P: Transmission System Planning and Grid Transformation, Docket No. E-100, Sub 179, 1 (N.C. Utils. Comm'n May 16, 2022) (Carbon Plan App. P).

22 *Id*.

23 *Id*. at 11-12.

24 *See In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plans and Carbon Plan*, Docket No. E-100, Sub 179, at 116 (N.C. Utils. Comm'n Dec. 30, 2022) (2022 Carbon Plan Order).

25 *See id*. ("Completion of the 2022 RZEP projects is a necessary first step to interconnect the solar volumes necessary to execute the Carbon Plan."), 121 ("[B]ased upon the potential magnitude of future transmission expenditures, the Commission urges Duke to explore all possible efficiencies . . ..").

26 *See id*. at 121 ("[T]he Commission urges Duke to . . . be vigilant in its participation in SERTP and in its coordination with PJM to assure a least cost path to achieve the carbon dioxide emissions reduction requirements while maintaining and improving reliability.").

Throughout the region, utilities have failed to proactively plan the transmission needed to facilitate retirement of coal-fired generation, prolonging the operation of these aging, uneconomic resources. In Georgia, Georgia Power Company (Georgia Power) recently proposed the North Georgia Reliability & Resilience Action Plan, "a multi-faceted plan to address future reliability needs associated with the retirement of Plant Bowen," as part of its 2022 IRP.[27] Because north Georgia "relies on the transmission system to import power from south Georgia,"[28] planned coal retirements in the north have exposed a need for substantial transmission expansion to avoid outages.[29] According to Georgia Power, this "significant gap between generation and load forecasted in north Georgia" will "require the transmission system to transport large amounts of energy from south to north Georgia and place additional strain on the existing transmission system."[30] To overcome these concerns, Georgia Power proposed an action plan that included, among other things, a "strategic portfolio of projects to address the long-term transmission planning operation needs" of the area.[31] Although the Georgia Public Service Commission ultimately approved Georgia Power's IRP, it deferred the retirement of the coal units at issue, given the uncertain timing of this proposed solution.[32] While temporarily halted, the inevitable retirement of these resources has revealed significant transmission needs in Georgia and demonstrated the perils of failing to proactively plan for them.

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27 *See* Georgia Power Company, 2022 Integrated Resource Plan: Main Document, Docket No. 44160, at 12-87 (Ga. Pub. Serv. Comm'n Jan. 31, 2022).

28 *Id.*

29 *See id.*

30 *Id.* at 12-88

31 *Id.*

32 *Georgia Power Company's 2022 Integrated Resource Plan*, Docket Nos. 44160 & 44161, at 18, 46 (Ga. Pub. Serv. Comm'n July 21, 2022).

In Tennessee, the Tennessee Valley Authority (TVA) has announced a goal to reduce its greenhouse gas emissions 80 percent by 2035 and reach net zero emissions by 2050.[33] As a federal agency, TVA is also subject to executive orders calling for a "carbon pollution-free" electricity sector by 2035.[34] Yet when TVA has sought to replace retiring coal-fired generation, it has elected not to procure capacity from renewable resources, asserting that it would require significant transmission investment to do so. For example, TVA recently resolved to retire the two coal-fired units at its Cumberland Fossil Plant and replace them with new gas generation units.[35] TVA assessed but rejected an alternative portfolio of solar plus storage resources, claiming, among other things, that it would require extensive regional transmission upgrades.[36] TVA also rejected wind generation external to TVA due to transmission costs, despite its ability to "provide dependable capacity in both summer and winter."[37] As commenters explained in the lead-up to this decision, the solar plus storage alternative would "provide operational benefits to the TVA system as a whole, such as improved reliability and resilience, and . . . facilitate the utility's plans to install 10,000 MW of solar by 2035."[38] Additional solar facilities would "benefit directly from any transmission upgrades required . . . because they can be sited to maximize the value of the prior

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33 Jonathan Mattise & Adrian Sainz, *Federal Utility Seeks Proposals for Big Carbon-Free Push*, Associated Press (Jul 12, 2022), https://apnews.com/article/technology-science-tennessee-utilities-climate-and-environment-ee6940c1c9050c90cd7469cef3dc2ac0?utm_medium=email.

34 *See* Exec. Order No. 14,008, 86 Fed. Reg. 7619, 7624 (Jan. 27, 2021); Exec. Order No. 14,057, 86 Fed. Reg. 70935, 70935-70936 (Dec. 8, 2021).

35 Tennessee Valley Authority, Cumberland Fossil Plant Retirement: Final Environmental Impact Statement, iii-iv (PDF pp. 5-6) (Dec. 2, 2022), https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/environment/cumberland-fossil-plant-retirement-final-eis4eeac6f0-b6bf-4843-9881-75d19ccf8ede.pdf?sfvrsn=d61f6b6f_7.

36 *Id*. at 56-57 (PDF pp. 96-97).

37 *Id*., Cumberland Retirement EIS: Final Alternatives Evaluation at 15 (PDF p. 639).

38 Southern Environmental Law Center et al., Conservation Groups' Comments on TVA's Draft Environmental Impact Statement for the Cumberland Fossil Plant Retirement, at 23 (June 13, 2022).

transmission investment."[39] As these comments imply, TVA cannot meet its stated decarbonization targets—much less the Biden Administration's more aggressive government-wide mandates—without integration of renewable resources, yet its reluctance to do so in the face of insufficient transmission capacity suggests an immediate need for new transmission infrastructure.

While anecdotal, these examples of pressing transmission needs originated from the utilities' own statements and emerged through official regulatory processes. They may be incapable of quantification, but the region's lack of transparent market pricing and regional transmission planning require creative solutions to identifying current needs. As it refines the Draft Study, the Department should acknowledge these and other existing needs, even where data sources are scarce, in order to capture a complete picture of transmission needs in the region.

B. Winter Storm Elliott

The Southeast's lack of transparency could not contain the force of nature, as Winter Storm Elliott dramatically demonstrated the deficiencies in the region's transmission network to tragic effect. The Draft Study omits any mention of Winter Storm Elliott, likely due to the relative timing of both, but the Department should include the storm's impact in the Final Report, in light of the interregional transmission needs it revealed in the Southeast.

Early in the morning of December 23, 2022, bitter cold incapacitated two of TVA's coal-fired plants and caused certain of its gas-fired units to operate below their rated capacity.[40] Starting at 10:30 AM, TVA commenced rolling blackouts throughout its territory that lasted through early evening.[41] This sequence repeated itself the next morning, as TVA's fossil generation failures and

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39 *Id*.

40 Att. 2, Anila Yoganathan, *How a Perfect Storm of Freezing Cold and Aging Power Plants Led to Rolling Blackouts*, Knoxville News Sentinel, 3-5 (Jan. 25, 2023).

41 *See id*. at 6.

underestimated load projections[42] required additional rolling blackouts of up to ten percent curtailment for nearly six hours.[43] To the east, Duke similarly underestimated demand while some of its coal- and gas-fired generation units failed, causing the utility to order rolling blackouts throughout the Carolinas.[44] Other utilities in the region, such as Southern Company, relied heavily on imports to avert similar outages.[45] Trading activity in SEEM halted altogether, with no transactions taking place between December 24 and 26.[46] Shortly following these events, the NCUC stated that this "sobering example of the consequences to customers during times of stress on the electric system" highlighted the need for vigilant oversight of utility generation and transmission planning efforts.[47] Electric service resumed in both the Duke and TVA service areas by Christmas, but the outages revealed an ongoing risk of service failures in the face of increasingly extreme weather events if the utilities failed to bolster their insufficient infrastructure.

The outages caused by Winter Storm Elliott corroborated certain of the Draft Study's key findings, but amplified their urgency, at least as applied to the Southeast. Specifically, the Draft Study finds significant need for additional transfer capacity between the Southeast and its neighbors, as much as 4.4 GW with Florida, 7.5 GW with the Midwest, 8.5 GW with the Delta region, and 9.9 GW with

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42 *See id*. 7-9.

43 *TVA Accepts Responsibility, Starts Full Review*, Tennessee Valley Authority (Dec. 28, 2022), https://www.tva.com/newsroom/press-releases/tva-accepts-responsibility-starts-full-review.

44 *See* Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, Presentation and Generating Unit Status Summary Document, Docket Nos. M-100, Sub 163 & M-1, Sub 0, at 4-12 (N.C. Utils. Comm'n Jan. 3, 2023), https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=63276e03-87af-42d5-b2c2-97293fc5fe83; David Boraks, *Cold-Weather Blackouts Challenge Conventional Wisdom on Reliability*, WFAE 90.7 (Jan. 6, 2023), https://www.wfae.org/energy-environment/2023-01-06/cold-weather-blackouts-challenge-conventional-wisdom-on-reliability.

45 *See Overview of Winter Storm Elliott December 23, Maximum Generation Event*, MISO: Reliability Subcommittee, at 17-18 (Jan. 17, 2023), https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf (showing substantial exports to the Southern Company ("SOCO") balancing authority area on December 23 and 24, 2022).

46 *See* SEEM December 2022 Report at 5-9.

47 2022 Carbon Plan Order at 10.

the Mid-Atlantic, all in moderate load and high clean energy scenarios.[48] The Draft Study frames these significant needs as required by 2035, but Winter Storm Elliot demonstrated the need for immediate increases to the Southeast's interregional transfer capacity.

To this end, a recent Grid Strategies report compared energy prices at the seams between the Duke/TVA territories and their neighboring regions to determine the value one GW of additional transfer capacity would have provided.[49] The report found that one such line "between the Electric Reliability Council of Texas (ERCOT) and TVA would have provided nearly $95 million in value, mostly to TVA customers" during Winter Storm Elliott.[50] Likewise, "one GW of additional transmission capacity from PJM into the Duke/Progress operating areas in the Carolinas could have provided those customers with electricity valued at over $80 million by helping to keep the lights on."[51] Finally, "[o]ne GW lines from neighboring Louisiana or Illinois, parts of the Midcontinent Independent System Operator (MISO), into TVA could have provided around $75 million or $79 million in value, respectively."[52] The magnitude of these figures demonstrates not only the immense benefits additional connections with neighboring systems could have provided, but also the insufficiency of the Southeast's existing ties with surrounding regions.

The status of these neighboring regions during Winter Storm Elliott further emphasizes this gap. In a recent analysis, RMI found that, at the moment the Southeast most needed assistance, "the central United States had an abundance of wind energy that could not be utilized in regions

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48 *See* Draft Study at xiii.

49 *See* Att. 3, Michael Goggin & Zachary Zimmerman, *The Value of Transmission During Winter Storm Elliott*, Grid Strategies LLC (Feb. 2023).

50 *Id*. at 2.

51 *Id*.

52 *Id*. at 3.

experiencing energy shortages and blackouts due to insufficient transmission."[53] Specifically, "while TVA was experiencing blackouts on December 23, SPP alone experienced about 3 GW of wind curtailments . . .. That 3 GW of wasted wind power is more energy than what can be produced at TVA's largest coal plant, the Cumberland Fossil Plant,"[54] which failed during the storm. "Had this energy been available, it could have alleviated the Southeast's shortage, both in terms of magnitude and duration, and kept the lights on for more households during the extreme cold."[55] These relative conditions show how interregional transmission ties can make "the grid bigger than the weather,"[56] even in a weather system as large as Winter Storm Elliott. Investment of this nature would mitigate the localized effects of extreme weather events and exploit geographic climate diversity,[57] significantly decreasing the likelihood of similar outages.

As Winter Storm Elliott demonstrated, the Southeast currently lacks the ability to capitalize on this geographic diversity. Last fall, the Niskanen Center sought to quantify the interregional transfer capacity between regions, in order to provide a starting point for determining any minimum requirements FERC might impose.[58] This effort found that the Southeast has perilously low transfer capacity with its neighboring regions—a finding that Winter Storm Elliott would confirm months later. Framing transfer capacity as a percentage of peak load, the Niskanen Center found the following current transfer capacities between the Southeast and its neighbors: 2 percent

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53 Ashtin Massie & Sarah Toth, *Wasted Wind and Tenable Transmission during Winter Storm Elliott*, RMI (Feb. 16, 2023), https://rmi.org/wasted-wind-and-tenable-transmission-during-winter-storm-elliott/.

54 *Id.*

55 *Id.*

56 Att. 3 at 9.

57 *See id.*

58 Liza Reed & Andrew Xu, *FERC is Coalescing Around the Idea of Minimum Transfer Capacity but Needs Data and Definitions*, Niskanen Center (Sept. 8, 2022), https://www.niskanencenter.org/ferc-is-coalescing-around-the-idea-of-minimum-transfer-capacity-but-needs-data-and-definitions/.

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with MISO South and SPP; 3 percent with Florida and PJM; and 9 percent with MISO North.[59] Similarly, a study conducted by General Electric Energy Consulting, which simulated both extreme heat and extreme cold events, found that the Southeast had the highest need for interregional transmission, especially in light of its higher generation costs.[60]

Winter Storm Elliott regrettably validated these findings and highlighted the existing need for interregional transfer capacity in the Southeast. While the Draft Study recognizes these needs, at least in the anticipated future context, the Final Report should reflect the emphasis that Winter Storm Elliot placed on them. Acknowledging their urgency will provide a more durable basis for addressing these needs in the near term, before they can again announce their disastrous potential.

C. Offshore Wind

Building the infrastructure needed to integrate offshore wind resources has also emerged as a pressing transmission need in the Southeast, especially in North Carolina, where the Department has commenced leasing activities for potential offshore wind projects. During the NCUC's initial Carbon Plan proceeding last year, Duke estimated that it would procure between 800 and 1,600 MW from offshore wind facilities, which alone would require \$1.3 to \$2.39 billion in transmission upgrades.[61] While significant, this is but a fraction of the offshore wind capacity planned off the Eastern Seaboard. Nevertheless, the Draft Study includes minimal discussion of offshore wind transmission needs, most of which focuses on more advanced projects in the

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59 *Id.*

60 Sheila Tandon Manz et al., *Economic, Reliability, and Resiliency Benefits of Interregional Transmission Capacity*, General Electric Energy Consulting, 12, 18-19, 24 (2022), https://www.nrdc.org/sites/default/files/ge-nrdc-interregional-transmission-study-report-20221017.pdf.

61 *See* Carbon Plan App. P, *supra* note 21, at 17.

Northeast.[62] Given the long lead time required to develop and integrate offshore wind resources[63] and the opportunity to coordinate the necessary transmission infrastructure at this early stage, the Final Report should identify offshore wind integration as an existing need in the Southeast and Mid-Atlantic. More specifically, the Final Report should recognize the benefits and necessity of proactive, coordinated transmission development along the East Coast to maximize efficiencies and economies of scale.

The Central Atlantic Draft Wind Energy Areas, which are located off the coast of the Delmarva Peninsula and the Outer Banks of North Carolina, when combined with existing wind energy areas and other neighboring offshore wind call areas, could provide approximately 66,350 MW of offshore wind capacity. At full deployment, that capacity would require roughly 34 points of interconnection to the Eastern Interconnection using individual radial export cable or generator lead line approaches. By contrast, a coordinated approach to offshore wind transmission that limits interconnections to the Eastern Interconnection's existing 500 kV network along the East Coast could reduce the number of interconnections to five.[64] Indeed, referencing multiple offshore wind-related studies, the Draft Study relates findings that "an offshore grid designed and built with the capability of a networked system will provide more benefits and will better facilitate the integration of OSW resources compared with each OSW resource connecting to the onshore grid

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62 *See* Draft Study at 57-58.

63 *See* Att. 4, Johannes P. Pfeifenberger et al., *The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs and Barriers to Achieving U.S. Clean Energy Goals*, The Brattle Group, 25 (Jan. 24, 2023) ("Transmission facilities for offshore wind may take a decade to plan and develop. As a result, any planning efforts started today will not yield significant transmission infrastructure until into the 2030s.").

64 This assumes high-voltage, direct current (HVDC) transmission import capability of 2,000 MW per cable. Arturs Purvins et al., *Submarine Power Cable between Europe and North America: A Techno-Economic Analysis*, 186 J. of Cleaner Prod. 131, 132 (2018) ("Current installations of submarine HVDC power cables can transfer up to 2000 MW power").

through a dedicated generator lead line."[65] In light of the challenging near- and long-term infrastructure needs involved, "this planning effort should have been started years ago", as "even modest further delays in starting coordinated planning efforts will lead to higher costs and greater environmental impacts."[66] The Draft Study does not adequately express this urgency.

One example of a coordinated approach that would require implementation at an early stage is a backbone transmission system, also known as an ocean grid. This would address the clear interconnection challenges and facilitate the deployment of significant offshore wind capacity through the limited installation of HVDC cables connecting offshore wind projects with each other and the onshore grid.[67] Limited, additional infrastructure, such as offshore collector and converter platforms, would aggregate offshore wind generation and convert the produced and delivered direct current power into alternating current.[68] This arrangement would dramatically reduce the number of necessary points of interconnection, transmission cables, and other physical infrastructure required to inject offshore wind energy onto the grid.[69] It would also greatly reduce the overall cost of interconnecting offshore wind when compared to current, individualized approaches. More specifically, a backbone transmission system would help mitigate the significant upgrade costs triggered by integrating increasingly larger offshore wind capacity at

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65 Draft Study at 57.

66 Att. 4 at 17.

67 *See Offshore Wind Transmission Study Prepared for New Jersey Board of Public Utilities*, Levitan & Associates, Inc., 6 (Dec. 29, 2020), https://www.nj.gov/bpu/pdf/publicnotice/Transmission%20Study%20Report%2029Dec2020%202nd%20FINAL.pdf (Levitan Report).

68 *See id.* at 53.

69 *See id.* at A1-2; Brandon W. Burke et al., *Offshore Wind Transmission White Paper*, The Business Network for Offshore Wind, 15 (Oct. 2020), https://www.offshorewindus.org/wp-content/uploads/2021/05/GT-White-Paper-030121.pdf (Burke White Paper).

diffuse points of interconnection.[70] Various studies have supported these efficiencies.[71] One of the studies cited in the Draft Study found that interregional transmission planning along these lines could save New York $500 million in combined offshore and onshore transmission upgrade costs.[72] A study specific to New Jersey found that a backbone transmission system could reduce the levelized cost of energy by 2.8 percent.[73] Additionally, pending FERC rules that would overhaul transmission planning processes could soon require developers to consider long-term costs in their transmission planning,[74] costs which backbone transmission systems would likely reduce.

Offshore wind is critical to the Southeast's—and the nation's—clean energy transition. A backbone transmission system that spans the Atlantic coast would connect major load centers, transmission and distribution infrastructure, and proposed offshore wind developments in the Southeast, Mid-Atlantic, and Northeast, along with facilitating the retirement of existing fossil fueled generating facilities.[75] If appropriately sited and responsibly developed, it would also help ensure that the regions' significant offshore wind capacity is deployed and interconnected in an efficient and environmentally sustainable manner. Given the forethought required to plan and develop a coordinated transmission solution, such efforts must begin immediately, before too

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[70] *See* Burke White Paper at 15.

[71] For studies demonstrating the savings of coordinated approaches to offshore wind transmission, *see, e.g.*, Att. 4 at 31-35.

[72] Johannes Pfeifenberger et al., *Offshore Wind Transmission: An Analysis of Options for New York*, The Brattle Group, 5-6 (Aug. 2020), https://www.brattle.com/wp-content/uploads/2021/05/19744_offshore_wind_transmission_-_an_analysis_of_options_for_new_york.pdf.

[73] *See* Levitan Report at 39.

[74] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 26504, 179 FERC ¶ 61,028 (2022).

[75] *See, e.g.*, Sarah Shemkus, *Groups Say Boston Electric Grid Upgrades Should Anticipate Offshore Wind*, Energy News Network (Sept. 1, 2020), https://energynews.us/2020/09/01/groups-say-boston-electric-grid-upgrades-should-anticipate-offshore-wind/.

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many offshore wind projects perpetuate a system of individual connection. The Final Study should recognize the need to pursue collaborative transmission solutions to offshore wind integration immediately and the value in maximizing efficiencies as offshore wind begins to proliferate.

D. Reponses to SERTP Sponsors Comments

Appendix A-2 to the Draft Study reproduces comments the Department received during the consultation period.[76] The Draft Study explains that the Department consulted with affected states, Indian Tribes, and appropriate regional entities in accordance with sections 216(a)(1) and 216(a)(3) of the FPA.[77] Of the listed entities that submitted comments in Appendix A-1, SERTP is the only entity that is not a governmental, regulatory, sovereign, or independent non-profit organization. Rather, the SERTP Sponsors are utilities that operate in the Southeast, including Southern Company, Duke, and TVA. Unlike their peer commenters, the SERTP Sponsors have a vested financial interest in avoiding the type of regional and interregional transmission facilities the Draft Study identifies as urgent needs.[78] Their comments reflect those biases, as they largely seek to diminish the Department's authority, narrow the Draft Study's scope, and discredit its findings. In finalizing its National Transmission Needs Study, the Department should view the SERTP Sponsors' criticisms within the context of these interests and their longstanding aversion to regional and interregional investment. It should by no means refrain from providing a complete picture of the Southeast's expansive transmission needs to satisfy any industry participants.

To aid the Department in this effort, Southeast Public Interest Groups provide responses to the criticisms levied by the SERTP Sponsors.

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[76] Draft Study at 111-159.

[77] *See id*. at 1 (citing 16 U.S.C. §§ 824p(a)(1), -(3)).

[78] *See supra* note 11.

43. SERTP Sponsors: The Draft Study specifically cites to FPA section 216 as its authority, but then undertakes a very broad analysis of "transmission needs" rather than the statutorily specified study of "electric transmission capacity constraints or congestion." The Draft Study states that a "transmission need" for purposes of the study is an upgrade or new transmission facility that would be built to address "present or expected future transmission congestion or transmission capacity constraints." The Draft Study presents a definition of "transmission congestion" tied to a "constraint on the transmission system" but then states that while "transmission congestion (and the related but not identical transmission constraint) have industry standard definitions, transmission capacity constraints do not." Based upon this purported ambiguity, DOE adds very broad criteria that greatly expand DOE's definition of transmission need to encompass matters that have been traditionally considered resource/generation/integrated resource planning ("IRP") planning and not transmission planning.

The Draft Study addressed these concerns by revising definitions to match the applicable statutory language. The definitions reflect the breadth of the Department's mandate under multiple statutory schemes.

Section 216(a)(1) of the FPA requires the Department to "conduct a study of electric transmission capacity constraints and congestion" every three years (Study).[79] Section 216(a)(2) directs the Department to issue a report, "based on the study," which may designate NIETCs in any area that "is experiencing" or "is expected to experience . . . energy transmission capacity constraints or congestion" (Report).[80] While section 216(a)(1) does not specify the timeframe for the capacity constraints and congestion the Study must capture, section 216(a)(2) explicitly grounds the Report in the Study's findings and requires that the Report consider both existing and expected conditions. Together, these clauses dictate that the Study must provide sufficient foundation to allow the Report to address both current and future needs. The Draft Study's inclusion of both is therefore necessary to enable the Department to carry out its obligation under section 216(a)(2) to develop the Report.

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79 16 U.S.C. § 824p(a)(1).

80 *Id.* § 824p(a)(2).

Nor does the Draft Study exceed its mandate to assess "transmission" needs. The FPA does not define "transmission capacity constraints or congestion," forcing the Department to rely on industry-standard definitions in some cases and reasonable interpretations in others. While the SERTP Sponsors characterize these and other definitions as overly broad, such that they "encompass matters that have been traditionally considered resource/generation/integrated resource planning ("IRP") planning,"[81] FPA section 216(a)(4) allows the Department to consider an expansive set of factors in developing the Report. These include whether:

> (A) the economic vitality and development of the corridor, or the ***end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity***;
>
> (B) (i) economic growth in the corridor, or the end markets served by the corridor, may be ***jeopardized by reliance on limited sources of energy; and (ii) a diversification of supply is warranted***;
>
> (C) the energy independence or energy security of the United States would be served by the designation;
>
> (D) the designation would be in the interest of national energy policy;
>
> (E) the designation would enhance national defense and homeland security;
>
> (F) the designation would ***enhance the ability of facilities that generate or transmit firm or intermittent energy to connect to the electric grid***;
>
> (G) the designation—(i) maximizes existing rights-of-way; and (ii) avoids and minimizes, to the maximum extent practicable, and offsets to the extent appropriate and practicable, sensitive environmental areas and cultural heritage sites; and
>
> (H) the designation ***would result in a reduction in the cost to purchase electric energy for consumers***.[82]

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81 Draft Study at 123-124, SERTP Sponsors Comment 43.

82 16 U.S.C. § 824p(a)(4) (emphasis added).

Because the 216(a)(1) Study must underlie the 216(a)(2) Report, the Department is legally justified in identifying needs in the Study using the considerations applicable to the Report, whose breadth is unquestioned. The Draft Study's reasonable definitions of "transmission capacity constraints" and "transmission needs," combined with its industry-standard definitions of "transmission congestion" and "transmission constraints," capture only a subset of these factors.[83] Accordingly, the Department is well within its authority to utilize them in assessing transmission needs in the Study and could justifiably go farther, along the lines of FPA section 216(a)(4).

Contrary to the SERTP Sponsors' assertions, the Draft Study does not, in any instance, *propose* transmission as a solution or as an alternative to any resource decisions. Instead, it identifies areas in which transmission *could* provide a solution, as could non-wires alternatives.[84] This identification is a critical prerequisite to allocating federal resources to any selected transmission solution; it does not dictate that transmission *be* the solution. The SERTP Sponsors have long insisted that they consider resource planning and transmission decisions to be inherently intertwined,[85] yet they fault the Department for failing to quarantine resource considerations from its assessment of transmission needs. By erecting this impossible double standard, the SERTP Sponsors seek to diminish the Department's authority and obstruct its obligations under the FPA.

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[83] *See* Draft Study at 10-11.

[84] *See id*. at 1-2 ("Consequently, this Needs Study includes an analysis of historical and anticipated electric transmission needs, defined as the existence of present or expected electric transmission capacity constraints or congestion in a geographic area. Geographic areas where a transmission need exists ***could benefit from an upgraded or new transmission facility—including non-wire alternatives***—to improve reliability and resilience of the power system; alleviate transmission congestion on an annual basis; alleviate transmission congestion during real-time operations; alleviate power transfer capacity limits between neighboring regions; deliver cost-effective generation to high-priced demand; or meet projected future generation, electricity demand, or reliability requirements.") (emphasis added) (emphasis added).

[85] *See, e.g.*, SERTP Sponsors' Initial Comments, Fed. Energy Regulatory Comm'n, Docket No. RM21-17-000, 16 (Aug. 16, 2022) ("[T]he SERTP's regional transmission planning does not conflict with state-regulated IRP/RFP resource decisions because those underlying state-regulated resource decisions are the primary driver of the SERTP Sponsors' transmission planning.").

55. SERTP Sponsors: Another concern with the Draft Study's conclusions on the need for significant interregional/interface facilities is that such "solutions" could allow certain regions to shift their resource adequacy responsibilities to neighboring regions, exacerbating existing resource adequacy problems and ultimately increasing reliability risks to all. For example, the Draft Study identifies several regions that are predicted to experience resource adequacy problems or that are likely to experience complications associated with not having sufficient dispatchable resources/high renewable penetration. While interregional transfer capability may temporarily, or in isolated instances, alleviate these complications, resource adequacy as a whole cannot fully and finally be resolved through transmission–it is, after all, a resource issue. If those regions do not directly address those problems internally but instead expand their interface ties, then those regions are merely exporting their problems to neighboring regions…this concern of allowing regions with resource adequacy problems to shift those problems to their neighbors appears borne out by the Draft Study's Table VI-3, which seems to indicate that current low-cost regions, such as the Southeast, would have to bear significant upgrade costs to enable its neighbors to "lean on" the Southeast. While there could be some benefits from geographic and resource diversity, it cannot come at the cost of encouraging regions to disregard their own respective resource adequacy. ….In sum, there may be better alternatives to the massive build-out of interfaces as forecasted in the Draft Study. These include regions addressing their problems with internal upgrades (which could be transmission or supply-or demand-side alternatives). The Draft Study, however, appears to give no consideration to the possibility of other, more cost-effective or efficient alternatives. For example, for the Southeast, the Draft Study specifically forecasts that 5,400-8,000 GW-mi of new transmission is needed but fails to consider whether there are more cost-effective or efficient or reliable alternatives.

The Draft Study addresses these concerns by recognizing that "diversity in load, generation, and weather patterns within and between regions helps support resource adequacy and reliability . . . so long as regional planners guard against shifting resource adequacy responsibilities to neighboring regions that face inter-dependent risks."[86] While expanded interregional transmission ties can enable load-serving entities to expand their options for maintaining resource adequacy, they do not in any way relieve them of their resource adequacy obligations. The Draft Study does not suggest as much and the Department does not purport to manage resource adequacy obligations through the Draft Study. Rather, the Draft Study recognizes—and the experience of Winter Storm Elliott confirms—that robust interregional transmission links can, among other

[86] Draft Study at 8.

things, help alleviate shortages during extreme weather events. Southeast utilities should know, as they relied heavily on imports to minimize outages during Winter Storm Elliott.[87] Expanded interregional transfer capability could protect against repeat occurrences and avoid such outages all together.

> *83. SERTP Sponsors: The Draft Study forecasts the need for a massive build-out of virtually all interface ties but does not give consideration to the corresponding vast amounts of local upgrades that would need to be made to accommodate expanding such ties by the projected gigawatts of capacity. To illustrate, and using HVDC lines as an example of expanded interregional capacity, such lines typically carry between 500 MW and 2000 MW of power. When transferring power across the HVDC line, the source end of the HVDC line would draw in up to 2000 MW of generation out of the system, acting like a 2000 MW load. The delivery end of the HVDC line would push 2000 MW of power into the receiving system, similar to adding 2000 MW of power, much like a large generation site. The existing transmission system is currently not designed to handle either the 2000 MW of generation being moved out of the system or the dumping of 2000 MW of generation into the system at the other end of the HVDC line. The existing infrastructure would require major, costly expansion (in addition to the HVDC line itself) of the AC transmission system to accommodate this type of large transfer. Transmission planners would have to study the impacts of each one of these proposed HVDC lines and rebuild the existing transmission system to accommodate the Draft Study's forecasts.*

In response to this and similar comments, the Department revised the Draft Study in multiple sections to acknowledge the additional engineering analyses and system upgrades that would be necessary to facilitate expanded interregional transfer capacity.[88] In the case of the SERTP Sponsors, such analyses could be conducted as part of the Economic Planning Study process, which assesses bulk power transfers and identifies the upgrades required to enable them.[89] Currently, the SERTP Sponsors conduct a maximum of five Economic Planning Studies each annual planning cycle, which are selected by the Regional Planning Stakeholder Group, but which are strictly informational and not actionable. The SERTP Sponsors—or potential merchant

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[87] *See supra* section II.B.

[88] *See* Draft Study at 112-113, 133, Responses to Comments 3 & 75.

[89] *See SERTP – 1st Quarter Meeting: First RPSG Meeting & Interactive Training Session*, SERTP, 17 (Mar. 14, 2023), http://www.southeasternrtp.com/docs/general/2023/2023_SERTP_1st_Qtr_Presentation_FINAL.pdf.

transmission developers—could instead assess the feasibility of such interregional or regional lines for the purpose of meaningfully considering them as part of the regional expansion plan, identifying any required upgrades in the process.

> *97. SERTP Sponsors: While the Draft Study emphasizes the value of additional transmission, since the scope of the Draft Study does not include specific cost ramifications, the Draft Study's assumed benefits are almost certainly overstated. For example, the Draft Study performs scenario analyses of several levels of renewable penetration to conclude that vast amounts of additional transmission capacity (i.e., gigawatts) are needed both internally and between transmission planning regions. The Draft Study does not, however, appear to weigh the costs associated with the specific benefits asserted, thereby calling into question whether net benefits would be provided or whether there may be more economic alternatives. The apparent narrow focus of the analysis calls into question the probative value of the projected transmission needs.*

Southeast Public Interest Groups agree that prudent transmission planning requires serious consideration of costs. It also requires identification and quantification of benefits.

The Draft Study does not purport to assess the costs of transmission facilities that would potentially address any identified transmission needs. But by focusing on regional and interregional facilities, the Draft Study prioritizes the types of transmission facilities that can more economically meet transmission needs if proactively planned to address them, as numerous studies have shown.[90] Additionally, by identifying the many benefits that transmission infrastructure can provide—including enhanced reliability, expanded optionality for resource adequacy, clean energy integration, reduced congestion, variable resource curtailment relief, increased resilience, facilitation of electrification, and deployment of non-wires alternatives—the Draft Study conducts a more comprehensive examination of transmission benefits than SERTP's annual planning cycle, which as described above, almost exclusively focuses on avoided transmission costs.[91] The

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90 *See, e.g.*, Johannes Pfeifenberger et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, The Brattle Group & Grid Strategies LLC (Oct. 2021), https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Planning-for-the-21st-Century-Proven-Practices-that-Increase-Value-and-Reduce-Costs_Final.pdf.

91 *See supra* section II.A. In rare instances, it also considers reduced line losses.

SERTP Sponsors simply compare the costs of a regional facility with the avoided costs of any displaced local facilities and decide whether to select the regional facility on that basis alone. Nowhere do they recognize, quantify, or account for the system resilience, reliability, and economic benefits, or any of the others discussed at length in section V of the Draft Study.

Despite this reliance on cost for assessing regional transmission facilities, SERTP does not apply the same rigorous cost evaluation to local facilities. In compiling the local transmission projects that collectively comprise the regional transmission expansion plan, the SERTP Sponsors do not disclose *any* estimated facility costs.[92] This practice severely complicates developers' and other stakeholders' ability to propose alternatives. To this end, Southeast Public Interest Groups recently filed comments with FERC requesting the inclusion of planning level cost estimates for all facilities included in the SERTP regional plan over a reasonable dollar threshold.[93] Cost transparency that extends to all proposed transmission facilities and potential alternatives would better facilitate proactive transmission planning and ensure that utilities are not unduly prioritizing piecemeal development of local facilities on which they receive a guaranteed return and are insulated from competition.

> *118. SERTP Sponsors: The Draft Study references the need for increased resilience due to hurricanes and tornados as a basis for the need for additional transmission in the Southeast. However, outages caused by these types of events are normally caused by damage to the distribution system, not the transmission system. Accordingly, the Draft Study statement that 270,000 customers in KY and TN suffered outages due to tornados and severe thunderstorms does not support DOE's conclusions about transmission need in the Southeast because those customer outages, for the most part, were not attributable to transmission outages. While December 2021 had the most severe tornado on record for that area, the loss of power was mostly due to buildings (that use power) being destroyed and distribution level outages.*

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92 *See, e.g.*, *Regional Transmission Plan & Input Assumptions Overview*, SERTP, 23-94 (Dec. 14, 2022), http://www.southeasternrtp.com/docs/general/2022/2022_Regional_Transmission_Plan_and_Input_Assumptions_Final_Non-CEII.pdf.

93 Post-Technical Conference Comments of the Southeast Public Interest Groups, Fed. Energy Regulatory Comm'n, Docket No. AD22-8-000, 18-21 (Mar. 23, 2023).

> *Defining National Corridors/NEITCs and/or significant transmission expansions would not have prevented the customer outages cited in the Draft Study.*

The Draft Study removed the specific weather-related outages highlighted by SERTP Sponsors. In their stead, the Department should include an assessment of the transmission needs revealed by Winter Storm Elliott, as discussed above.[94]

> *128. SERTP Sponsors: At a high level, the SERTP Sponsors recommend that DOE make greater utilization of NERC-registered transmission planners and transmission owners that have the actual "duties to serve" and corresponding legal obligations to expand their respective transmission systems in an economic and reliable manner to meet the needs of their customers. In this regard, the SERTP Sponsors have concerns about the decision to rely solely on capacity modeling studies that use abstracted, generalized assumptions, disregarding industry-led regional studies based on actual operation of the grid. The Draft Study also relies heavily on existing studies performed by consultants, who are often funded by certain market participants. To better ground the study through the use of actual electric system forecasts, data, and established practices, the SERTP Sponsors recommend a higher utilization of the expertise afforded by the Eastern Interconnection Planning Collaborative ("EIPC"). The EIPC performs coordinated transmission planning among the transmission planners in the Eastern Interconnection, including both RTOs/ISOs and non-RTO/ISO transmission planners, and increased coordination with the EIPC would provide a more reliable study informed by transmission planners who have the needed experiential perspectives on the needs of the grid.*

The SERTP Sponsors urge the Department to rely on the "NERC-registered transmission planners and transmission owners" in developing its transmission needs assessment. Put another way, they suggest that the Department defer to the SERTP Sponsors in identifying transmission needs. As explained above, relying on transmission-owning utilities to disclose transmission needs that could be addressed by additional intra- or interregional transfer capacity may provide an inaccurate accounting of existing and anticipated future needs.[95]

The Department should observe similar caution with respect to the EIPC, which is comprised of the RTOs/ISOs in the Eastern Interconnection, the SERTP Sponsors, and vertically

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94 *See supra* section II.B.

95 *See supra* section II.A, note 11.

integrated utilities in South Carolina and Florida.[96] The EIPC operates in a manner similar to SERTP, albeit on a larger scale. Using a ten-year forward forecast (like SERTP), the EIPC "combine[s] the individual plans of each of the major Planning Coordinators in the Eastern Interconnection" to assess "how well the regional plans mesh into a combined plan for the interconnection."[97] To do so, the EIPC conducts a "gap analysis" meant to "identify interconnection-wide power flow interactions that may result from the effects of plans of one Planning Coordinator on another."[98] This process mirrors SERTP's roll-up of the SERTP Sponsors' individual local plans to confirm their simultaneous feasibility under applicable reliability standards. The EIPC additionally conducts a linear transfer analysis "designed to analyze the amount of power that can be reliably moved between regions."[99] The most recent iteration of the gap analysis found that "the regional plans will work well together, and there were very few gaps," while the linear transfer analysis results "were very positive."[100] These findings cut against the substantial body of evidence represented in the dozens of studies compiled and relied upon in the Draft Study, which together show the multiplicity of transmission needs throughout the Eastern Interconnection.[101]

A process concluding that the "respective Planning Coordinator transmission planning and interconnection processes have yielded transmission plans that are well-coordinated on a regional

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96 *See Members*, Eastern Interconnection Planning Collaborative, https://eipconline.com/ (last visited Apr. 13, 2023).

97 *EIPC State of the Grid Report – 2021*, Eastern Interconnection Planning Collaborative, 6-8 (Dec. 2021), https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/61b8f9ae4172c60bdd3a72ad/1639512495712/2021+EIPC+State+of+the+Grid+12-7-21.pdf (2021 EIPC Report).

98 *Id*. at 7.

99 *Id*. at 8.

100 *Id*. at 7-8.

101 *See generally* Draft Study at 19-79.

and interconnection-wide basis,"[102] in the face of well-documented transmission needs and clogged interconnection queues provides an uncertain empirical basis on which to assess transmission needs. At least as it pertains to the Southeast, the EIPC represents an outgrowth of SERTP, thereby reflecting the narrow, reliability-focused planning methodologies SERTP employs.[103] Reliance on EIPC's planning activities thus amounts to reliance on the SERTP Sponsors' preferred transmission plans and represents an incomplete dataset on which to base this inquiry.

> *129. SERTP: Sponsors: In reaching the Draft Study's conclusions in section VI, DOE utilizes NREL's ReEDS model. This model and software were developed by NREL for their own use, and is self-described as subject to misconstruction. Per NREL's website describing ReEDS: "ReEDS is a large, complex optimization model with many inputs, outputs, variables, and constraints. Understanding and appropriately using the model may take time and require some knowledge of optimization modeling. A typical model run includes hundreds of thousands or millions of variables and constraints and produces millions of outputs. Because of this complexity and size, it can be easy to misinterpret results or to ascribe more accuracy to certain model results than is merited."…DOE has apparently selected studies that employ load forecasts that are speculative in nature. In this regard, the Draft Study itself recognizes that "industry-led studies tend to be less speculative about the characteristics of the future power system" but as noted above, specifically chose not to include these less speculative, industry-led studies.*

In order to assess anticipated future needs, which the FPA explicitly authorizes,[104] the Department must necessarily engage in some degree of speculation. The Department should ensure that the datasets upon which it relies are sufficiently thorough and expansive to capture the wide range of potential scenarios. As the SERTP Sponsors themselves acknowledge, NREL's ReEDS model "includes hundreds of thousands or millions of variables and constraints and

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[102] 2021 EIPC Report at 13.

[103] *See supra* section II.A.

[104] *See* 16 U.S.C. § 824p(a)(2)(ii).

produces millions of outputs."[105] The Department is well-equipped to interpret the results in a manner that gives due consideration to their complexity.

132. SERTP Sponsors: The Draft Study states that transfer capability is sometimes referred to as transfer capacity. These are two very different concepts. Per the NERC Glossary of Terms, total transfer capability is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. Capability refers to the ability to transfer power without causing facility overloads under contingency. Capacity normally refers to the sum of the thermal ratings of the transmission tie lines between two entities. While indicative of the robustness of the interconnection, use of the term capacity fails to include constraints that are not tie lines. The terms capability and capacity, thus, are not interchangeable.

The Draft Study revised its use of the terminology in response to this comment.[106]

147. SERTP Sponsors: DOE has expanded the scope of its studies from the statutorily mandated "transmission capacity constraints and congestion" analysis to one that is more akin to a future generation/resource study. In doing so, DOE intrudes into resource planning activities that extend well beyond the scope authorized by FPA section 216. the Draft Study could unlawfully open the way for FERC to authorize transmission projects predicated upon resource decisions made by the federal government (not the states, as prescribed in the FPA). Therefore, we recommend that DOE continue to perform a transmission assessment and not an expansive future generation study predicated upon theoretical resource assumptions. We further suggest that the accuracy of such transmission studies would be improved if DOE were to coordinate more closely with North American Electric Reliability Corporation-("NERC") registered transmission planners and transmission owners. In the alternative, DOE should clarify that the Draft Study is not for FPA section 216 purposes and provide further explanations of the Draft Study's scope.

See responses to SERTP Sponsors Comments 43 and 128.

148. SERTP Sponsors: DOE broadly defines a transmission need to be...an upgrade to or a new transmission facility—including non-wire alternatives—that would optimally be built to... -improve reliability and resilience of the power system; -alleviate transmission congestion on an annual basis; -alleviate transmission congestion during real-time operations; ***-alleviate power transfer capacity limits between neighboring regions; -deliver new, cost-effective generation to high-priced demand; and -to meet projected future generation, electricity demand, or reliability requirements****. The last three criteria bolded above were not within the scope of the DOE's 2020 triennial transmission congestion study,*

105 Draft Study at 146-27, SERTP Sponsors Comment 129 (quoting *About the Regional Energy Deployment System Model*, NREL, https://www.nrel.gov/analysis/reeds/about-reeds.html#:~:text=ReEDS%20is%20a%20large%2C%20complex%20optimization%20model%20with,variables%20and%20constraints%20and%20produces%20millions%20of%20outputs (last visited Apr. 13, 2023)).

106 *See id*. at 147-148, Response to SERTP Sponsors Comment 132.

which defined "transmission constraint and congestion" to consist of essentially the first three criteria quoted above. The new criteria have apparently been added to the scope of the Draft Study based upon Congress' recent addition of the term "capacity" before the word "constraint" in FPA section 216(a)(1). The addition of this word "capacity" apparently is being used to expand the scope of the Draft Study from being focused on transmission matters (i.e., the first three criteria quoted above) to also encompass resource/generation/IRP planning matters (i.e., the last three criteria quoted above). Indeed, a review of the Draft Study establishes that it primarily concerns DOE's projection of the addition of significant amounts of renewable generation.14 Then, having assumed certain levels of specified generation resources based upon certain modeling scenarios, the Draft Study concludes, without any real explanation, that huge amounts (i.e., gigawatts) of additional transmission capacity are needed within and between essentially all transmission planning regions.… Rather than DOE independently performing such de facto resource/generation/IRP planning, DOE should coordinate with NERC-registered transmission planners and transmission owners to utilize their load and supply-side and demand-side forecasts that incorporate the results of state-regulated IRP and resource procurement processes. This approach would allow for an accurate assessment of "electric transmission capacity constraints and congestion" in accordance with FPA section 216 as well as being consistent with the overall structure of the FPA. Further, the Draft Study incorporates studies that are predicated upon very aggressive clean energy and renewables assumptions that are not tied to federal mandates. With the Draft Study's resource forecasts predicated upon neither state-regulated forecasts nor federal mandates, the basis upon which DOE is incorporating such assumptions is unclear. Instead of DOE independently making such determinations, the better approach would be for DOE to use the "projected future generation, electricity demand, or reliability requirements" determined to be appropriate for transmission planning purposes by NERC-registered transmission planners and transmission owners–those having the responsibilities under FPA section 215 to do so–and which incorporate the results of state-regulated IRP and resource procurement processes.

See responses to SERTP Sponsors Comments 43 and 128.

149. SERTP Sponsors: The studies utilized by DOE predominantly use a zonal model. Compared to a nodal model, the use of a zonal model greatly underestimates the required transmission buildout that would be necessary. This characteristic means that the transmission build-out to support the Draft Study's increased inter-regional transfer capability is likely significantly underestimated.

See response to SERTP Sponsors Comment 97.

150. SERTP Sponsors: If a transmission needs study is to be performed, specific transmission planning studies to assess transmission expansion should be performed and not derived from a conglomeration of different types of studies. EIPC has begun discussing the preparation of a combined Eastern Interconnect study that will assess expected renewable generation and synchronous generation retirements as well as incorporating climate change transfer capability needs. This process includes:

-building eastern interconnect models which include renewable generation in expected rural areas

-modeling expected synchronous generation retirements
-identifying extreme weather events
-forecasting generation requirements in areas experiencing the extreme weather event - modeling transfers of power from areas not experiencing the SAME weather event to the areas experiencing the SAME extreme weather event; this step identifies the required transfer capability for extreme weather
-identifying transmission constraints resulting from modeling the required transmission transfer capability requirements
-identifying transmission needs to mitigate the transmission constraints which includes non-wires solutions where appropriate SERTP respectfully submits that this type of specific, engineering-based study, rather than an abstracted, aggregated meta-study, is more appropriate to determine transmission needs.

See response to SERTP Sponsors Comment 128.

III. ATTACHMENTS

Attachment 1: Southeast Public Interest Groups' Initial Comments in Response to Federal Energy Regulatory Commission Notice of Proposed Rulemaking in Docket No. RM21-17-000

Attachment 2: Anila Yoganathan, *How a Perfect Storm of Freezing Cold and Aging Power Plants Led to Rolling Blackouts*, Knoxville News Sentinel (Jan. 25, 2023)

Attachment 3: Michael Goggin & Zachary Zimmerman, *The Value of Transmission During Winter Storm Elliott*, Grid Strategies LLC (Feb. 2023)

Attachment 4: Johannes P. Pfeifenberger et al., *The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs and Barriers to Achieving U.S. Clean Energy Goals*, The Brattle Group (Jan. 24, 2023)

IV. CONCLUSION

Southeast Public Interest Groups commend the Department for the effort it has expended so far in preparing the Draft Study. The Draft Study's identification of existing and anticipated future needs appropriately conveys the urgent need to expand the transmission grid to account for changes in the resource mix, demand, and increasingly extreme weather. In furtherance of this effort, Southeast Public Interest Groups urge the Department to utilize the material provided in these comments to bolster its findings of existing transmission needs in the Southeastern United States as it finalizes the National Transmission Needs Study. For this process to realize its promise of upgrading the transmission grid to adapt to a rapidly changing landscape, the Final Study must accurately capture the extent of the transmission needs currently affecting this region. Doing so will provide a durable foundation to maximize the effectiveness of federal assistance in remaking the transmission grid.

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April 20, 2023

Attachment 1

Southeast Public Interest Groups' Initial Comments in Response to Federal Energy Regulatory Commission Notice of Proposed Rulemaking in Docket No. RM21-17-000

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Building for the Future Through Electric	)	
Regional Transmission Planning and Cost	)	Docket No. RM21-17-000
Allocation and Generator Interconnection	)	

COMMENTS OF THE SOUTHEAST PUBLIC INTEREST GROUPS

August 17, 2022

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COMMENTS OF THE
SOUTHEAST PUBLIC INTEREST GROUPS

Southern Environmental Law Center, Energy Alabama, North Carolina Sustainable Energy Association, South Carolina Coastal Conservation League, Southface Energy Institute, and Southern Alliance for Clean Energy (together, Southeast Public Interest Groups) submit these initial comments in response to the Federal Energy Regulatory Commission's (FERC or Commission) Notice of Proposed Rulemaking, published on May 4, 2022 in the above-captioned proceeding (NOPR).[1] Southeast Public Interest Groups take this opportunity to show the Commission the degree to which its transmission planning policies have failed to materialize in the Southeast, leaving the region ill-equipped to adapt to an energy transformation that is already underway and rapidly intensifying.[2] The NOPR's proposed reforms provide an essential starting point, but a firm application of these expanded procedural mandates is imperative if the Southeast is to effectively meet the challenges before it in a cost-effective manner. Failure to do so will only deepen the financial strain on a region that already faces the highest energy burden in the country.[3]

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[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 87 Fed. Reg. 26504, 179 FERC ¶ 61,028 (2022) (NOPR).

[2] *See, e.g.*, *Annual Energy Outlook 2022*, U.S. Energy Information Administration, at 6-7 (Mar. 2022), AEO2022 Narrative (eia.gov); Heather Prohnan & Maggie Shober, *Tracking Decarbonization in the Southeast: Generation + CO_2 Emissions Fourth Annual Report*, Southern Alliance for Clean Energy, at 6 (June 2022), Tracking Decarbonization in the Southeast Fourth Annual Report (cleanenergy.org).

[3] *See, e.g.*, *Low-Income Household Energy Burden Varies Among States – Efficiency Can Help In All of Them*, U.S. Department of Energy (Dec. 2018), https://www.energy.gov/sites/prod/files/2019/01/f58/WIP-Energy-Burden_final.pdf (identifying Mississippi, South Carolina, Alabama, Georgia, and Arkansas as the five states with the

I. INTRODUCTION

The energy landscape is undergoing a rapid transformation. Driven by economic, technological, and political trends, the generation mix is evolving in both character and location. Centrally-located coal plants are retiring and far-flung renewable resources are connecting to the grid in their stead. Commercial and residential ratepayers are seeking cheaper and cleaner energy from their utilities, while overall demand is becoming more flexible and dynamic. Meanwhile, global temperatures continue their sustained upward march, presenting a constant threat to the grid as the weather careens between extremes of increasing severity.[4]

The Southeast is not immune to these shifts and, in many ways, is actively addressing them. In North Carolina, the General Assembly has established carbon-reduction targets for the power sector and directed the North Carolina Utilities Commission (NCUC) to create a roadmap for the state's largest utility to meet them (Carbon Plan).[5] In South Carolina, where ratepayers have shouldered the ballooning costs of a failed nuclear project,[6] the General Assembly has mandated a study of market alternatives, including joining or creating a Regional Transmission Organization

highest low-income energy burden); Ariel Drehobl et al., *How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burden Across the U.S.,* American Council for an Energy-Efficient Economy (Sept. 10, 2020), https://www.aceee.org/sites/default/files/pdfs/u2006.pdf; *Low-Income Energy Affordability Data (LEAD) Tool*, U.S. Department of Energy, https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool (last visited Jul. 27, 2022).

4 *See, e.g.*, *2022 Summer Reliability Assessment*, North American Electric Reliability Corporation, at 7-8 (May 2022), 2022 SRA Draft (nerc.com) ("Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of North America this summer. . . . In addition, drought exists or threatens wide areas of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand."); *2021-2022 Winter Reliability Assessment*, North American Electric Reliability Corporation, at 4 (Nov. 2021), 2021-2022 WRA Draft (nerc.com) ("Extreme weather events, including extended durations of colder than normal weather, pose a risk to the uninterrupted delivery of power to electricity consumers").

5 2021 N.C. Sess. Laws 165 (H.B. 951).

6 Specifically, abandonment of the V.C. Summer facility caused customers to cover $9 billion for a generation facility that will never generate electricity. *See* Brad Plumer, "U.S. Nuclear Comeback Stalls as Two Reactors Are Abandoned," N.Y. Times (July 31, 2017), U.S. Nuclear Comeback Stalls as Two Reactors Are Abandoned - The New York Times (nytimes.com).

(RTO).[7] Across the region, utilities are retiring coal-fired plants while scrambling to replace their generation capacity with more economic alternatives. But despite these efforts, the region remains perilously unprepared to meet the challenges created by convulsions in resource mix, demand, and severe weather.[8] The oncoming wave of generation and transmission investments is poised to unfold in siloed, utility-by-utility planning processes, without the benefit of economies made possible by regional markets or coordinated transmission planning. Regulatory approval timelines, technology change, and increasingly severe weather will add both economic and reliability risk to this transition. So long as it remains burdened by a balkanized grid with minimal coordination among its utilities, the Southeast risks falling ever farther behind, with ratepayers once again bearing the burden. For the region to avoid this fate, the Commission must once again curb utility behavior with firm direction.

More than any other region of the country, the Southeast's energy landscape continues to resemble that which caused the Commission to overhaul transmission service requirements in Order Nos. 888,[9] 890,[10] and 1000.[11] Vertically integrated utilities preside over partitioned retail

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[7] 2020 S.C. Acts 187 (H.4940).

[8] For example, on multiple occasions this summer, the Tennessee Valley Authority (TVA) has asked customers to limit their electric consumption to ease strain on the grid during prolonged stretches of intense heat. *See, e.g.*, Paige Hill, "TVA Asks Customers to Reduce Electric Usage Due to Increased Temperatures," WVLT 8 (June 13, 2022), TVA asks customers to reduce electric usage due to increased temperatures (wvlt.tv).

[9] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils*., Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996) (cross-referenced at 75 FERC ¶ 61,080), *order on reh'g*, Order No. 888-A, 62 FR 12274 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,048 (cross-referenced at 78 FERC ¶ 61,220), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N. Y. v. FERC*, 535 U.S. 1 (2002).

[10] *Preventing Undue Discrimination and Preference in Transmission Serv*., Order No. 890, 118 FERC ¶ 61,119, 51, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[11] *Transmission Plan. & Cost Allocation by Transmission Owning & Operating Pub. Utils*., Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and*

service territories pursuant to state-granted monopolies. They have largely insulated themselves from competition, having consistently resisted joining or developing an organized wholesale energy market. This isolation extends to transmission planning, as the utilities "collaborate" by submitting their individual transmission expansion plans to the regional transmission planning processes, which the utilities themselves conduct. Without the independent oversight found in an RTO or Independent System Operator's (ISO) centralized planning process, the utilities approach the "regional" aspects of these processes—consideration of regional alternatives, economic studies, and Public Policy Requirements—as unserious boxes to be checked. Far from optimizing the region's transmission investment, the planning processes have yielded patchwork local transmission facilities addressing minimum reliability needs. The utilities routinely ignore or overlook the common transmission needs of their neighbors, leading to an overdevelopment of small-scale solutions instead of more cost-effective and efficient regional solutions that could produce systemwide savings. Ultimately, ratepayers bear the difference.

The impotence of the region's transmission planning processes owes in large part to the flexibility the Commission afforded utilities in establishing regional planning procedures.[12] Although well-intentioned, this experiment in regional deference has produced paltry results in the Southeast. Without firm Commission parameters for engaging in coordinated and meaningful regional transmission planning, the Southeast must rely on the initiative of the utilities themselves to do so. But, as the Commission found in first establishing transmission planning requirements, such reliance ignores the utilities' incentives: "[V]ertically-integrated utilities do not have an

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clarification, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[12] *See, e.g.*, Order No. 1000 at P 61 ("[T]his Final Rule accords transmission planning regions significant flexibility to tailor regional transmission planning and cost allocation processes to accommodate these regional differences.").

incentive to expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors."[13] They have no incentive to either (1) "relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive,"[14] or (2) "increase the import or export capacity of [their] transmission system[s] if doing so would allow cheaper power to displace [their] higher cost generation or otherwise make new entry more profitable by facilitating exports."[15] Courts have agreed that "[u]tilities that own or control transmission facilities naturally wish to maximize profit,"[16] which dictates that they will "act in their own interest to maintain their monopoly and to use that position to retain or expand the market share for their own generated electricity, even if they do so at the expense of lower-cost generation companies and consumers."[17] Acting on these incentives, utilities in the Southeast have systematically exploited gaps in the Commission's transmission planning requirements, rendering them largely ineffective:

> IOUs are at the heart of the problem. They are driven to maintain the status quo, in part by capitalizing on FERC's rules that allow them to build projects within their state-granted territories without competitive pressures and on the backs of their captive retail ratepayers. This local focus is at odds with FERC's decades-long push for regionalization, and the IOUs' defensive approach to transmission development has no place in a technologically dynamic industry.[18]

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13 Order No. 890 at P 57.

14 *Id*. P 422.

15 *Id*.

16 *Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d at 683-84. *See N. Y. v. FERC*, 535 U.S. at 8 ("[P]ublic utilities retain ownership of the transmission lines that must be used by their competitors to deliver electric energy to wholesale and retail customers. The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions.").

17 *Transmission Access Pol'y Study Grp. v. FERC*, 225 F.3d at 683-84.

18 Ari Peskoe, *Is the Utility Transmission Syndicate Forever?,* 42 Energy L.J. 1, 2 (2021).

By identifying these vulnerabilities in the Commission's rules and taking advantage of its flexibility, utilities are acting rationally; the established framework is simply insufficient to achieve the Commission's stated goals.

Foremost among these is ensuring that transmission planning processes do not result in unjust, unreasonable, or unduly discriminatory rates for transmission service.[19] In Order No. 1000, the Commission sought to achieve this goal in part by "enhanc[ing] the ability of the transmission grid to support wholesale power markets."[20] That concern is particularly acute in the Southeast, where there is no organized wholesale power market.[21] Instead, the region's utilities engage exclusively in bilateral wholesale transactions driven by their and other load-serving entities' (LSE) changing needs. This spot market lacks consistent independent oversight or any type of economic dispatch. As such, independent power producers in the region depend entirely on the utilities to provide an outlet for their output. This includes ensuring access to transmission capacity, particularly where that generation is located far from load centers. But as the Commission has recognized, one "cannot rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner."[22]

Multiple studies have demonstrated the tremendous savings the Southeast could realize from greater regional coordination, most often in the form of creating a Southeast RTO.[23] For

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19 *See, e.g.*, Order No. 1000 at P 42.

20 *Id*. P 12.

21 The utilities in the Southeast have proposed to create the Southeast Energy Exchange Market (SEEM), a loose coalition of utilities engaging in an automated bilateral market construct. As proposed, SEEM would differ significantly from the organized wholesale energy markets that cover most of the country, with glaring deficiencies in terms of transparency, independence, and market access. SEEM's authorization is currently pending before the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit).

22 Order No. 890 at P 422.

23 *See, e.g.*, Eric Gimon et al., *Summary Report: Economic and Clean Energy Benefits of Establishing a Southeast U.S. Competitive Wholesale Electricity Market*, Energy Innovation Policy & Technology LLC (Aug. 2020), Economic-And-Clean-Energy-Benefits-Of-Establishing-A-Southeast-U.S.-Competitive-Wholesale-Electricity-Market_AUG_2020.pdf (energyinnovation.org) (Energy Innovation Report); Jennifer Chen, *Evaluating Options for*

example, Energy Innovation: Policy & Technology LLC concluded in 2020 that a Southeastern RTO would result in cumulative economic savings of approximately $384 billion by 2040, compared to the balkanized status quo.[24] The report explained that "[r]egional transmission planning through an RTO rationalizes transmission planning to reduce congestion and expose more expensive plants in load pockets to competition."[25] While the study did not isolate the savings created by coordinated regional planning, it compared a true RTO model—yielding the $384 billion savings figure—with an Economic IRP that did not optimize the generation and transmission buildout across the region, resulting in $298 billion in savings by 2040.[26] It stands to reason that a significant portion of the $86 billion delta owes to the optimized regional transmission investment. A regional transmission planning regime that ignores savings of this magnitude patently fails to "enhance the ability of the transmission grid to support wholesale power markets"[27] and results in unjust, unreasonable, and unduly discriminatory rates.

These ingrained inefficiencies stand to worsen in the coming years. The Commission overhauled its transmission planning policies in Order No. 1000 due to an impending transmission investment boom "driven, in large part, by changes in the generation mix," in which "existing and potential environmental regulation and state renewable portfolio standards [were] driving significant changes in the mix of generation resources, resulting in early retirements of coal-fired generation, an increasing reliance on natural gas, and large-scale integration of renewable

Enhancing Wholesale Competition and Implications for the Southeastern United States, Duke, Nicholas Institute for Environmental Policy Solutions (Mar. 2020), Evaluating Options for Enhancing-Wholesale-Competition-and-Implications-for-the-Southeastern-United-States-Final.pdf (duke.edu).

24 Energy Innovation Report at 1.

25 *Id*. at 10.

26 *Id*. at 19-20.

27 Order No. 1000 at P 42.

generation."[28] Those trends have only intensified in the decade since, as have increasingly common extreme weather and high-intensity, low-frequency events, both of which tax the grid's resilience. Once again, bold action is required to adapt regional transmission planning processes to these changes. This time, however, the Commission must impose firm requirements upon public utilities to overcome their natural incentives to avoid coordinated regional transmission planning, especially in non-RTO/ISO regions.

These comments will demonstrate the structural inability of the Southeast's regional transmission planning processes to proactively address these trends. First, they will discuss the region's planning processes, the Southeastern Regional Transmission Planning (SERTP) process, the South Carolina Regional Transmission Planning (SCRTP) process, and the Florida Reliability Coordinating Council, Inc. (FRCC) regional planning process, all of which have failed to prepare the regional grid for the substantial changes in motion. Second, they will survey the states in this region and showcase examples of the emerging transmission needs that, in the words of the utilities themselves, are shaping generation decisions. Finally, they will examine the NOPR proposals that can best address the existing deficiencies, including certain necessary tweaks.

Taken together, these comments will create a record that will allow the Commission to ensure that a non-RTO/ISO region like the Southeast has the tools it needs to provide just, reasonable, and reliable transmission service in an era of fundamental change. By their recommendations, the Southeast Public Interest Groups do not seek to disrupt the Commission's traditional planning paradigm of mandating a reasonable and transparent planning process rather dictating specific investment outcomes. Instead, the Southeast Public Interest Groups support a prescriptive and comprehensive regional planning process capable of identifying and evaluating

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[28] *Id*. P 45.

regional transmission alternatives that could more efficiently and cost-effectively meet the region's collective needs. The transmission planning process must create a robust array of fully-considered, publicly-accessible transmission options that will allow state regulators and stakeholders to assess and scrutinize the utilities' ultimate choices. Ratepayers can only benefit from a fully transparent and exhaustive planning process that fundamentally prioritizes their interests.

II. BACKGROUND

The Southeast's energy landscape is segmented, with investor-owned utilities, TVA, and cooperative and municipal utilities occupying defined service territories and operating largely independently of one another. Southern Company's affiliates Georgia Power Company (Georgia Power), Alabama Power Company (Alabama Power), and Mississippi Power Company tend to their respective states.[29] Duke Energy Corporation's subsidiaries Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, and Duke Energy Florida, LLC (collectively, Duke) provide service throughout most of North Carolina and parts of South Carolina and Florida.[30] The remainder of South Carolina largely receives power from either Dominion Energy South Carolina (Dominion) or the South Carolina Public Service Authority (Santee Cooper). NextEra Energy is the parent company of Florida Power & Light (FPL), the largest utility in Florida. In Tennessee and parts of six surrounding states, TVA provides wholesale power and transmission services, while cooperative and municipal utilities known as Local Power Companies provide distribution services to end users.

[29] The generation and transmission assets of Southern Company's vertically integrated utility subsidiaries are operated as a single, integrated electric system. *See* Southern Company, Annual Report (Form 10-K), at I-2 (Feb. 16, 2022), 0000092122-22-000003 (d18rn0p25nwr6d.cloudfront.net).

[30] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC jointly dispatch their generation resources subject to a Joint Dispatch Agreement.

State regulatory authorities oversee the investor-owned utilities and in some cases assess and approve the utilities' broad generation—and occasionally transmission—investment plans through an Integrated Resource Plan (IRP) or similar process. The IRP processes throughout the region differ substantially in their scope, frequency, and opportunities for public engagement. For instance, the North Carolina, South Carolina, and Georgia state commissions hold public proceedings to assess the investor-owned utilities' IRPs, although North Carolina's occurs every two years, while Georgia's occur every three. In Alabama, neither the state commission nor stakeholders formally assess Alabama Power's IRP, but the state commission reviews each of the utility's generation and transmission investments on a case-by-case basis. In Tennessee, TVA's Board of Directors approves TVA's IRP with no state review or approval.

Regarding procurement, the utilities in the Southeast do not participate in any organized wholesale energy market[31] and instead obtain their power supply from their own generation resources, through long-term arrangements with third-party generation, or on the bilateral spot market.[32] There is minimal coordination among the utilities, as exemplified by their perfunctory participation in the regional transmission planning processes. Insular planning persists even though each utility has encountered significant transmission needs caused by changes to the resource mix and demand. At the heart of the issue lies the utilities' disinterest in using the current planning framework to address these trends and explore appropriate solutions.

[31] As mentioned above, the utilities' authorization to create SEEM is pending before the D.C. Circuit. *See supra* note 21.

[32] However, the investor-owned utilities' unregulated affiliates—such as Duke Energy Renewables and Southern Power—have robust portfolios of renewable resources operating in RTO/ISO markets.

A. Transmission Planning in the Southeast

1. SERTP

Most of the region's utilities participate in SERTP. In addition to Southern Company, Duke, and TVA, participants include Associated Electric Cooperative, Inc., Dalton Utilities, Georgia Transmission Corporation (GTC), Louisville Gas & Electric Company and Kentucky Utilities Company (LG&E/KU), Municipal Electric Authority of Georgia (MEAG), and PowerSouth Energy Cooperative. While SERTP sponsors often tout the combined line-miles of the transmission network SERTP covers,[33] not one of those miles originated from regional collaboration in SERTP. In reality, SERTP presents "a forum merely to confirm the simultaneous feasibility of transmission facilities contained in [the utilities'] local transmission plans," an outcome the Commission expressly sought to avoid in Order No. 1000.[34] As required by that final rule, SERTP culminates in a regional transmission plan, but it does so by simply compiling the local transmission plans of each member utility and presenting the compilation as a "regional plan." In the process, it provides minimal opportunity for stakeholders to influence outcomes and performs the bare minimum of the utilities' responsibilities to assess regional alternatives, consider Public Policy Requirements, and conduct economic studies. As currently constituted, SERTP is woefully insufficient—by design—to address the transmission needs emerging in the states. SERTP's status as one of the largest transmission planning regions in the country only amplifies the significance of that structural deficiency.[35]

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33 SERTP Sponsors Oct. 12, 2021 Comments at 10 (SERTP Sponsors ANOPR Comments).

34 Order No. 1000 at P 147.

35 The eight balancing authority areas in the SERTP region "serve combined peak loads totaling more than 121,404 MWs." *2021 Regional Transmission Plan & Input Assumptions Overview*, SERTP, at 6 (2021), 2021-Regional-Transmission-Plan-and-Input-Assumptions-Non-CEII.pdf (southeasternrtp.com).

Each year, SERTP rolls up the local transmission plans of its member utilities in order to create a regional powerflow model. This powerflow model provides "representations of the existing transmission topology plus forecasted topology changes" over a "ten-year planning horizon."[36] The "independent reliability planning studies . . . start with the combined local transmission plans of participating utilities,"[37] and the results comprise the ten-year regional expansion plan. In other words, the utilities individually conduct their own local reliability planning processes and submit the final local plans for inclusion in the regional plan, which SERTP sponsors first present during the Second Quarter meeting each year. Barring minor tweaks by the utilities to their own plans during the planning cycle, the regional expansion plan is substantially complete when the local plans are compiled and first unveiled to stakeholders. During the Third Quarter meeting, the SERTP sponsors reveal the results of the Economic Planning Studies, which have no bearing on the regional expansion plan. The process concludes during the Fourth Quarter meeting, when the SERTP sponsors present the largely unchanged regional expansion plan. There is no formal adoption process—largely because no regional projects that would require multi-utility concurrence ever emerge—so the utilities simply proceed to carry out their individual plans. As such, neither stakeholders nor state regulators has any actual influence over the ultimate facility selection in SERTP.[38]

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36 *Id*. at 14.

37 Joseph H. Eto & Giulia Gallo, *Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000*, Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, at 13 (Nov. 2017), Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000 | Electricity Markets and Policy Group (lbl.gov).

38 *See* Joseph H. Eto, *Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans*, Energy Analysis and Environmental Impacts Division, Lawrence Berkeley National Laboratory, at 7 (Sept. 2016), Planning Electric Transmission Lines--A Review of Recent Regional Transmission Plans.pdf (energy.gov) (Berkeley Lab Transmission Planning).

This theme of limited stakeholder influence runs throughout the entire SERTP process. Stakeholders may participate in the process through the Regional Planning Stakeholder Group (RPSG).[39] The RPSG exists primarily to select and provide feedback on the Economic Planning Studies to be conducted by the SERTP sponsors, up to a maximum of five voluntary studies.[40] These Economic Planning Studies evaluate hypothetical bulk power flows that are not resource-specific and need not have any relevance or connection to the regional expansion plan. Because the Economic Planning Studies do not affect the regional plan, the RPSG's role is limited by design, and this overall impotence has borne out in lackluster membership. For 2022, the RPSG consists of two members: a representative from Santee Cooper in the Power Marketers sector and a representative from the Southern Renewable Energy Association in the Generation Owners/Developers sector.[41] There are no members in the Transmission Owners/Operators, Transmission Service Customers, Cooperative Utilities, Municipal Utilities, or ISO/RTOs sectors.[42] The RPSG has had only two members in three of the last five years, and three and four members in the other two years.[43] Given minimal opportunities to provide meaningful input, certain stakeholders—including some of the Southeast Public Interest Groups—have made the calculation that RPSG participation is not worth their time.

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39 Alabama Power, Open Access Transmission Tariff, Att. K, The Southeastern Regional Transmission Planning Process, § 1.2.1 (5.0.0) (Southern Company Transmission Planning Tariff).

40 *See id*.

41 *See 2022 SERTP RPSG Sector Members*, SERTP (2022), 2022-RPSG-Sector-Members.pdf (southeasternrtp.com).

42 *See id*.

43 *See id; 2021 SERTP RPSG Sector Members*, SERTP (2021), 2021-RPSG-Sector-Members.pdf (southeasternrtp.com); *2020 SERTP RPSG Sector Members*, SERTP (2020), 2020-RPSG-Sector-Members.pdf (southeasternrtp.com); *2019 SERTP RPSG Sector Members*, SERTP (2019), 2019 RPSG Sector Members.pdf (southeasternrtp.com); *2018 SERTP RPSG Sector Members*, SERTP (2018), 2018-RPSG-Sector-Representatives.pdf (southeasternrtp.com).

Similarly, stakeholders have had no success in proposing studies for transmission needs driven by Public Policy Requirements. Although SERTP includes a process whereby stakeholders may submit such requests once a year, the SERTP sponsors have rejected every request to study Public Policy Requirements-driven transmission needs. In 2015, 2016, and 2017, certain non-utility stakeholders submitted requests to evaluate transmission needs driven by various state and federal requirements, including North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard and EPA requirements applicable to coal-fired generation.[44] Regarding the latter, stakeholders asserted in 2017 that they

> internalize costs at coal-fired generation resources. The transmission need that would result from these decisions should be identified and evaluated to ensure that the 2017 SERTP transmission expansion plan incorporates the most cost-effective local and regional solutions.
>
> Without transparently addressing the impact of these PPRs as they may relate to the potential retirement(s) and/or replacement(s) of generation resources, such as a large coal-fired unit(s), it cannot be said that the SERTP process is cost-effectively and efficiently planning for situation(s) and/or system condition(s) for which a solution(s) is needed may arise.[45]

The SERTP sponsors denied the request, claiming that the Public Policy Requirements "have been factored into the resource assumptions for the 2017 transmission planning cycle" and do not "indicate that there is a transmission need."[46] Recent experience has contradicted this claim, as utilities across the region have struggled to replace coal-fired generation due to insufficient

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[44] *See 2017 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2017), 2017 Planning Cycle Transmission Needs Driven by Public Policy Requirements.pdf (southeasternrtp.com) (2017 Public Policy Requirements); *2016 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2016), 2016 SERTP PPR Results.pdf (southeasternrtp.com) (2016 Public Policy Requirements); *2015 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2015), 2015 SERTP PPR Results.pdf (southeasternrtp.com) (2015 Public Policy Requirements).

[45] 2017 Public Policy Requirements at 2.

[46] *Id*. at 2-3.

transmission capacity.[47] The proactive planning proposed by stakeholders at SERTP for three straight years could have averted this issue.

The SERTP sponsors have also rejected Public Policy Requirements study requests (1) on the assumption that the LSE in question would have already considered them, or (2) on the basis that there can be no transmission need until resource decisions have been made at the state level.[48] Again, experience in the states shows that this is not always the case, as utilities are routinely making resource decisions *based* on available transmission capacity.[49] Unsurprisingly, in light of the SERTP sponsors' consistent and unfounded refusal to study Public Policy Requirements, no stakeholder submitted a Public Policy Requirement study request between 2017 and 2021.[50] When a stakeholder made a verbal request to study the effects of North Carolina's H.B. 951 earlier this year, the SERTP sponsors summarily rejected it. Surely, the Commission could not have intended the utilities to carry out this important function with such casual indifference.[51]

In theory, the other opportunity for stakeholder involvement consists of proposing alternatives to transmission facilities identified in the regional plan. However, this task is

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47 *See infra* section II.B.

48 *See* 2017 Public Policy Requirements at 1.

49 *See infra* section II.B.

50 *See 2021 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2021), 2021-SERTP-PPR-Results.pdf (southeasternrtp.com); *2019 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2019), 2019 SERTP PPR Results.pdf (southeasternrtp.com); *2018 Planning Cycle, Transmission Needs Driven By Public Policy Requirements*, SERTP (2018), 2018-SERTP-PPR-Results.pdf (southeasternrtp.com). The SERTP website does not contain a document related to transmission needs driven by Public Policy Requirements for the 2020 Planning Cycle.

51 "When conducting transmission planning to serve native load customers, a prudent transmission provider will not only plan to maintain reliability and consider whether transmission upgrades or other investments can reduce the overall costs of serving native load, but also consider how to plan for transmission needs driven by Public Policy Requirements. Therefore, we conclude that, to avoid acting in an unduly discriminatory manner against transmission customers that serve other loads, a public utility transmission provider must consider these same transmission needs for all of its transmission customers. Moreover, given that consideration of transmission needs driven by Public Policy Requirements could facilitate the more efficient and cost-effective achievement of those requirements, we conclude the reforms adopted herein are necessary to ensure that rates for Commission-jurisdictional services are just and reasonable." Order No. 1000 at P 83.

complicated by SERTP's information sharing policies. In order to access the regional powerflow models, interested stakeholders must undergo a background check and receive pre-clearance for Critical Energy Infrastructure Information (CEII).[52] They must also pay a $180 application fee, a $100 background investigation fee, and execute a restrictive non-disclosure agreement.[53] Once completed, this process only facilitates access to the materials necessary to replicate the powerflow studies, assuming the requester has the necessary software and expertise. Missing from the materials is any cost estimate for the identified transmission facilities[54] or a specific explanation of the transmission need giving rise to them. This information deficit makes proposing alternatives to the SERTP sponsors, including viable Non-Transmission Alternatives, extremely difficult. Further, even if a stakeholder could develop and suggest an alternative with the limited information made available, their only recourse is to confer directly with the utility proposing the new facility and attempt to persuade the utility to pursue the alternative. The SERTP sponsors do not conduct a public study of these suggested alternatives within the broader context of the local or regional transmission plans.

This fundamentally flawed planning process that the SERTP sponsors implemented in response to Order No. 1000 has yielded correspondingly meager results. Since its inception, SERTP has *never* resulted in a regional facility displacing a local facility and being included in the regional transmission plan for cost allocation.[55] This owes primarily to the narrow evaluation

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52 *See* Secure Area, SERTP, SRTP - Secure Area | Secure Area | Southeastern Regional Tranmission Planning (southeasternrtp.com) (last visited Aug. 9, 2022).

53 *See id*.

54 *See Georgia Power Company*, Docket No. 44160, Tr. 246:11-17 (Ga. Pub. Serv. Comm'n June 21, 2022) ("Q. Are you aware that the SERTP regional transmission plan does not currently provide estimates of the cost of transmission projects proposed and ultimately included in the plan? A. (Witness Robinson) . . . Subject to check, those costs are not included.").

55 Additionally, no independent transmission developer has ever pre-qualified for a SERTP planning cycle. *See 2022 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2021), 2021-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2022-Planning-Cycle.pdf (southeasternrtp.com); *2021 Planning Cycle,*

criteria applied to such regional alternatives. In each SERTP transmission planning cycle, the SERTP sponsors will "assess[] whether there may be more efficient or cost effective transmission projects to address transmission needs than transmission projects included in the latest regional transmission plan."[56] In practice, this involves consideration of a handful of regional projects each year. First, the SERTP sponsors consider whether the regional project would address identified transmission needs and could therefore displace projects currently identified in the regional plan. If not, the inquiry ends there, as the proposed alternative cannot be "a more efficient or cost effective project to address transmission needs" if there is no underlying local upgrade.[57] Of the 47 regional projects considered since 2014, only nine were found to address a transmission need identified in the regional plan and moved to the second step of the analysis.[58] *Not one* has been found to address a transmission need since 2017.

Pre-Qualified Transmission Developers, SERTP (2020), 2020-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2021-Planning-Cycle.pdf (southeasternrtp.com); *2020 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2019), 2019-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2020-Planning-Cycle.pdf (southeasternrtp.com); *2019 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2018), 2018-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2019-Planning-Cycle.pdf (southeasternrtp.com); *2018 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2017), 2017-October-Pre-qualified-Transmission-Developers-for-the-Upcoming-2018-Planning-Cycle.pdf (southeasternrtp.com); *2017 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2016), 2016 October - Pre-qualified Transmission Developers for the Upcoming 2017 Planning Cycle.pdf (southeasternrtp.com); *2016 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2015), 2015October-PrequalifiedTransmissionDevelopersfortheUpcoming2016PlanningCycle.pdf (southeasternrtp.com); *2015 Planning Cycle, Pre-Qualified Transmission Developers*, SERTP (2014), 2014-11-01_SERTPPre-QualifiedTransmissionDevelopersList.pdf (southeasternrtp.com).

56 Southern Company Transmission Planning Tariff at § 11.1.1.

57 *E.g.*, *2014 Regional Transmission Planning Analyses*, SERTP, at 10 (2014), SERTP Regional Transmission Planning Analyses Summary.pdf (southeasternrtp.com) (2014 Analyses).

58 *See 2021 Regional Transmission Planning Analyses*, SERTP (2021), 2021-SERTP-Regional-Transmission-Planning-Analyses-Summary-Final.pdf (southeasternrtp.com); *2020 Regional Transmission Planning Analyses*, SERTP (2020), 2020-SERTP-Regional-Transmission-Planning-Analyses-Summary-FINAL.pdf (southeasternrtp.com); *2019 Regional Transmission Planning Analyses*, SERTP (2019), 2019-SERTP-Regional-Transmission-Planning-Analyses-Summary.pdf (southeasternrtp.com); *2018 Regional Transmission Planning Analyses*, SERTP (2018), 2018-SERTP-Regional-Transmission-Planning-Analyses-Summary.pdf (southeasternrtp.com); *2017 Regional Transmission Planning Analyses*, SERTP (2017), 2017-Regional-Transmission-Planning-Analyses-Summary.pdf (southeasternrtp.com) (2017 Analyses); *2016 Regional Transmission Planning Analyses*, SERTP (2016), 2016 SERTP Regional Transmission Planning Analyses Summary.pdf

When the rare regional project progresses to the second stage of the analysis, the SERTP sponsors compare its costs to the identified project(s) it would displace. In all nine cases, the larger regional project's costs far exceeded the small local project's costs and none of the regional projects has been selected.[59] The entirety of a representative analysis appears as follows:

> The planning level estimate for the South Hall – Oconee 500 kV transmission line is approximately **$227,000,000**. The total cost of all the potentially displaced transmission projects within the SERTP region is approximately **$26,000,000** and therefore, this transmission project alternative is not currently a more efficient or cost-effective project to address transmission needs in the SERTP region. A calculation of real power transmission loss impacts was not performed as it would be unlikely to measurably change the results of the 2017 regional assessment.[60]

This identical analysis, with the project names and costs swapped out, accompanies each of the nine rejected regional transmission projects.[61] This cut-and-paste cost comparison is the extent of the "consideration" given to regional facilities.

The jurisdictional utilities' tariffs establish this hollow exercise. Per Southern Company's tariff, a "proposed transmission project should yield a regional transmission benefit-to-cost ratio of at least 1.25 and no individual Impacted Utility should incur increased, unmitigated transmission costs."[62] The "benefit" in this calculation is "quantified by the Beneficiaries' total cost savings" associated with displaced transmission projects and any alternative projects not identified in the regional plans whose needs the regional project would address.[63] The "cost" is the transmission

(southeasternrtp.com) (2016 Analyses); *2015 Regional Transmission Planning Analyses*, SERTP (2015) (2015 Analyses), 2015 Regional Transmission Planning Analyses Summary.pdf (southeasternrtp.com); 2014 Analyses.

59 *See* 2017 Analyses at 19; 2016 Analyses at 11, 15, 17, 19; 2015 Planning Analyses at 11; 2014 Analyses at 12, 18.

60 2017 Analyses at 19.

61 *See supra* note 59.

62 Southern Company Transmission Planning Tariff at § 17.2.1.

63 *Id*. § 17.2.1(1).

cost of the regional project and any additional projects needed to implement it.[64] If the benefit-to-cost calculation of these values equals or exceeds 1, changes in real power transmission losses will be considered as well.[65] Rather than a comprehensive benefits analysis, this process amounts to a straight cost comparison of the regional project versus the displaced local projects, with reductions in losses only potentially warranting consideration. By that measure, a large regional project's costs will always exceed its "benefits," i.e., the cost of the much smaller, immediate local project(s) it displaces. Further, SERTP's ten-year planning horizon fails to account for the benefits regional projects could provide over a much longer duration, which could dwarf the costs of many immediate-need local projects. Without considering a more comprehensive suite of benefits provided by the regional project over a longer period, this rubric will never result in selection of a regional project for cost allocation.

In a vacuum, SERTP's historical failure to produce any such regional transmission facilities is not necessarily a problem if the utilities' existing transmission systems can ably connect all generation to all load. It becomes problematic when utilities across the region have identified nearly identical, unaddressed transmission needs caused by the same resource trends. In the Southeast, coal retirements have become a particular flashpoint. In some cases, utilities have affirmatively sought to replace the retiring units with offsite renewable generation.[66] In others, utilities have sought to replace the coal units with new onsite gas units and have parried stakeholder protests by claiming that transmission deficits prevent them from installing renewable replacements.[67] In all cases, faced with actual transmission needs, utilities must seek the most

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64 *Id*. § 17.2.1(2).

65 *Id*. § 17.2.3.

66 *See infra* sections II.B.1-2.

67 *See infra* sections II.B.3-5.

efficient and cost-effective manner of meeting them, particularly when all other costs of providing electricity costs are rapidly increasing. They can realize significant cost efficiencies through optimized regional transmission expansion,[68] but due to the superficial planning criteria they have implemented in SERTP, the widespread benefits of regional transmission facilities are simply not considered. Instead, SERTP's planning process ensures that utilities will select piecemeal local solutions to address increasing transmission needs, resulting in larger aggregate costs covered by captive ratepayers.

2. SCRTP

In South Carolina, Dominion and Santee Cooper conduct "regional" transmission planning through SCRTP. SCRTP is even less suited to assess regional solutions than SERTP. First and foremost, it operates on a much smaller scale, involving two utilities as opposed to twelve, meaning that the universe of regional transmission facilities that could create measurable efficiencies amongst the participants is severely limited. Missing from the process entirely are the two transmission systems with the largest actual interchange with Dominion and Santee Cooper: Southern Company and Duke. By planning on such a confined scale, Dominion and Santee Cooper necessarily overlook significant transmission optimization benefits they could realize by planning on the regional scale of SERTP. Second, SCRTP's regional planning process takes place over a two-year planning cycle,[69] which produces a regional plan that is less up-to-date and dynamic than SERTP's. Finally, SCRTP represents both the local and regional planning processes for its

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[68] *See* Johannes Pfeifenberger et al., *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs*, The Brattle Group, at iii-iv (Oct. 2021), Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs (brattle.com) (Brattle Report).

[69] Dominion, Open Access Transmission Tariff, Att. K, Transmission Planning Process, § III.E.2 (0.0.0) (Dominion Transmission Planning Tariff).

utilities.[70] Although certain utilities like Southern Company use SERTP for both their local and regional planning processes, most of the SERTP utilities have distinct local processes from which they derive their inputs to the regional plan.

In most other respects, SCRTP is identical to SERTP. It has similar stakeholder sectors and participation processes.[71] Like SERTP, state regulators and stakeholders have no influence over the ultimate facility selection.[72] It also considers regional alternatives to local transmission projects in a similar manner. Proposed regional transmission projects "must yield a regional benefit to cost ratio equal to or greater than 1.25 and must not have an unmitigated adverse impact on reliability."[73] The "benefit" is based on the total regional benefits associated with cancelled or postponed projects, the cost reductions of other existing projects, the alternative projects that would otherwise be required, and the reduction of real power losses.[74] The "costs" are calculated based on the cost of the regional project, the costs of any additional projects, and the increase of real power losses.[75] Although marginally more expansive than SERTP's benefits evaluation, this process effectively amounts to a straight cost comparison, which, like SERTP, has not resulted in regional transmission projects selected for regional cost allocation. Accordingly, many of the fundamental changes needed to reform SERTP apply with equal force to SCRTP.

3. FRCC

Similar to SERTP and SCRTP, though falling somewhere between the two in scope, the FRCC transmission planning process discourages stakeholder participation and has failed to yield

70 *Id.* § I.

71 *See id.* § III.B.

72 Berkeley Lab Transmission Planning at 7.

73 Dominion Transmission Planning Tariff at § VII.G.1.

74 *Id.* § VII.G.1.

75 *Id.* § VII.G.2.

regional transmission investment. FRCC conducts two parallel transmission planning processes: (1) an Annual Transmission Planning Process (ATPP), which FRCC defines as "the result of coordinating each of the FRCC members' local plans to develop the overall Regional Plan,"[76] and (2) a Biennial Transmission Planning Process (BTPP), held in odd-numbered years, which allows FRCC members to propose cost-effective or efficient transmission solutions (CEERTS) and studies of transmission needs driven by Public Policy Requirements.[77] The ATPP begins when Florida's utilities submit their Ten Year Site Plans (TYSP) on April 1 of each year.[78] The TYSP is essentially a slimmed-down version of an IRP, in which each utility provides its load forecast, existing and planned generation, and a list of any planned transmission over the next ten years.[79] These planned transmission projects form the basis for the ATPP. Because the TYSP process begins anew each year, a utility's TYSP can change drastically from one year to the next.

Like SERTP and SCRTP, FRCC utilizes a simplistic cost-benefit calculation to determine whether CEERTS projects can be considered for inclusion in the BTPP. To merit consideration, the CEERTS project's costs must not exceed the sum of the costs of the local projects it would replace, with resulting changes to line losses considered as well.[80] Any CEERTS or Public Policy Requirements-driven projects that result in a benefits-to-cost ratio greater than 1.0 can be presented for potential approval to the FRCC Board of Directors,[81] which is dominated by the incumbent utilities. This rarely occurs, however. In the last three cycles of the BTPP—starting in 2017—no

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76 *FRCC Regional Transmission Planning Process FRCC-MS-PL-018*, FRCC, at 5 (Jul. 1, 2022), https://www.frcc.com/order1000/Shared%20Documents/Procedures-Public/FRCC/FRCC-MS-PL-018_FRCC_Regional_Transmission_Planning_Process.pdf.

77 *See id*.

78 *See id*. at 7.

79 *See id*. at 15.

80 *See id*. at 22-29.

81 *See id*. at 23.

potential CEERTS projects have been submitted.[82] Similarly, since at least 2019,[83] there have been no requests for studies of transmission needs driven by Public Policy Requirements.[84]

The development of the ATPP and BTPP by FRCC members takes place largely behind closed doors. After FRCC compiles the proposed transmission facilities from utility TYSPs and lists them in its annual "Load and Resources" report to the Florida Public Service Commission, the process becomes significantly more opaque. Information such as who represents the members on the FRCC standing committees and when meetings are held is not available to the public. All pertinent information and documents are housed on a password-protected website that is available only to members. Given the lack of meaningful stakeholder influence and ineffective consideration of both regional facilities and transmission needs driven by Public Policy Requirements, FRCC's failure to yield viable regional projects is not surprising. Nevertheless, significant transmission needs continue to surface in Florida. Recently, FPL completed a 176-mile transmission line, but limited the line's voltage to 161 kV in order to avoid meaningful regulatory

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82 *FRCC 2021-2022 BTPP Potential CEERTS Project Submittals 2017/2018*, FRCC (Jul. 13, 2021), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=43&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A; *FRCC 2019-2020 BTPP Potential CEERTS Project Submissions*, FRCC (June 11, 2019), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=32&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A; *2017 - 2018 FRCC Regional Projects Subcommittee Proactive Planning Result Notice*, FRCC (Apr. 5, 2017), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=9&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A.

83 A record of the 2017/2018 BTPP Public Policy Requirements submissions, if any, is not available on the FRCC website.

84 *Results of FRCC 2021-2022 BTPP Public Policy Planning Submissions*, FRCC (Feb. 8, 2021), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=38&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A; *Results of FRCC 2019-2020 BTPP Public Policy Planning Submissions*, FRCC (Feb. 8, 2019), https://www.frcc.com/order1000/Lists/Announcements/DispForm.aspx?ID=28&ContentTypeId=0x01040068DF21F4B5757A4A9484377CD0C16F8A.

oversight.[85] As a result, FPL's ratepayers must bear the costs of a long line with limited transfer capability, as well as any other subsequent local facilities needed to pick up the slack, whereas a higher-voltage regional facility could have provided demonstrable benefits to ratepayers across the state. Like SERTP and SCRTP, FRCC's regional planning process ensures such efficient alternatives do not see the light of day.

B. Developments in the States

Throughout the Southeast, states have experienced significant upheaval in the generation resource mix.[86] Featured below are snapshots of various states in the region and their individual encounters with these changes. In their own words, the states' prominent utilities describe the significant transmission needs they face, which are overwhelmingly driven by these generation shifts. Yet none of these utilities identifies its regional planning process as a suitable venue to addressing the shared needs.

1. Georgia

Georgia Power recently completed its triennial IRP process, as the Georgia Public Service Commission (Georgia PSC) approved Georgia Power's IRP on July 21, 2022.[87] Throughout the proceeding, the issue of coal retirements in the northern part of the state and the utility's failure to proactively plan for them received substantial attention. The terrain of north Georgia—where the retiring coal plants and corresponding load centers are located—is not well suited to large-scale solar resources, which Georgia Power considers an ideal resource to replace the retiring coal units.

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85 *See* Ivan Penn, "How a Florida Power Project Flew Under the Regulatory Radar," N.Y. Times, (May 31, 2022), How a Florida Power Project Flew Under the Regulatory Radar - The New York Times (nytimes.com).

86 *See supra* note 2.

87 *See Georgia Power Company*, Docket No. 44160 (Ga. Pub. Serv. Comm'n July 21, 2022) (GPC IRP Order).

The southern part of the state has significantly more potential for solar capacity, but there is insufficient transmission capacity to transport south Georgia solar to north Georgia load.

Georgia Power attempted to address this issue in the IRP through its proposed North Georgia Reliability & Resilience Action Plan, "a multi-faceted plan to address future reliability needs associated with the retirement of Plant Bowen."[88] Because north Georgia "relies on the transmission system to import power from south Georgia,"[89] generation retirements in the north create a need for significant transmission expansion to avoid outages:

> The current projected transmission and generation infrastructure cannot sufficiently support reliable electric service to north Georgia following the retirement of Plant Bowen Units 1-4. However, the combination of renewable generation expansion, low load growth, forecasted low gas prices, and substantial environmental pressures will continue to place a significant burden on coal unit economics, including Plant Bowen.[90]

This "significant gap between generation and load forecasted in north Georgia" will (1) "be further increased by future coal retirements" and (2) "require the transmission system to transport large amounts of energy from south to north Georgia and place additional strain on the existing transmission system."[91] To overcome these issues, Georgia Power proposed an action plan that included: (1) controls on certain coal units to allow continued operation; (2) a request for proposals (RFP) for solar facilities sited in north Georgia, which is unlikely to succeed given the area's physical constraints; (3) a "strategic portfolio of projects to address the long-term transmission

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88 *See Georgia Power Company*, Docket No. 44160, Georgia Power, 2022 Integrated Resource Plan, Main Document, at 12-87 (Ga. Pub. Serv. Comm'n Jan. 31, 2022).

89 *Id*.

90 *Id*.

91 *Id*. at 12-88

planning operation needs" of the area; and (4) a consolidated expansion plan for the area's generation needs.[92]

Beyond the quixotic attempt to site solar resources in the unsuitable terrain of north Georgia, attention shifted to transmission planning. Concern over the lack of adequate transmission capacity on Georgia Power's system was also driven by its parallel plan to integrate 6,000 MW of new renewable energy by 2035.[93] For these transmission needs as well as the North Georgia Reliability & Resilience Plan, Georgia Power committed only to conducting planning activities among the Integrated Transmission System (ITS) participants.[94] The ITS is comprised of the aggregate of transmission facilities in the state owned by Georgia Power, GTC, MEAG, and Dalton.[95] It is jointly planned, and its expansion is funded by the ITS members.[96] Although the ITS joint planning process represents the first step for any transmission expansion in the state, it is not open to the public and features no stakeholder involvement beyond the ITS members.[97] Georgia Power officially conducts its Order No. 890 local transmission planning process through SERTP (along with Southern Company's other affiliates),[98] but practically speaking, local transmission planning in Georgia occurs on the ITS level. As such, the transmission portion of the North Georgia Reliability & Resilience Plan would depend entirely upon the ITS coordination process.

92 *Id*.

93 *Id*. at 11-72.

94 *Id*. at 12-88.

95 *See, e.g.*, Georgia Power, Dalton ITS Agreement, § 1.04 (0.0.0).

96 *See id*. at art. III.

97 *See Georgia Power Company*, Docket No. 44160, Georgia Power, 2022 Integrated Resources Plan, Vol. 3 at 12-14 (Ga. Pub. Serv. Comm'n Jan. 31, 2022).

98 Southern Company Transmission Planning Tariff at preamble (Local Transmission Planning).

Throughout the IRP proceeding, the Georgia PSC Public Interest Advocacy Staff (Public Staff) questioned the usefulness of this closed-door process, especially given the scale of transmission investment required to facilitate both the North Georgia Reliability & Resilience Plan and the planned integration of 6,000 MW of renewable resources:

> I recommend that the [Georgia PSC] develop a collaborative transmission planning process which has [Georgia PSC] oversight, and includes all of the ITS Participants, the Staff and the Company to wrestle with this issue and come up with a comprehensive plan that considers the regional needs for a reliable, resilient and economic grid to support the Company's transition to a clean energy future.[99]

Looking back, the Public Staff asked how Georgia Power arrived in this position, scrambling to address coal retirements it should have anticipated long ago:

> Not already having a transmission expansion plan that is designed to facilitate new generation to feed North Georgia is a serious problem that requires rapid decisions. The failure of the Company to have a long-term strategic plan in place for the loss of Bowen generation is a flaw in [Georgia Power]'s planning process and something that should have been addressed in a [Georgia PSC]-directed, transparent process long before the 2022 Integrated Resource Plan. Many organizations conduct long-term planning assessments beyond the ten-year horizon, and [Georgia Power] and [the Georgia PSC] would benefit from such a collaborative long-term transmission planning process which includes Staff, consultants, and ITS Participants.[100]

Of course, stakeholders in SERTP had asked the SERTP sponsors to study certain Public Policy Requirements that would result in coal retirements every year from 2015 to 2017.[101] Yet, as noted

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[99] *See Georgia Power Company*, Docket No. 44160, Public Staff, Direct Testimony and Exhibits of John W. Chiles, at 9-10 (Ga. Pub. Serv. Comm'n May 6, 2022) (Chiles Test.).

[100] *Id*. at 11-12.

[101] 2017 Public Policy Requirements at 2-3; 2016 Public Policy Requirements 2-3; 2015 Public Policy Requirements at 2-3.

above, the SERTP sponsors rejected these requests on the basis that they did not demonstrate a transmission need.[102]

Part of the problem, as identified by the Public Staff, is the truncated transmission planning horizon used by Georgia Power in both the ITS and SERTP. Seemingly echoing this Commission, Public Staff asserted that "[t]he significant changes in [Georgia Power]'s generation mix and retirement/siting strategy requires a long-term view and will likely require much analysis."[103] Georgia Power representatives acknowledged during the hearing that SERTP's ten-year planning horizon limits the company's ability to proactively plan transmission expansion.[104] When asked how, then, Georgia Power intended to plan for the North Georgia Reliability & Resilience Plan and 6,000 MW of renewable resources by 2035, the company's representative identified this NOPR proceeding and the Commission's proposal to expand the planning horizon to 20 years.[105] SERTP's existing planning constraints—in addition to the SERTP sponsors' reluctance to conduct Public Policy Requirements studies—directly limited its ability to facilitate long-term proactive planning.

Between the North Georgia Reliability & Resilience Plan and Georgia Power's 6,000 MW renewable energy goal, the need for expanded transmission infrastructure in Georgia is apparent. Unfortunately, each of the systems in place for planning those enhancements is wholly insufficient to do so in an efficient, least-cost manner. Put another way, there is a fundamental disconnect

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102 *Id*.

103 Chiles Test. at 13.

104 *See Georgia Power Company*, Docket No. 44160, Tr. 280:11-281:9 (Ga. Pub. Serv. Comm'n June 21, 2022) ("Q. Does SERTP have a planning horizon further than ten years out? A. (Witness Robinson) Not at the moment.").

105 *Id*. ("Q. So how are you going to be able to take a longer than ten-year planning horizon with the North Georgia reliability projects and insert them into SERTP if SERTP can't even accept them? A. (Witness Robinson) Well, I think there's ways you can talk beyond the horizon. I think the current NOPR that's out there that FERC let a couple weeks ago, it proposes to address that horizon issue. Q. How so? A. (Witness Robinson) They propose a 20-year horizon.").

between the three forums relevant to transmission planning in the state, contributing to Georgia Power's transmission planning paralysis. The ITS operates without regulatory oversight or stakeholder input, insulating its utilities from any outside influence, yet forms the basis for Georgia Power's local transmission plans. The Georgia PSC reviews Georgia Power's IRP, but only does so every three years, and it is unclear—even to Georgia Power—whether the Georgia PSC must affirmatively approve the portfolio of transmission facilities contained in the ten-year transmission plan or examine the process that created it.[106] And SERTP has failed to avert the situation in which Georgia Power now finds itself, due to—among other failings—its limited planning horizon and failure to consider the resource trends driving transmission needs, even where stakeholders had previously identified those very needs.

The Georgia PSC ultimately approved Georgia Power's IRP, but directed no changes to its transmission planning process aside from a minor reporting requirement.[107] The Georgia PSC also deferred a decision on the retirement of some of the coal units that created the need for the North Georgia Reliability & Resilience Plan.[108] These units are still expected to retire and will still cause the need for additional transmission capacity, but if anything, Georgia Power earned a short reprieve and another chance to proactively plan for this eventuality. To do so, Georgia Power

106 *Compare Georgia Power Company*, Docket No. 44160, Tr. 546:19-547:8 (Ga. Pub. Serv. Comm'n Apr. 4 21, 2022) (Q. Are you seeking approval of . . . the ten-year transmission plan in this IRP? A. (Witness Robinson) No. This is a transmission plan that we developed with the ITS participants as part of the SERTP process as well. We bring this to show our prudency as it relates to planning the system and meeting the transmission plan associated with the resource plan to make sure that we deliver the megawatts from the generation to the load. Q. So the Commission is not going to approve this ten-year transmission plan in this IRP? A. (Witness Robinson) It's part of the IRP. We're not asking for explicit approval of the transmission plan. This is a work product of the ITS that also feeds into the SERTP process on an annual basis.") *with Georgia Power Company*, Docket No. 44160, Tr. 264:1-8 (Ga. Pub. Serv. Comm'n June 21, 2022) (Q. If the IRP and stipulation are approved by the Commission, is the Commission also approving the ten-year transmission plan? A. (Witness Grubb) Yes. I believe that's one of the items in there, yes. Q. Okay. A. (Witness Robinson) That is explicitly in? A. (Witness Grubb) That is correct.").

107 *See* GPC IRP Order at 18.

108 *See id*. at 46.

must overcome a transmission deficit that spans the entire state. Neighboring states are experiencing similar needs, presenting a golden opportunity for regional coordination, but given the current processes in place, that option has not been seriously considered.

2. North Carolina

In North Carolina, the NCUC is conducting a proceeding to establish a Carbon Plan for Duke to comply with the state's carbon reduction mandate, H.B. 951. The law requires a 70 percent reduction in power sector carbon emissions from 2005 levels by 2030 and carbon neutrality by 2050.[109] It also directs the NCUC to develop a plan by December 31, 2022 that "may, at a minimum, consider power generation, transmission and distribution, grid modernization, storage, energy efficiency measures, demand-side management, and the latest technological breakthroughs to achieve the least cost path" to meet the required reductions.[110] On May 16, 2022, Duke submitted its Carbon Plan proposal, which contained four discrete portfolios, each of which "outlines near-term development and procurement needed in 2022-2024 to bring projects into service in the period of 2026-2029, along with development activities necessary for longer lead-time resources to remain on track to come online between 2030-2034."[111] Each of the four portfolios would require greater integration of wind and solar resources, electric storage, energy efficiency, demand response, as well as newer resources like nuclear small modular reactors and

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109 H.B. 951 at § 1.

110 *Id*. § 1(1).

111 *See Duke Energy Progress, LLC and Duke Energy Carolinas, LLC*, Docket No. E-100, Sub 179, Duke, Carolinas Carbon Plan, Executive Summary, at 3 (N.C. Utils. Comm'n May 16, 2022). On July 15, 2022, parties to the proceeding filed comments in response to Duke's proposed Carbon Plan, including alternative plans. Although many of these submissions made compelling cases that Duke has not presented the best way forward to meeting H.B. 951's milestones, it is a virtual certainty that the final Carbon Plan will require significant transmission upgrades, which will necessitate forward-looking transmission planning.

hydrogen solutions.[112] Three of the four portfolios involve significant offshore wind additions.[113] All four depend on the retirement of Duke's remaining coal-fired units, but "the timing of actual retirements will ultimately be driven by the ability to place in service the necessary replacement resources and access to fuel supply."[114] Importantly, given H.B. 951's directive that the Carbon Plan "achieve the least cost path" to its carbon reduction goals, cost containment will be a key consideration throughout this process.

Not surprisingly, this overhaul of the generation fleet "requires transformation of the [Duke] transmission system in the near-term and long-term to interconnect the unprecedented amounts of new supply-side resources that will be needed to retire significant amounts of coal-fired generation and achieve the carbon emission reduction targets."[115] Interconnecting the tremendous number of new renewable resources while retiring all remaining coal units necessitates "significant investment in the transmission system on an aggressive timeline."[116] These include certain "Red Zone" transmission upgrades that have arisen in many generator interconnection studies but which have uniformly caused the interconnection customers to withdraw due to their cost.[117] Further, even though Duke has proposed an expedited generator replacement process for new generation that can repurpose the interconnection facilities vacated by retiring coal facilities, new transmission will be needed if the replacement generation cannot interconnect to the same switchyard.[118] Finally, given most of the portfolios' reliance on substantial offshore wind

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112 *Id*. at 12.

113 *Id*. at 12-13.

114 *Id*. at 17.

115 *See Duke Energy Progress, LLC and Duke Energy Carolinas, LLC*, Docket No. E-100, Sub 179, Duke, Carolinas Carbon Plan, App. P, at 1 (N.C. Utils. Comm'n May 16, 2022) (Carbon Plan App. P).

116 *Id*.

117 *Id*. at 11-12.

118 *Id*. at 15.

facilities, the ultimate Carbon Plan will likely require significant new transmission facilities to unlock their output.[119]

Duke estimates that injecting between 800 and 1,600 MW from offshore wind facilities will require \$1.3 to \$2.39 billion in transmission upgrades.[120] Estimates for all the transmission upgrades necessary to implement Duke's proposed Carbon Plan range from \$3.76 to \$4.76 billion by 2035.[121] As interconnection of incremental resources and coal retirements progress, "more extensive transmission network upgrades will be required to ensure more remote interconnected resources can safely and reliably deliver energy to load centers under various stressed grid conditions."[122] This will require new greenfield transmission infrastructure as Duke seeks to achieve carbon neutrality by 2050, which could cost as much as \$7 billion.[123] To the extent these facilities require new rights-of-way, development would take ten to 15 years.[124] In light of this significant investment of time and money, Duke acknowledges that "a more proactive approach to transmission planning and expansion is needed to meet the Carbon Plan objectives."[125]

The proactive transmission planning process Duke intends to utilize to implement the Carbon Plan is not SERTP, but the North Carolina Transmission Planning Collaborative (NCTPC).[126] The NCTPC is Duke's local planning process under Order No. 890 and involves North Carolina Electric Membership Corporation and ElectriCities of North Carolina, Inc., the

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119 *See id*. at 16-17.

120 *See id*. at 17.

121 *See id*. at 19-20.

122 *Id*. at 20.

123 *Id*. at 20-21.

124 *Id*. at 21.

125 *Id*. at 13.

126 *See id*. at 13-14.

organizations representing cooperative and municipal power suppliers in the state, respectively.[127] The NCTPC creates a Local Transmission Plan focused on cost-effective, reliability-focused transmission upgrades.[128] Non-LSE stakeholders generally cannot serve on the Planning Working Group that develops the local transmission plan or the Oversight/Steering Committee that approves it, but they may participate on the Transmission Advisory Group that provides input on the transmission plan, including recommendations regarding Public Policy Requirements.[129]

Throughout its Carbon Plan proposal, Duke proposes to rely upon the NCTPC to plan the transformative transmission investment needed to implement the final Carbon Plan. In fact, Duke has already presented the "Red Zone" transmission upgrades to the NCTPC for assessment.[130] Rather than proactively study and plan for these facilities, however, the NCTPC has deferred doing so until the NCUC approves a final Carbon Plan,[131] even though Duke has known about these necessary upgrades since at least 2016.[132] Duke also intends to submit a comprehensive 2022 Public Policy Requirements study request in the NCTPC for the long-term transmission facilities needed to meet the Carbon Plan targets.[133] Acknowledging the likelihood that substantial greenfield transmission facilities will be required, Duke states that the NCTPC "will help Duke

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127 Duke Energy Carolinas, LLC, Open Access Transmission Tariff, Att. N-1, Transmission Planning Process, § 1 (10.0.0).

128 *See id*. § 4.

129 *See id*. § 2.4.

130 *See* Carbon Plan App. P at 12.

131 *See Status of NCTPC's Review of Red Zone Expansion Plan Projects and Release of Final 2021 Mid-Year Update to the NCTPC Transmission Plan*, NCTPC, at 4 (Aug. 15, 2022) ("The NCTPC will likely wait on the NCUC Order in the current open Carbon Plan Docket prior to considering approval of a Local Transmission Plan that includes the RZEP Projects.").

132 *See TAG Meeting: Webinar Final*, North Carolina Transmission Planning Collaborative, at 40 (June 27, 2022), TAG_Meeting_Presentation_for_06-27_2022_FINAL.pdf (nctpc.org).

133 *See* Carbon Plan App. P at 13.

Energy work through how to achieve the Carbon Plan targets of 70% CO_2 emissions reductions and carbon neutrality by 2050."[134]

Aside from a brief descriptor,[135] Duke barely mentions SERTP and evinces no intention to utilize the regional process to implement its proposed Carbon Plan, even though it will require billions of dollars in transmission investment and Duke must adhere to least-cost planning principles. Despite the clear efficiencies and cost savings to be realized from optimized regional transmission and despite the common regionwide transmission needs caused by coal retirements and renewable integration, Duke intends to avoid the only applicable regional planning forum. This omission is a damning indictment of SERTP's ability to create efficient regional solutions to inherently regional transmission needs. It is also entirely understandable, given the demonstrated apathy with which its utility sponsors—including Duke—approach coordinated planning. Without significant overhaul, it is unlikely SERTP will play any facilitative role in North Carolina's transformational generation shift.

3. Alabama

Another Southern Company affiliate, Alabama Power, serves the vast majority of customers in Alabama.[136] Unlike in Georgia and North Carolina, the Alabama Public Service Commission (Alabama PSC) does not approve Alabama Power's IRP; there is no formal assessment of the company's broad facility investment plans in which interested parties and the public may participate. As a result, the Alabama PSC and the public are limited to assessing—

134 *Id*. at 21.

135 *See id*. at 10.

136 *See Electricity in Alabama*, Find Energy, Alabama Electricity in Facts, Statistics, Companies (findenergy.com) (last visited Aug. 9, 2022).

and if necessary, contesting—the utility's resource decisions and the transmission facilities that may be required to facilitate them on a case-by-case basis.

Earlier this year, Alabama Power proposed to acquire a generation facility comprised of four simple cycle combustion turbine units (Calhoun Power Facility)[137] in order to replace retiring coal capacity.[138] In seeking the Alabama PSC's approval, the company disclosed the alternatives it considered to acquiring the Calhoun Power Facility. These included a portfolio of 17 solar facilities and energy storage proposed in response to a previous renewable resource solicitation.[139] Alabama Power compared the estimated costs of this alternative, which came to $1,067/kW, to the costs of acquiring the Calhoun Power Facility, which came to $497/kW, and summarily ruled out the solar/storage alternative.[140] The company asserted that transmission costs largely accounted for the difference: "The costs to integrate these facilities into our transmission system is a significant cost, both for delivery of the power and for charging of the batteries."[141]

In calculating these comparative costs, the company made no effort to assess the potential benefits the transmission expansion would bring:

> Q. [W]ould those transmission costs in the facilities that are associated with them, would those only be associated with those projects, or would that be available for any sort of electron to use those transmission?

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137 *See Alabama Power Company*, Docket No. 33182, Alabama Power, Petition for Certificate of Convenience and Necessity, at 1-2 (Ala. Pub. Serv. Comm'n Oct. 28, 2021).

138 *See Alabama Power Company*, Docket No. 33182, Alabama Power, Petition for Certificate of Convenience and Necessity, Direct Testimony of John B. Kelley, at 6:119-9:195 (Ala. Pub. Serv. Comm'n Oct. 28, 2021).

139 *See id*. at 14:294-15:301.

140 *See id*. at 15:320-16:335.

141 *Alabama Power Company*, Docket No. 33182, Deposition of John B. Kelley, at 145:10-20 (Ala. Pub. Serv. Comm'n May 4, 2022) (Kelley Depo.). When the company allocated these transmission costs across all projects in the portfolio, a subset of 15 solar projects were competitive with the Calhoun Power Facility, at $545/kW, but still exceeded the costs associated with the acquisition. *See Alabama Power Company*, Docket No. 33182, Alabama Power, Brief, at 26 (Ala. Pub. Serv. Comm'n May 10, 2022).

> A. Well, the way we evaluated it was if these projects were undertaken, they created, they gave rise to these transmission dollars, these interconnection delivery and charging dollars. So once they were put in place, you know, we're looking at cost causation caused by the projects. Once they were put in place, our transmission system would be there to transmit and deliver those, the electricity from those projects.
>
> Q. So would there be benefits to those transmission facilities?
>
> A. Could be, maybe. I mean, it might help future projects or it might not.
>
> Q. And those benefits were not considered in this analysis, correct?
>
> A. No. We were looking at what costs did they cause in the transmission system, that's how we look at every transmission. Whenever we site a resource. . . . the transmission cost is a key consideration, especially given our ever-changing system today. We try to minimize that cost.
>
> Q. So I guess on the flipside of that, that investment creates benefits down the line when you do invest in that transmission apparatus?
>
> A. In the form of a more robust transmission system or something, conceivably, but we don't look at what additional transmission benefits it would provide.[142]

Despite acknowledging the likelihood that transmission expansion could bring benefits to the greater Alabama Power system, the company did not attempt to quantify these benefits within the context of assessing alternatives to the Calhoun Power Facility. To be sure, integration of the solar and storage facilities would have required significant additional investment, but the transmission improvements had the potential to both strengthen the utility's transmission system and facilitate the integration of future projects.

Although this Alabama PSC proceeding is distinct from SERTP, there are clear parallels between the two processes. First, Alabama Power and its parent, Southern Company, are

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142 Kelley Depo. at 194:9-195:17.

prominent SERTP sponsors. Second, the company's approach to assessing transmission benefits within its own resource planning process mirrors SERTP's approach, where cost is the only relevant metric and broader, quantifiable benefits are ignored. In order to plan for resource changes that are affecting the entire region—like the coal retirements that precipitated the Calhoun Power Facility proceeding—in an efficient and cost-conscious manner, a more holistic consideration of benefits is necessary. The Calhoun Power Facility example calls into question whether the state level is the most appropriate forum for that assessment, as the SERTP sponsors have long asserted.[143] The lack of any regular, formal proceeding to consider Alabama Power's comprehensive facility investment plan is troubling and ensures that both generation and transmission are considered on a project-by-project basis. This piecemeal approach to addressing transmission needs for individual generation resource decisions will cause sticker-shock every time and an institutional aversion to broader transmission investment, especially when transmission benefits are expressly ignored. Instead, transmission system upgrades will occur primarily through the generator interconnection process, despite its many inefficiencies.

Because no forward-looking, portfolio-based consideration of Alabama Power's transmission facilities exists at the state level, SERTP provides the only alternative forum for such planning. As these comments have shown, however, SERTP's focus on local transmission facilities and emphasis on cost present the same problem and fail to adequately account for the efficiencies inherent to broad-based planning.

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[143] SERTP Sponsors ANOPR Comments at 4 ("[T]he Commission must avoid unlawfully intruding into resource/IRP planning reserved to the states or inappropriately seeking to force 'substantive outcomes' rather than merely regulating the transmission planning process.").

4. Tennessee

Whereas most states in the Southeast are predominantly served by one or two investor-owned utilities, the federal utility TVA dominates the energy landscape in Tennessee. TVA controls the generation and transmission facilities in the state, providing mostly wholesale service to cooperative and municipal distribution utilities in Tennessee and parts of six surrounding states. Although broadly subject to Congressional oversight, TVA is governed by its Board of Directors[144] and its activities are largely unregulated. TVA participates in SERTP as part of its "voluntary response" to Order Nos. 890 and 1000,[145] but its transmission planning activities outside of SERTP, like much of TVA's processes, are a black box.

In recent years, TVA has publicized a goal to reduce its greenhouse gas emissions by 80 percent by 2035, compared to 2005 levels, and to reach net zero emissions by 2050.[146] In July 2022, TVA announced an RFP for 5,000 MW of carbon-free energy before 2029, from resources both internal and external to TVA.[147] Without assessing the likelihood that TVA follows through on either its aspirational carbon reduction goals or this latest clean energy procurement push, any integration of renewable resources at this scale will require significant transmission planning and investment. In practice, when TVA has sought to replace retiring coal-fired generation, it has shied away from procuring renewable capacity, asserting in part that it would require significant transmission investments. For example, TVA recently proposed to retire the two coal-fired units at its Cumberland Fossil Plant (Cumberland) and replace them with either new gas generation or

[144] *Our Leadership*, TVA, Our Leadership (tva.com) (last visited Aug. 6, 2022).

[145] *Southeastern Regional Transmission Planning Group: TVA Membership Background and History – Note to OASIS*, TVA (Aug. 10, 2015), Microsoft Word - Note for OASIS on SERTP Aug10-15.doc (oati.com).

[146] Jonathan Mattise & Adrian Sainz, "Federal Utility Seeks Proposals for Big Carbon-Free Push," Associated Press (Jul 12, 2022), Federal utility seeks proposals for big carbon-free push | AP News.

[147] *See id*.

a portfolio of solar and storage resources.[148] TVA has shown a clear preference for the new gas option, having estimated that the solar/storage alternative would cost $2.3 billion more and would require "extensive regional transmission upgrades."[149] TVA also rejected replacing Cumberland's capacity with wind generation external to TVA due to transmission costs, despite its ability to "provide dependable capacity in both summer and winter."[150] Putting aside the fact that TVA has not shared the detailed assumptions underlying its renewables and storage alternative (including related to project siting), or even the projected costs of its claimed transmission needs, it is apparent that TVA has not considered the benefits of regional transmission investment. As commenters have explained, such investment would "provide operational benefits to the TVA system as a whole, such as improved reliability and resilience, and will facilitate the utility's plans to install 10,000 MW of solar by 2035. . . .Those projects will benefit directly from any transmission upgrades required . . . because they can be sited to maximize the value of the prior transmission investment."[151]

Like its utility neighbors, TVA asserts that it plans to integrate significant renewable capacity, primarily to serve large corporate customers with renewable energy goals, over the next decade and beyond. Also like its utility neighbors, it has claimed that the required transmission facilities make it cost-prohibitive to replace retiring coal facilities with renewable capacity. Yet it has also neglected to collaboratively plan for these eventualities alongside those neighbors who share the same stated transmission needs. Like Southern Company, which also has internal carbon

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148 *Cumberland Fossil Plant Retirement: Draft Environmental Impact Statement*, TVA, at i (2022), Cumberland Retirement Draft Environmental Impact Statement Report (azureedge.net) (Draft EIS).

149 *Cumberland Retirement EIS: Alternatives Evaluation*, TVA, at 17 (Apr. 2022), TVA Public Meeting (azureedge.net).

150 Draft EIS at 43.

151 Southern Environmental Law Center et al., Conservation Groups' Comments on TVA's Draft Environmental Impact Statement for the Cumberland Fossil Plant Retirement, at 23 (June 13, 2022).

reduction goals, TVA has not attempted to incorporate these goals into the regional transmission planning process. Although the Commission does not have jurisdiction over TVA's participation in regional transmission planning, it may shape SERTP in a manner that convinces TVA that SERTP can provide a forum to seek solutions to regionwide problems. Otherwise, the Southeast utilities will continue to plan for themselves in parallel, disregarding their shared issues and the cost-savings that could be realized from optimized planning.

5. South Carolina

As discussed above, South Carolina differs from the other states in the region due to its two separate regional transmission planning processes. Duke, which serves a significant portion of the state, participates in SERTP. Dominion, the other major investor-owned utility in the state, participates in SCRTP with Santee Cooper. Just like the other states in the region, however, South Carolina has seen accelerated retirement of coal units, necessitating replacement capacity. It has similarly struggled with the questions of whether and to what degree its utilities should upgrade its transmission facilities to adapt.

In its 2020 IRP, Dominion modeled the 2028 retirements of the Wateree and Williams coal units.[152] Dominion's Electric Transmission Planning Department performed a Transmission Impact Analysis (TIA) to assess the transmission impacts of these retirements. The TIA concluded that, while retirement of Wateree by the end of 2028 was feasible, retiring Williams before 2030 was not due to "the complexity of selecting and siting replacement resources including electric transmission and fuel supply."[153] Under each of the cases modelled, Dominion found that

152 *See Dominion Energy South Carolina, Inc.*, Docket No. 2021-418, Dominion, 2022 Coal Plants Retirement Study Report, at 3 (S.C. Pub. Serv. Comm'n May 16, 2022).

153 *Id*. at 5.

"maintaining reliable service after Williams and Wateree are retired will require significant upgrades to the DESC transmission system."[154]

Putting aside the prudence of investing in significant transmission upgrades in this instance, as intervenors to the proceeding persuasively argued that Dominion did not adequately consider non-wires alternatives or siting generation nearby,[155] Dominion's predicament is common to other utilities across the region, as these comments have shown. By virtue of its commitment to SCRTP's confined planning sphere, however, Dominion is isolated from its regional peers. It cannot then assess whether regional transmission facilities could alleviate its current constraints on a lower-cost basis than if it made such investments alone. Taking those options off the table entirely creates costs for Dominion's ratepayers that they might otherwise avoid, but neither state regulators nor stakeholders will ever know their extent.

The reforms included in the NOPR and supported in these comments are not designed to lead to specific outcomes; they are meant to create an array of fully vetted options and to allow state regulators and stakeholders to assess whether the transmission provider selected the option that would provide the most reliable service at the lowest cost. This is especially important as overwhelming changes confront the energy industry, requiring an accurate assessment of the role transmission can play in providing just and reasonable solutions. SCRTP's limited scope and SERTP's structural myopia fail primarily because they do not present sufficient optionality to ensure that ratepayers are receiving the best outcome available to them.

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[154] *Id*. at 17.

[155] *See Dominion Energy South Carolina, Inc.*, Docket No. 2021-418, Sierra Club et al., Comments on Coal Retirements Study, at 19-25 (S.C. Pub. Serv. Comm'n June 27, 2022).

III. REFORMS

These developments demonstrate the glaring need for an overhaul to the Southeast's regional transmission planning processes. Each of the region's prominent utilities has recognized that keeping pace will require substantial transmission investment, yet each has neutered and then effectively ignored the one forum that would allow them to proactively plan that investment on the scale required. Given the ubiquity of the transmission needs throughout the region and the efficiencies to be realized from optimally planning transmission on a regional basis, no moment could better justify SERTP, SCRTP, and FRCC's existence. The sheer scale of the transmission investment needed to meet this moment presents both a golden opportunity for efficient growth and a looming threat of exorbitant overbuilds. If the Commission cannot ensure the former, it will have to better police the latter, perhaps by revoking the presumption of prudence for facilities planned in the local processes. Otherwise, the region's ratepayers will see their already immense energy burdens become unbearable. Recognizing the significance of this moment, the Commission should use this proceeding to ensure that the regional planning processes avoid that outcome by comprehensively and genuinely assessing regional transmission facilities.

The NOPR's proposals to implement forward-looking, scenario-based planning are essential to shaping SERTP, SCRTP, and FRCC into processes that meaningfully assess efficient, regional transmission facilities. This in turn would allow state regulatory bodies and stakeholders to scrutinize the utilities' choices in a well-informed manner. As things stand, these cost-effective regional alternatives are either not presented or not seriously considered, leaving both state decisionmakers and ratepayers in the dark, and causing the latter to foot the bill. The NOPR's proposals could go a long way toward alleviating these flaws, but if the Commission allows the utilities too much leeway in establishing the ground rules, regional transmission planning in the Southeast will continue to be an empty, box-checking exercise. Firm direction is required, especially with respect to the process and criteria with which regional projects are assessed and selected. Below, Southeast Public Interest Groups discuss the most important reforms the Commission can implement to address the concerns expressed above.[156]

A. Long-Term Regional Transmission Planning

Southeast Public Interest Groups acknowledge the Commission's reluctance to dictate outcomes through the transmission planning process. They recognize that the regional transmission planning process exists instead to involve stakeholders, ensure transparency, and assess whether any regional transmission facilities or upgrades might provide a more efficient or cost-effective alternative to local transmission investment. Each of these principles has eluded the region's regional transmission planning processes. The ultimate intent remains selecting transmission facilities that will be approved by state regulatory authorities, but the process requires significant changes to ensure that multiple options are adequately vetted at the regional level before they reach the approval stage. Through a firm application of the NOPR's proposed reforms, including a defined set of minimum benefits, the reformed regional transmission planning process could live up to its promise as a collaborative venue for consideration of regional alternatives.

1. Long-Term Scenario Planning

Southeast Public Interest Groups strongly support the NOPR's proposal to require public utility transmission providers to engage in Long-Term Regional Transmission Planning (LTRTP) by developing and incorporating multiple Long-Term Scenarios that cover different assumptions about the changing electric power system over a 20-year planning horizon.[157] Comprehensive and proactive LTRTP in this vein is necessary to avoid the fate of Order No. 1000's Public Policy

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[156] The discussion of NOPR reforms herein takes a higher-level view of the proposed reforms. Southeast Public Interest Groups largely support the more granular proposals contained in the Public Interest Organizations' initial comments.

[157] *See* NOPR at PP 84, 97

Requirements obligations, which the SERTP sponsors do not seriously observe. Whereas the SERTP sponsors can currently reject stakeholder requests for Public Policy Requirements studies, LTRTP would become a regular obligation they cannot skirt. For LTRTP to provide any value, however, the Commission must establish a robust set of minimum requirements; as experience in the Southeast shows, the bare minimum expected of utilities will become the norm.

First and foremost, expanding the breadth of the compulsory study factors beyond minimum legal requirements would prevent utilities from discounting resource trends simply because they do not reflect state legislation, like the wave of coal retirements affecting the region. To this end, Southeast Public Interest Groups support the NOPR's proposed mandatory factors for incorporation in LTRTP:

> (1) federal, state, and local laws and regulations that affect the future resource mix and demand; (2) federal, state, and local laws and regulations on decarbonization and electrification; (3) state-approved utility integrated resource plans and expected supply obligations for load-serving entities; (4) trends in technology and fuel costs within and outside of the electricity supply industry, including shifts toward electrification of buildings and transportation; (5) resource retirements; (6) generator interconnection requests and withdrawals; and (7) utility and corporate commitments and federal, state, and local goals that affect future resource mix and demand.[158]

Factors 1-3 largely cover the existing Public Policy Requirements definition but provide additional specificity. Factor 4 requires consideration of resource trends that have had a much larger effect on the region's resource mix and demand than legislation. Most of the Southeastern states do not have decarbonization mandates or renewable portfolio standards, but all of them are susceptible to fuel price volatility given their reliance on gas and coal. And each has made at least halting progress in integrating renewables due to improved technology and economics. On the demand

158 *Id*. P 104.

side, an influx of electric vehicles—which are and will continue to be manufactured in the region in substantial numbers[159]—could also have a material effect. Factor 5, resource retirements, incorporates a development that has affected each state in the region and created transmission needs throughout, as discussed at length above. Factor 6's focus on needs created by interconnection requests and withdrawals has specifically arisen in North Carolina's Red Zone transmission upgrades.[160] And corporate renewable goals among both utilities—including Southern Company[161] and TVA[162]—and customers—such as Google[163]—have driven resource procurement decisions without the force of law.

These factors establish a strong foundation to drive LTRTP, and the Commission should require that each Long-Term Scenario explicitly account for each factor. However, allowing for their evolution as additional developments emerge is crucial. For this reason, Southeast Public Interest Groups support the NOPR's proposal to provide "stakeholders, including states, with a meaningful opportunity to propose potential factors that public utility transmission providers must incorporate."[164] As the ultimate arbiter of facility investment, the states have a substantial interest in guaranteeing that the factors they consider when approving utilities' plans inform the utilities'

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159 *See, e.g.*, *The State of the Green Mobility Industry in the Southeast: Market Trends and Policies Driving Transportation Electrification*, N.C. Clean Energy Technology Center (Nov. 29, 2021), The State of the Green Mobility Industry in the Southeast: Market Trends and Policies Driving Transportation Electrification - NC Clean Energy Technology Center (ncsu.edu) ("'Most of the states in the Southeast are home to either vehicle assembly plants or automotive supply chain manufacturers,' said Heather Brutz, . . . Finance & Operations Manager for NCCETC's Clean Transportation program. Additionally, several Southeast states like Tennessee, Georgia and South Carolina had a higher prevalence of manufacturing specifically related to battery electric or fuel cell vehicles.").

160 *See supra* section II.B.2.

161 *See Southern Company Releases Plan on Net Zero Carbon Emissions Goal*, Southern Company (Sept. 21, 2020), Southern Company releases plan on net zero carbon emissions goal (discussing Southern Company's goal of achieving net zero greenhouse gas emissions by 2050).

162 *See supra* section II.B.4.

163 *See 24/7 Carbon-Free Energy by 2030*, Google Data Centers, 24/7 Clean Energy – Data Centers – Google (last visited Aug. 7, 2022).

164 NOPR at P 109.

planning processes. They do not currently engage in the regional planning processes to any meaningful degree. Accordingly, the Commission should not only permit but encourage their participation in shaping and conducting LTRTP. And states should take the initiative to actively participate at this stage of the process to create better continuity between the planning and approval processes. LTRTP would better enable this synergy compared to the current framework.

Second, the Commission must establish the baseline format by which public utilities must conduct LTRTP to ensure they will actually engage in transparent and proactive transmission planning. Otherwise, they will seize on any opportunity to avoid additional process. SERTP sponsors have summarily rejected stakeholder requests to study transmission needs driven by Public Policy Requirements, yet they can arguably claim compliance with the Commission's loose standard for "consideration" under the current planning regime. Similarly, the utilities conduct a half-hearted consideration of regional alternatives, which corresponds with the narrow cost-benefit analysis contained in their tariffs and approved by the Commission. Accordingly, Southeast Public Interest Groups support the NOPR's proposal to require utilities to develop a minimum of four distinct Long-Term Scenarios.[165]

The Southeast Public Interest Groups further urge the Commission to require utilities to affirmatively incorporate all of the factors listed above into the Long-Term Scenarios, rather than merely "consider" them. While flexibility in distinguishing between the four Long-Term Scenarios is warranted, the baseline requirement that utilities develop four plausible, diverse, and comprehensive scenarios should prevent LTRTP from devolving into a box-checking exercise on par with the current Public Policy Requirements studies. Likewise, the requirement that one of the Long-Term Scenarios account for a high-impact, low-frequency event ensures that reliability

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165 *See id*. P 121.

remains critical to the planning process.[166] Crucially, the Commission must ensure that stakeholders have the opportunity to provide timely and meaningful input into the Long-Term Scenarios' development.[167] Stakeholder participation has suffered in SERTP due to the minimal opportunities for input and a general lack of transparency. A clear opportunity for stakeholders to actively engage from the beginning of the Long-Term Scenarios' development—as opposed to commenting on a fully-baked transmission expansion plan—would address many of these issues.

Third, Southeast Public Interest Groups support the NOPR's proposal to set the minimum LTRTP planning horizon at 20 years.[168] SERTP's current ten-year planning horizon has contributed to utilities' reticence to utilize the process to account for longer-term projects, such as the North Georgia Reliability & Resilience Plan in Georgia[169] and certain greenfield transmission investment likely to be included in the NCUC's ultimate Carbon Plan.[170] A 20-year planning horizon would better account for long-term transmission needs that are nevertheless relatively certain.

Fourth, Southeast Public Interest Groups support the NOPR's proposal to require "best available data inputs" in developing the Long-Term Scenarios.[171] Southeast Public Interest Groups ask the Commission to specify and regularly update sources that meet this standard to ensure that public utilities select their inputs from a respected, nonbiased data source. Whichever data inputs public utility transmission providers ultimately use, it is crucial that they do so transparently and that such inputs be available to stakeholders. Information asymmetries have devalued stakeholder

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166 *See id*. P 122

167 *See id*.

168 *See id*. PP 97-98.

169 *See supra* section II.B.1.

170 *See supra* section II.B.2.

171 NOPR at P 130.

participation in SERTP, as the SERTP sponsors do not share all relevant information utilized in the planning process, such as the estimated costs of proposed transmission facilities. Stakeholders must have access to all relevant information in order to meaningfully participate. Further, the same data inputs must be utilized across the entire planning region. The Southeast is comprised of multiple balancing authority areas, each of which operates independently of the others. Uniformity of planning data inputs would help to bridge existing informational gaps that contribute to the balkanized planning processes.

Finally, although the NOPR proposes not to change the current reliability and economic planning processes,[172] Southeast Public Interest Groups recommend that LTRTP encompass these planning priorities as well. Currently, SERTP focuses entirely on reliability planning, while treating economic planning and Public Policy Requirements as afterthoughts. Even if the Commission mandates a fairly comprehensive LTRTP process, the SERTP sponsors will continue to prioritize reliability planning, likely at LTRTP's expense. However, multi-value planning that does not silo these three overlapping aspects would allow them to complement each other. The factors that necessitate LTRTP—changing resource mix, demand, and weather—substantially affect system reliability and economics as well. A comprehensive planning process should reflect all of these values to avoid marginalizing any one of them.[173]

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[172] *Id.* P 3.

[173] *See Duke Energy Progress, LLC and Duke Energy Carolinas, LLC*, Docket No. E-100, Sub 179, North Carolina Sustainable Energy Association et al., Joint Comments, Ex. 2, Report of Jay Caspary, at 4-8 (N.C. Utils. Comm'n July 15, 2022) ("Reliability and economics are inseparable when it comes to the value proposition of prudent transmission expansion planning. Today's transmission expansion project to address a reliability need, based on existing reliability standards, provides economic benefits to support grid operations. Conversely, economic upgrades in the near term will also provide reliability benefits that are difficult to quantify since operating conditions rarely mirror planned scenarios. The benefits associated with the flexibility and optionality provided by a strong electric transmission network are significant and will not be realized if incremental least cost planning is performed with limited planning horizons, particularly if those do not align with corporate, institutional, state and municipal commitments to decarbonize their electric power supply resources by a date certain, as is the case following enactment of HB 951.").

LTRTP is not the silver bullet that will solve the region's increasing transmission needs or the utilities' aversion to collaboratively planning for them. Nor will it dictate which transmission facilities will ultimately be built. But LTRTP would build upon Order Nos. 890 and 1000's focus on process to ensure that public utility transmission providers engage in comprehensive and proactive transmission planning, while closing the loopholes that have allowed them to escape this responsibility to this point. Ideally, LTRTP will present a menu of well-considered potential transmission facilities that address the region's rapidly changing needs in the most efficient and cost-effective manner possible. Once these alternatives see the light of day, it will be incumbent upon the utilities to choose the options that best serve their customers' needs and defend those choices before the regulators that will ultimately approve them.

2. Benefits/Selection Criteria

Ultimately, stakeholders, state regulators, and ratepayers cannot meaningfully scrutinize the utility's decisions if the alternative transmission facilities' benefits are not quantified, presented, and evaluated in a manner that reflects their true value. If the assessment of regional alternatives amounts to a cost comparison between a small local facility and a multi-state transmission line, the utilities will choose the local facilities every time. Worse, when presented in this manner, the choice will always appear reasonable. True transparency in transmission planning requires that alternatives be presented accurately, with costs and benefits accurately calculated. Conducting a true cost-benefit analysis—which SERTP, SCRTP, and FRCC purport to do—requires a complete consideration of benefits: "Quantifying a broader range of transmission benefits . . . will yield a more accurate benefit-cost analysis, provide more insightful comparisons, and would avoid rejected beneficial investments that would reduce system-wide costs."[174]

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[174] Brattle Report at 32.

Southeastern utilities *could* do this under the Commission's planning policies, but they chose not to when establishing their current processes, and the Commission validated that choice. The Commission afforded utilities flexibility in establishing and assessing benefits in Order No. 1000, and utilities in the Southeast exploited that flexibility to implement a straight cost comparison. If the Commission takes that path again and allows utilities to flexibly assess transmission benefits, they will select benefits that amount to avoided transmission costs, all under the guise of regional variation. This time, to ensure regional facilities are accurately represented in the planning processes, the Commission must establish a minimum set of benefits for the utilities to incorporate in their assessment of regional transmission facilities.

Southeast Public Interest Groups urge the Commission to prescribe a set of benefits for use in the utilities' cost-benefit analyses, starting with the entire list of benefits the NOPR offered as optional:

> (1) avoided or deferred reliability transmission projects and aging infrastructure replacement; (2) either reduced loss of load probability or reduced planning reserve margin; (3) production cost savings; (4) reduced transmission energy losses; (5) reduced congestion due to transmission outages; (6) mitigation of extreme events and system contingencies; (7) mitigation of weather and load uncertainty; (8) capacity cost benefits from reduced peak energy losses; (9) deferred generation capacity investments; (10) access to lower-cost generation; (11) increased competition; and (12) increased market liquidity.[175]

Proposed benefits 1 and 4 are factored into SERTP, SCRTP, and FRCC's cost-benefit analyses to some degree today, but the remainder are not considered in any appreciable form. The reliability benefits captured by proposed benefits 2, 6, and 7 are particularly relevant to the region. The geographical area covered by SERTP is immense, which provides significant load diversity due to

175 NOPR at P 185.

the regional differences in weather and climate across so large an expanse: "Climate diversity benefits . . . are particularly pronounced in . . . the Southeast" because it "contain[s] both winter-peaking and summer-peaking power systems."[176] Yet the ability of regional transmission facilities to better connect the various systems and capitalize on these benefits is not currently captured by SERTP's processes and therefore not reflected in the cost-benefit analysis.

Granted, some of these benefits may not apply in the same manner to RTO/ISO regions as they do to the Southeast, whose utilities are neither in an RTO/ISO nor an organized energy market, but that should not allow Southeastern utilities to evade quantifying these benefits in some form. For example, the NOPR notes that RTO/ISO regions typically quantify production cost savings using security-constrained production cost models that simulate electric system operation and the wholesale electricity market.[177] Because the Southeastern utilities do not participate in RTO/ISO markets, they do not regularly calculate security-constrained production costs or locational marginal prices.[178] However, just like utilities in RTO/ISO regions, Southeastern utilities would realize "savings in fuel and other variable operating costs of power generation"[179] from the expansion of regional transmission facilities. They have the means and the system knowledge to quantify those savings and must be made to do so. Indeed, the NOPR acknowledges that non-RTO/ISO regions often utilize alternative methods of quantifying production costs.[180] It highlights WestConnect's process of "modeling the potential of the transmission facilities to support more

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176 Brattle Report at 40-41.

177 *See* NOPR at P 199.

178 To the extent wholesale market-related metrics are required to quantify some of the proposed benefits, such as increased competition or increased market liquidity, the Southeast could have a quasi-organized wholesale market in SEEM, pending the outcome of ongoing litigation. *See supra* note 21. If SEEM commences operations, the participating utilities cannot claim that they are wholly isolated from wholesale electricity markets in order to escape assessment of these market-related benefits.

179 NOPR at P 198.

180 *See id*. P 201.

economic bilateral transactions between generators and loads in the region" by "consider[ing] the transactions between loads and lower-cost generation that [] proposed regional transmission facilities could support and, accounting for the costs associated with transmission service, identif[ying] the transactions that are likely to occur."[181] As a similarly bilateral market, the Southeast could implement an analogous production cost model to capture the savings regional facilities could bring to the region. To this end, the Commission should fashion equivalent, standardized metrics for both RTO/ISO regions and non-RTO/ISO regions that ultimately capture the same concepts.

As the above descriptions of emerging transmission needs in the Southeast show, there are tremendous benefits to be realized from regional transmission facilities. For instance, Georgia Power's insistence on replacing retiring coal capacity with solar facilities in a topographically unsuitable area could be addressed by proposed benefits 9 and 10: deferred generation capacity investments and access to lower-cost generation. Couple that transmission need with the low-cost, plentiful solar in south Georgia and TVA's claimed intent to import renewable capacity, and a regional transmission facility connecting south Georgia to north Georgia and tapping into TVA's north Georgia system would provide measurable benefits. Similarly, both Georgia Power and Dominion must accommodate coal retirements with replacement generation. Georgia Power prefers solar in north Georgia while Dominion prefers gas due to transmission constraints. A regional facility that links these neighboring systems with east-west load diversity could address their respective needs much more efficiently than local solutions. But because SERTP and SCRTP operate independently and limit their cost-benefit assessments to straight cost comparisons, none of these benefits is considered. Without a firm Commission directive that a full suite of benefits

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181 *Id*.

be incorporated into the calculation, utilities will continue to focus solely on costs and in the process, deprive states and stakeholders of a full picture of the utilities' transmission options.

Ultimately, a transparent regional transmission planning process that assures state regulators and stakeholders that viable alternatives were comprehensively evaluated—and allows them to scrutinize that evaluation in an informed manner—should be the goal of this proceeding. In the Southeast, where IRP or other state regulatory processes solidify resource decisions, states and regulators need certainty that the utilities have identified the most efficient, lowest-cost alternatives for investment. A regional transmission planning process that quantifies and fully accounts for the benefits of regional alternatives would provide some measure of assurance. Contrary to the SERTP sponsors' assertions that prescriptive regional planning is incompatible with the region's bottom-up, IRP-driven process,[182] a fulsome regional transmission planning process would facilitate a better-informed state regulatory process that ensures the most cost-effective alternatives are considered. As the Commission has previously found, open and transparent regional transmission planning allows for "the identification and evaluation of transmission solutions that may be more efficient or cost-effective than those identified and evaluated in the local transmission plans of individual public utility transmission providers" and therefore "provide[s] more information and more options for consideration by public utility transmission providers and state regulators."[183] If the planning process does not accurately account for and evaluate the benefits of these options while selecting the facilities that comprise the ultimate expansion plan, it will not have the same facilitating effect.

[182] *See supra* note 143.

[183] Order No. 1000 at P 190.

Certain aspects of regional transmission planning lend themselves to regional flexibility while still advancing the Commission's broader goal of improving the process. Evaluation criteria do not fall within that category. Giving public utility transmission providers free rein to define the metrics that underlie the cost-benefit analysis—when they have built-in incentives to avoid regional transmission investment[184]—will undermine the entire process. It has already done so in the Southeast, where consideration of regional alternatives is designed to fail. To avoid this, the Commission must impose a set of minimum benefits for quantification and implementation into the cost-benefit analysis.

B. Local/Regional Coordination

Southeast Public Interest Groups support the NOPR's proposal to increase coordination between the local and regional planning processes by enhancing the transparency of the local processes and establishing an iterative process that would allow stakeholders opportunities to participate in local planning through the regional process.[185] Closer coordination between the planning processes would better ensure that the local process does not operate to nullify the effectiveness of the regional process. That has already occurred in the Southeast, where utilities invest exclusively in local transmission facilities and the local transmission plans arrive at SERTP fully baked and immune to change. True consideration of regional alternatives will require that the local and regional planning processes mesh at an earlier stage so that local facilities do not become entrenched before they appear in the regional plan.

Southeastern utilities have taken wildly divergent approaches to their local processes. North Carolina's NCTPC is wholly removed from SERTP until its local plan rolls up into the

[184] *See supra* section I.

[185] *See* NOPR at P 400.

SERTP regional plan. Southern Company utilizes SERTP for both its local and regional processes, meaning that SERTP's structural deficiencies taint both. Additionally, Southern Company's subsidiary, Georgia Power, substantially conducts its local planning through the ITS process, which does not permit non-utility stakeholder participation. Accordingly, requiring an iterative process in which stakeholders provide input into (1) the criteria, models, and assumptions used, (2) the transmission needs identified, and (3) the transmission facilities evaluated to address those local needs, will better integrate separate local processes like the NCTPC while building out the local planning aspects already inherent to SERTP. The former will be of significant use as North Carolina implements its ultimate Carbon Plan through the NCTPC, which, as discussed above, will require significant transmission investment.[186]

In any event, drawing the local and regional processes into closer coordination will ideally allow stakeholders to influence the local plans before they calcify into unchangeable components of the regional plan.

C. Cost Allocation

Southeast Public Interest Groups support the NOPR's proposal to require public utilities to seek the agreement of relevant state entities regarding a cost allocation method for the region.[187] Because SERTP has not produced a regional transmission project for cost allocation, the region has not had occasion to encounter state opposition to development. This provides a unique opportunity for states in the region to agree ahead of time on a cost allocation methodology they can support. The states' role in transmission facility approval is fiercely protected in the Southeast, where the IRP process predominantly drives generation investment. As discussed above, regional

[186] *See supra* section II.B.2.

[187] *See* NOPR at P 303.

transmission planning is eminently compatible with that process. Accordingly, state involvement in this important aspect of the process would ideally smooth the approval of any regional transmission facilities that emerge from the regional planning process if cost allocation is already established. The significant role that states play in transmission expansion suggests that their participation in developing a cost allocation methodology on the front end will avoid potentially insurmountable issues on the back end.

In terms of the mechanics of assessing state approval, Southeast Public Interest Groups propose that "state agreement" entail unanimous acceptance by the states in the region. However, if the utilities are unable to achieve unanimity, the Commission could presumptively impose the cost allocation mechanism approved by a plurality of the region's states.

D. Oversight

Although proposed in the Advanced Notice of Proposed Rulemaking, the NOPR declined to "establish an independent entity to monitor the planning and cost of transmission facilities in the region."[188] Southeast Public Interest Groups urge the Commission to revisit the concept of an independent transmission monitor, which could have significant value in the Southeast. As transmission planning processes outside of RTOs/ISOs, SERTP, SCRTP, and FRCC are overseen and conducted by the utilities that participate in the process, despite the Commission's acknowledgment that public utility transmission providers do not have an incentive to "expand the grid to accommodate new entries or to facilitate the dispatch of more efficient competitors."[189] As discussed at length above, this has led to an intentionally ineffectual process and predictably poor results. For this reason, introducing a form of independent oversight into the region's transmission

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[188] *Building for the Future Through Electric Regional Transmission Planning & Cost Allocation & Generator Interconnection*, 86 FR 40266 (July 15, 2021), 176 FERC ¶ 61,024, at P 163 (2021).

[189] Order No. 890 at P 57.

planning process would go a long way toward ensuring that the Commission's transmission planning directives are followed. There is a clear need for cost-effective regional projects in the Southeast given the widespread transmission needs in each state. Planning for and assessing options to address these needs is a mandatory process, and utilities in the region have not shown that they warrant trust in conducting the process seriously and comprehensively.

E. Planning Regions

As discussed above, while most of the public utilities in the SERC Reliability region participate in SERTP, Dominion conducts its regional transmission planning in SCRTP with Santee Cooper.[190] Given the broader benefits that regionally optimized transmission investment can bring, South Carolina ratepayers would be better served if their utilities planned transmission expansion on a truly regional basis, alongside the utilities in SERTP. SCRTP's capacity to conduct proactive regional planning that adapts to changes in the resource mix and demand is severely limited by the size of its planning region, which contains one other utility with one other set of transmission needs. This prevents Dominion from facilitating its multiple coal retirements through regular coordination with the neighboring systems of Duke and Southern Company—both of which have similar needs with similar causes—short of resorting to the cumbersome interregional process. Accordingly, Southeast Public Interest Groups urge the Commission to revise its criteria for transmission planning regions to require at least two public utility transmission providers within each region.

IV. <u>CONCLUSION</u>

The Southeast is experiencing the same seismic shifts in generation mix, demand, and weather as the rest of the country. However, by virtue of its independence from any RTO/ISO or

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190 *See supra* sections II.A.II, II.B.5.

organized wholesale energy market, it lacks an effective mechanism for regional coordination. This extends to its mandatory regional transmission planning process, which has manifestly failed to assess regional alternatives to its widespread transmission needs, thereby resulting in unjust and unreasonable rates for transmission service. Recognizing the failure of its transmission planning policies to take hold in the region, the Commission must take a firmer stand in requiring Southeast utilities to engage in a robust planning process with substantial minimum responsibilities. Otherwise, they will continue to plan their own systems, ignoring efficiencies and overbuilding local transmission whose excessive costs will burden their customers. This insular investment will only further entrench itself as the generation and demand changes accelerate, ensuring that the burden to ratepayers will grow insurmountable. Accordingly, Southeast Public Interest Groups respectfully request that the Commission craft a final rule that addresses the concerns raised in these comments and adopts the suggested reforms.

Respectfully submitted,

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August 17, 2022

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Attachment 2

Anila Yoganathan
How a Perfect Storm of Freezing Cold and Aging Power Plants Led to Rolling Blackouts
Knoxville News Sentinel
Jan. 25, 2023

knox news.

TENNESSEE

How a perfect storm of freezing cold and aging power plants led to rolling blackouts

TVA has sold itself on its reliability, but finds itself scrambling to restore confidence in its ability to keep the lights on

Anila Yoganathan
Knoxville News Sentinel

Published 8:16 a.m. ET Jan. 19, 2023 | **Updated 12:18 p.m. ET Jan. 25, 2023**

Key Points

TVA experienced its highest single-day demand for power on Dec. 23, but even that amount would normally have fallen well within the utility's capability.

Additionally, over two days, TVA underestimated the amount of electricity that would be needed.

A major power plant couldn't operate because of mechanical problems, reducing TVA's ability to produce enough power.

TVA asked the 153 local power companies it serves to reduce their energy demand.

TVA pledged to get to the bottom of what caused the problems.

The Tennessee Valley Authority thought it was prepared for the single-digit temperatures and wind from the fierce winter storm that descended days before Christmas.

But not a few hours into Dec. 23, errors had already set off a series of miscalculations and failures that led to the first-ever rolling blackouts across the Southeast, leaving 10 million residents frustrated, cold and questioning the reliability of the federal utility.

How did the agency responsible for keeping the lights on in its seven-state region miscalculate the demand for energy and its ability to keep power humming during a major storm?

In the weeks since TVA administrators had to rely on rolling blackouts to reduce energy demand, two major setbacks have come to light:

- Starting at midnight Dec. 23 and throughout most of the next 48 hours, TVA underestimated the amount of electricity it needed to provide to residents across the region, according to the Energy Information Administration.
- A significant number of the power plants TVA planned to fire up proved to be unreliable during the cold weather.

In the wake of the storm: TVA creates independent panel to review rolling blackouts before Christmas

Under normal circumstances, the utility can generate more than 32,000 megawatts of energy. In addition to the 32,000, TVA can purchase 6,000 more megawatts from neighboring electric grids. A megawatt is enough to power about 585 homes, TVA spokesperson Scott Brooks said.

So it shouldn't be that heavy a lift to provide up to 33,425 megawatts, the amount that was needed on a freezing cold Dec. 23, even though that marked the highest ever single-day demand TVA had experienced. Going into that stretch of extreme cold weather, TVA knew it would have to draw on all of its resources, and planned to run all of its power plants.

Then, in the early hours of Dec. 23, TVA experienced a major setback. Its largest power plant, the coal-fired Cumberland Fossil Plant, on which it relies consistently, shut down after being damaged by the cold.

Events went downhill from there.

Unable to keep some of its backup natural gas plants or its only big gas plant in East Tennessee running consistently, TVA struggled to keep the lights on. The only category of power plants that did its job uninterrupted was nuclear plants.

Customers and elected officials were furious about the rolling blackouts. They're demanding answers:

- Why wasn't the utility prepared for every possibility with the weather?
- Why is the grid so reliant on fossil fuel power plants?
- Why did those plants fail when they were needed most?
- Can TVA customers expect to see rolling blackouts again?

All this happened in the wake of TVA's decision - confirmed on Jan. 10 - to replace the Cumberland Fossil Plant with a natural gas combined cycle plant, raising questions about whether that's the right option for the future of the power grid.

TVA administrators said they are investigating the infrastructure failure that occurred amid the bitter cold leading up to Christmas. Here's how events unfolded that left Tennesseans in the dark.

Midnight-6 a.m. Dec. 23: Cumberland plant shuts down just as extreme cold moves in

Starting at midnight EST, TVA underestimates the amount of electricity it needs to generate by 655 megawatt hours, according to the Energy Information Administration. This trend will continue throughout most of the frigid weather over the next two days. A megawatt is an output of energy while a megawatt hour is the amount of energy used in an hour.

The temperature at the Knoxville airport measures 46 degrees just after midnight, the warmest it will be for the next 48 hours. In Nashville, the temperature at the airport drops to 10 degrees by 12:30 a.m.

One of the two units at TVA's coal-fired Cumberland Fossil Plant goes offline at 2:57 a.m. because "critical instrumentation" at the top of the boiler has frozen due to the cold temperatures and high winds, according to TVA.

> Cumberland generates a lot of electricity for the Tennessee Valley at a maximum capacity of 2,470 megawatts, and TVA likes to run that plant as often as possible. To lose even one of its boilers during a major winter storm means electricity generation is going to be more challenging for the grid.

The temperature drops to 21 degrees at the Knoxville airport by 3 a.m. At the same time, coal generates its largest amount of electricity for the day at 4,482 megawatt hours.

By 4 a.m., the temperature at the Nashville airport is down to just 5 degrees. TVA's trend of underestimating how much electricity is needed continues, now off by 1,099 megawatts hours, the same amount of energy that could be produced by one of its bigger natural gas plants.

The second unit at the Cumberland plant goes offline at 4:55 a.m., effectively shutting down the plant at a crucial time. During the winter, TVA typically sees a peak in power demand in the morning as people wake up, turn up their heat and start using appliances.

On top of that, TVA is unable to start its coal-fired Bull Run Fossil Plant in Anderson County in East Tennessee. Unlike most of its other coal plants, TVA does not run Bull Run 24/7. Instead, the plant is intended to run during peak seasons - summer and winter - but the plant is old and often unreliable, according to a 2022 report by the TVA Office of Inspector General.

> The TVA inspector general's report revealed TVA has been more reliant on Bull Run than it initially planned to be. Bull Run is one of TVA's oldest coal plants and its lack of upgrades and maintenance has caused the plant to deteriorate, be unreliable and pose safety concerns to workers, according to the report. Bull Run is set to retire in December 2023.

TVA's coal plant generation drops by 1,044 megawatt hours between 5 and 6 a.m., according to the Energy Information Administration.

6 a.m. Dec. 23: TVA struggles to meet full capacity with natural gas plants

As many people are waking up, the temperature is 10 degrees at the Knoxville airport by 6:05 a.m., and it's only getting colder.

From 6 a.m. until 5 p.m., natural gas is generating electricity for TVA, but its output fluctuates between about 8,550 and a little over 9,600 megawatt hours.

Adding to its growing list of problems, TVA can't get one of its big power-generating natural gas plants, the John Sevier Combined Cycle Gas plant in East Tennessee, to run properly. In the next week, TVA will say it is investigating the causes but is unsure which days John Sevier was struggling.

> As with some of TVA's coal plants, TVA likes to run its combined cycle gas plants continuously because they can generate a lot of electricity at once and can serve TVA's 24/7 need for energy. John Sevier is the only combined cycle gas plant located in East Tennessee and has a maximum capacity of 871 megawatts.

The big plants aren't the only facilities giving TVA trouble. At least some of the smaller backup natural gas plants won't stay on consistently during the winter storm. In the next week TVA will say it is investigating the causes of this as well.

These smaller plants can be switched on and off relatively quickly so TVA does not run these plants all day, every day of the year. TVA primarily uses them during high demand for electricity like during cold or hot seasons - such as, say, the coldest days of the year. During winter months, TVA sees a peak in demand in the morning. Having 10 million people crank up their heat in the morning causes a strain on the grid, so turning on some of these smaller gas plants can help reduce that strain … if they work.

9-10 a.m. Dec. 23: The sun comes up and so does solar power

By 9 a.m., it's about 6 degrees at the Knoxville airport and below 0 degrees in Nashville. With the sun up, solar begins adding 75 megawatt hours of energy to the grid by then.

Earlier in the morning, solar power was providing a negative amount of energy to the grid because the sun was not shining. TVA's solar portfolio is limited to 1,600 megawatts. Solar's ability to generate electricity changes based on time of day and weather.

For most of December, TVA's solar does not generate more that 1,000 megawatts at any given time, according to the Energy Information Administration. Additional solar panels could generate more megawatts for the grid but solar requires a lot of land and planning ahead. TVA plans to have 10,000 megawatts of solar on its grid by 2035.

Battery storage takes energy generated from solar panels on the grid and stores it for later use, like when the sun isn't shining. The current technology for batteries, however, can store the energy for only up to four hours. More solar panels paired with storage could contribute more megawatts to the grid but TVA will need to build more of those sites first. TVA's first battery storage site is set to be in Loudon County, in East Tennessee, and will hold up to 40 megawatt hours of energy. The facility was supposed to be operational in 2022 but has not yet come online.

TVA underestimates the demand for electricity by 1,911 megawatt hours at 10 a.m.

10:30 a.m.-6 p.m. Dec. 23: TVA requests rolling blackouts for the first time ever

TVA asks 153 local power companies to reduce their energy demand by 5% immediately at 10:31 a.m. EST, according to the Knoxville Utilities Board and TVA. This request starts the process of rolling blackouts across the region.
The temperature is 8 degrees at Knoxville airport at 12:04 p.m., as people's heat and lights go off and back on while blackouts roll through. Less than 30 minutes later, TVA sends a message on social media asking residents to reduce their electric use.

TVA tells local power companies at 12:42 p.m. that they can turn everyone's lights back on at 12:43 p.m. EST, according to KUB, bringing an end to the blackouts for this day. After TVA's calls for rolling blackouts, the utility's estimated demand for electricity is much closer to the actual demand at 4 p.m., underestimated by only 35 megawatts.
Solar generates its largest amount of energy for the day at 458 megawatt hours, while hydro generates its smallest amount at 2,083 megawatt hours.

TVA sends another round of messages on social media asking residents to reduce their electricity use at 5:10 p.m.

The temperature at the Nashville airport drops to 5 degrees at 5:53 p.m. CST , and it's going to stay that way for most of the night. Solar generates its last amount of energy for the day with 31 megawatt hours at 6 p.m. EST / 5 p.m. CST.

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7 p.m.-midnight Dec. 23: TVA back on track through the night

The temperature is down to 5 degrees at the Knoxville airport around 7 p.m., and TVA is back to underestimating the demand by more than 2,000 megawatts.
Meanwhile, hydro generates its largest amount of energy for the day at 5,673

megawatt hours. TVA uses its single pumped hydro facility on Raccoon Mountain during the extreme cold weather. TVA later says it will investigate whether Raccoon Mountain ran on both the 23rd or the 24th, or just one day. Raccoon Mountain works like a battery; water is pumped to the top of a mountain, and when TVA needs additional energy added to the grid, it releases the water, which turns a turbine, generating additional energy.

Natural gas generates its largest amount of energy for the day at 11,216 megawatt hours at 8 p.m. EST.
All of TVA's nuclear plants have been running at full power around the clock on Dec. 23.
Initial numbers show TVA received about 1,500 megawatts of relief from participants of its "demand response" programs, according to TVA. Demand response asks participants such as corporations or industry to use electricity only during nonpeak hours to reduce additional demand and stress on the electric grid. For example, industries could conduct operations at night when most residents are asleep and not using additional electricity.
TVA purchases on average 5,433 megawatts of energy per hour from other utilities and market operators on both the 23rd and 24th. Because neighboring grids - including Duke Energy - also are experiencing high demand during the winter storm those days and have to institute their own blackouts, TVA is unable to purchase as much as the 6,000 megawatts it normally would be able to, especially on Dec. 24.

1-6 a.m. Dec. 24: Early hours play like a rerun of the day before

TVA continues to have issues with Cumberland and is unable to start the Bull Run plant.
TVA continues to have issues with different natural gas plants.
All of TVA's nuclear power plants are still running throughout the day.

The temperature is 4 degrees at the Knoxville airport at 1 a.m. EST / midnight CST and TVA underestimates the demand for electricity by almost 3,000 megawatt hours, mimicking the issues from the day before.

An hour later, TVA sees its highest peak in power demand on a weekend at 31,756 megawatts at 2 a.m.
Natural gas is generating 11,462 megawatt hours at 6 a.m.

5-7 a.m. Dec. 24: TVA asks local utilities for more rolling blackouts

TVA underestimates the demand for electricity by about 2,400 megawatt hours just as people are waking up at 5 a.m.
Less than an hour later, TVA requests KUB reduce electricity demand by 5% again by 5:51 a.m., according to KUB. Within the same hour TVA asks the local utility to reduce electricity by 10% by 6:12 a.m.

As the blackouts continue and electricity demand consequently falls, TVA's underestimation of electricity is now only off by 309 megawatt hours at 7 a.m.
Hydro and natural gas generate their largest amount of electricity for the day at 5,345 and 11,541 megawatt hours respectively.

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8 a.m. Dec. 24-2 a.m. Dec. 25: Blackouts bring TVA's electricity demand projections more in line with reality

TVA estimates demand will be at 31,261 megawatt hours, and the actual demand is 29,819 at 8 a.m. For the first time since Dec. 22, TVA is overestimating the demand for electricity. This continues until 1 p.m.
Solar starts adding around 96 megawatts hours of energy to the grid by 9 a.m.
The continued rolling blackouts in Tennessee draw national attention when Nashville Mayor John Cooper cites them in a 9:46 a.m. CST announcement on Twitter that he has asked the Tennessee Titans to postpone kickoff against the Houston Texans from noon until 1:02 p.m. CST.

TVA notifies KUB it can restore electricity to residents at 11:30 a.m.

The temperature has risen to 16 degrees at the Knoxville airport by 1 p.m. TVA begins underestimating demand again by 70 megawatt hours.
By 2 p.m. it's 25 degrees in Nashville, and that's the warmest it's going to be there for the entirety of the winter storm.
At 4 p.m. solar generates its largest amount of electricity for the day at 498 megawatt hours, while natural gas generates its lowest amount of electricity for the day at 8,691.
Coal generates its lowest amount of electricity for the day at 1,436 megawatt hours at 5 p.m. An hour later, solar and hydro generate their lowest amount of electricity for the day at 38 and 1,659 megawatt hours respectively.
TVA overestimates the demand for electricity by 448 megawatt hours at 2 a.m. Dec. 25. This is the first time TVA has overestimated demand since 1 p.m. Dec. 24.

Changes in the Tennessee Valley region are affecting the power grid

Before it began ordering the rolling blackouts on Dec. 23, TVA went through an established 50-step process intended to protect the power grid. The days before Christmas marked the first time the utility had ever reached step 50. The federal utility's main objective is providing reliable electricity, a fact its leaders have touted to explain their actions and decision-making, but on Dec. 23 and 24 they struggled to do so.

"We have invested hundreds of millions of dollars in hardening this system and preparing it for events like this," TVA CEO Jeff Lyash said in a call with elected officials on Dec. 24. "And so when we experience equipment issues, like we did in this case with some of our generators, stations that although we thought we had prepared them for low, long-duration temperatures, in some cases, the preparation wasn't effective. And so we clearly need to do more."

TVA is still reviewing the problems that led to the events before Christmas. It might seem like an isolated incident, but December's chain of events warns of the potential for worsening electricity reliability in the future.

Growing population equals growing demand: The demand for electricity in the Tennessee Valley is only increasing, whether from growing population or more industries moving to Tennessee, not to mention the push to electrify the economy to reduce carbon emissions. This demand was continuously underestimated throughout the winter storm.

Replacing aging coal-fired plants: TVA also was reliant on one of its coal plants as a large generator of electricity during the storm. But its coal plants are old, and as they get older they become more unreliable. While TVA can update and maintain the plants, at some point keeping them running becomes more expensive than it's worth, which is why TVA is retiring all of its coal plants. What replaces those plants will be the key to deciding how reliable and clean the power grid will be, a debate TVA has been having with environmental groups since it began retiring coal plants.

Increasingly extreme weather: Climate change impacts are becoming more prevalent, as evidenced by the December storm, with more extreme increases and dips in temperatures. This means TVA will need to learn from its mistakes from this winter quickly, before it faces its next seasonal peak in summer when its customers will need their air conditioning during the increasingly extreme Southern heat.

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Commercial Appeal reporter Samuel Hardiman contributed to this report.

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Attachment 3

Michael Goggin & Zachary Zimmerman
The Value of Transmission During Winter Storm Elliott
Grid Strategies LLC
Feb. 2023

THE VALUE OF TRANSMISSION DURING WINTER STORM ELLIOTT

FEBRUARY 2023

ACORE
AMERICAN COUNCIL ON RENEWABLE ENERGY

FOR THE AMERICAN COUNCIL ON RENEWABLE ENERGY

GridStrategies

MICHAEL GOGGIN AND ZACHARY ZIMMERMAN
GRID STRATEGIES LLC

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As families gathered for the holidays at the end of last year, in many regions they were joined by an unwelcome guest: bitter cold. From December 22-26, 2022, Winter Storm Elliott brought near-record low temperatures and wind chills across much of the Central and Eastern U.S. In the power sector, record winter electricity demand coincided with the large-scale loss of fossil power plants due to equipment failures and interruptions to natural gas supplies. Parts of the Southeast experienced rolling blackouts as electricity demand exceeded supply, while power prices spiked in many regions.

Additional transmission capacity would have protected consumers from those blackouts and price spikes by bringing in power from other regions. The large differences in power prices across regions as Winter Storm Elliott moved west-to-east across the country, plus the economic cost of outages in parts of the Southeast, indicate the value a stronger power grid could have provided during the event. This report finds that in some areas modest investments in interregional transmission capacity would have yielded nearly $100 million in benefits during the 5-day event, while most areas could have saved tens of millions of dollars. The following map summarizes the benefits a hypothetical one gigawatt (GW) expansion of interregional transmission capacity could have provided in different areas.

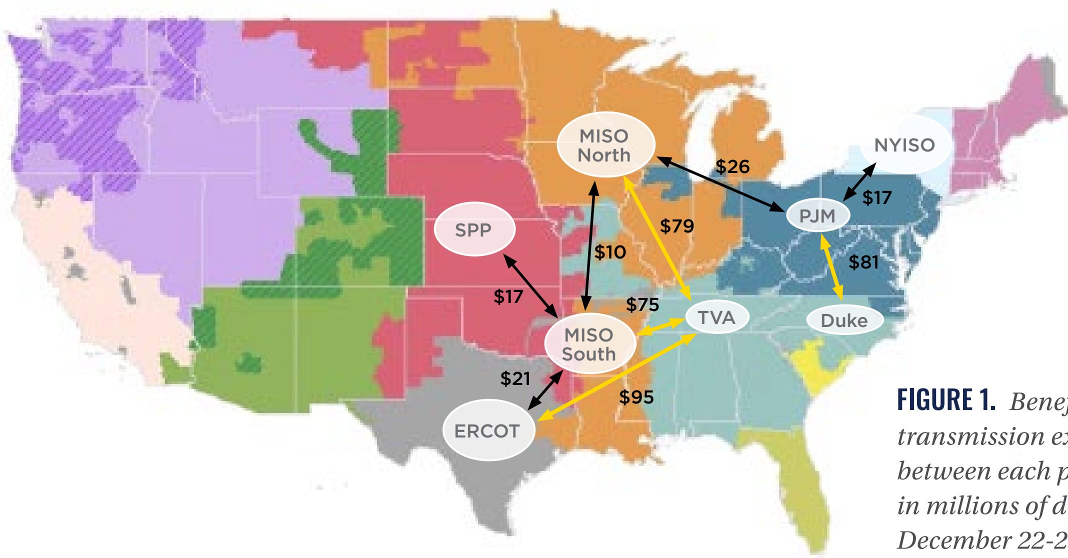

FIGURE 1. *Benefit of 1 GW transmission expansion between each pair of regions, in millions of dollars, December 22-26, 2022*

Additional transmission into the Duke/Progress utility area in the Carolinas and the Tennessee Valley Authority (TVA) would have provided the largest benefit by alleviating customers' rolling outages. The value of additional transmission into these regions was calculated by using power prices at TVA's interface with MISO as well as Duke's interface with PJM during hours without outages, and an assumed Value of Lost Load of $9,000/MWh during time periods with outages.[1] For all other regions in our analysis the value of transmission was calculated based entirely on the difference in hourly power prices, as these regions did not experience rolling outages.

1 https://pubs.naruc.org/pub/2AF1F2F3-155D-0A36-3107-99FCBC9A701C, at 3, footnote 7.

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As shown in Figure 2 below, a one GW transmission line between the Electric Reliability Council of Texas (ERCOT) and TVA would have provided nearly $95 million in value, mostly to TVA customers. That adds to the nearly $1 billion in value that line, flowing in the other direction, would have provided Texans suffering through outages during Winter Storm Uri in February 2021.[2] Similarly, one GW of additional transmission capacity from PJM into the Duke/Progress operating areas in the Carolinas could have provided those customers with electricity valued at over $80 million by helping to keep the lights on, when combined with the expansion of PJM's ties to MISO and NYISO shown in Figure 1 above..

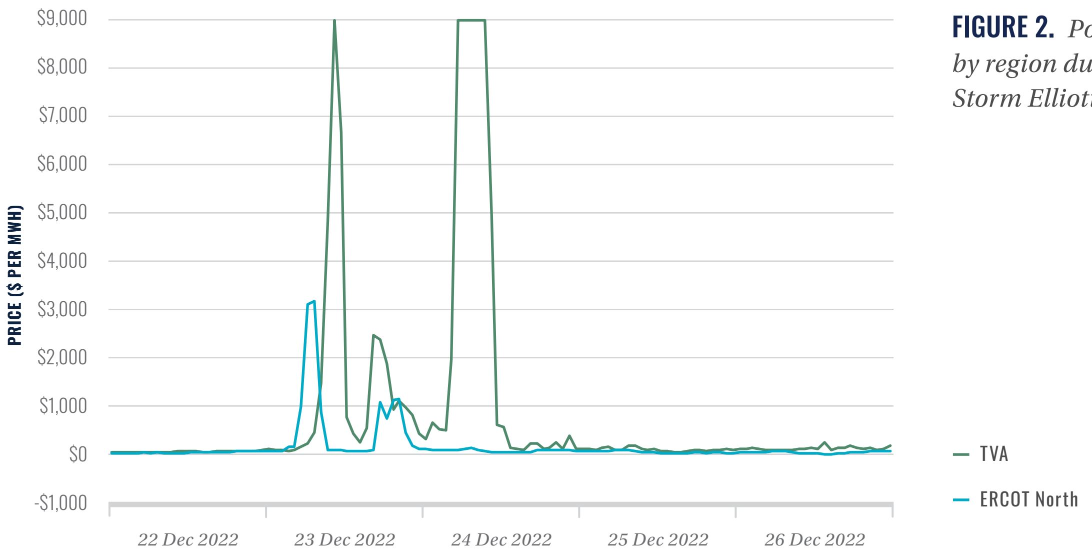
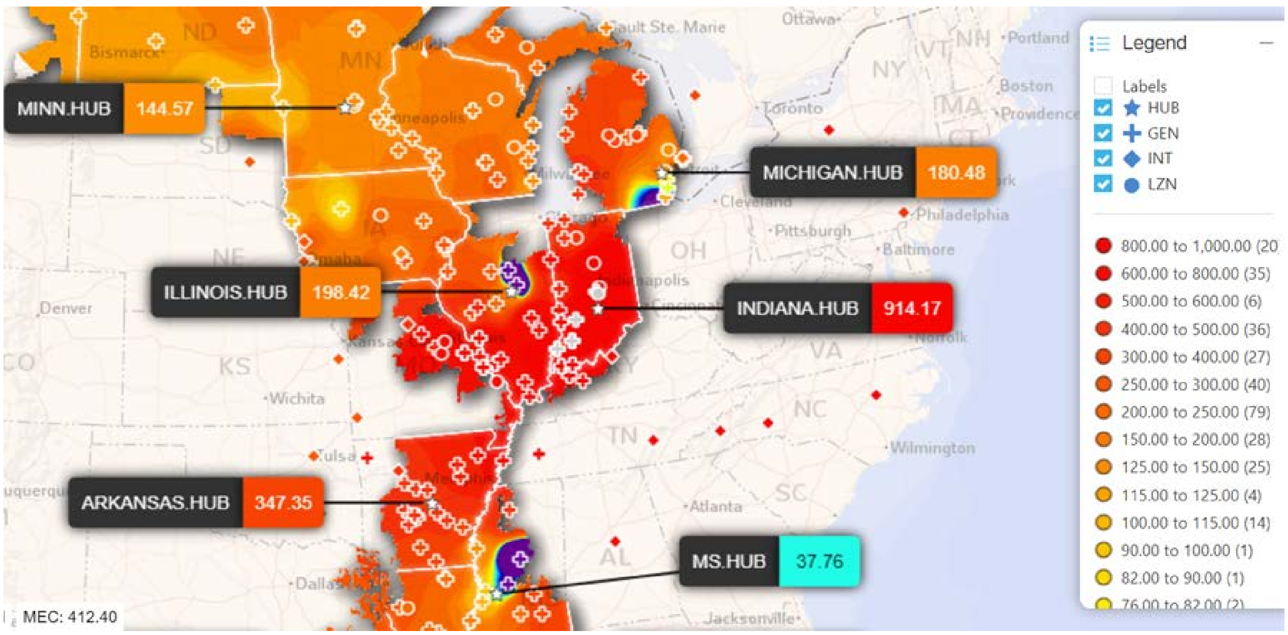


FIGURE 2. *Power prices by region during Winter Storm Elliott*

2 https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf

One GW lines from neighboring Louisiana or Illinois, parts of the Midcontinent Independent System Operator (MISO), into TVA could have provided around $75 million or $79 million in value, respectively. As an influx of polar air caused record low wind chills, it also drove up wind energy output across the MISO, Southwest Power Pool (SPP), ERCOT, and PJM grid operating areas, driving power prices down. Unfortunately, there was insufficient transmission to deliver that wind energy to areas that needed it. It appears that on Christmas Eve morning, wind plants in parts of western MISO were forced to curtail their output while the lights went out in neighboring TVA. At several points in time that morning power prices were slightly negative in western MISO, likely reflecting the curtailment of wind energy. The large west-to-east gradient in Locational Marginal Prices (LMPs) within MISO at one point on the morning of December 24 is shown below.

FIGURE 3. *MISO LMPs on December 24, 2022 at 8:00 am, Eastern Time*



Additional transmission within MISO and SPP would have enabled additional low-cost wind energy to reach customers who needed it, saving nearly $9 million within MISO and $6 million within SPP, and could have helped to alleviate outages in TVA. Congestion and seams issues between MISO and PJM, and between MISO and the Southeast, appear to have caused the localized pockets of negative prices seen in Mississippi, Illinois, and Michigan in the map above.

As shown in Figure 4 below, power prices across parts of MISO North were very low or even slightly negative the morning of December 24, reflecting seams congestion and possibly the curtailment of wind energy.

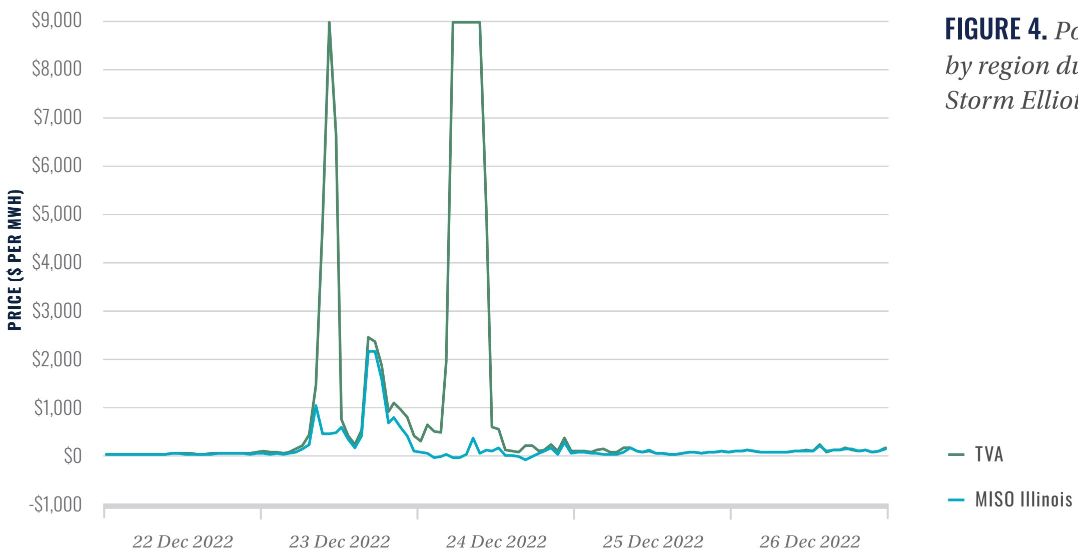


FIGURE 4. *Power prices by region during Winter Storm Elliott*

Over December 22-26, each GW of additional transmission capacity across the MISO-PJM seam in Illinois, between MISO's Illinois hub and the Commonwealth Edison zone in PJM, would have provided around $27 million in economic value. Both regions would have benefited significantly, reflecting that over the course of the event prices and power flows reversed as the extreme cold moved from west to east across the country. As shown below, power prices spiked in MISO on the morning of December 23, while it was not until that evening and the next morning that the extreme cold reached much of PJM.

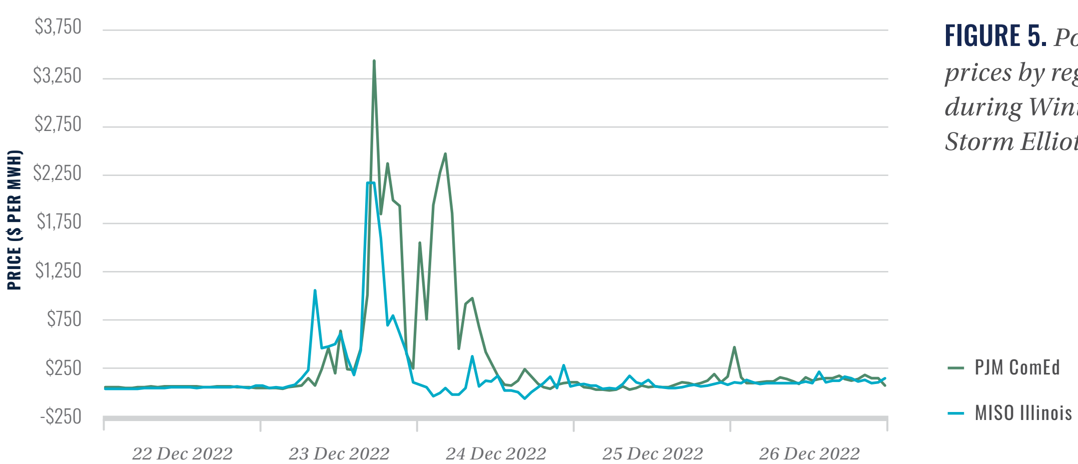
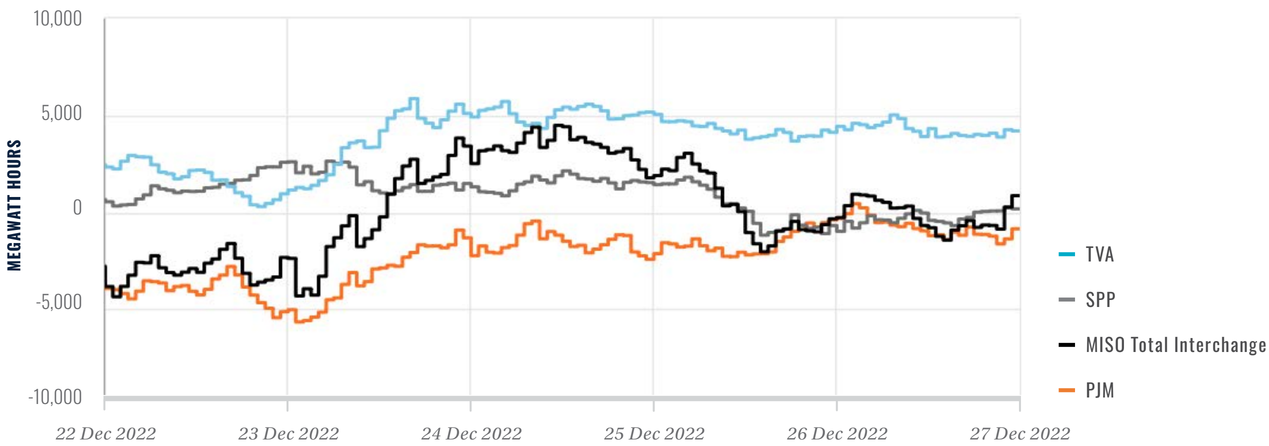


FIGURE 5. *Power prices by region during Winter Storm Elliott*

MISO swung from initially importing nearly 4,500 MW as it and SPP dealt with the worst of the extreme cold, to exporting nearly 4,500 MW later in the event after the extreme cold moved farther east, as shown below. Bidirectional flips in power flows and prices have occurred during past events as the area of most severe weather migrates over time.[3]

FIGURE 6. *MISO electricity interchange with neighboring balancing authorities 12/22/2022–12/26/2022, Eastern Time (positive = export, negative = import)*

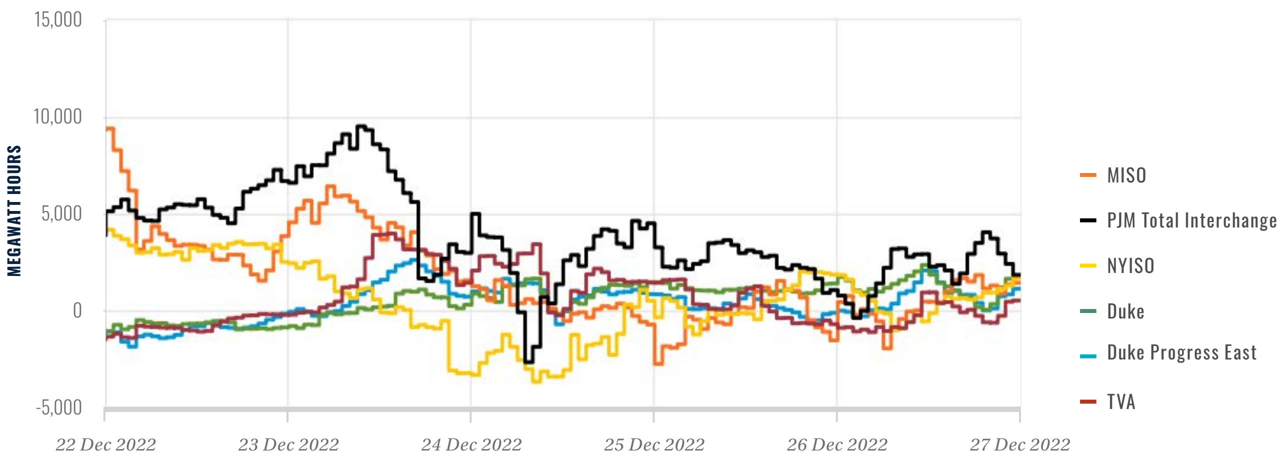


Similarly, a region that primarily exports power during one severe weather event is likely to benefit from imports during another event. While Winter Storm Elliott had the largest impact on the Southeast, Winter Storm Uri primarily affected the Central U.S. and had minimal impact on the Eastern U.S. As a result, expanded ties between Texas and the Southeast would have helped keep the heat on in Texas during Winter Storm Uri and in the Southeast during Winter Storm Elliott. Other studies have confirmed that expanded ties between ERCOT and the Southeast have large reliability value, due to diversity in weather patterns and generation resources and because the main Texas grid lacks strong transmission ties to other states.[4]

3 https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf.
4 https://www.esig.energy/wp-content/uploads/2022/07/EStvIG-Multi-Value-Transmission-Planning-report-2022a.pdf.

In less than 24 hours between December 23 and the morning of December 24, PJM also flipped from exporting nearly 10,000 MW to importing more than 2,500 MW, as shown in Figure 7. Much of that swing involved transactions with New York. While PJM power prices spiked during the evening of December 23 and the morning of December 24, prices in New York remained relatively low because the extreme cold had not yet reached the Northeast, so additional transmission capacity could have allowed additional electricity exports to PJM and other regions facing the brunt of the storm. Over the course of the 5-day event, additional transmission between PJM and NYISO would have saved nearly $17 million.

FIGURE 7. *PJM electricity interchange with neighboring balancing authorities 12/22/2022–12/26/2022, Eastern Time (positive = export, negative = import)*



One GW of additional transmission capacity within PJM, between Commonwealth Edison in Illinois and the Dominion zone in Virginia, also would have yielded nearly $27 million in savings during the event. Similarly, expanding ties between the Louisiana hub in MISO South and the Illinois hub in MISO North would have saved around $10 million, with those benefits fairly evenly split between those zones. As indicated in the chart below, this occurred because power prices peaked at alternating times between MISO South and North, reflecting the movement of the storm and the lack of strong transmission ties between those MISO subregions.

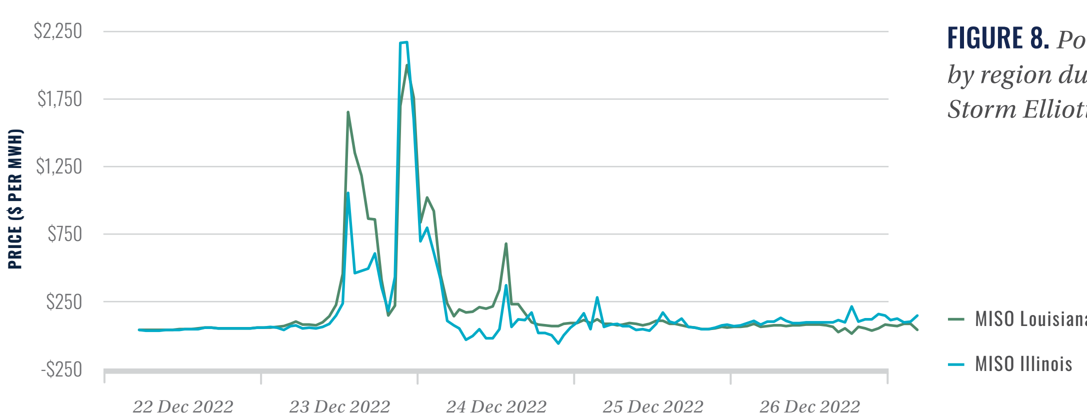


FIGURE 8. *Power prices by region during Winter Storm Elliott*

Additional transmission also would have helped to alleviate significant congestion among ERCOT, SPP, and MISO. An additional GW connection between ERCOT and the Louisiana hub in MISO South would have saved over $20 million over those five days, with the benefits nearly evenly split between ERCOT and MISO customers. As shown below, one GW of expanded transmission between SPP's South hub and the MISO Louisiana hub would have saved around $17 million.

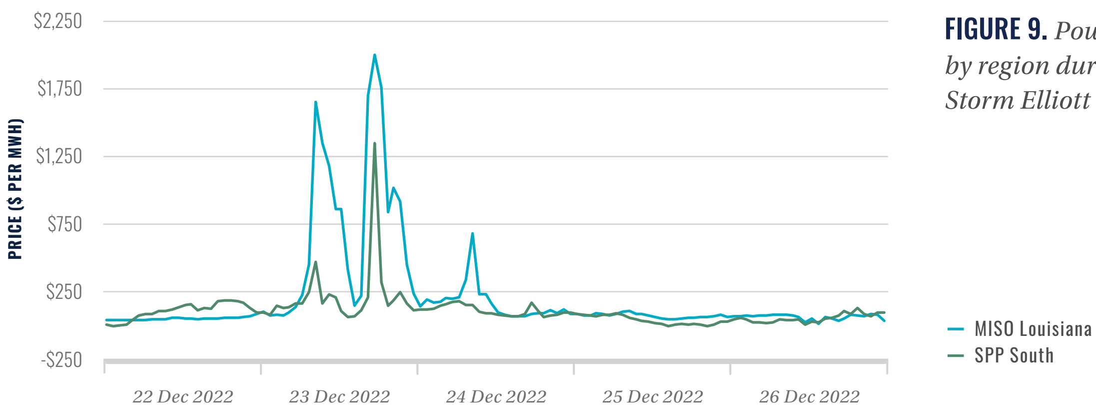


FIGURE 9. *Power prices by region during Winter Storm Elliott*

Table 1 summarizes the benefits of expanding transmission across the 12 regional and interregional interfaces discussed above.

TABLE 1. *Benefit of 1 GW transmission expansion between each pair of regions, December 22-26, 2022*

Region-to-region interface (primary exporting region listed first)	Benefit of 1 GW transmission expansion
ERCOT North-TVA	$95 million
PJM Dominion-Duke/Progress intertie	$81 million
MISO North-TVA	$79 million
MISO South-TVA	$75 million
PJM ComEd-PJM Dominion	$27 million
MISO North-PJM ComEd	$26 million
ERCOT North-MISO South	$21 million
SPP South-MISO South	$17 million
NYISO- PJM Dominion	$17 million
MISO North- MISO South	$10 million
Western MISO-MISO North	$9 million
Western SPP-SPP South	$6 million

Making the grid bigger than the weather

Transmission is becoming increasingly valuable as climate change causes more frequent and more severe extreme weather events. Changes in the generation mix are also making interregional transmission more valuable. A primary cause of the outages and price spikes during Elliott appears to have been the loss of gas generators due to a systemic failure of the natural gas system, as was also the case during Uri and other recent cold snaps, including the 2014 and 2019 Polar Vortex events, the 2018 Bomb cyclone and South Central U.S. cold snaps, and the 2011 Southwest outages. As the press reported after Elliott:

On Dec. 23, US natural gas production suffered its worst one-day decline in more than a decade, with roughly 10% of supplies wiped out because of wells freeze-offs. Output was as low as 84.2 billion cubic feet on Saturday, a 16% decline from typical levels, before a slow recovery started, according to BloombergNEF data based on pipeline schedules… Most of the output loss was seen in the Northeastern Appalachia basin, where supplies plunged to the lowest level since 2018. US natural gas futures posted gains on Tuesday as supplies remained severely constrained by freeze-offs. Supplies from Appalachia to the Tennessee Valley and the Midwest more than halved from typical levels, according to pipeline flow data compiled by BloombergNEF.[5]

Equipment failures across all types of power plants also played a significant role in electricity shortfalls during Elliott, as was the case in previous cold snaps. At one point on December 23,

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5 Gerson Freitas, Jr. et al., *America's electrical grid barely escaped a calamity as massive storm exposes a vulnerable natural-gas infrastructure*, Fortune (Dec. 27, 2022, 2:36 PM EST), https://fortune.com/2022/12/27/america-electrical-grid-barely-escaped-a-calamity-as-massive-storm-exposes-a-vulnerable-natural-gas-infrastructure/.

2022, TVA lost more than 6,000 megawatts of power generation or nearly 20% of its load at the time, including three large coal units.[6] Preliminary data for MISO,[7] PJM,[8] and SPP[9] show all fuel types were taken offline, though gas makes up the largest share of lost capacity.

Investigations are underway to determine which generators failed during Winter Storm Elliott, and why. Regardless of which energy sources failed, strengthening transmission is an essential part of the solution for preventing future outages due to all types of severe weather, including extreme heat, cold, and drought. Extreme weather events tend to be most severe in relatively small areas, so stronger transmission ties to neighboring regions can be a lifeline to keep homes warm and people safe. Transmission ties cancel out local fluctuations in the weather that affect electricity demand, primarily due to heating and cooling needs, and supply, including changes in wind and solar output as well as failures of conventional power plants due to extreme weather. A few weeks before Winter Storm Elliott, nearly all panelists at a Federal Energy Regulatory Commission (FERC) workshop endorsed expanding interregional transmission as an insurance policy against severe weather events that affect all energy sources.[10]

Most transmission planning processes do not account for severe weather events in the net benefit calculations that determine whether grid investments move forward.[11] This is despite the fact that recent analysis by Lawrence Berkeley National Laboratory indicates that half of transmission's value accrues in only 5% of hours, typically when the power system is being stressed by extreme weather.[12] Policy changes are therefore needed to account for transmission's value as an insurance policy for grid resilience, such as through a minimum interregional transfer requirement as was discussed at FERC's December 2022 workshop.

Making the grid bigger than the weather will become even more important as wind and solar provide a larger share of our electricity.[13] Just as transmission helps cancel out the localized impact of severe weather events, it also captures geographic diversity in wind and solar output across larger regions. This reduces the variability of wind and solar output and ensures a higher level of dependable output during periods of peak need. Transmission also captures complementary output profiles between wind and solar resources in different regions on a daily and seasonal basis. For example, transmission will allow the Southeast to export solar power to the Midwest during the day and during summer months, and then import wind energy from the Midwest at night and during the winter.[14]

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6 Dave Flessner, *Chattanooga area hit with 1-minute power outages as cold weather forces rolling blackouts*, Chattanooga Times Free Pres (Dec. 24, 2022, 9:42 AM), https://www.timesfreepress.com/news/2022/dec/24/power-outages-tfp/.

7 https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf.

8 https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx.

9 SPP, "December 2022 Winter Storm Elliott."

10 https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission

11 https://www.brattle.com/wp-content/uploads/2021/10/2021-10-12-Brattle-GridStrategies-Transmission-Planning-Report_v2.pdf, at 36, 82.

12 https://emp.lbl.gov/news/regional-and-interregional-transmission-have

13 https://www.ferc.gov/media/panel-3-christopher-clack-vibrant-clean-energy-llc.

14 https://cleanenergygrid.org/wp-content/uploads/2020/10/Consumer-Employment-and-Environmental-Benefits-of-Transmission-Expansion-in-the-Eastern-U.S..pdf.

Methodology

The transmission benefits in this report were primarily calculated by comparing Locational Marginal Prices (LMPs) within Regional Transmission Organizations (RTOs) and at interfaces with non-RTO areas in each hour during December 22-26, 2022.[15] The Cimarron River LMP node in western SPP and LMPs at the NSP/OTP interface in western MISO were used to represent prices in the wind-heavy western parts of those RTOs, while all other calculations were based on prices at the major RTO hubs and interfaces listed in Table 1 above. As noted above, a $9,000/MWh value was assumed for deliveries into TVA[16] and Duke/Progress[17] during their rolling outages.

The analysis conservatively used hourly average LMPs instead of prices at 5-minute intervals, as current practices for scheduling transactions between regions include market seam inefficiencies that limit the ability to use transfers to address short-term fluctuations in price. To test the impact of this assumption, the hourly results were compared against results using 5-minute prices for the SPP West-SPP South and NYISO-PJM ties, which indicated that using 5-minute prices would increase the calculated value of transmission by 5.4% in SPP and 4.1% for the NYISO-PJM tie.

This understatement of savings is about equal to the estimated overstatement of savings because this analysis did not account for increases in LMPs in exporting regions due to the 1 GW increase in demand that would be caused by the expansion of transmission ties. Our 2021 analysis found comparably modest increases in prices in exporting regions due to that effect, as the price increase on the delivering end of a line is generally much smaller than the price decrease on the receiving end because the electricity supply curve slopes much more steeply upward when demand is high.[18] Because those two factors roughly offset each other, they are not accounted for in this analysis.

15 MISO LMP and TVA interface price data obtained from https://www.misoenergy.org/markets-and-operations/real-time--market-data/market-reports/#nt=%2FMarketReportType%3AHistorical%20LMP%2FMarketReportName%3AReal-Time%20Final%20Market%20LMPs%20(csv)&t=10&p=0&s=MarketReportPublished&sd=desc; PJM LMP, NYISO interface, and Progress/Duke interface price data at the Roxboro intertie obtained at https://dataminer2.pjm.com/feed/rt_hrl_lmps; SPP LMP data from https://marketplace.spp.org/pages/rtbm-lmp-by-location#%2F2022%2F12%2FBy_Day; and ERCOT North LMPs from https://www.ercot.com/misdownload/servlets/mirDownload?doclookupId=886632075.

16 https://www.wbir.com/article/news/local/tva-artic-blast-rolling-blackouts-east-tennessee/51-9fac437b-6cce-40eb-a0ce-650be785b1de indicates the TVA outages on December 23 extended from 9:31 AM to 11:43 AM, while on December 24 they extended from 4:51 AM to 10:31 AM.

17 https://ncpolicywatch.com/2023/01/04/several-crises-malfunctions-at-duke-energy-led-to-rolling-blackouts-on-christmas-eve-utility-officials-tell-state-regulators/ indicates Duke/Progress outages occurred from 6:14 AM to 4 PM on December 24.

18 https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf, at 20-21.

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Attachment 4

Johannes P. Pfeifenberger et al.
The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs and Barriers to Achieving U.S. Clean Energy Goals
The Brattle Group
Jan. 24, 2023

The Benefit and Urgency of Planned Offshore Transmission:

Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals

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Executive Summary

There is an urgent need to plan the transmission grid necessary for achieving America's increasingly ambitious offshore wind (OSW) and clean energy goals. Proactive and holistic planning for long-term transmission needs offers significant benefits, but unless these planning efforts are started *now*, more attractive near-term transmission solutions will not be identified and the most effective long-term grid development pathways may be foreclosed.

While the most ambitious state and federal clean energy goals will not have to be attained until 2040 or 2050, we project that starting proactive planning for these long-term offshore wind generation needs *now* likely will save U.S. consumers at least $20 billion and reduce environmental and community impacts by 50%. Doing so will also support the timely achievement of policy goals, increase reliability, lower development and investment risks, increase energy independence, and improve climate resilience.

To achieve these benefits, state and federal policymakers, industry regulators, system operators, and market participants must expeditiously address several well-documented challenges. As shown in this analysis, even modest delays in developing and implementing actionable plans for both near- and long-term transmission investments substantially reduces the benefits of such planning efforts.

This report—funded by the Natural Resources Defense Council (NRDC), GridLab, the Clean Air Task Force (CATF), the American Clean Power Association (ACP), and the American Council on Renewable Energy (ACORE)—first lays out in Section I the urgent case for proactively and holistically planning transmission solutions for the nation's increasingly ambitious offshore wind goals. Section II reviews existing studies that document the benefits of proactive planning and quantifies the economic, environmental, and reliability benefits offered by carefully planned offshore wind transmission solutions. Section III summarizes barriers that currently prevent the realization of these benefits. Section IV recommends specific steps that states, grid operators, the federal administration and key federal agencies, and industry stakeholders need to take to create a pathway for no-regrets grid solutions that allows achieving near- and long-term offshore wind goals in a more cost-effective and timely manner. Section V summarizes available federal support for these initiatives—including through the Inflation Reduction Act (IRA), the Infrastructure Investment and Jobs Act (IIJA, which includes the new Transmission Facilitation Program), and U.S Department of Energy (DOE) appropriations—although more dedicated federal funding would likely be necessary to make interregional offshore wind transmission a reality. The remainder of this executive summary briefly discusses each of these points.

THE AMOUNT OF OSW GENERATION THAT NEEDS TO BE INTEGRATED INTO THE GRID

Increasingly ambitious federal and state clean energy goals require comprehensive, coordinated planning for OSW generation. While the most urgent transmission solutions address OSW goals of the next decade, a least-regrets development of these near-term solutions also requires the consideration of long-term goals. Developing transmission plans that are cost-effective in the near-term while creating attractive pathways for addressing long-term goals must start with a clear understanding of both near-term and long-term offshore wind goals.

While most current grid planning is still focused only on meeting state procurements and the federal administration OSW goal of 30 gigawatts (GW) by 2030, the OSW procurements and goals of 11 coastal U.S. states exceed 50 GW through 2035 and reach 77 GW by 2045, as shown in Table ES-1 and illustrated in Figure ES-1.

TABLE ES-1: OFFSHORE WIND PROCUREMENTS, GOALS, AND LONG-TERM NEEDS

State	Already Procured (GW)	Current Goals		Projected 2050 Needs (GW)
		(GW)	Year	
Massachusetts	3.2	5.6	2027	23
Connecticut	1.2	2	2030	9-11
Rhode Island	0.4	1-1.4	2035	5
Maine	0.01			5
New York	4.4	9	2035	14-25
New Jersey	3.8	11	2040	11-26
Maryland	2	2	2030	2
Virginia	2.7	5.2	2034	20-30
North Carolina		8	2040	7-10
South Carolina				
Louisiana		5	2035	5
California		25	2045	25
Washington				4-10
Oregon		3	2030	20
State Total	**17.6**	**77**		**150-197**
U.S. Goal/Need		**110**	**2050**	**220-460**

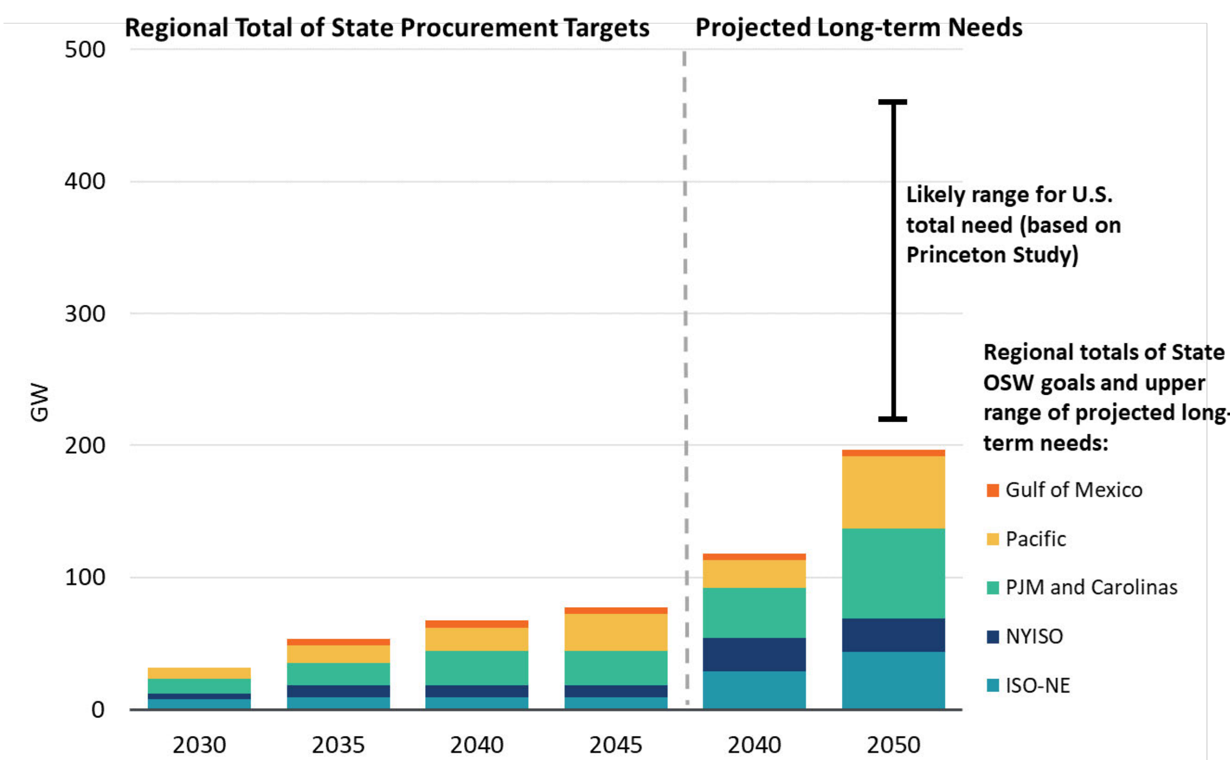
Source: Appendix A.

As Table ES-1 and Figure ES-1 further summarize, state-specific studies of clean energy and decarbonization needs show that close to 200 GW of OSW generation may be required by 2050 to meet the total of state-specific needs in the U.S. While the federal administration's 2050 OSW target is 110 GW, some nationwide analyses (such as Princeton's "Net Zero America" study) project that substantially more OSW will be required to cost-effectively decarbonize the U.S. economy by 2050.

The generation output of most of these OSW projects developed in the Atlantic, Pacific, and the Gulf of Mexico—including floating turbines in deep-water lease areas in the Gulf of Maine and off the Pacific coast—will have to be delivered to the onshore grid and to electricity customers in population centers, recognizing that some may be used to produce hydrogen. Doing so will require a large number of submarine cables buried in the ocean floor, beach crossings, points of interconnection (POIs) to the existing grid, upgrades to the onshore grid near those POIs, and additional transmission to reach various load centers.

To achieve this grid expansion cost effectively requires improved and well-coordinated generation interconnection and transmission planning processes by the regional independent transmission system operators (ISOs). On the East Coast, where OSW development is the most advanced, these system operators are ISO New England (ISO-NE), New York ISO (NYISO), and PJM Interconnection (PJM, which covers the coastline from New Jersey to North Carolina).

FIGURE ES-1: REGIONAL OFFSHORE WIND PROCUREMENT TARGETS AND LONG-TERM NEEDS



As shown in Figure ES-1 above, the existing state OSW goals and projected long-term needs quickly increase beyond near-term grid interconnection requirements. **Through 2050, NYISO likely needs transmission to interconnect up to 25 GW of OSW, ISO-NE may need to interconnect up to 40 GW, and PJM and the Carolinas up to 70 GW**. System operators along the **West Coast may have to develop transmission solutions to interconnect 55 GW** of floating OSW generation.

Given this rapid acceleration of OSW generation, proactive planning of both near-term and long-term transmission needs is essential to create cost-effective options for interconnecting the large amount of OSW generation—along with integrating the necessary land-based clean-energy resources and mitigating any environmental and community impacts from the construction of the necessary onshore and offshore transmission facilities.

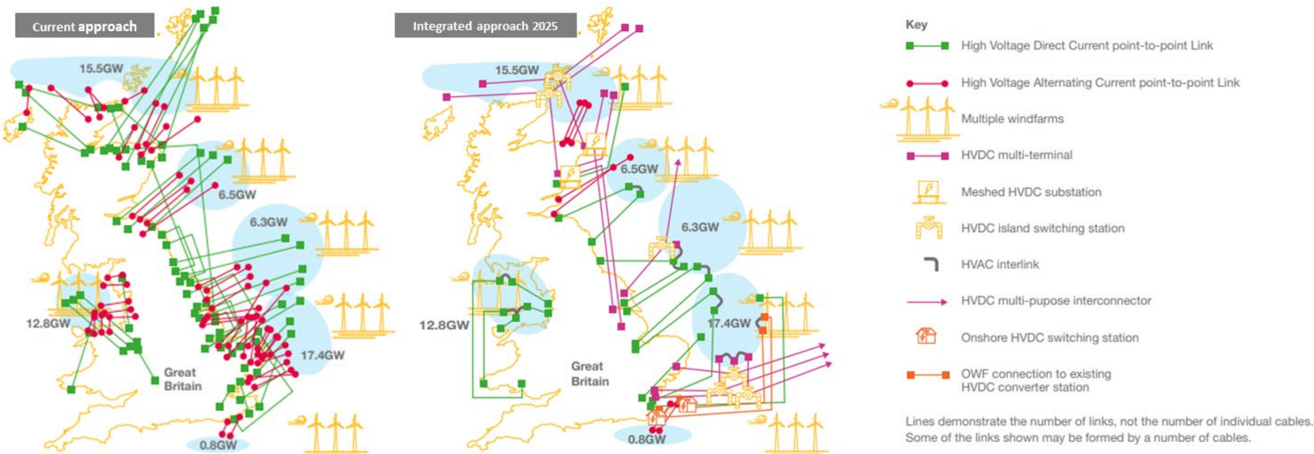
THE BENEFITS OF PROACTIVE OSW TRANSMISSION PLANNING

Starting to plan *today* for the transmission infrastructure development pathway that can integrate this amount of offshore wind generation, and do so cost-effectively over time, will achieve significant economic, environmental, and social benefits. These benefits have been well documented by a wide range of studies and planning efforts. For example:

- A nation-wide study conducted for National Grid UK found that proactively planned offshore and onshore grid investments for approximately 60 GW of OSW generation in the United Kingdom added between 2025 and 2050 would: (1) reduce overall transmission costs by 19% (approximately $7.4 billion); (2) reduce the miles of transmission cables installed in the ocean floor by 35%; (3) reduce onshore transmission line miles by 60%; and (4) reduce the number of beach crossings by 70%. Importantly, the study found that delaying the implementation of a planned solution by only five years (by beginning to address 2050 needs starting in 2030 instead of 2025) would reduce the benefits of a planned 2050 solution by about half. The study's results for 2030 and 2050 are illustrated in Figure ES-2 below. While similar U.S. studies are still ongoing, the insights from the U.K. are directly applicable to the U.S. and consistent with initial U.S. OSW experience to date.
- For example, New Jersey's recently concluded proactive planning effort with PJM for interconnecting an incremental 6.4 GW of OSW generation resulted in cost savings of over $900 million (a 13% reduction of total OSW transmission-related costs) by reducing the cost of upgrades to the existing onshore grid by approximately two thirds. Doing so also reduced interconnection-related risks, created a more competitive environment for future offshore wind procurements, and mitigated environmental and community impacts by consolidating

the number of additional onshore transmission corridors needed from three to one. This was the case even though New Jersey's selected solution focused almost entirely on the *onshore* transmission needs to integrate OSW generation. If the scope of the planning effort had been broader than just for offshore wind and only for New Jersey, the benefits would have been even larger.

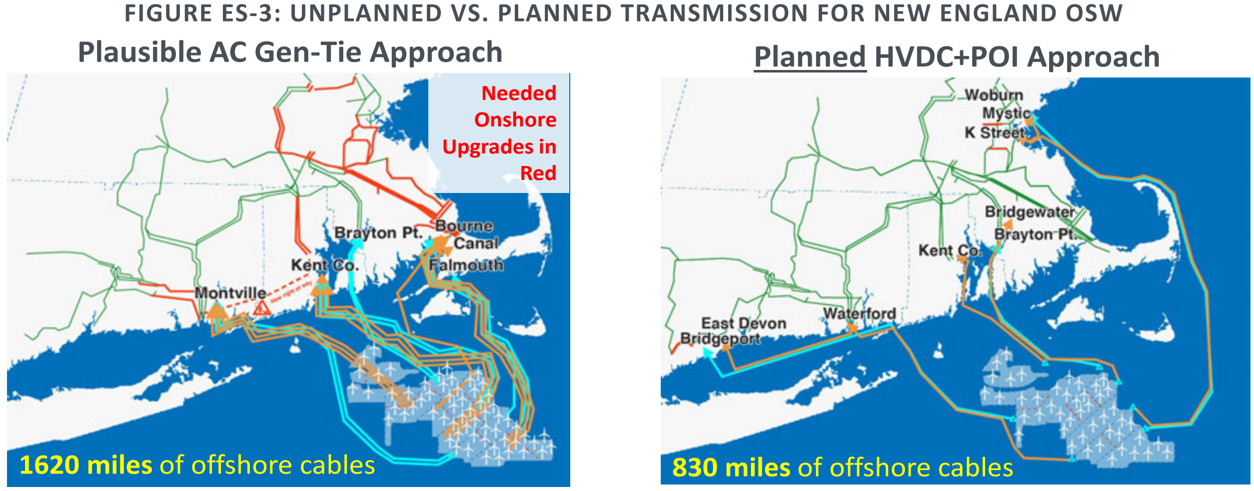
FIGURE ES-2: UNPLANNED VS. PLANNED TRANSMISSION FOR U.K. OFFSHORE WIND IN 2050
(Assuming planning efforts start to be effective by 2025)



Source: National Grid ESO, *Offshore Coordination Phase 1 Report*, December 2020.

- Similarly, two studies by The Brattle Group for Anbaric (an independent transmission developer) found that proactive planning of offshore wind transmission solutions significantly reduces both costs (*e.g.*, by $0.5 billion for an additional 3.6 GW of OSW in New England) and environmental impacts (*e.g.*, reducing the ocean cable miles installed by approximately 50% for an additional 8 GW of OSW, as illustrated in Figure ES-3 below).

FIGURE ES-3: UNPLANNED VS. PLANNED TRANSMISSION FOR NEW ENGLAND OSW



Source: J. Pfeifenberger, S. Newell, W. Graf, The Brattle Group, *Offshore Transmission in New England: The Benefits of a Better-Planned Grid*, May 2020.

- A preliminary study by PJM evaluating the grid upgrades necessary to interconnect 15 GW of OSW generation along with 60 GW of land-based renewable resources also shows the benefits of this type of proactive planning when applied to address the entire region's clean-energy and reliability needs: it would reduce the cost of necessary upgrades to the existing grid by over 80% compared to PJM's existing generation interconnection process.
- Recently completed joint interconnection and long-term transmission planning efforts for onshore renewables by system operators in the Midwestern U.S.—the Midcontinent ISO (MISO) and Southwest Power Pool (SPP)—similarly show that proactive transmission planning can reduce interconnection-related transmission costs by over 50% and provide significant reliability and other grid-wide benefits that reduce total costs.
- A timelier, more cost-effective, and risk-mitigated development of OSW generation through improved transmission planning facilitates significant state and regional employment and economic benefits. Several studies [1][2][3] estimate that approximately 80,000 full-time jobs would be stimulated by the approximately 30,000 MW of OSW construction planned through 2030.

Extrapolating from the consistent set of findings from these studies, and conservatively assuming at least 100 GW of offshore wind generation additions by 2050 (beyond already-ongoing procurements), the U.S.-wide benefits of starting proactive planning efforts for offshore transmission *now* are projected to:

- Lead to at least $20 billion in transmission-related cost savings;
- Result in 60–70% fewer shore crossings and necessary onshore transmission upgrades;
- Reduce marine transmission cable installations on the ocean floor by 50% or approximately 2,000 miles; and
- Significantly accelerate achievement of offshore wind deployment timelines by eliminating transmission-related delays, reducing project-development and cost-escalation risks, reducing community impacts, achieving more competitive procurement outcomes, and facilitating investments in the local clean energy economy.

Planning studies by DNV, PowerGEM, and WSP for NYSERDA further found that networked HVDC offshore transmission grids can deliver significant operational benefits. Going forward, OSW generation should consequently be procured with offshore facilities that are based on a **standardized, modular design** such that can interconnect with a "meshed" or "networked" offshore grid as part of a holistic grid planning process. Achieving such a **networked offshore transmission** system would further:

- Improve the reliability and value of offshore wind generation deliveries;
- Allow for the utilization of new, higher-capacity transmission cables (each able to deliver 2–2.6 GW of offshore wind generation), which further reduces costs and impacts to communities and the environment;
- Improve the utilization and flexibility of the offshore transmission infrastructure;
- Reinforce, avoid upgrades of, and support the existing regional onshore grids, which will improve grid-wide resilience and reduce future congestion costs; and
- Offer unique, cost-effective opportunities to create valuable new transmission links between regions, including addressing system transmission constraints into New York City and New England that reduce system-wide cost and increase interregional grid reliability and resilience.

As summarized in this report, numerous regional and national studies confirm that expanding regional and interregional transmission capabilities offer substantial benefits that increase grid resilience, reduce system-wide costs, and mitigate increases in electricity rates as the U.S. transitions to a more decarbonized electric sector by 2035 and—as called for by state policies and the federal administration—aims to achieve a substantially decarbonized economy by 2050. If planned proactively and holistically, multi-purpose transmission links between OSW facilities can offer the lowest-cost, lowest-impact, and most feasible solutions for adding such regional and interregional transfer capabilities to the existing grid.

THE URGENCY OF STARTING LONG-TERM TRANSMISSION PLANNING FOR OSW NOW

While the nation's mid-century offshore wind goals may appear quite distant, proactive and coordinated planning **efforts must begin immediately to fully realize these planning-related benefits**. Actions taken in the next several years will not only impact the cost and environmental footprint of achieving OSW generation goals for the next decade, but will also pre-determine to a significant extent what is (or is not) possible by 2050.

There are several reasons why it is so urgent to initiate regional and interregional planning for both near-term OSW goals and to create a least-regrets pathway for addressing long-term OSW transmission needs:

- **Long developing timelines**: Transmission facilities for offshore wind will take at least a decade to plan, permit, and construct. This timeline is worsened by supply chain bottlenecks, which necessitate that equipment (such as submarine transmission cables, transformers, and highly specialize installation vessels) be ordered years in advance of installation. As a result, any planning steps taken today are unlikely to yield significant new transmission infrastructure until the early 2030s.

- **Effective use of limited corridors and interconnection points**: The type and location of transmission facilities built to address 2030 or 2035 offshore generation needs will, in turn, directly impact the type and location of transmission facilities that can be built to meet 2040 and 2050 needs. As states continue to procure OSW resources that rely on single-project, radial delivery facilities, the lowest-cost corridors and interconnection points will be utilized first, making it increasingly costly and challenging to find more attractive long-term solutions and reduce environmental community impacts for the substantial OSW additions needed to achieve long-term goals. Both near- and long-term needs have to be considered to specify least-regrets grid expansion pathways that can lead us to more attractive long-term planning outcomes.
- **Technology compatibility**: Unless existing regional transmission planning processes are improved and compatible technology standards are developed *now*, a combination of poor planning and continued reliance on incompatible technologies will make it nearly impossible to realize efficiently integrated regional and interregional grid solutions in the future.
- **Federal support**: Finally, through the Infrastructure Investment and Jobs Act (IIJA) and the Inflation Reduction Act (IRA), the federal government is currently offering support and tax credits to lower costs, address planning, and facilitate contracting for state and nationwide clean-energy needs, including regional and interregional transmission. Some of this support funds may not be available if planning efforts are delayed.

Importantly, as is well documented, identifying the most attractive long-term solutions requires the development of more proactive planning processes that simultaneously consider the full set of transmission needs (*i.e.*, reliability, congestion relief, public policy, and generation interconnection needs) over a long-term planning horizon (*i.e.*, through 2040 or 2050 to consider already-known policy needs). Focusing only on near-term transmission needs and addressing them incrementally will not yield cost-effective solutions in the longer-term.

BARRIERS TO COST-EFFECTIVE, LEAST-REGRETS OFFSHORE WIND TRANSMISSION

The timely development of cost-effective and least-regrets long-term transmission solutions that integrate offshore wind generation holistically in coordination with onshore grid planning faces several distinct challenges. These challenges can be addressed expeditiously and collaboratively as reflected in the recommendations below.

- **Inadequate generation interconnection processes:** The slow, costly, reactive, and incremental generator interconnection processes currently used by regional grid operators are not suitable for optimizing grid interconnection points for the timely and cost-effective integration of renewable generation, including the 30 GW of offshore generation that states will soon have procured to meet their clean energy policy goals over this next decade.
- **Uncertain tax credits**: There is significant uncertainty over the extent to which the availability of federal investment tax credits for offshore wind generators' "wind energy property" applies to the cables and interconnection facilities that deliver the generation to shore and the extent to which these credits are available for such facilities if they are shared by multiple OSW generators or owned by third parties.
- **Siloed transmission planning**: Many existing transmission planning processes do not yet proactively consider long-term public policy needs, nor do so holistically in combination with other transmission needs. Rather, regional grid planning is typically siloed into specific project categories that fail to simultaneously optimize the broad range of reliability, economic, and public policy benefits that can be provided by holistically-planned transmission investments that lower system-wide costs and mitigate increases in customer rates.
- **No effective interregional planning**: The grid planning challenge is even more severe for interregional transmission as these needs are not well defined and no effective interregional transmission planning processes currently exist.
- **HVDC technology integration challenges**: HVDC transmission technology is becoming critical to achieving cost-effective and less environmentally impactful OSW transmission solutions. Yet, the relatively slow adoption and operational integration of advanced HVDC technology in the U.S. creates its own set of unique challenges: (a) the functional requirements of HVDC grids, optimal voltage levels, and transfer capabilities are not yet standardized; (b) equipment from different vendors is not yet compatible or otherwise standardized; (c) critical grid elements (such as DC circuit breakers) are not yet widely commercially available for offshore applications; (d) the large capacity of new HVDC technologies also exceed what many system operators currently view as an acceptable "most severe single contingency (MSSC)"; and (e) the capabilities of advanced technologies—such as voltage support, black-start, fast power-flow control, means to address MSCC concerns, and system-stabilization capability of advanced HVDC converters—are not yet typically accounted for or accepted as solutions in transmission planning.
- **Uncertain offshore network designs**: The optimal choices for technology, grid topology, and cost-effective design of "meshed" or "backbone" offshore grids are still uncertain. While

some studies are underway, detailed benefit-cost cases are not yet available for specific offshore grid designs in the U.S., nor for designs that will likely develop over the coming decades.

- **Regulations and contracts:** The regulatory and contractual frameworks for the shared and networked operation and use of offshore transmission facilities (including procurement method, structure, evaluation criteria, cost allocation, and the inherent tension between open access provisions and priority interconnection rights) are not yet established.
- **Grid operations:** With infrequent exceptions, regional grid operators are not yet equipped to optimize the operations of a regional or interregional offshore grid to take full advantage of networked offshore transmission from a reliability operations and wholesale markets perspective. Transmission tariffs under the jurisdiction of the Federal Energy Regulatory Commission (FERC) do not yet satisfactorily address coordinated operation of existing interregional transmission, which would also make it difficult to capture the full value of new interregional facilities.
- **BOEM transmission permitting**: The Bureau of Ocean Energy Management (BOEM) does not currently have a well-defined or broadly understood maritime spatial planning and permitting process for offshore transmission that is distinct from offshore wind generators' individual interconnection cables. The project-by-project approach to OSW transmission is driven in part by BOEM's regulations, which bundle permitting for radial transmission lines as an easement right associated with the permitting of offshore wind generation in individual wind lease areas. Additionally, BOEM has not clarified how the presence of third-party offshore transmission would affect the right of adjacent leaseholders to utilize their own radial lines if at all.
- **Disjointed lease, procurement, and planning processes**: The processes of lease area auctions, state procurement of OSW generation, and regional transmission planning are siloed and lack coordination. When OSW developers purchase offshore leases that can serve more than one RTO/ISO, it is often uncertain which region they will be connecting into and where the specific points of interconnection might be. When states issue solicitations for OSW generation, they do not know which lease area will serve them (although, realistically, only a few generators with nearby lease areas can effectively compete in those solicitations). And transmission planners attempting to pre-build an offshore grid to address some states' clean energy needs do not know which lease or call areas to target. This separation of leasing, procurement, and planning is inefficient and time consuming because it: (1) creates delays since neither OSW generators nor transmission developers can start planning and permitting the offshore transmission until they know which region they will be

serving as determined by the outcomes of state procurements; (2) challenges the planning and development of efficient transmission solutions, adding costs to any prebuilt transmission since any chosen location of offshore collector stations may turn out to be suboptimal and lead to duplicative offshore substations; (3) can reduce competition in OSW generation procurements since only a limited number of entities with nearby leases can compete; and (4) creates additional barriers for shared offshore transmission.

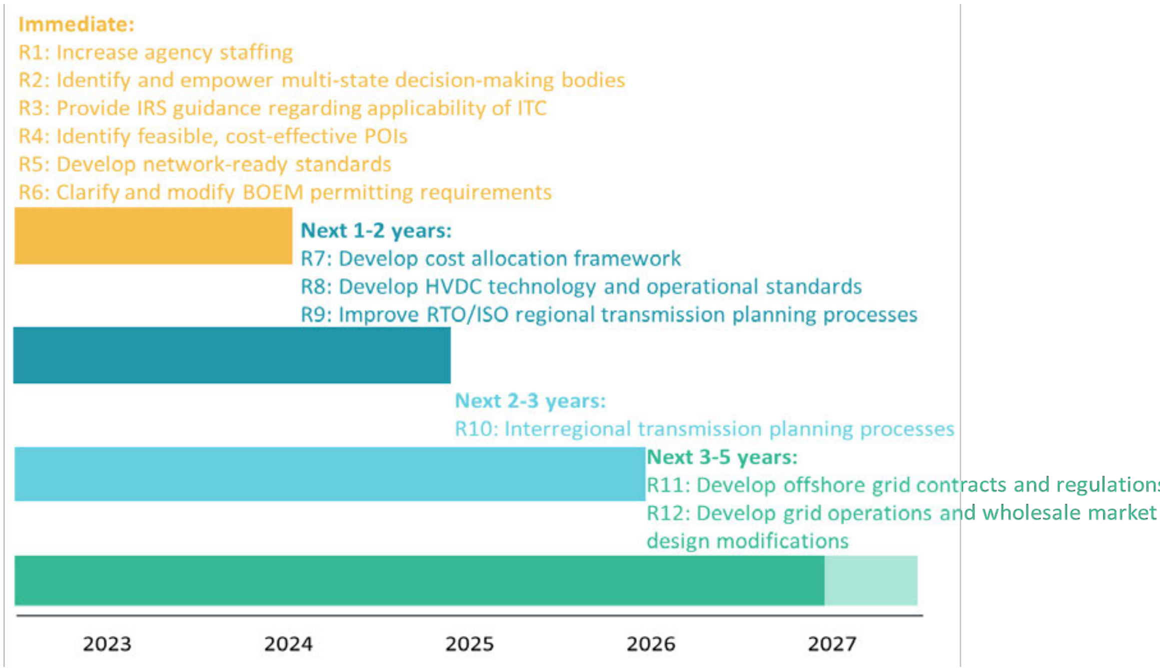
RECOMMENDATIONS FOR ACHIEVING COST-EFFECTIVE REGIONAL AND INTERREGIONAL TRANSMISSION SOLUTIONS WHILE INTEGRATING STATES' ONGOING OFFSHORE WIND PROCUREMENT EFFORTS

We recommend that state and federal policymakers and regulators, federal agencies, regional grid operators, and market participants expeditiously collaborate on the following initiatives to address the challenges discussed above. As summarized in Figure ES-4 below, these recommendations have been grouped into the following four categories:

- **Immediate (this year)**: actions to ensure some of the identified challenges can be addressed expeditiously in states' OSW generation procurements;
- **Near-term (over the next 1–2 years):** actions to ensure that holistic planning of offshore transmission networks can start at the regional grid operator level;
- **Mid-term (over the next 2–3 years):** actions to enable effective interregional transmission planning processes between existing grid operators; and
- **Longer-term (over the next 3–5 years):** actions to develop the necessary grid operations, wholesale market, regulatory, and contractual frameworks, which need to be in place before networked offshore facilities are placed into service.

Brief summaries of each of these recommendations are provided below, including an identification of the relevant entities that should be involved in implementing the recommended actions—many of which can be supported with available federal support and funding.

FIGURE ES-4: TIMELINE OF RECOMMENDATIONS



IMMEDIATE ACTIONS (this year)

1. **Increase staffing at state and federal regulatory agencies involved in OSW planning**: Increased staffing and budgets will be necessary for state and federal regulatory agencies involved in planning for evolving OSW and other clean energy needs to enhance their capabilities to develop, evaluate, and utilize the updated regulatory frameworks necessary to reliably integrate these new facilities in a timely, cost-effective manner while mitigating environmental and community impacts.
   Relevant entities: state governors or senior policymakers, federal policymakers

2. **Create and empower multi-state decision-making entities**: Multi-state entities should be created that are authorized to facilitate planning and procuring of effective regional and interregional transmission solutions to integrate the clean energy resources, including offshore wind, needed over the 2030–2050 timeframe. A multi-state “transmission authority” modeled after the Regional Greenhouse Gas Initiative (RGGI) is one potential option. Governors of adjacent states should immediately begin collaborating to develop a declaration of shared goals for offshore wind transmission and interconnection, create a task force of state agencies to address those goals, and provide dedicated funding. The multi-state task force should then develop a Memorandum of Understanding (MOU) signed by state agencies with specific state goals and a framework for making decisions. This task force would start the work of implementation the recommendations below and identify

what states will need from the regional grid operators, DOE, BOEM, and FERC to accomplish those goals.
Relevant entities: state governors or senior policymakers and state regulatory agencies with support of grid operators, DOE, FERC, BOEM, industry stakeholders, possibly with PMAs

3. **Provide IRS guidance regarding applicability of ITC**: Within the next 90 days, the Internal Revenue Service (IRS) should provide guidance to confirm the applicability of the investment tax credit (ITC) to offshore wind-related interconnection facilities owned by either generators or third parties.
Relevant entities: IRS

4. **Identify feasible, cost-effective POIs**: In collaboration with grid operators and transmission owners, states should immediately begin efforts to proactively identify feasible, cost-effective, and future-proof points of interconnections to the existing grid. POIs should be planned with the necessary transmission corridors and onshore upgrades for all generation interconnection needs associated with existing state OSW and other clean energy goals within each planning region (*e.g.*, initiate efforts similar to New Jersey's recent offshore wind transmission procurement with PJM at full regional scale). These POIs will be needed for both the interconnection of OSW generation with radial export cables and any unbundled networked offshore transmission facilities. POIs for near-term OSW interconnection needs should be selected within a least-regrets pathway to meet likely future OSW transmission needs. Interconnection rights to the specific POIs should be made available to state-procured OSW generation and/or unbundled offshore transmission through a fast-track (*i.e.*, first-ready/first-served) interconnection process.
Relevant entities: states, multi-state entities, DOE, grid operators, FERC

5. **Develop network-ready offshore facility standards:** States and grid operators should immediately develop and implement "network-ready" standards for modular offshore substations and export cables that ensure physical and functional compatibility and expandability of offshore transmission infrastructure. This will enable states to require such network-ready capabilities in all of their upcoming OSW transmission and generation procurements, so that any export links built today can to be integrated into a planned offshore network in the future.
Relevant entities: DOE, states, grid operators with input from OSW generation and transmission developers

6. **Clarify and modify BOEM transmission permitting and lease-process coordination**: BOEM should clarify and modify transmission permitting to add specificity to the permitting process for third-party offshore cable routes between lease areas and to the pre-specified

interconnection points on the existing grid. In addition, DOE, with BOEM, should explore—and evaluate for possible federal legislative action—more effective alternatives to the existing auction, lease, and permitting processes to align them better with state OSW generation procurements.
Relevant entities: BOEM, DOE, OSW transmission developers

NEAR-TERM ACTIONS (1–2 years)

7. **Develop cost-allocation framework**: States should develop an actionable cost allocation framework that covers their OSW commitments within each region. The framework should clearly identify which costs and benefits should be considered, how they should be quantified and monetized to inform cost allocation. Without being formulaically based on quantified benefits, the costs of OSW-related transmission facilities should be allocated in a fair and transparent way that is roughly commensurate with their benefits (*e.g.*, in proportion to their OSW and/or other clean-energy needs).
Relevant entities: state regulatory agencies, grid operators, FERC

8. **Develop HVDC-technology and operational standards**: A full set of HVDC-technology and operational standards should be developed—beyond network-ready requirements, and in coordination with similar efforts in Europe and elsewhere—to ensure vendor compatibility in offshore transmission procurements and allow for a "future proof" evolution of an offshore transmission network capable of meeting long-term state, regional, and interregional needs.
Relevant entities: DOE, grid operators, states

9. **Improve regional transmission planning and interconnection processes**: Ongoing efforts to improve transmission planning processes should be continued in coordination with improving generation interconnection processes to address onshore and offshore renewable generation grid integration needs more proactively and from a long-term, multi-value planning perspective that considers the broad range of benefits offered by well-designed transmission networks.
Relevant entities: FERC, grid operators

MID-TERM ACTIONS (2–3 years)

10. **Improve interregional transmission planning**: It is critical to create effective interregional transmission planning processes with the requisite cost allocation agreements able to identify the needs and approve the investment necessary to capture well-documented benefits of expanded interregional transmission—increased grid resilience, lower system-wide costs, taking advantage of load and resource diversity. The planning processes should

be able to identify where offshore transmission links between regions may be the most feasible and cost-effective way to address the identified (multi-driver/multi-value) interregional needs.
Relevant entities: FERC, grid operators, multi-state entities with input from market participants

LONGER TERM ACTIONS (3–5 years)

11. **Develop offshore grid contracts and regulations**: Before networked offshore facilities are placed in service, offshore grid contracts and regulations—such as shared use/ownership agreements, transmission rights, open access agreements and regulations, liability and decommissioning provisions, cost allocations for shared and networked offshore facilities across multiple POIs—will have to be developed to support the evolving OSW industry and enable a transition from using radial lines to meshed radial lines and (ultimately) fully networked regional and interregional grid solutions.
Relevant entities: DOE, FERC, states, multi-state entities, grid operators, with input from OSW generation and transmission developers

12. **Develop grid operations and wholesale market design modifications**: Develop recommendations for grid operations and wholesale market design modifications that allow for the regional and interregional optimization of offshore-wind-related transmission including the unique capabilities of HVDC links within and across regions.
Relevant entities: DOE, FERC, grid operators, transmission owners

AVAILABLE FEDERAL SUPPORT

As discussed in Section V of this report, substantial technical, regulatory, and financial federal support for these initiatives is available *now* through collaboration with BOEM and the U.S. Department of the Interior (DOI), grid operators, DOE, FERC, and the North American Electric Reliability Corporation (NERC). Federal funding to support implementing these recommendations is available through several avenues, facilitated through DOE's Building a Better Grid Initiative, which coordinates many new programs including the Transmission Facilitation Program, the Grid Resilience Utility and Industry Grants, Smart Grid Grants, and the Grid Innovation Program. Other funding sources include siting facilitation grants, energy infrastructure reinvestment program, and tax credits for certain eligible offshore wind generation property. In addition, the DOE's Wind Energy Technology Office also provides additional funding opportunities, including a recent $28 million opportunity related to addressing key wind energy deployment challenges, along with managing the federal administration's Earthshot™ for floating offshore wind.

The remainder of this report is structured as follows:

- Section I outlines the urgent case for proactively and holistically planning transmission solutions. For this purpose, we identify the substantial and growing OSW goals that will need to be considered and enabled by such planning efforts, driving the urgency to begin planning efforts.
- Section II documents identified benefits of proactive planning and quantifies the economic, environmental, community, and reliability benefits only offered by carefully planned offshore wind transmission solutions.
- Section III summarizes the challenges that currently prevent effective planning, which limit the realization of these identified benefits.
- Section IV provides a roadmap for overcoming these barriers, and recommends specific steps that states, grid operators, the federal administration and key federal agencies, and industry stakeholders need to take immediately and in the near term to create a pathway for no-regrets grid solutions that can achieve OSW goals in the most cost-effective and timely manner.
- Finally, Section V summarizes available federal support for these initiatives, including through the Inflation Reduction Act (IRA), the Infrastructure Investment and Jobs Act (IIJA, which includes the new Transmission Facilitation Program), and U.S Department of Energy (DOE) appropriations.

I. The Urgency of Starting to Plan Offshore Transmission Now

Coordinated planning for transmission to enable OSW is a key element of efficiently achieving state and national clean energy and climate policies. Without a plan and swift action toward identifying and upgrading the limited near-shore grid locations that can accept substantial volumes of OSW generation, achieving state and federal clean energy goals will be more costly, time consuming, and more disruptive to local communities and the environment. Compared to the current process of developing and interconnecting one OSW generation project at time, each with its own cables to shore, a coordinated comprehensive transmission plan could unlock numerous efficiencies and benefits unavailable under current processes. Because state and national goals will require substantial decarbonization efforts over the next decade and beyond, it is of upmost importance to start proactive transmission planning now.

Given both accelerating near-term and challenging long-term infrastructure needs, this planning effort should have been started years ago. At this point, as existing studies show, even modest further delays in starting coordinated planning efforts will lead to higher costs and greater environmental impacts. Currently available federal support and funding options make starting these planning efforts even more urgent and beneficial.

A. Offshore Wind Commitments and Needs

Developing transmission plans that are cost-effective in the near-term while creating pathways for efficiently addressing long-term goals must start with a clear understanding of both near-term OSW commitments and long-term needs.

Many states and the federal government have set ambitious clean energy and decarbonization goals that will require large-scale renewable resource additions, including substantial amounts of OSW generation. This is evidenced by the significant quantities of OSW in resource interconnection queues, the accelerating pace of OSW procurement activities, and the significant OSW development efforts internationally.[1] In addition to individual state goals, OSW generation targets include the Biden Administration's announcement of a 30 GW by 2030 goal, which includes a goal of 15 GW floating OSW by 2035, unlocking a pathway to develop 110 GW in the United States by 2050.[2] The significant OSW resource pipeline demonstrates the urgency of beginning coordinated transmission planning efforts now to identify more cost-effective and lower-impact solutions for integrating these resources into the existing electricity grid.

Table 1 summarizes the current procurements, state and federal policy and planning goals, and projected long-term needs to achieve decarbonization goals.

1 W. Musial, P. Spitsen, P. Duffy, *et al.*, DOE, Offshore Wind Market Report 2022, August 2022.

2 The White House, FACT SHEET: Biden Administration Jumpstarts Offshore Wind Energy Projects to Create Jobs, March 29, 2021; The White House, FACT SHEET: Biden-Harris Administration Announces New Actions to Expand U.S. Offshore Wind Energy, September 15, 2022.

TABLE 1: OFFSHORE WIND TARGETS AND LONG–TERM NEEDS

State	Already Procured (GW)	Current Goals (GW)	Current Goals Year	Projected 2050 Needs (GW)
ISO-NE	**5**	**8**		**42-44**
Massachusetts	3.2	5.6	2027	23
Connecticut	1.2	2	2030	9-11
Rhode Island	0.4	1-1.4	2035	5
Maine	0.01			5
NYISO	**4.4**	**9**		**14-25**
New York	4.4	9	2035	14-25
PJM	**8.4**	**18.2**		**33-58**
New Jersey	3.8	11	2040	11-26
Maryland	2	2	2030	2
Virginia	2.7	5.2	2034	20-30
SERC		**8**		**7-10**
North Carolina		8	2040	7-10
South Carolina				
MISO		**5**		**5**
Louisiana		5	2035	5
CAISO		**25**		**25**
California		25	2045	25
NWPP				**24-30**
Washington				4-10
Oregon		3	2030	20
State Total	**17.6**	**77**		**150-197**
U.S. Goal/Need		**110**	**2050**	**220-460**

Sources: See Appendix A.

As this table shows, collective procurement goals of the top 11 states now exceed 75 GW by 2045. States have already procured the first 18 GW of this OSW generation, which is projected to be in service by 2035 along the U.S. Atlantic coast from Massachusetts to Virginia. In addition to the offshore wind goals set recently by East Coast states, offshore wind goals now exist along the Pacific Coast with California's recently announced planning goal of 25 GW OSW by 2045. In the Gulf of Mexico, Louisiana set the target of 5 GW OSW by 2035 in its Climate Plan.

Many states with ambitious clean energy and decarbonization goals recognize that OSW will be a substantial part of achieving their long-term goals. Most states have already conducted decarbonization pathways studies that identify likely long-term OSW generation needs that substantially exceed their current OSW goals and targets. As Table 1 above shows, the total projected OSW generation needs based on studies for individual states now range from 150–

200 GW by 2050.[3] Looking beyond state-specific needs, national decarbonization studies have already projected OSW generation developments as high as 460 GW.[4]

As illustrated in Figure 1 below, the individual state and regional decarbonization pathways studies document substantial future generation interconnection needs for the regional grid operators along the U.S. Atlantic Coast. By 2050, ISO-NE will need to interconnect over 40 GW of OSW, NYISO will need to interconnect up to 25 GW, PJM will need to interconnect up to 58 GW, and the Carolinas will need to interconnect up to 10 GW. Full decarbonization roadmap studies often indicate substantial future OSW needs for even individual states, with Massachusetts most recently identifying a goal of 23 GW of OSW generation by 2050,[5] New York identifying 16–19 GW (possibly up to 25 GW) of OSW,[6] New Jersey's 2019 Energy Master Plan envisioning up to 26 GW,[7] studies for Virginia projecting up to 30 GW,[8] and studies for Oregon projecting 20 GW of offshore wind in some 2050 scenarios.[9] Similarly, state decarbonization goals likely mean that system operators on the West Coast will have to interconnect up to 55 GW of floating OSW generation by 2050. On a nationwide basis, these state-specific needs would require 150–200 GW of OSW generation by 2050—with a total possible nationwide need of over 400 GW based on a nationwide study scope. Most of this offshore wind energy will have to be delivered to shore and integrated with the existing grid—recognizing that some of it may be used to produce hydrogen at the offshore plants' locations.

3 *See* Appendix A for a complete list of state clean energy transition and decarbonization pathway studies considered in Table 1.

4 E. Larson, *et al.*, Princeton University, Net-Zero America—National data, January 9, 2022, at 41, Table 42.

5 Massachusetts Clean Energy and Climate Plan for 2050, December 2022, at 24. See also Massachusetts 2050 Decarbonization Roadmap Study, Energy Pathways to Deep Decarbonization, December 2020, showing a projected range of 11–19 GW for 2050 OSW generation.

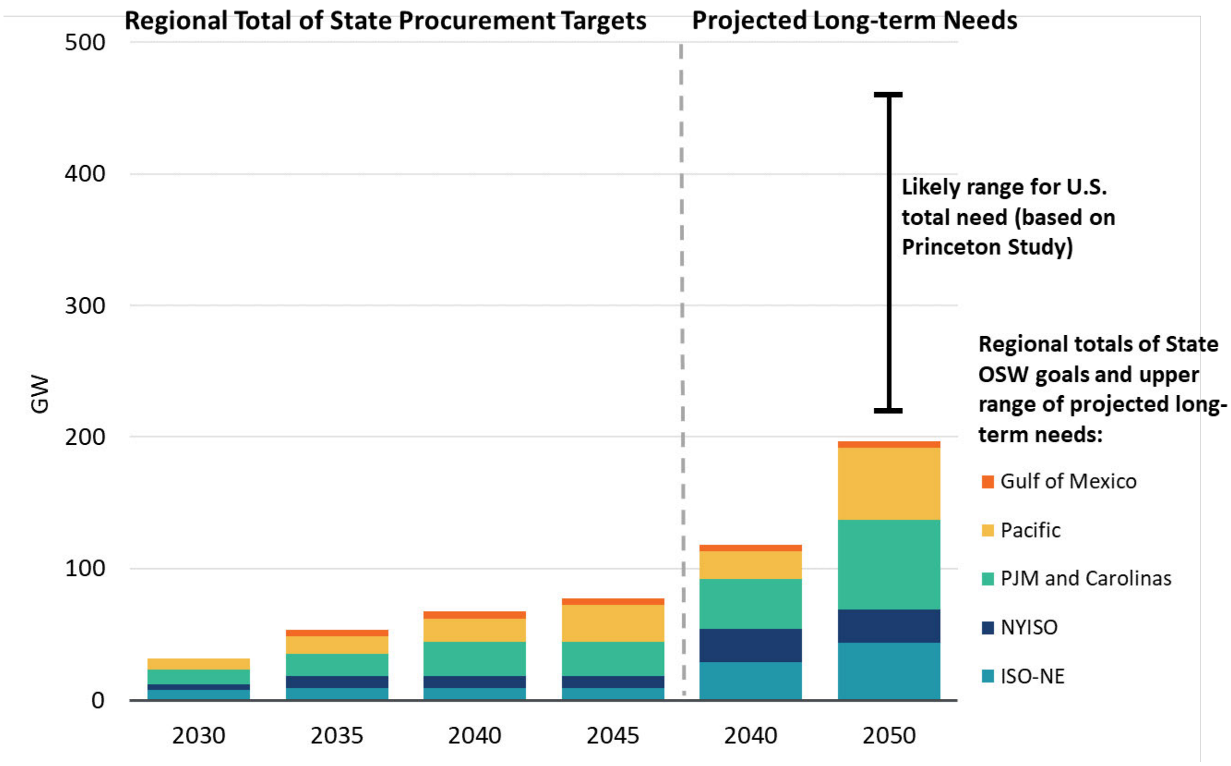
6 New York State Climate Action Council, Final Scoping Plan, Full Report, December 2022, Table 13. Note that some studies of New York's clean energy needs identify up to 25 GW of OSW generation requirements (see Brattle New York Electric Grid Evolution Study (nyiso.com), pp. 32, 44)

7 New Jersey 2019 Energy Master Plan, Integrated Energy Plan Technical Appendix, January 2019, at 25.

8 W. Shobe, *et al.*, Decarbonizing Virginia's Economy: Pathways to 2050, University of Virginia and Evolved Energy Research, January 2021, Fig. 34.

9 Evolved Energy Research, Renewable Northwest, GridLab, and the Energy Transition Institute, Oregon Clean Energy Pathways Final Report, June 15 and July 2, 2021.

FIGURE 1: REGIONAL OFFSHORE WIND PROCUREMENT TARGETS AND LONG-TERM NEEDS



Available data shows that an OSW development pipeline of 52 GW exists as of December 2022. As shown in Table 2, of the 52 GW of OSW generation under various stages of development, nearly 20 GW have submitted Construction and Operation Plans (COPs) to BOEM, and an additional 24 GW has been made available to developers by BOEM. Table 2 also reflects the updated draft Call Area of 9.9 million acres in the Gulf of Maine that BOEM published in January 2023,[10] the two Wind Energy Areas (WEAs) that BOEM finalized in October 2022 in Texas and Louisiana, enabling at least 8 GW of OSW development[11] and the 373,000 acres BOEM sold in its December 2022 California Lease auction, which is estimated to enable over 8 GW of OSW generation.[12]

10 BOEM, Gulf of Maine activities.

11 BOEM, BOEM Designates Two Wind Energy Areas in Gulf of Mexico, October 31, 2022. (based on BOEM's assumption of 3 MW/km^2).

12 A. Buljan, offshoreWIND.biz, California Lease Sale Winners Are: RWE, Equinor, CIP, Ocean Winds, and Invenergy. Floating Wind Farm Capacities Higher than Initially Estimated, December 7, 2022. (BOEM estimated a lower 4.5 GW based on 3 MW/km^2).

TABLE 2: OSW DEVELOPMENT PIPELINE AS OF DECEMBER 2022

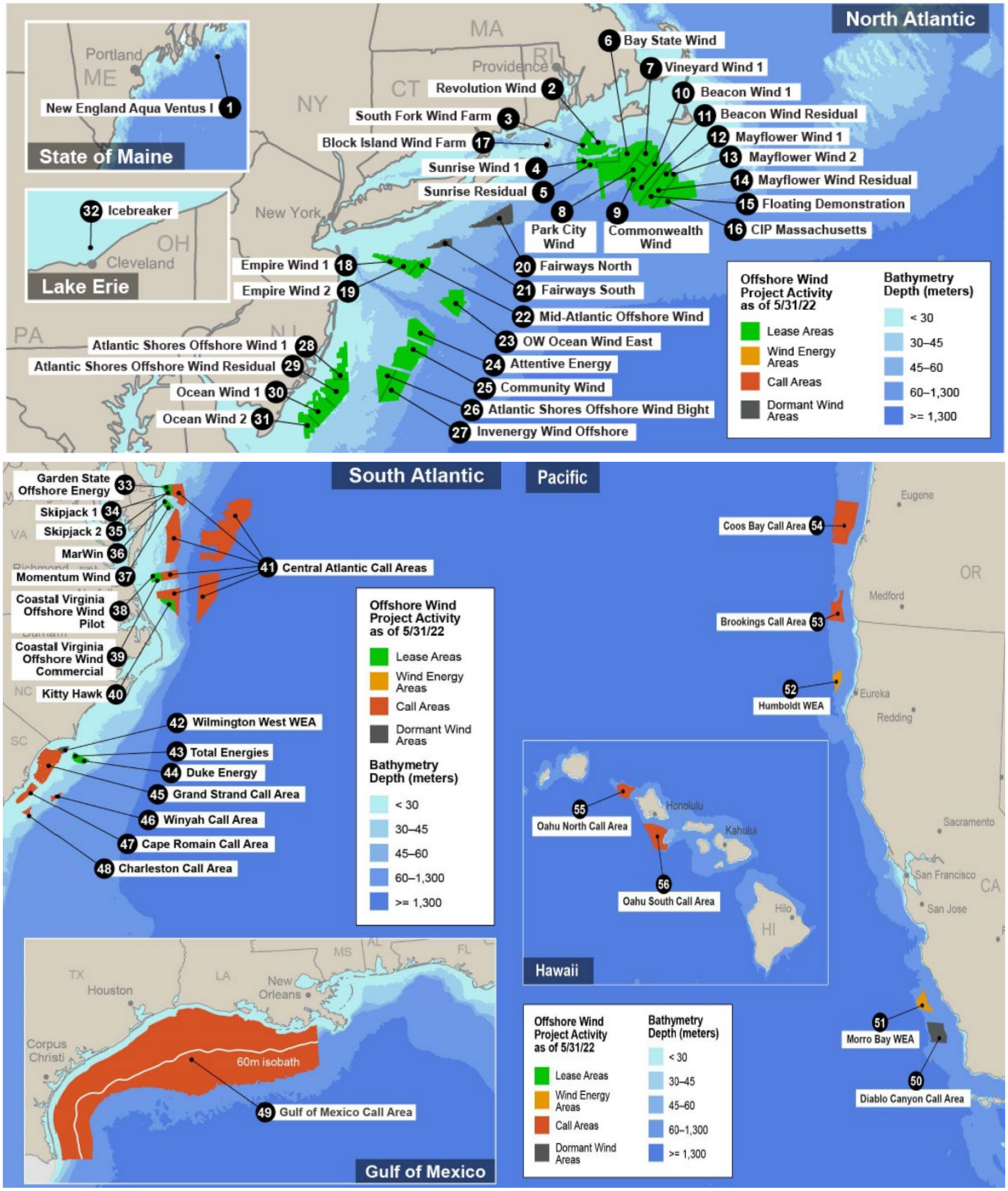
Status	Description	Total (MW)
Operating	The project is fully operational with all wind turbines generating power to the grid.	42
Under Construction	All permitting processes completed. Wind turbines, substructures, and cables are in the process of being installed. Onshore upgrades are underway.	932
Financial Close	All permitting processes completed. Begins when sponsor announces final investment decision and has signed contracts.	0
Approved	BOEM and other federal agencies reviewed and approved a project's COP. The project has received all necessary state and local permits as well as acquiring an interconnection agreement to inject power to the grid.	0
Permitting	The developer has site control of a lease area, has submitted a COP to BOEM, and BOEM has published a Notice of Intent to prepare an Environmental Impact Statement on the project's COP. If project development occurs in state waters, permitting is initiated with relevant state agencies.	18,581
Site Control	The developer has acquired the right to develop a lease area and has begun surveying the lease area.	24,096
Unleased Wind Energy Area	The rights to a lease area have yet to be auctioned to offshore wind energy developers. Capacity is estimated using a 3 MW/km^2 wind turbine density assumption.	8,290
Total U.S. OSW Pipeline:		51,941

Source: W. Musial, P. Spitsen, P. Duffy, *et al.*, DOE, Offshore Wind Market Report 2022, August 2022, at 8. Updated with the latest activities of BOEM in the Gulf of Mexico and California.

Existing lease areas, identified wind energy areas, and call areas in different regions are shown in Figure 2. BOEM is planning to continue to make available WEAs and award leases through its auction process as shown in Figure 3—with additional lease auctions planned for the Gulf of Mexico, the Central Atlantic, Oregon, and the Gulf of Maine before the end of 2024.[13]

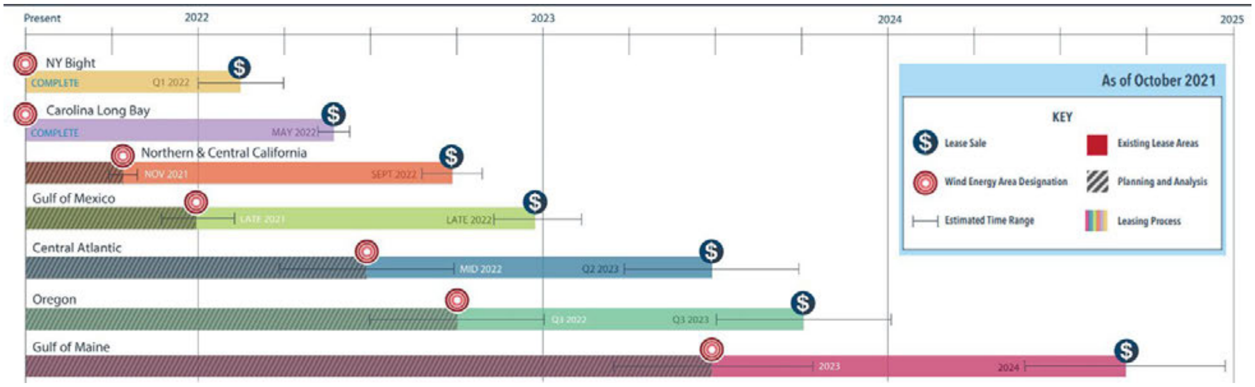
[13] The process to identify and release a new lease area to developers takes several years. For example, BOEM first initiated action in support of the California leases in August of 2016, with a published Request for Interest. BOEM then published a call for information and comment in 2018, another call in 2021, before identifying the wind energy areas in July of 2021, announcing a lease sale in May of 2022, and conducting the lease sale in December of 2022. See BOEM, Request for Interest in California OSW, August 18, 2016; California Activities, History.

FIGURE 2: U.S. OFFSHORE WIND ENERGY AREAS AND CALL AREAS (AS OF 05/31/2022)



Source: W. Musial, P. Spitsen, P. Duffy, *et al.*, DOE offshore wind market report 2022, August 2022, at 12, 14, 18 (BOEM activities as of 05/31/2022). Since May 31, 2022, BOEM updated the draft Call Area of 9.9 million acres in the Gulf of Maine in January 2023; finalized two WEAs in the Gulf of Mexico on October 31, 2022 within the Call Area 49 in the figure above; and sold two lease areas off central and northern California on December 7, 2022 (WEA 51 and 52).

FIGURE 3: BOEM OFFSHORE WIND LEASING SCHEDULE



Source: BOEM, Offshore Wind Leasing Path Forward 2021–2025, October 2021.

Importantly, the ability to develop OSW generation off U.S. coasts through 2050 substantially exceeds the capability of the leases and WEAs BOEM has made available to date or is planning to make available in the near future. For example, NREL's 2022 study of Offshore Wind Energy Technical Potential found that, after excluding areas unavailable or unsuitable to OSW development, more than 4,000 GW of technical offshore wind resource potential exists off the coasts of the continental United States, as summarized in Table 3 below.

TABLE 3: UNITED STATES' TECHNICAL OSW RESOURCE POTENTIAL

Region	Total (GW)	Fixed-Bottom (GW)	Floating (GW)	Share of Fixed (%)
California	92	4	88	4%
Great Lakes	575	160	415	28%
Gulf	1,563	696	867	45%
Mid-Atlantic	323	157	166	49%
North Atlantic	706	264	442	37%
Washington/Oregon	216	7	209	3%
South Atlantic	774	188	586	24%
Continental U.S. Total	**4,249**	**1,476**	**2,773**	**35%**

Source: NREL, Offshore Wind Energy Technical Potential for the Contiguous United States, August 15, 2022, at 16.

Without a doubt, sufficient OSW development potential technically exists to meet currently projected state OSW generation needs of over 100 GW by 2040 and state and broader national needs of 200–460 GW by 2050 as summarized in Figure 1 above. The generation output of these OSW plants developed in the Atlantic, Pacific, and the Gulf of Mexico—including floating plants in deep-water lease areas in the Gulf of Maine and off the Pacific coast—will need to be delivered to the onshore grid and to electricity customers in the various population centers. Doing so will require many offshore cables buried in the ocean floor and numerous landfall locations. It will also require points of interconnection (POIs) to the existing grid, and upgrades to the onshore grid to allow for the injection of OSW generation at these POIs and to deliver the energy from there to the various load centers. The development of these OSW-related transmission solutions will have to be coordinated with the existing generation interconnection and transmission planning processes of the regional transmission system operators. On the East Coast, where U.S. OSW development is most active, these system operators are ISO-NE, NYISO, and PJM (which covers the coastline from New Jersey to North Carolina).

B. The Urgency of Starting Proactive Planning

Addressing the interconnection and transmission needs for the substantial amount of U.S. OSW generation development will be challenging. This is particularly the case for meeting the large 2040 and 2050 OSW generation needs, because the transmission grid currently lacks the capability to connect these amounts of new OSW generation and deliver the generation to loads. For example, ISO-NE's 2050 transmission study shows that upgrades will be needed to address 4,500 miles of overloaded onshore transmission lines[14] and several national studies, such as the "Net Zero America" study by Princeton University, project that the capability of today's transmission grid would need to be at least doubled (if not increased five-fold) of this timeframe.[15] It is clear that neither the physical infrastructure nor the current processes of planning and developing the necessary transmission are adequate to meet the challenges presented by the deployment of OSW resources at the already-known scale.

If offshore wind and broader clean energy goals are to be achieved in a timely and cost-effective manner, it is clear that policymakers and the industry must start to reform the transmission planning process and other associated reforms *now*. To cost-effectively and reliably integrate the anticipated new generation and achieve OSW and decarbonization goals, it is essential and urgent to start planning processes that can identify cost-effective and least-regrets transmission development pathways for interconnecting the significant amounts of OSW generation projected to be necessary to meet clean energy goals over the next decades. The immediate challenge is to find solutions that can cost effectively integrate the 30 GW of OSW generation already procured or scheduled to come online over the next decade without

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14 A. Kniska and R. Collins, ISO-NE, 2050 Transmission Study: Preliminary N-1 and N-1-1 Thermal Results, March 15, 2022, at 18.

15 E. Larson, *et al.*, Princeton University, Net-Zero America: Potential Pathways, Infrastructure, and Impacts—Final Report Summary, October 29, 2021, at 17.

foreclosing cost-effective pathways towards integrating at least 110 GW (and possibly more than 400 GW) by 2050.

Transmission facilities for offshore wind may take a decade to plan and develop.[16] As a result, any planning efforts started today will not yield significant transmission infrastructure until into the 2030s. Further, because a transmission solution often must be identified significantly in advance of an offshore wind generation solicitation being issued, the lack of a federal or multi-state transmission planning effort risks locking in the current radial tie-line approach.

Integrating a large amount of additional offshore wind energy between 2030 and 2050 will need significant offshore and onshore transmission infrastructure to connect the projects to the existing grid. The ongoing delays in generation interconnection and transmission planning pose a challenge to even the OSW generators procured to meet near-term OSW goals. Any delay in acting to reform transmission and interconnection planning for OSW generation and other clean energy policy needs would only increase the challenge of timely and efficiently realizing long-term state, regional, and national clean energy and decarbonization goals. This is because today's transmission planning and interconnection processes rely on piecemeal and reactive approaches that fail to identify the most cost-effective and lowest-impact transmission solutions to allow for the integration of OSW generation in both the near term but particularly the even larger amounts of OSW generation required by 2040 and 2050.

This planning challenge was analyzed in the United Kingdom, where a study found that the use of proactive national transmission planning could reduce by 19% the costs to integrate an incremental 60 GW of OSW generation needed by 2050 (£5.5 billion or $7.4 billion in capital cost plus £1 billion saving in operational costs), reduce the miles of transmission cables installed in the ocean floor by 35%; reduce onshore transmission upgrades by 62%; and reduce the number of beach crossings by 70%.[17] The study also found that an only 5-year delay of implementing such planning would reduce the benefits of doing so by half. Similarly, NYISO system planning and interconnection studies found that continued reliance on current processes will result in significant OSW curtailments and increase future upgrade costs by hundreds of millions of dollars.[18]

[16] For example, see J. Saul, N. Malik and D. Merrill, The Clean-Power Megaproject Held Hostage by a Ranch and a Bird, *Bloomberg Green*, April 12, 2022.

[17] NationalGrid ESO, Offshore Coordination Phase 1 Final Report, 2020, at 4, 31, and 34.

[18] Shell, Comments of Shell Energy North America (US), L.P. and Shell New Energies, LLC Addressing Participating New England States Regional Transmission Initiative—Request for Information, 2022, at 6–7.

As described more fully below, many of these long-term planning benefits are reliant on beginning the process for identifying and constructing transmission far enough in advance of OSW project development to enable the necessary level of near- and long-term coordination and planning of transmission solutions. Without such proactive planning, the type and locations of transmission facilities chosen built to address the interconnection of individual OSW generation projects over the next decade will necessarily impact the type and locations of transmission facilities that can be built to meet 2040 and 2050 needs. If transmission technologies, corridors, and grid interconnection points used to address OSW generation interconnection over the next decade do not consider longer-term needs, achieving 2040 and 2050 goals will be more expensive and result in increased environmental and community impacts.

Any delay in starting proactive planning efforts for integrating the large amounts of OSW generation needed over the next decade and beyond will, accordingly, result in suboptimal transmission solutions with higher costs, greater risks and possible delays, and higher environmental and community impacts. If states proceed with OSW procurements that rely on conventional radial interconnection facilities, opportunities to coordinate elements of needed transmission will rapidly shrink; each selected OSW project will utilize a landing point and grid interconnection point in a way that will almost invariably be inefficient in the long term.

If the development of offshore wind transmission solutions continues to be focused solely on near-term needs, it will inevitably lead to technology choices that—while suitable for individual projects—prevent the development of modular transmission solutions that can serve near-term needs while simultaneously creating the flexibility to expand and integrate the facilities into a more beneficial, regionally and interregionally networked offshore transmission solution over time. Thus, even as states proceed with their already-scheduled procurements of OSW generation, there is an opportunity to specify modular transmission designs—such as network-ready offshore substations or higher-capacity high voltage, direct current (HVDC) designs—that create flexibility and preserve the ability to maximize the long-term value of the facilities by being able to integrate them into a networked grid over time. Unless future-proof technology standards are developed *now*, the continued use of incompatible technologies will make it nearly impossible to realize efficient regional and interregional grid solutions in the future.

Reflecting this urgency of more proactive transmission planning for OSW generation, some states have started to procure more comprehensive transmission solutions for meeting their OSW goals. For example, New Jersey has just completed a transmission-only procurement with PJM to address its entire 2035 OSW generation needs, which yielded transmission solutions for

6,400 MW of OSW generation that reduced costs by approximately $900 million and offered significantly lower environmental and community impacts.[19] New Jersey's experience demonstrates vividly that currently used generation interconnection processes are not designed to optimally utilize available POIs and existing transmission capability and yield transmission solutions that could cost-effectively meet the much broader set of future transmission needs. New England states have similarly issued a Request for Information (RFI) to address the regions' current OSW transmission needs.[20] However, while a step in the right direction, the limited geographic scopes and time horizon of these OSW transmission planning efforts will not yield regional and interregional transmission solutions that can most cost-effectively address the full suite of state, regional, and national long-term OSW transmission needs. In contrast, the more holistic planning efforts now underway in the UK have already identified specific transmission projects that will enable the interconnection of 23 GW of OSW resources, while satisfying reliability needs, enhancing OSW availability, reducing environmental impacts by up to 30%, and resulting over £5 billion in customer benefits.[21]

Identifying the most attractive long-term solutions will require the development of more proactive planning processes that simultaneously consider the full set of transmission needs (*i.e.*, reliability, congestion relief, public policy, and generation interconnection needs) over a long-term planning horizon (*i.e.*, through 2040 or 2050 to consider already-known policy needs).[22] Such a long-term, multi-value planning process—which will have to be scenario based to consider long-term uncertainties—will be able to identify least-regrets transmission solutions that (if flexibly developed) can more cost-effectively integrate OSW and other clean-energy resources over time and reduce environmental impacts compared to the currently used incremental generation interconnection and narrowly focused transmission planning efforts.

As discussed further in Section II below, where such proactive, long-term, multi-driver, scenario-based transmission planning processes are already used, they have led to planning outcomes that substantially reduce system-wide costs. In the context of OSW integration, existing proactive studies and planning efforts have shown that proactive planning will reduce the environmental and community impacts through fewer landing points, fewer cable line

[19] J. P. Pfeifenberger, J. M. Hagerty, J. DeLosa III, The Brattle Group, New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report, October 26, 2022. (BPU SAA Evaluation Report)

[20] See New England States Transmission Initiative.

[21] NationalGrid ESO, Pathway to 2030, July 2022, at 9.

[22] See J. Pfeifenberger, R. Gramlich, *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, the Brattle Group and Grid Strategies, October 13, 2021; J. Pfeifenberger and J. DeLosa, Transmission Planning for a Changing Generation Mix, OPSI 2022 Annual Meeting, October 18, 2022.

miles, and less onshore land use. With fewer facilities built at a larger, more efficient scale, proactive planning will significantly reduce permitting challenges and increase the likelihood of meeting the clean energy and decarbonization goals in a timely fashion.

Many OSW experts and market participants have highlighted the urgency to start proactive planning for offshore wind transmission in their responses to the recent RFI of New England States on regional offshore transmission needs.[23] For example:

- Shell explained that "the need to coordinate the interconnection of [individual offshore transmission] facilities is paramount first on a regional basis and, subsequently, as a critical building block for the development of an integrated interregional transmission network."[24]
- Tufts University noted that "there are many benefits to thinking holistically about transmission landfalls in coordination with port infrastructure, storage, and hydrogen production. A 300 GW OSW build-out represents an approximately $1 [trillion] investment to be made on a very short timeframe (27 years). The U.S. has only one chance to get this right, and it is essential that we view this massive challenge with the respect it deserves. Interregional collaboration and planning with input from state, federal and RTO personnel is essential to working these issues out on a holistic level."[25]
- Anbaric explained that the "radial only" approach that was used to interconnect OSW projects at the inception of these programs is no longer viable. "Moving to a planned approach is a prerequisite to achieving the 30,000 MW of offshore wind needed to achieve 2050 decarbonization goals [in New England]."[26]
- The American Clean Power Association (ACP) and RENEW Northeast (RENEW) highlighted the urgency of initiating planning efforts based on robust long-term goals: "Major transmission projects typically take longer to complete than generation projects, and

[23] *See Regional Transmission Initiative* (including Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island)*, Notice of Request for Information and Scoping Meeting*, September 1, 2022; For further information, see the New England States Transmission Initiative—New England Energy Vision webpage.

[24] Shell, Comments of Shell Energy North America (US), L.P. and Shell New Energies, LLC Addressing Participating New England States Regional Transmission Initiative—Request for Information, 2022, p.at 2 ("… the need to coordinate the interconnection of these facilities is paramount first on a regional basis and, subsequently, as a critical building block for the development of an integrated interregional transmission network.")

[25] Tufts University, Request for Information: Regional Transmission Initiative Connecticut, Maine, Massachusetts, New Hampshire, and Rhode Island, 2022, at 9.

[26] Anbaric, Scaling Renewable Energy (RFI Comments), 2022, at 1.

proactive development of the near-term transmission projects must start now if growth of renewable energy is to continue."[27]

- Eversource stressed that: "the evolution of policy objectives dictates that the New England region could benefit from a more comprehensive, holistic and forward-looking planning process to identify, with direction from the states, transmission investments that will be needed to integrate the coming influx of renewable resources to achieve state policy goals…. [W]e need to act ***now*** on a set of targeted solutions that address existing interconnection queue backlogs, facilitate near-term clean energy procurements, improve winter reliability, position the region for electrification, and provide financial benefit to customers via DOE funding…. Eversource is concerned that transmission procurements modeled directly on prior RFPs for clean energy generation could result in siloed and chaotic transmission development that results in higher costs to customers, does not comprehensively address the region's reliability and clean energy needs, and indeed puts meeting clean energy goals at risk."[28]

The need to expeditiously address OSW transmission through more proactive planning is particularly pressing because today's generation interconnection processes, which evaluate needs only incrementally (such as one project or one group of projects at a time), have already been stretched well beyond what they have been designed for, resulting in significant delays and unnecessarily high costs of OSW interconnections. As Ocean Winds (OW) has noted in its New England RFI response:

> OW's collective US interconnection experience … has been that the ambiguity and the long duration of existing interconnection practices … have been a challenge for advancing large offshore wind projects. Given the cost, capacity, and temporal uncertainty of the interconnection process, offshore wind developers are effectively and implicitly encouraged to file multiple duplicative interconnection requests in order to de-risk their projects potentially delaying interconnection studies of later interconnection applicants…. As more and more interconnection requests are filed, the self-interest of each developer will further incentivize each developer to file even a higher number of interconnection requests in advance, further hindering

[27] American Clean Power Association and RENEW Northeast, Comments of the American Clean Power Association and RENEW-Northeast on Changes and Upgrades to the Regional Electric Transmission System Needed to Integrate Renewable Energy Resources, 2022, at 6.

[28] Eversource, Comments of Eversource Energy Service Company on behalf of The Connecticut Light and Power Company, NSTAR Electric Company and Public Service Company of New Hampshire, at 2 [emphasis original].

> the speed of interconnection process for all market participants in a vicious cycle of self-interest of first movers in the interconnection queue. This unintended consequence of the existing interconnection process perpetually increases the number of grid upgrades being cost-allocated, putting an unreasonable price tag and a level of cost-uncertainty in each interconnection application.… Simply limiting speculative, hence risk-mitigating, duplicative interconnection requests and "purging queues" is not the answer. Instead, there is an urgent need for proactive action: a clear policy signal to offshore wind developers that if a state-facilitated offshore wind project is awarded, the State will enable the grid upgrades needed to "beef up" the key coastal POIs that offshore wind projects will need to utilize.[29]

Finally, initiating planning and technology standardization efforts now is particularly compelling since, as discussed further in Section III below, the federal government is offering technical and financial support, including tax credits for generation interconnection facilities, that can be used to address planning challenges, lower costs, and facilitate contracting for the state and nation-wide clean-energy needs, and proactively develop both regional and interregional transmission solutions. Some of this support and funding may not be available if planning efforts are delayed. States need to act quickly to secure available federal funding. For example, DOE issued a Funding Opportunity Announcement (FOA)[30] in November 2022 for the Grid Innovation Program (GIP) as part of the Bipartisan Infrastructure Law (Section 40103(b)) to fund projects that aim to improve grid reliability and resilience and states are eligible to apply. Some states including Massachusetts, Connecticut, Rhode Island, and Maine have started to act and requested notices of interest and draft concept papers from developers for states to consider as part of a GIP funding application.[31]

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29 Ocean Winds, Comments of OW North America LLC on Regional Transmission Initiative Notice of Request for Information and Scoping Meeting, October 28, 2022.

30 Opportunity: BIL Grid Resilience and Innovation Partnerships (GRIP)

31 See the individual states' notices: Massachusetts (responses due December 22, 2022), Connecticut (responses due December 23, 2022), Rhode Island (responses due December 28, 2022), and Maine (responses due December 30, 2022).

II. The Benefits of Proactively Planned Offshore Wind Transmission

The advantages of proactive regional and interregional planning are increasingly well-understood and show that proactive planning offers a wide range of benefits. These benefits include: (1) cost savings; (2) improved grid reliability and resilience; (3) environmental benefits and reduced community impacts; and (4) the employment and economic benefits of developing OSW resources in an efficient and timely fashion. Studies that document these benefits of proactive planning are summarized below. Based on these studies, assuming at least 100 GW of additional U.S. OSW generation procurements between 2030 and 2050, the benefits of proactive planning efforts translate to around $20 billion in reduced transmission costs, 60–70% fewer shore crossings and onshore transmission upgrades, and up to 2,000 fewer miles of marine transmission cable trenches on the ocean floor by 2050. Many of these benefits are reduced considerably if proactive planning efforts are delayed.

A. Cost Savings from Proactive Regional Planning

Proactive long-term planning can reduce the total cost of a clean-energy grid by developing solutions that can more efficiently address multiple transmission needs simultaneously, instead of relying on incremental solutions to many individual needs over time. These proactive planning benefits have been demonstrated through targeted interconnection studies as well as regional multi-value planning efforts.

Benefits associated with proactive planning that includes offshore transmission are likely to increase as technology continues to develop, allowing for the integration of multiple and larger OSW generation projects into networked transmission solutions that add to regional and interregional transfer capability of the existing grid. To enable the benefits, the planning efforts must consider the transition from today's interconnection processes based on radial interconnection facilities to more cost-effective regional and interregional transmission solutions.

Several recent transmission studies document the significant cost savings that proactive planning efforts can achieve:

- ***PJM's Offshore Wind Transmission Study*** highlights the stark difference in generation interconnection costs if long-term interconnection needs are planned proactively. A previous OSW study showed that under the then-current interconnection process, which relied on individual interconnection studies for each queue request, PJM identified $6.4 billion in required upgrades to the onshore grid for 15.6 GW of individual OSW plants,[32] or $413 per kW of renewable generation.[33] In contrast, PJM's 2021 Offshore Wind Transmission Study showed that proactively planning interconnection needs for an estimated 74.5 GW of combined onshore wind, offshore wind, and solar capacity needed to meet the current public policy goals of PJM states would require only $3.2 billion of onshore system upgrades to facilities above 100kV,[34] resulting in interconnection costs of only $43 per kW of renewable generation. If these study results were actually implemented by PJM, it would yield a nearly 90% reduction in the cost of major onshore upgrades (before adding the cost of lower-voltage transmission upgrades) to accommodate interconnection of the resources necessary to meet existing clean energy goals of PJM states.

- The recent ***PJM-New Jersey State Agreement Approach (SAA)*** experience with more proactively addressing the 6,400 MW of additional OSW generation interconnections needed to reach the state's 7,500 MW OSW goal for 2035 similarly showed substantial savings compared to pursuing generation interconnection incrementally through PJM's conventional process. This proactive planning effort, conducted under PJM's never-previously used SAA, was focused only on New Jersey's OSW interconnection needs through 2035, yet yielded substantially lower-cost solutions for the identified upgrades to the onshore grid. In response to the SAA solicitation that received 80 proposals from 13 bidders, PJM and the New Jersey Board of Public Utilities have now approved onshore transmission upgrades to nine companies that will: (1) reduce the total cost of transmission needed to add an additional 6,400 MW of OSW generation by 2035 by over $900 million; (2) significantly reduce schedule and cost uncertainties; (3) utilize the existing grid more efficiently; (4) develop a shared collector substation with sufficient space for the HVDC converter stations of up to four OSW generators that allows for a significant reduction of transmission-related environmental and community impacts; (5) maximize the availability of approximately $2.2 billion in federal tax credits; and (6) allow the state to more cost-effectively reach its new 11,000 MW by 2040 offshore wind goal through future

[32] Business Network for Offshore Wind and Grid Strategies LLC, Offshore Wind Transmission Whitepaper, 2020, at 11.

[33] See also J. Seel, *et al.*, Interconnection Cost Analysis in the PJM Territory, Berkeley Lab, January 2023. Figure 5 of this study similarly shows approximately $400/kW in average cost for OSW generation in PJM's interconnection queue currently—higher than the interconnection costs of any other resource type and with an uncertainty range of $200/kW to over $500/kW.

[34] PJM, Offshore Wind Transmission Study: Phase 1 Results, 2021, at 14, 18.

procurements.[35] While New Jersey did not select any offshore transmission through this SAA, the state issued its new draft solicitation framework for the next OSW generation procurement with provisions that require both (a) the use of "network-ready" HVDC cables and offshore substation designs and (b) the construction of a shared onshore transmission corridor with the space for HVDC converter stations pre-built conducts and vaults that can accommodate the HVDC cables of up to four OSW generators.[36]

- The benefits of proactive planning—even if focused solely on generation interconnection needs—are similarly documented in ***MISO's and SPP's Joint Targeted Interconnection Queue Study (JTIQ)***. By pooling 5-years' worth of generation interconnection requests on both sides of the MISO-SPP seam, the two RTOs identified $1.6 billion in interregional transmission solutions that facilitate the integration of over 28 GW of generation interconnection at a cost of only $58 per kW of renewable resources, reducing interconnection costs by over 50% (from $117/kW under the system operators' individual interconnection processes), while additionally reducing the congestion and fuel costs of MISO and SPP customers by approximately $1 billion.[37]
- ***MISO's Long Range Transmission Planning (LRTP)*** effort is perhaps the best available example of how scenario-based long-term planning for multiple transmission needs—simultaneously for generation interconnection, regional reliability, congestion relief, and public policy needs—offers substantial overall cost savings to electricity customers. MISO's LRTP effort resulted in the approval of a $10 billion "least regrets" portfolio consisting of 18 multi-value transmission projects in MISO's Midwestern Subregion. In addition to addressing long-term reliability needs throughout the region, the multi-value portfolio of transmission investment will reduce congestion and fuel costs, avoid capital costs of local resource and other transmission facilities, reduce resource adequacy costs and customer load shedding, while also supporting member states' decarbonization policies by helping integrate low-cost wind resources in its footprint. MISO estimated that the transmission investments, which are associated with $14 billion of expenses (including operating costs) over the initial 20 years, will reduce other MISO costs by between $37 billion and $54 billion over the same timeframe—producing significant net benefits that reduce the total costs

35 See BPU SAA Evaluation Report. The SAA process identified $575 million in upgrades to the existing grid for 6,400 MW, or $90 per kW of OSW generation. This is approximately 60% less than the $1.5 billion ($234/kW) cost of grid upgrades estimated based on PJM's most recent individual OSW interconnection studies.

36 New Jersey Board of Public Utilities, Solicitation Documents—NJ Offshore Wind, Attachment 10 (Prebuild Infrastructure Requirements) and Attachment 11 (Offshore Transmission Network Preparation Requirements).

37 Tsuchida, Proactive Planning for Generation Interconnection A Case Study of SPP and MISO, The Brattle Group, August 17, 2022, at 9.

faced by MISO's customers.[38] Importantly, this portfolio of transmission projects is designed to facilitate a significant shift in MISO's generation mix over the next two decades, including the retirement of about 58 GW of mainly coal-fired power plants, and the addition of about 90 GW of solar, gas, and wind generation by 2039.[39]

- National Grid's ***U.K. OSW study*** analyzed the impact planning would have on the integration of 60 GW of wind generation between 2025 and 2050. The study estimated that, if planning results are implemented starting in 2025, the U.K. could reduce total transmission-related capital costs by 19%, saving approximately $7.4 billion. The estimated savings drop to half that amount if implementation of planning results is delayed by only 5 years, from 2025 until 2030.[40]
- Anabaric's ***New England OSW transmission study*** found that a planned approach based on more expensive high-capacity offshore transmission links to more distant load centers on the existing grid decreases the total combined onshore and offshore transmission costs by $0.5 billion for 3,600 MW of planned additional New England OSW procurements—an 11% reduction of total transmission-related costs.[41]
- A study by the Lawrence Berkley National Laboratory (***LBNL Study***) has analyzed differences in wholesale electricity prices over the last decade to estimate the extent to which expanding transmission capabilities within and between regions could offer significant benefits. The analysis shows that the median price differences across locations within individual regions was $11/MWh in 2021. The analysis also shows that 1,000 MW of expanded transfer capabilities between coastal locations within PJM or CAISO—which may be achievable cost-effectively through proactively planned offshore networks—would have offered benefits of $100–150 million annually in each of 2021 and 2022.[42]

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[38] MISO, LRTP Tranche 1 Portfolio Detailed Business Case, June 25, 2022, at 57–58.

[39] *Id*. at 4. *See* also Utility Dive, MISO board approves $10.3B transmission plan to support 53 GW of renewables, July 26, 2022.

[40] National Grid ESO, Offshore Coordination Phase 1 Final Report, 2020, at 31. National Grid's UK OSW study found that without proactive planning, the best POIs for connecting offshore wind to the UK electric transmission network quickly became saturated, and that additional POIs developed to supplement them were not as ideal, requiring extensive upgrades to the onshore transmission network.

[41] J. Pfeifenberger, Offshore Transmission in New England: The Benefits of a Better-Planned Grid, The Brattle Group, prepared for Anbaric, May 2020, at 17. See also J. Pfeifenberger, *et al.*, Offshore Wind Transmission: An Analysis of Options for New York, The Brattle Group, prepared for Anbaric, August 2020, documenting a similar magnitude of savings for New York.

[42] LBNL, Empirical Estimates of Transmission Value Using Locational Marginal Prices, 2022, at 3 and 18–19.

- The ***Massachusetts Decarbonization Pathways*** report found that to achieve a cost-effective regional electricity system, significant transmission expansions would be necessary within New England and to neighboring regions. For example, between 1.8 GW and 2 GW of additional transfer capability would be cost effective between Maine, New Hampshire, and Massachusetts and approximately 1 GW of additional transfer capability would be cost effective between Connecticut, Rhode Island, and Massachusetts in the study's regional coordination scenario.[43] The study identified even larger interregional transmission needs as discussed below.

As noted in RENEW's "Blueprint for New England" study, interconnection costs are currently rising rapidly for new OSW generation projects. In New England, early OSW projects interconnected at a cost of $10/kW, which has now increased to $275/kW for the most recent projects.[44] Additional attempts to interconnect OSW generation through current interconnection processes will lead to further increases in OSW interconnection costs unless addressed proactively. However, when interconnection requests are addressed proactively and at sufficiently large scale, the average costs of interconnection tend to be lower.[45] The studies summarized above consistently document that these significant increases in interconnection costs that OSW generation faces under the current interconnection processes can be mitigated through more proactive planning of generation interconnection needs, particularly when planned in conjunction with other regional and interregional transmission needs.

Extrapolating from these studies, **proactive planning for** the interconnection of at least **100 GW of additional offshore wind generation** beyond already ongoing procurements would yield at least **$20 billion in transmission-related cost savings**—even before considering risk mitigation, reduced environmental and community impacts, and the broader regional and interregional benefits of a networked offshore transmission grid.[46] Given that incremental offshore wind

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[43] R. Jones, *et al.*, Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, Evolved Energy Research, December, 2020, Table 8, p. 64.

[44] RENEW Northeast, Comments of the American Clean Power Association and RENEW-Northeast on Changes and Upgrades to the Regional Electric Transmission System Needed to Integrate Renewable Energy Resources, 2022, at 2.

[45] Compare incremental interconnection costs of $413/kW from previous PJM generation interconnection studies for individual OSW generators, and $275/kW anticipated in the short-term in New England, against costs of proactive planning efforts at $89/kW for Option 1a (interconnection) facilities in New Jersey's SAA (for 6.4 GW of OSW generation), MISO-SPP JTIQ at $58/kW (for 28 GW of renewables), and the PJM Offshore Wind Transmission Study at $40/kW (for 75 GW of renewables, including OSW).

[46] For example, the New Jersey BPU evaluation of transmission alternatives estimated that in the absence of coordinated transmission procurements through the State Agreement Approach, the total cost of onshore and offshore transmission facilities to interconnect 6,400 MW of OSW generation would be $8.9 billion (before

generation needs will likely exceed 100 GW through 2050, and could possibly reach more than 400 GW, the total savings associated with proactively planned transmission solutions will be substantial. Importantly, the planning activities conducted over the next few years will determine if the OSW generation procured for the next decade can be integrated in a timely and cost-effective manner. Because decisions made today will have long-term consequences, they determine the extent to which 2050 OSW generation needs can be integrated cost effectively.

B. Cost Savings and Resilience Value of Expanding Interregional Transmission

Well-planned offshore transmission can integrate OSW generation more cost effectively while also reinforcing the onshore grid, with cost and resilience benefits spread across regions. Interregional benefits include more efficient wholesale market outcomes, reduced congestion, fewer curtailments of renewable generation, reduced costs, improved reliability during challenging market conditions, and resilience benefits during extreme conditions. These benefits are enabled through increased interregional transfer capabilities—some of which may be made feasible and most cost-effectively provided through a well-designed offshore transmission network. In other words, since OSW generation is expected to account for a large share of additional clean energy resources in coastal areas, expanding interregional transfer capability through networked offshore transmission facilities may be a cost-effective way to achieve these benefits.

Several studies document the significant potential cost savings and resilience value associated with expanding interregional transmission:

- The ***LBNL Study*** analyzed regional and interregional price differences in wholesale electricity markets. The study showed interregional price differences offered significantly more

applying federal tax credits) or $6.7 billion (assuming federal tax credits for generation interconnection facilities). Applying these estimates of OSW transmission costs to 100 GW of nation-wide OSW additions, this translates to $139 billion (before tax credits) and $105 billion (after tax credits) in total OSW transmission costs. A 19% reduction of these transmission costs (as documented in the UK study summarized above) will translate to $20–26 billion per 100 GW of OSW. The estimated $20+ billion (or $200/kW) cost savings estimates exceed the savings realized by the smaller-scale OSW integration studies (such as the Anbaric and PJM SAA studies) but is consistent with savings identified in larger-scale studies—such as MISO LRTP results, which show that $10 billion in proactively planned transmission investments facilitates the integration of 90 GW of new resources, while reducing other costs between $37 billion and $54 billion over the first 20 years. The estimated $200/kW savings in OSW-related transmission cost is consistent with the results of PJM's 2021 study of the grid upgrade costs associated with integrating 75 GW of renewable generation (as discussed above).

opportunities for expanding transmission capabilities, including interregional transfer. For example, the median price difference between regional power markets was $24/MWh in 2021, compared to $11/MWh within regions.[47] While the highest interregional price differences have historically been observed in the interior of the U.S., average 2021 and 2022 price differences between ISO-NE, NYISO, and PJM indicate that expanding interregional transmission capacity between any two of these regions by 1,000 MW would have saved $100–300 million per year in wholesale power purchases. That benefit is anticipated to grow over time as more low-cost clean energy is added to the grid.

- The benefits of planned interregional transmission extend beyond U.S. borders. For example, an ***MIT study of the Northeastern U.S. and Canada*** found that "adding 4 GW of transmission between New England and Canada (Quebec in particular) is estimated to lower the costs of a zero-emission power system across New England and Quebec by 17–28%."[48] The study further notes that "in a low-carbon future, it is optimal to shift the utilization of the existing hydro and transmission assets away from facilitating one-way export of electricity from Canada to the U.S. and toward a two-way trading of electricity to balance intermittent U.S. wind and solar generation. Doing so reduces power system cost by 5–6% depending on the level of decarbonization."[49]
- A ***nationwide MIT study*** found that in a deeply decarbonized U.S. electricity system, an optimally expanded interregional transmission system could reduce the wholesale power price by 20% from $91/MWh to $73/MWh, when compared with a scenario without expanded interregional transmission capacity.[50]
- The ***Massachusetts Decarbonization Pathways*** report found that to achieve a cost-effective regional electricity system, significant transmission expansion would be necessary between New England and its neighboring regions in addition to expanding transmission within New England. For example, for the lower-cost, coordinated scenario, the study estimates that 6 GW of additional transfer capability would be cost effective between New York and PJM, that 2.3 GW of additional transmission would be cost effective between New York and New England (Connecticut and Massachusetts), and that 6.7–6.8 GW of additional transmission would be beneficial between Quebec and each of New York and New England (Maine,

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47 LBNL, Empirical Estimates of Transmission Value Using Locational Marginal Prices, 2022, at 3 and 18–19.

48 E. Dimanchev, *et al.*, MIT CEEPR, Two-Way Trade in Green Electrons: Deep Decarbonization of the Northeastern U.S. and the Role of Canadian Hydropower, 2020, at 1.

49 *Ibid.*

50 P. Brown, *et al.*, The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System, 2021, Figure 2.

Vermont and Massachusetts).[51] At least some of this additional interregional transfer capability may be provided most cost-effectively through a well-designed offshore transmission network.

- A recent General Electric Study for the Natural Resources Defense Council (***GE-NRDC study***) showed that expanding interregional transmission capability by 87 GW on various paths within the Eastern U.S. would provide $83 billion in estimated generation cost savings and avoided customer outage value.[52] The GE-NRDC study specifically concluded that interregional transmission would need to be expanded between New England and New York (by approximately 2 GW), between New York and PJM (by approximately 5 GW), and between PJM and the Southeast (by approximately 8 GW)[53]—all paths for which networked offshore transmission may be the most feasible and/or cost-effective solution.

  The GE-NRDC study illustrated resilience benefits based on system performance during a 2035 Polar Vortex, during which increased interregional transmission capability on the East Coast would provide $1 billion in resilience value (during the single event) by preventing around 2 million customers losing power in Boston, New York City, Baltimore, and Washington, DC. The GE-NRDC study similarly analyzed a heat wave event, during which the added interregional capability provided $875 million of benefits by preventing 740,000 customers from losing power in New York City and Washington, DC.[54] These resilience benefits of interregional transmission have generally been broadly recognized in the industry and by its regulators. As a FERC staff report has emphasized, "[t]he ability to share resources across regions, through use of the high voltage transmission system, provides important reliability and resilience benefits when the resources in one area are impacted due to an unexpected disruptive event."[55]

- Although the resilience value of expanding interregional transmission is difficult to quantify with the simulation models commonly utilized, the **LBNL Study** of historical wholesale energy market price differentials separately analyzed periods of stressed system conditions, which provides a strong indication of the importance of these benefits. The LBNL Study

[51] R. Jones, *et al.*, Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, Evolved Energy Research, December, 2020, Table 8, p. 64.

[52] S. Tandon Manz, *et al.*, Economic, Reliability, and Resiliency Benefits of Interregional Transmission Capacity Case Study Focusing on the Eastern United States in 2035, prepared by General Electric for NRDC, October 17, 2022, at 26.

[53] *Id.*, Figure 15).

[54] *Id.*, at 22.

[55] Report on Barriers and Opportunities for High Voltage Transmission, Prepared by the Staff of the Federal Energy Regulatory Commission, at 8 (June 2020), ("FERC High Voltage Transmission Report").

documented that 40% to 80% of the energy market value of transmission links is concentrated in only 5% of all hours of a year, reflecting the most challenging system conditions—including storms, cold snaps, and heat waves—that are often not considered in system simulations.[56] LBNL concluded that such spikes in transmission values "occur in different regions in different years" and that "extreme conditions in a single year, or even season, can materially increase the 10-year value of a [transmission] link."[57]

Proactive planning efforts can determine the extent to which offshore transmission networks offer the most feasible and cost-effective solutions to provide valuable additional interregional transmission capabilities between the regions along the nation's coasts. This opportunity to utilize offshore networks to expand interregional transmission capabilities has been broadly recognized. For example, the New York Public Service Commission highlighted that offshore transmission networks may create "additional benefits in terms of trading opportunities and increased reliability by making available alternative delivery routes through a neighboring system in the event offshore outages should affect the direct transmission links."[58] OSW generation developers have similarly noted in their New England RFI comments that "[l]arge-scale OSW project development across the Northeast presents unique opportunities to develop regional and interregional transmission infrastructure."[59]

The recent GE-NRDC study further notes that the additional interregional transmission would preferably be provided by HVDC links due to the additional system control and stability benefits HVDC technology can provide compared to traditional high voltage, alternating current (HVAC) transmission lines.[60] HVDC technology's advantages over traditional HVAC transmission solutions—including frequency response benefits and system stability enhancement,

[56] LBNL, Empirical Estimates of Transmission Value Using Locational Marginal Prices, 2022, at 28.

[57] *Id.*, at 22.

[58] State of New York Public Service Commission, Order on Power Grid Study Recommendations, January 20, 2022, at 11.

[59] Shell, Comments of Shell Energy North America (US), L.P. and Shell New Energies, LLC Addressing Participating New England States Regional Transmission Initiative—Request for Information, 2022, at 13.

[60] GE-NRDC Study, at 27–28.

particularly when transmitting power over long distances—have long been noted by transmission developers,[61] in FERC reports,[62] and by grid operators.[63]

As Invenergy explains in a recent request for a FERC technical conference on HVDC transmission, the benefits of HVDC lines, which in large part stem from advanced converter technologies, include, in addition to the reliability and resiliency benefits of interregional transfer capability: "(1) dynamic voltage support to the AC system, thereby increasing its transfer capability; (2) frequency support through fast ramp rates; (3) improved transient stability and reactive performance; (4) AC system (oscillation) damping; (5) 'decoupling' of the interconnected system so that faults and frequency variations between the wind farms and the AC network or between different parts of the AC network do not affect each other and otherwise providing a 'firewall' to limit the spread of system disturbances; and (6) black start capability to re-energize a 100% blacked-out portion of the network."[64]

FERC staff similarly recognized that grid-forming HVDC designs can provide black start capability by increasing the resilience of the grid by contributing to system restoration process in emergency conditions and reducing impacts of widespread outages[65] as well as ancillary services historically provided by localized dispatchable generation, which will be needed throughout the energy transition.[66]

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[61] Invenergy, Request for Technical Conference of Invenergy Transmission, FERC Docket AD22-13, July 19, 2022 (Invenergy Technical Conference Request).

[62] FERC HV Transmission Report at 10 ("HVDC transmission projects can also provide a variety of system stability benefits. For example, the Pacific DC Intertie is a long distance HVDC line (±500 kV DC, 3100 megawatts (MW)) that is used to transmit electricity from the Pacific Northwest to Los Angeles. Active modulation of real power in this HVDC line has been deployed as an effective strategy to improve system stability by dampening inter-area modes of oscillation in the Western interconnection.)(internal citations omitted)

[63] PJM, 2008 RTEP Reliability Analysis Update, October 15, 2008, at 8–10.

[64] Invenergy Technical Conference Request, at 5.

[65] FERC HV Transmission Report at 10 ("[I]f the system experiences a wide-area blackout, system restoration can be enhanced by using adjoining in-service transmission facilities to restore transmission lines, substations, generating plants, and customers to service. For example, the ability to energize transmission from neighboring systems sped the system restoration following the August 2003 blackout.")

[66] FERC HV Transmission Report, at 13.

C. Environmental and Community Benefits of Proactively Planning OSW Transmission

Proactive planning of OSW transmission offers the opportunity to select solutions with substantially reduced environmental and community impacts. The current OSW development processes results in separate transmission corridors to deliver the output of individual OSW generation project to shore and the points of interconnection with the existing grid. Coordinated planning and development processes for future OSW integration needs can significantly reduce the number of transmission corridors and construction efforts that result in environmental impacts and community disturbances. The planning for OSW transmission could incorporate the community and equity as core elements. A meshed transmission networks have the potential of realizing higher community and equity benefits.[67] Both U.S. and international studies and procurement efforts have documented these benefits.

- National Grid found that proactive planning of the U.K.'s 2050 OSW transmission needs offers significantly **reduced marine and shoreline impacts**. The study found that the number of beach crossings needed to achieve 2050 OSW goals could be reduced by 70% (from 105 to 30) if implementation of planning efforts starts in 2025; if implementation of planning efforts is delayed to 2030, the number of beach crossings needed by 2050 would increase to 60.[68] The impacts on the marine environment to reach these landing points would be approximately 30% less, with the total length of offshore cable trenches reduced from 5,100 to 3,400 miles.[69]
- The U.K. OSW study similarly found substantially **reduced onshore impacts**. The study shows that proactive planning could reduce the length of needed onshore transmission lines and cable by about 60%, from 2,100 miles to 800 miles.[70] The study similarly found that if coordinated planning (with implementation starting in 2025) would reduce the land needed for onshore substation by 55%, from 953 acres to 427 acres;[71] if implementation of planning efforts is delayed until 2030, 766 acres would be required instead.

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67 V. Bourg-Meyer, S. Schacht, Clean Energy States Alliance, Offshore Wind and Equity Clean Energy States Alliance State of the States Report, November 2022, at 13-14.

68 National Grid ESO, Offshore Coordination Phase 1 Final Report, December 16, 2020 (U.K. OSW Study) at 34; based on Offshore Coordination Cost-Benefit Analysis of Offshore Transmission Network Designs, prepared by DNV-GL2020 (DNV OSW Study), at 37.

69 DNV OSW Study, at 36 (converted from km to miles).

70 DNV OSW Study, at 36 (converted from km to miles).

71 DNV OSW Study, at 38 (converted from hectares to acres).

- These findings have also been confirmed in studies by The Brattle Group for Anbaric (an independent transmission developer). For example, proactively planning the use of high-capacity HVDC submarine cables to reach more distant but more robust interconnection points on the existing grid is estimated to **reduce the need for onshore transmission** upgrades by 65%, while simultaneously **reducing the miles of cable trenches** on the ocean floor by approximately 50% for an additional 8 GW of OSW generation.[72]
- The general magnitude of environmental and community impacts estimated by the studies summarized above have been confirmed by **New Jersey's experience** of proactively procuring transmission solutions under PJM's State Agreement Approach—which allowed regulators to consolidate the onshore transmission needs of three OSW generators into a single transmission corridor that could be pre-built, thereby reducing onshore environmental and community impacts by approximately two-thirds.[73]

Based on this experience, proactive planning of OSW transmission **solutions for over 100 GW** of OSW generation would offer substantially reduced environmental and community impact, requiring **60–70% fewer shore crossings and onshore transmission upgrades**, and up to a **2,000 miles (50%) reduction of marine transmission cable trenches** impacting the ocean floor by 2050.[74] Additionally, proactive planning that provides a degree of "future-proofing" would reduce the need for highly expensive, specialized cable-laying and installation vessels to "re-do" offshore transmission facilities, by utilizing a coordinated approach that builds at the appropriate scale at the outset.

D. Employment Benefits of OSW Development

Development of the transmission solutions necessary to integrate OSW generation supports the substantial employment and economic stimulus benefits that OSW development offers to the states and regions. Several existing studies have evaluated the employment benefits of offshore wind development, estimating that the construction of 30 GW OSW would create between 80,000 and 135,000 jobs.

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72 J. Pfeifenberger, *et al.*, Offshore Transmission in New England: The Benefits of a Better Planned Grid, prepared for Anbaric, May 1, 2020, at 9.

73 BPU SAA Evaluation Report, at 14 (Scenario 18A).

74 Assuming an average OSW plant size of 1,200 MW and submarine cable of 50 miles for each plant, over 4,000 miles of submarine cable would need to be installed to integrate 100 GW OSW. Based on the 50% reduction estimated by Anbaric and 35% ocean cable mileages savings estimated in the U.K. OSW Study, the reduction in ocean miles of cable installations would range from 1,500 to 2,000 miles.

- A roadmap study for multi-state cooperation on offshore wind development, commissioned by the **Clean Energy State Alliance (CESA)**, found that the development of 8,000 MW of offshore wind generation is likely to create 36,000 full-time-equivalent jobs in project development and management, supply and installation of electrical substations and subsea cable, wind farm operation and maintenance, and equipment manufacturing. At the current scale of development—30 GW off the U.S. Atlantic Coast by the early 2030s, which greatly increases the likelihood of manufacturing more of the needed equipment locally—this would translate to 135,000 jobs for the region.[75]
- The **American Wind Energy Association** has forecasted that the development, construction, and operation for 20–30 GW offshore wind projects will support between 45,000 and 83,000 jobs by 2030.[76]
- **American Clean Power** estimates that the construction of 23–40 GW offshore wind projects would create 73,000–128,000 jobs, while 28,000 to 48,000 jobs in operations and maintenance roles, in the supply chain, and in surrounding communities could be permanently supported for the life of the projects.[77]

Continued industry growth to meet broader domestic targets are anticipated to foster higher shares of domestic manufacturing, which would further economic growth and employment opportunities. Proactively planned transmission solutions for offshore wind generation will support and enhance these employment and local economic stimulus benefit by reducing OSW development risk and ensuring that state and regional goals can achieved in a more timely and cost-effective fashion.

III. The Challenges and Barriers to Achieving Timely, Cost-Effective OSW Transmission Solutions

The development of more cost-effective long-term transmission solutions to meet state and national offshore wind goals faces several significant challenges that will need to be addressed

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[75] BVG Associates Limited for Multi-State Cooperation on Offshore Wind, U.S. Job Creation in Offshore Wind, Final Report, October, 2017, at S-1.

[76] American Wind Energy Association, U.S. Offshore Wind Power Economic Impact Assessment, March 2020, at 1.

[77] American Clean Power Association, Federal Revenue and Economic Impacts from BOEM Offshore Wind Leasing, December 2021, at 1.

expeditiously and collaboratively to achieve the benefits described above. These challenges include:

1. Slow, costly, reactive, and incremental **generator interconnection processes** currently used by the regional grid operators create delays and increase the cost of integrating clean energy resources.
2. Uncertainty over **federal investment tax credits** for generator and third-party-owned interconnection facilities and other federal funding imposes substantial uncertainty on OSW planning efforts.
3. Siloed **regional grid planning** processes that fail to identify cost-effective solutions that can simultaneously address the broad range of reliability, economic, and public policy transmission needs.
4. The absence of effective planning processes for **interregional transmission**.
5. The lack of HVDC **technology standardization** (*e.g.*, an HVDC grid code) and the slow adoption and operational integration of advanced HVDC technology in the U.S.
6. The lack of a compelling **benefits case** for meshed offshore grid solutions that reinforce the regional grid and provide interregional transmission capability.
7. Undefined **regulatory and contractual frameworks** for the shared and networked operation and use of offshore transmission facilities.
8. Regional **grid operations** that are not yet equipped to optimize fully regional or interregional HVDC links.
9. An unclear and poorly understood **BOEM permitting** process for offshore transmission that is distinct from offshore wind generators' individual interconnection cables.
10. **Uncoordinated processes** for lease-area auctions, state procurement of OSW generation, and regional transmission planning.

Several of these challenges have been highlighted in gaps assessments performed by DOE, including one each for the Atlantic[78] and West Coast[79] regions, and by the Business Network for Offshore Wind in its OSW transmission whitepaper.[80]

[78] Department Of Energy Office of Energy Efficiency & Renewable Energy, Atlantic Offshore Wind Transmission Literature Review and Gaps Analysis, October, 2021.

[79] Department Of Energy Office of Energy Efficiency & Renewable Energy, West Coast Offshore Wind Transmission Literature Review and Gaps Analysis, September 15, 2022.

[80] B. Burke, M. Goggin, R. Gramlich, Offshore Wind Transmission Whitepaper, Business Network for Offshore Wind, October, 2020.

These challenges are discussed in more detail below. If not addressed expeditiously, they collectively represent a substantial barrier to the timely and cost-effective development of OSW resources.

1. Inadequate Generator Interconnection Processes

The slow, highly-uncertain, costly, reactive, and incremental processes for generator interconnection (GI) currently used by regional grid operators is not suitable to optimize grid interconnection points for a timely and cost-effective integration of the substantial amount of OSW needed to meet even the already-existing state policy goals for the next decade. It will certainly not be able to support the much higher long-term needs through 2040 and 2050. While recent reforms to these GI processes have enabled minor improvements, the siloed structure of generator interconnection processes and their current separation from regional transmission planning processes will not enable the identification of optimal points of interconnections or efficient use of the transmission system.

As the volume of interconnection needs has increased, generation interconnection processes have become a barrier to timely and cost-effectively integrating clean energy into the grid. Historically, generator interconnection processes were designed to evaluate one connection request at a time in a process designed for legacy fossil fuel plants, when far fewer projects were simultaneously seeking to come online. Several regions have somewhat improved on a purely incremental study process[81] by studying “clusters” of several interconnection requests simultaneously, with the goal of speeding up interconnection processes. Unfortunately, these improvements have generally been insufficient to address the substantial backlog and uncertainty associated with the GI processes. Developers continue to identify interconnection processes as a major challenge to the timely and cost-effective development of clean energy resources.[82]

The incremental GI process may also ultimately cause substantial costs for offshore wind project interconnection. As described above, there are substantial benefits to the onshore grid associated with coordinating larger amounts of interconnection requests in a single study

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[81] See, for example, *PJM Interconnection LLC,* 181 FERC ¶ 61,162 (2022).

[82] See, for example, Ocean Wind, Comments of OW North America LLC on Regional Transmission Initiative Notice of Request for Information and Scoping Meeting, October 28, 2022, at 1 (“The ambiguity and the long duration of existing interconnection practices and procedures to identify, optimize, and cost quantify the full nameplate power deliverability at onshore injection points have been a challenge for advancing large offshore wind projects.”)

process. These benefits have been demonstrated through the JTIQ, PJM's OSW transmission study, and MISO's LRTP. The downside risks have also been observed, including the substantial growth in interconnection costs in Massachusetts from $10/kW for early projects, to over $275/kW for the most recent.[83] The cost of interconnecting the next wave of OSW to the grid in southeastern New England is anticipated to be well over $1 billion[84] and individual interconnection costs for OSW generation in PJM have grown increasingly uncertain and to a level where they exceed those of any other resource type.[85] Without coordinated planning, this individualized construction will likely prove insufficient to meet wider clean energy goals, increasing the costs of future OSW facilities that may require similar system capability.

Even the new cluster study processes, where GI requests are studied in a group rather than individually, retain large amounts of uncertainty for OSW project developers and are not designed to holistically optimize regional transmission systems considering long-term OSW integration and other system-wide needs. These processes continue to be separate from broader regional transmission planning efforts that, if integrated, would be able to identify more efficient regional transmission solutions that enable the integration of identified clean-energy resources with reliability and market efficiency needs, as discussed further below. Improvements to streamline GI processes also are not designed to proactively identify or optimize limited POIs in a manner that will ensure cost-effective solutions for long-term needs. FERC's recent Notices of Proposed Rulemaking regarding long-term transmission planning and

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83 American Clean Power Association and RENEW Northeast, Comments of the American Clean Power Association and RENEW-Northeast on Changes and Upgrades to the Regional Electric Transmission System Needed to Integrate Renewable Energy Resources, 2022, at 2. $7.7 million interconnection costs for 800 MW Vineyard Wind 1, $195.5 million for 800 MW Park City Wind and $335 million for the next 1200 MWs.

84 J. Pfeifenberger, S. Newell, W. Graf, K. Spokas, Offshore Transmission in New England: The Benefits of a Better Planned Grid, The Brattle Group, May 2020.

New 345kV overhead and underground transmission from West Barnstable to K Street in Boston has been estimated to cost $1.4 billion.

85 See J. Seel, *et al.*, Interconnection Cost Analysis in the PJM Territory, Berkeley Lab, January 2023. Figure 3 of this study shows that average interconnection costs of active projects in PJM's queue have grown from $29/kW to $240/kW, with the average interconnection cost of withdrawn projects (a measure of cost uncertainty faced by generators as they submit interconnection requests) now at $600/kW. Figure 4 shows that the large majority of interconnection-related costs are connected to upgrades to the broader regional network that are triggered by interconnection study criteria—upgrades that can be addressed more cost effectively through holistic planning, rather than incrementally. Figure 5 shows that the average cost of OSW generation in PJM's interconnection queue is now close to $400kW, higher than interconnection costs of any other resource type, and with an uncertainty range of $200/kW to over $500/kW. As discussed earlier, these interconnection costs and cost uncertainties compare to an average cost of proactively-planned onshore network upgrades of less than $90/kW for 6,400 MW under New Jersey's SAA with PJM.

generation interconnection[86] also fall short of requiring necessary improvement to generation interconnection processes and their integration with near- and long-term regional transmission planning processes. While the transmission planning NOPR proposed to add long-term multi-value transmission planning processes, it also does not propose to change the existing planning processes approved by Order 1000.[87] As a result, incremental generation interconnection and near-term transmission needs continue to be addressed first, pre-empting more efficient solutions that could be identified through more proactive planning processes that simultaneously consider multiple longer-term needs.[88]

2. Uncertain Federal Investment Tax Credits and Funding

A source of federal funding is likely to be necessary to promote offshore wind transmission efforts, particularly at the interregional level. The Federal ITC is a key component supporting the capital investment and development of OSW and other clean energy projects. While the Inflation Reduction Act (IRA) renewed provisions for a 30% investment tax credit for OSW generation, there is considerable uncertainty as to whether (a) HVDC transmission facilities from offshore wind generators to the onshore grid qualify for Federal ITC that applies to OSW generators' "wind energy property," including "transfer" and "power conditioning facilities" under Treas. Reg. § 1.48-9(e)(1); and (b) if so, whether those opportunities would extend to comparable facilities that are shared by multiple generators or are independently owned by stand-alone developers. Expeditiously confirming that the ITC is available for OSW generators' and third-party-owned "transfer" and "power conditioning" facilities that include HVDC converters and radial lines to shore is critical to promoting offshore wind transmission.

This uncertainty was specifically referenced in New Jersey BPU's SAA Evaluation Report, noting that:

> In contrast to independently owned transmission assets, the current ITC arguably does apply to "transmission assets" associated with the delivery of offshore wind generation, such as export cables and onshore interconnection

86 *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022); *Improvements to Generator Interconnection Procedures and Agreements*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 (2022).

87 *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 at P 3 (2022)("We do not propose in this NOPR to change Order No. 1000's requirements for public utility transmission providers with respect to existing reliability and economic planning requirements.").

88 For additional discussion of current GI challenges and recommended solutions, see also J. Pfeifenberger, Generation Interconnection and Transmission Planning, ESIG Special Topic Workshop, August 9, 2022.

> assets. In this regard, the Treasury Regulations that define "wind energy property" note that both transfer equipment and power conditioning equipment constitute ITC eligible property, while transmission equipment does not. The IRS has issued guidance on these regulations only once, in the context of an onshore wind farm with a single step-up transformer, and in that guidance demarcated the high side of the step-up transformer as the cut-off point. In contrast to an onshore wind project, we note that offshore wind facilities often must account for commercial and technical considerations when selecting the stepped-up voltage for the export cable. Because that voltage is often again stepped up (or potentially down) to transmission voltage at an onshore substation, many have found persuasive the argument that the export cable and onshore interconnection assets constitute power conditioning or transfer equipment, and not transmission equipment.[89]

Certain precedent potentially allows for ITC eligibility to include wind energy property that is owned by a separate entity. We understand that the Tax Court has rejected arguments that energy property only exists in the context of a "completely functional system,"[90] suggesting that energy property should be eligible for ITC even when only developing a portion of the complete system (*e.g.,* only the offshore transmission). Additional precedent appears to exist that may permit separate ownership of ITC-eligible property under certain circumstances.[91] Developers, such as Anbaric, have submitted comments to seek IRS guidance on the applicability of ITC to export cables and power conditioning equipment.[92]

The Internal Revenue Service (IRS) has not yet ruled on these issues in the context of OSW transmission, which means for OSW generation and (in particular) any independently planned and developed interconnection facilities, ITC eligibility remains uncertain. This uncertainty applies to all segments between the offshore substation (to which cables from each individual wind turbines tie into) and the onshore injection point of OSW energy—including offshore

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89 BPU SAA Evaluation Report, at Appendix C.3.

90 See *Cooper v. Commissioner*, 88 T.C. 84, 116–17 (1987) (rejecting an argument that energy property only includes "a completely functional system" in finding that ITC eligibility is not dependent on an individual taxpayer owning a complete system).

91 See Rev. Rul. 78-268, 1978-2 C.B. 10 (allowing proportionate ITC to co-owners of an electric generating facility despite their owning the facility as tenants in common with tax-exempt and municipally owned entities that are disqualified from receiving the ITC).

92 Anbaric, Anbaric OSW ITC Comments, December 19, 2022.

cabling, landing infrastructure, and upgrades to existing onshore electrical infrastructure. This has a substantial impact on the extent to which independent offshore transmission solutions are more cost effective than continued reliance on OSW generator-developed radial interconnection facilities. The New Jersey BPU's SAA Evaluation Report found, for example, that foregoing the ITC on facilities that interconnect OSW plants with the onshore grid would increase the cost of achieving New Jersey's offshore wind goals by approximately \$2.2 billion.[93]

A successful approach to building interregional transmission facilities likely requires federal cost-sharing beyond the ITC currently available. The full cost of a regional offshore wind transmission network is likely more than any one state's ratepayers can afford to fund, likely requiring both a broad regional cost allocation and federal assistance to buy-down the cost of a full offshore grid. Current federal transmission funding programs, including the GIP and Transmission Facilitation Program, do not have funds specifically directed towards offshore wind transmission, and do not appear well-tailored to provide funding opportunities for offshore wind, although several New England States have requested proposals that would employ these funding streams.[94] Instead, the federal government, either through an existing program or through new legislation, should establish a dedicated "challenge grant" opportunity that would encourage coastal states to come together with a joint proposal to compete for offshore wind grid funding.

3. Siloed Transmission Planning

Many existing transmission planning processes do not yet consider public policy and other transmission needs holistically and proactively. Rather, transmission planning is typically siloed into specific project categories that fail to optimize the broad range of reliability, market efficiency, and public policy benefits that can be provided simultaneously by well-planned regional transmission investments.[95] In addition, generation interconnection-related transmission upgrades and local transmission investments planned by Transmission Owners (often categorized as asset management or supplemental projects)[96] are separated from regional planning efforts that could identify more cost-effective regional solutions. Despite

93 BPU SAA Evaluation Report at 52, Table 7.

94 See New England States Transmission Initiative, December 16, 2022 Update, which includes state notices from Massachusetts, Connecticut, Rhode Island, and Maine.

95 See, for example, J. Pfeifenberger and J. DeLosa, Transmission Planning for a Changing Generation Mix, OPSI 2022 Annual Meeting, October 18, 2022.

96 See, for example, *PJM Interconnection LLC,* 172 FERC ¶ 61,136 (2020); see also ISO-NE, Final Asset Condition List, March 2021 (identifying \$4.6 billion dollars in ISO-NE Asset management projects as of June 2021); ISO-NE, 2021 Regional System Plan, November 2, 2021, at § 5.8.

differences in the transmission processes across the ISO/RTO regions, similarities exist in this reliance on siloed planning processes for different types of incremental needs, creating a substantial barrier for the identification of more cost-effective transmission solutions for OSW.

Furthermore, while it is critical that the results of offshore wind transmission planning be incorporated into the transmission plans developed by each grid operator, the process for inserting the results of any offshore wind transmission planning process into each planning process differs across regions. States may also need to engage in a coordinated submittal of planning goals into each regional transmission plan to ensure that offshore wind transmission planning has a tangible path forward. FERC initiatives such as the State Agreement Approach in PJM provide a path for individual states to insert their planning priorities into the regional transmission expansion plan,[97] but significant challenges remain.

The three eastern regional system operators—NYISO, ISO-NE, and PJM—will be instrumental to the planning of cost-effective transmission solutions for OSW generation on the Atlantic coast. Yet, all three regions overlook opportunities to more holistically consider a broader range of identified system needs, including for public policy, in their planning process. While the three regions consider public policies as required by FERC Order 1000,[98] these regions do not consistently and comprehensively identify and incorporate all known public policy needs into their transmission planning processes. Instead, each region uses a rather narrow approach to considering public-policy-related transmission needs. While NYISO is addressing some OSW related needs through its Public Policy Transmission Planning Process (PPTPP), and PJM is addressing some of New Jersey's OSW-related needs through its first SAA, ISO-NE has not identified any public-policy-related system upgrades in its most recent regional system plan. Due to concerns of the New England States over the adequacy of the existing planning process, the states did not request[99] that ISO-NE conduct its Public Policy Transmission Studies (PPTS) in either 2017[100] or 2020.[101] This lack of an adequate holistic planning process stands in stark contrast to the substantial transmission investments that will be necessary over the next

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[97] See also *State Voluntary Agreements to Plan and Pay for Transmission Facilities,* 175 FERC ¶ 61,225 (2021).

[98] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities,* Order No. 1000, 136 FERC ¶ 61,051 at P 203 (2011) ("The Commission requires public utility transmission providers to amend their [tariffs] to describe procedures that provide for the consideration of transmission needs driven by Public Policy Requirements in the local and regional transmission planning processes.")

[99] NESCOE, Submission Regarding Transmission Needs Driven by State and Federal Public Policy Requirements, May 1, 2017; NESCOE, Submission Regarding Transmission Needs Driven by State and Federal Public Policy Requirements, May 1, 2020.

[100] ISO-NE, 2020 Public Policy Transmission Upgrade Process, June 17, 2020.

[101] ISO-NE, 2017 Public Policy Transmission Upgrade Process, June 21, 2017.

decade to accommodate the 8 GW OSW goal of the New England states and the region's much larger long-term needs. None of the three eastern RTOs currently employ a proactive, scenario-based planning process that, like MISO's LRTP,[102] could simultaneously address long-term reliability, market efficiency, generation interconnection, and state public policy needs. Most recently, California has begun reviewing system needs associated with offshore wind as part of its long-term scenario-based planning outlook, having included 10 GW of offshore wind in its 20-year planning scenarios.[103]

One of the most important steps in building out an offshore wind transmission grid is building a bridge between several recent and ongoing transmission-related "desktop" studies and the transmission planning processes overseen by each ISO and RTO. Currently, many of these studies are academic in nature and divorced from actual ISO/RTO planning processes and planning criteria. Others simply do not involve a comprehensive analysis of the onshore upgrades necessary to support new offshore wind facilities. In addition, there are few effective paths for getting identified large-scale regional and interregional public policy-driven transmission needs integrated with other needs and holistically considered in existing planning processes.

4. Ineffective Interregional Planning

As we have pointed out elsewhere,[104] numerous studies have confirmed the significant benefits of expanding interregional transmission in North America. Building new interregional transmission projects can lower overall costs, help diversify and integrate renewable resources more cost effectively, and reduce the risk of high-cost outcomes and power outages during extreme weather events.[105] Several recent events, including the 2021 winter storm Uri, illustrated the very large potential but thus far unrealized reliability benefits and cost savings that interregional transmission can provide. Yet, despite broad consensus that the benefits and value of expanding interregional transmission capabilities often exceed its costs, thereby reducing overall system-wide costs, these studies are not integrated with any actionable transmission planning processes of the regional grid operators. Not surprisingly, virtually no major interregional transmission projects have been built in the U.S. over the last few decades.

102 See MISO, Long Range Transmission Planning.

103 California ISO, Transmission Planning for Offshore Wind, November 10, 2022, at 15.

104 J.P. Pfeifenberger, *et al.*, A Roadmap to Improved Interregional Transmission Planning, November 30, 2021 (Interregional Planning Roadmap).

105 For a summary of interregional transmission studies, see Interregional Planning Roadmap, at 2 (Table 1) and Appendix B.

One of several reasons why interregional transmission is not developed despite the many studies documenting the need for and benefit of doing so is the lack of actionable planning processes that could holistically identify interregional transmission needs, and approve projects that could address such needs.[106] The lack of effective interregional planning processes has been noted in FERC's 2021 Advance Notice of Proposed Rulemaking (ANOPR)[107] and at least 32 reply comments, most of which recommended improving interregional planning processes.[108]

In addition to the near-total absence of actionable interregional planning processes, cost effective interregional transmission solutions are often pre-empted by the design and sequencing of existing transmission planning processes:[109]

- First, since each planning region has to ensure that its own system meets all applicable reliability standards, all of these reliability needs are addressed at the local and regional level. Almost by definition, there is no reliability need for interregional transmission projects left to address.
- Second, many regional planning processes do not account for multiple drivers of the overall need for interregional transmission projects, which means that these processes are not set up to identify interregional transmission project solutions that can simultaneously and more cost-effectively address multiple regional and interregional needs.
- Third, the scope of regional planning processes tends to consider too narrowly transmission-related benefits and their geographic scope, typically quantifying only a subset of transmission-related economic and public policy benefits and considering only benefits that accrue to that particular region without considering the broader set of interregional benefits. This means quantified benefits are frequently understated and even regional projects near regional seams often fail to meet applicable benefit-cost thresholds for regional market efficiency and public policy needs, simply because the planning process ignores the benefits that accrue on the other side of the seam.
- Finally, local and regional reliability needs tend to be addressed quickly and projects are often approved before larger, proactive, and potentially more cost-effective interregional solutions can be considered and approved in a sufficiently timely manner.

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[106] For a survey of interregional transmission planning barriers, see Interregional Planning Roadmap, Appendix A.

[107] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022).

[108] Interregional Planning Roadmap, at 3.

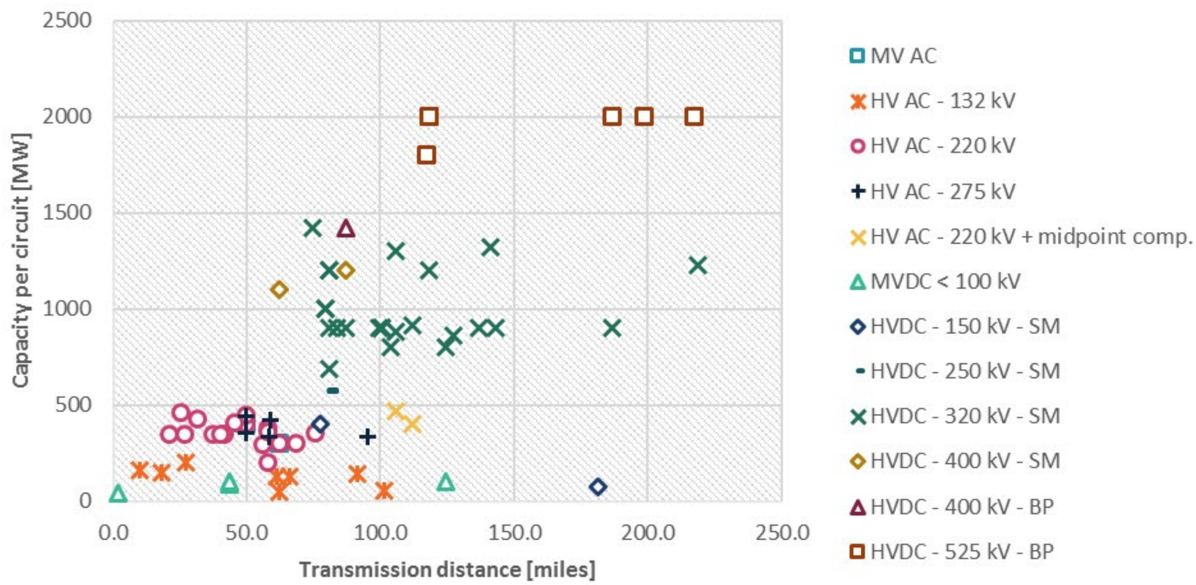
[109] Interregional Planning Roadmap, at 10–11.

Unless these challenges are addressed through improved, actionable interregional planning processes, interregional offshore transmission solutions will not have a feasible development and approval pathway even if additional industry studies, such as DOE's Atlantic Offshore Wind Transmission Study,[110] continue to point out the cost-effectiveness of interregional solutions.

5. Slow Adoption and Lack of Standardized HVDC Technology

HVDC transmission technology has proven to be able to offer more cost-effective and less environmentally impactful offshore wind transmission solutions, particularly as the size of individual OSW plants has increased to 1,200 MW and beyond and distances from onshore interconnection points continue to increase as well. The ability to transmit a substantially greater amount of power over longer distances through a single HVDC cable circuit allows for a significant reduction of offshore cable miles, shore crossings, and onshore impacts. The ability to select more robust, but more distant, grid interconnection points allows for a significant reduction in necessary upgrades to the existing grid.

FIGURE 4: TRANSMISSION TECHNOLOGIES FOR EXISTING AND PROPOSED OSW PLANTS



Source: DNV. The types of HVDC designs shown also distinguishes between "Symmetrical Monopole" (SM) configurations and higher-capacity "Bi-Pole" (BP) configurations.

Proactively designed, mesh-ready HVDC transmission solutions to integrate OSW generation with these technologies can offer attractive options to create regional and interregional multi-terminal offshore HVDC networks that can reinforce the existing grid. For example, as the New

[110] See US DOE Wind Energy Technology Office and National Renewable Energy Laboratory, Atlantic Offshore Wind Study.

England states have illustrated in their RFI, OSW projects in neighboring wind lease areas near Martha's Vineyard with radial transmission links to Boston, Connecticut, and New York City may provide attractive opportunities to increase the reliability of OSW deliveries and enhance both regional and interregional transmission capabilities through relatively short links between neighboring OSW plants.[111] The U.K. is evaluating multi-purpose interconnector pilot schemes that propose to interconnect to Belgium, Netherlands, and Norway in an offshore wind network to achieve multi-governmental objectives and offshore wind goals.[112]

Integrating radial HVDC links into a networked HVDC offshore transmission system does, however, face several challenges that need to be addressed. First, the still relatively limited global adoption of high-capacity HVDC technologies—such as 525 kV cables capable of delivering between 2 GW and 2.6 GW of OSW generation—creates several challenges for suppliers, developers, network planners, and grid operators. Second, HVDC technologies from different manufacturers are not currently compatible even when operating at the same voltage level. Third, key elements of high-capacity offshore HVDC networks, such as HVDC circuit breakers, are not yet widely available. Fourth, grid operators have very limited planning and operational experience with HVDC technologies necessary to take full advantage of the technology's capabilities. And, finally, for individual HVDC export cables to be networked into a meshed offshore grid, they either need to use the same HVDC voltage level and technology if linked on the DC-side of offshore substations or utilize HVAC links on the AC-side of offshore substations.[113] The different interlink technologies come with different pros and cons, which need to be evaluated carefully in the light of the planned future use of the interlinks.

Commenters in the New England RFI have noted the potential for incompatibility of equipment from different manufacturers, which would create substantial barriers to expansion or modularity benefits associated with coordinated offshore transmission. PPL and WindGrid stated that:

> given the absence of an HVDC standard at this stage, the compatibility between different vendors is not guaranteed by default. For the

[111] New England Regional Transmission Initiative, Notice of Request for Information, at 11.

[112] The Office of Gas and Electricity Markets, Decision on Multi-Purpose Interconnector Pilot Project Selection, December 15, 2022.

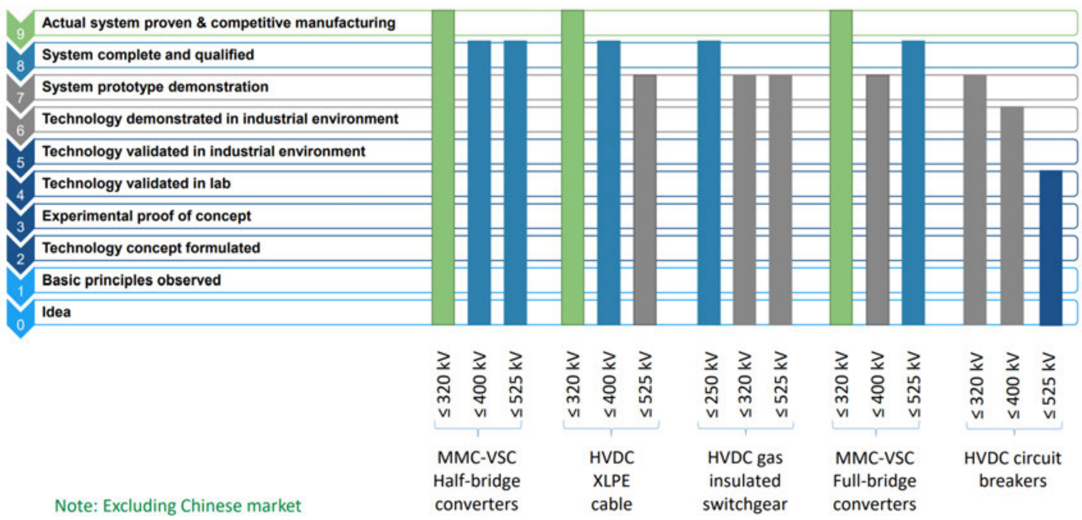
[113] For a summary of offshore transmission designs and the pros and cons of using AC or DC links between OSW export cables, see J. Pfeifenberger, Promoting Efficient Investment in Offshore Wind Transmission, DOE-BOEM Atlantic Offshore Wind Transmission Economics & Policy Workshop, August 16, 2022, at 16–20.

> interoperability of converters from competing manufacturers, the industry has recognized the need for interoperability and multivendor converters.[114]

Multiple initiatives are currently underway in Europe[115] to address the concern over vendor interoperability and will have completed well before any multi-terminal HVDC systems will appear in the U.S.

Figure 5 shows the readiness levels for different technology components required to enable various OSW transmission configurations at different voltages. Notably, HVDC circuit breakers, which would enable multi-terminal HVDC networks, are not yet widely available for offshore applications, even for the lower HVDC voltage levels currently in use.

FIGURE 5: HVDC TECHNOLOGY READINESS



Source: C. A. Plet, Multi-terminal HVDC Transmission Grids: Pros, cons and next steps, IEEE PES GM, 2022, at 17.

The development and standardization of these technologies is being actively pursued in Europe. TenneT has developed a new 2,000 MW, 525 kV HVDC standard that already is planned to be deployed for 13 platform- and 5 island-based offshore 525 kV converter systems, including network-ready OSW connections to support German and Dutch goals of developing an additional 20 GW OSW generation by 2030.[116] Most recently, AMPRION, a transmission system

[114] PPL TransLink and WindGrid Response to RFI, October 28, 2022, at 11.

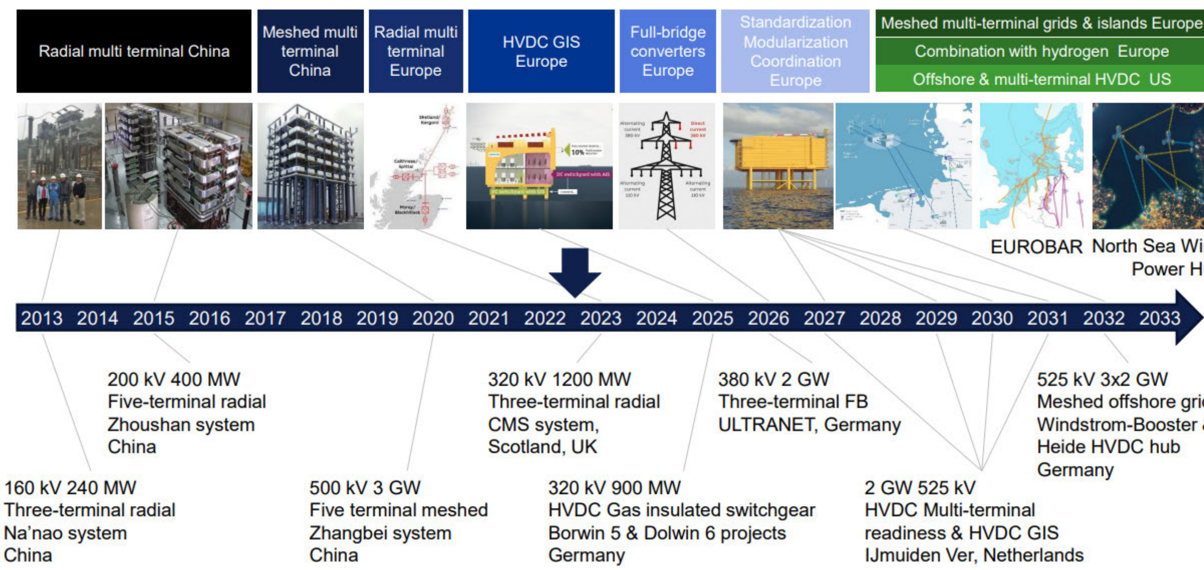
[115] Including Ready4DC and InterOpera.

[116] TenneT, TenneT has opened 2GW Program tender for 525 kV DC offshore Cable manufacturing and installation, July 11, 2022.

See also TenneT Netherlands 8×2 GW (https://www.tennet.eu/projects/offshore-projects-netherlands#9618); TenneT Germany 3×2GW (https://www.tennet.eu/de/unsere-projekte/offshore-projekte-deutschland); Amprion Germany 2×2 GW (https://offshore.amprion.net/Offshore-Projekte/LanWin1-LanWin3/); Belgium's operator in Germany, awarded Siemens Energy and Dragados Offshore to build 2,000 MW converter stations for the LanWin1 and LanWin3 offshore wind connection systems.[117]

As discussed further in Section IV below, the development timeline for use of these advanced technologies in Europe provides an opportunity for the U.S. to participate in the development of technical HVDC standards that would ensure interoperability of various manufacturers HVDC equipment. As shown in Figure 6, these standards are being developed now for development of multi-terminal-ready 525kV HVDC facilities planned for 2027 through 2031 that could be integrated into a meshed offshore grid by 2032.

FIGURE 6: TIMELINE OF FUTURE TECHNOLOGY DEVELOPMENT FOR OFFSHORE WIND



Source: C. A. Plet, Multi-terminal HVDC Transmission Grids: Pros, cons and next steps, IEEE PES GM, 2022, at 14.

Until these (or comparable) types of design and technology standards are developed or adopted for U.S. applications, interoperability of different equipment manufacturers is ensured, and system operators implement HVDC capabilities in their planning processes and operational

Princess Elisabeth island 2.3 GW (1st phase) multi-terminal connections to UK and Denmark (https://www.oedigital.com/news/499883-belgium-s-elia-presents-plans-for-world-s-first-artificial-energy-island, https://www.elia.be/infrastructure-and-projects/infrastructure-projects/tritonlink, https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/nautilus); Denmark's North Sea Island 3 GW (1st phase, two converters) multi-terminal connections to Netherlands, Germany (to 50Hertz TSO) and Belgium (via Princess Elisabeth island) (https://ens.dk/sites/ens.dk/files/Energioer/the_energy_island_in_the_north_sea_-_teaser_for_potential_investors_november_2022.pdf); and Denmark's Bornholm Island 3 GW (two converters), multi-terminal connections to Germany (https://en.energinet.dk/About-our-reports/Reports/Business-case-for-Energy-Island-Bornholms-electrical-infrastructure/).

[117] Amprion, Amprion awards converter stations to Siemens Energy and Dragados Offshore, January 10, 2023.

protocols, the development of offshore HVDC networks will remain a challenge. Design and technology standards must be sufficiently flexible (*e.g.*, modular) so networks can be built over time, incorporate evolving technology, while ensuring near-term needs can be met in a timely and cost-effective manner. Work on this issue has been initiated through DOE's recent HVDC standardization efforts, enabled by recent federal funding.[118]

An additional challenge exists as the capacity of new HVDC technologies (2.0–2.6 GW for a bi-pole 525 kV HVDC circuit), which could most effectively deliver the output of several OSW plants to shore, exceeds what system operators view as an acceptable "most severe single contingency (MSSC)."[119] For example, ISO-NE is currently limiting new interconnections to 1,200 MW through its planning procedure which, as several commenters in the New England RFI have pointed out, unnecessarily prevents interconnection of new HVDC technologies with capabilities that exceed the size of the region's single largest contingency.[120] As commenters note, the 1,200 MW limit could be raised if ISO-NE were to accept operational measures to address the current concerns over larger power injections. However, while ISO-NE planning processes are most rigid about limiting interconnection to 1,200 MW, concerns over power injections that exceed the system's current single-largest contingency also exist in other RTOs.

6. Uncertain Design and Benefits of Networked Offshore Transmission

The optimal choices for transmission technology, offshore network configuration, and the design of meshed or backbone offshore links, in particular the offshore hubs/substations, are still uncertain. As shown in Figure 7 below, several offshore transmission configurations are possible, each with its own costs, benefits, and challenges. Radial tie lines, meshed generator ties, shared collector stations, and a full offshore backbone have been identified (and in some

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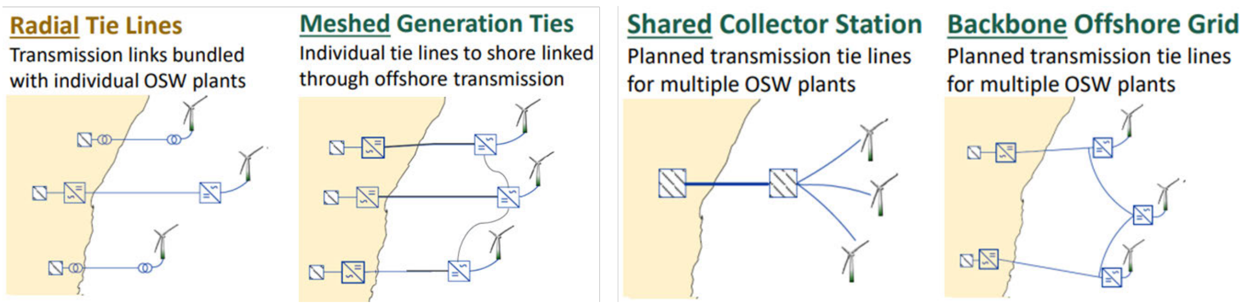
[118] Department of Energy Wind Energy Technologies Office, WETO Releases $28 Million Funding Opportunity to Address Key Deployment Challenges for Offshore, Land-Based, and Distributed Wind, December 6, 2022.

[119] As defined by NERC Standard BAL-002-2, the MSSC is "The Balancing Contingency Event, due to a single contingency, that would result in the greatest loss (measured in MW) of resource output used by the Reserve Sharing Group (RSG) or a Balancing Authority that is not participating as a member of a RSG at the time of the event to meet firm system load and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the sink Balancing Authority)."

[120] Comments of Hexicon USA, LLC in Response to Request for Information of The New England States Concerning Transmission of Offshore Wind, October 28, 2022, at 7 (referencing Attachment G of the ISO-NE tariff)
See also Anbaric, Scaling Renewable Energy (New England RFI comments), October 28, 2022, at 13.

cases evaluated) as options to deliver offshore generation to the onshore grid.[121] The already-procured OSW projects in the U.S. have all employed radial interconnection facilities, with a new round of solicitations in some regions requiring mesh-ready (or "network-ready") offshore interconnection facilities. Without a selected network design and the further development of standards that ensure of interoperability of technology between different equipment manufacturers, shared or backbone offshore facilities face additional challenges compared to current radial approaches.[122]

FIGURE 7: OFFSHORE TRANSMISSION DESIGN CONCEPTS



Source: J. Pfeifenberger, Promoting Efficient Investment in Offshore Wind Transmission, August 16, 2022, at 16.

Uncertainty in the design, technology type, and cost-benefits case for networked offshore wind transmission systems, particularly as HVDC technology continues to evolve, thus creates a challenge to the development of offshore transmission networks today. The high capital costs associated with nascent technologies create additional challenges in justifying the increase in offshore system capability that would be developed by offshore interlinks. While different designs provide different system benefits and value streams, consensus has not yet emerged in the U.S. as to which system design is preferred. Different transmission designs capable of providing valuable system capabilities—such as voltage support, black-start, power-flow control, and system-stabilization benefits of offshore HVDC networks—are not yet fully understood, accepted, and accounted for by U.S. RTOs in their system operations and

[121] For an evaluation of these offshore transmission options, see NYSERDA, New York Power Grid Study, Appendix D (Offshore Wind Integration Study), January 2021. The NYSERDA study concluded that "because a meshed configuration can achieve a more reliable and resilient delivery of OSW generation," the State should ensure that new "radial connections are constructed in ways that include the option to integrate the radial lines into a meshed system later." (Executive Summary at 3)

[122] See also J. Pfeifenberger, Promoting Efficient Investment in Offshore Wind Transmission, August 16, 2022, at 17–20. As illustrated in Figure ES-2, the optimal design of an offshore transmission solution for 60 GW is considerably more complex than the concepts illustrated in Figure 7, and vary dependent on the location of wind lease areas, the configuration of the existing onshore grid, the regional resource mix, and numerous other factors. Detailed planning efforts will be necessary to identify the most cost-effective and beneficial combination of onshore and offshore grid configurations and technology choices.

transmission planning efforts. In Europe, however, there is a clear trend towards radial HVDC lines with standardized technology so that they can be connected—through DC interlinks with HVDC circuit breakers—to yield offshore networks, including multi-purpose offshore interconnectors between countries.

Importantly, within the existing actionable planning frameworks that could result in the approval and development of regional and interregional offshore networks, the need for and benefit-cost analyses for creating such networks in the U.S. has not yet been established. While some studies suggest that regional and interregional offshore will be cost-effective in the future,[123] no RTOs have proactively considered networked offshore transmission options in their transmission planning processes. While networked offshore transmission configurations have been solicited by PJM and proposed by bidders in New Jersey's State Agreement Approach, the process did not produce sufficient evidence that, under current planning paradigm, offshore links would benefit the State's OSW procurement.[124] As discussed in the BPU Evaluation Report, SAA bidders did not submit proposals showing that the deliverability advantage (*i.e*., outage mitigation benefit) of networked offshore configurations justified the cost of the necessary offshore links and did not propose technology solutions with the operational capabilities that would allow these links to be controlled and optimized in real-time to capture market efficiency benefits. Importantly, PJM's market efficiency analysis did not yet document any onshore transmission constraints between POIs that would yield energy and capacity market benefits sufficient to justify offshore links between OSW export cables at this point.

However, acknowledging the future benefits that networked offshore transmission will likely be able to provide, both New York and New Jersey state regulatory commissions have recognized the value of creating the option to integrate radial OSW export lines into an offshore network at some point in the future. In response, both commissions have directed that future procurements of OSW generation include mesh-ready/network-ready offshore substations.[125] The New England states have similarly recognized the likely value of regionally and interregionally networked offshore transmission in their joint Request for Information seeking

[123] For example, a study for NYSERDA found that linking Long Island and New York City through "meshed" OSW transmission may be attractive at some point in the future (*e.g.*, by 2040), with payback periods for adding links between mesh-ready offshore substations possibly as short as several years. See J.P. Pfeifenberger, *et al.*, The Benefit and Cost of Preserving the Option to Create a Meshed Offshore Grid for New York, November 9, 2021.

[124] BPU SAA Evaluation Report, at 118–122.

[125] See 2022 Solicitation—NYSERDA (Appendix G: Meshed Ready Technical Requirements) and Solicitation Documents—NJ Offshore Wind (Attachment 11: Offshore Transmission Network Preparation Requirements)

comment on an initiative to integrate offshore wind and other resources in a cost-effective, reliable and efficient manner.[126]

7. Undefined Regulatory and Contractual Frameworks

The regulatory and contractual frameworks for the shared use and networked operation of offshore transmission facilities—including procurement methods, procurement structure, evaluation criteria, cost allocation, market operation, and the inherent tension between open access provisions and priority interconnection rights—have not yet been developed. Europe has been addressing this gap for the last few years through "research into the requirements of the legal, economic, and financial framework that could facilitate the cost-effective construction and governance of a [meshed offshore grid]."[127] Initial regulatory work is also underway in Great Britain focusing on regulatory questions related to shared, networked offshore transmission as part of the Offshore Transmission Network Review.[128] In the EU, recent European Network of Transmission System Operators for Electricity (ENTSO-E) work defined and analyzed the various functions necessary to plan, build, own, operate, and maintain interregional offshore transmission networks under various organizational structures.[129] The still undefined nature of these regulatory and contractual elements presents unique challenges in pursuing shared and networked transmission solutions for offshore wind in the U.S.

One potential avenue to address these challenges is through multi-state agreements. However, while such agreements are enabled and encouraged by FERC,[130] no multi-state agreements that could plan and procure effective regional or interregional offshore transmission solutions currently exist. Unanswered regulatory questions associated with multi-state agreements include:

- **Procurement Method:** How would states identify and commit to the amount of public policy transmission to be regionally planned? Would this require state commission orders or new FERC regulations? How would the rights to the capability created by multi-state transmission procurement be apportioned and used? Would capability be preserved in accordance with states' public policy development schedules?

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[126] New England States Transmission Initiative—New England Energy Vision

[127] PROMOTioN, D7.9 Regulatory and Financing principles for a Meshed HVDC Offshore Grid, April 2019, at 4.

[128] See Ofgem, Consultation—Offshore Transmission Network Review—Multi-Purpose Interconnectors: Minded-to Decision on interim framework, April 14, 2022.

[129] ENTSO-E, ENTSO-E Position on Offshore Development: Assessment of Roles and Responsibilities for Future Offshore Systems, November 2022.

[130] State Voluntary Agreements to Plan and Pay for Transmission Facilities*,* 175 FERC ¶ 61,225 (2021).

- **Procurement Structure:** What would be the scope of the procurement? How would shared offshore transmission facilities be planned, identified, selected, and procured? Are separate procurements needed for onshore and offshore transmission components? How will procurement of OSW transmission address project-on-project risks faced by interconnecting OSW generation developers? What type of contracts (*e.g.*, fixed-priced contracts vs. cost-of-service) should be used?
- **Evaluation Criteria:** What project selection criteria are most important to the states? How will these criteria be used in selecting the project? Are there benefit/cost thresholds required to proceed with selection? Which categories of benefits will be considered and how will these benefits be quantified? How should non-monetary considerations (*e.g.*, development schedule, risks, experience, environmental and community impacts) be evaluated? Are there any threshold criteria?
- **Selection Process:** Who will determine which projects should be selected? Should states make a final selection from candidates pre-selected by regional system planners? If so, how? Or should the regional planner make the final project selection?
- **Cost Allocation:** How would costs of selected projects be allocated? Based solely in proportion to the public policy needs of the participating states? Or should some of the costs be allocated to other states in the region as long as such allocation is roughly commensurate with benefits received? Are there federal funds available to buy-down the costs of a project that would help make it more attractive to state regulators?

In addition, the advance planning and reservation of system capability creates inherent tensions with FERC's open-access principles. FERC has already addressed some of these tensions, including noting that capability can be preserved on projects that would "not have been planned but for" a state's decision to pursue policy.[131] FERC has found that generators not "designated" by a state are not similarly situated with respect to the state-selected transmission facilities, which resolves concerns related to undue discrimination between state-selected generators and other generators who would benefit from accessing the transmission facilities.[132] Networked offshore transmission projects that address multiple needs (*e.g.,* a combination of public policy, grid reliability, or market efficiency needs) may require additional regulatory structures to ensure that open access regulations do not prevent the participating states from capturing benefits that are roughly commensurate with their cost responsibility.

[131] *Order Accepting Agreement,* 179 FERC ¶ 61,024 at P 46 (2022).

[132] *Ibid.*

8. Inefficient Regional and Interregional Grid Operations

With some exceptions, regional grid operators are not yet fully equipped to integrate and optimize regional or interregional HVDC links from either a reliability operations or a wholesale markets perspective. Transmission tariffs under FERC jurisdiction do not yet satisfactorily define or address coordinated operation of interregional facilities that would be required to capture their full value. The inability of grid operators to fully utilize the unique and valuable capabilities of regional or interregional HVDC links creates challenges that need to be addressed before effective HVDC OSW transmission solutions can be planned and operated.

For example, while ISOs/RTOs would be able to optimize the commitment and dispatch of generation resources in both day-ahead and real-time markets to reduce system-wide generation costs, their market design often is not yet able to co-optimize the "dispatch" of HVDC lines within their regions.[133] Similarly, several of the HVDC links currently connecting PJM with New York are not operated optimally from an interregional efficiency perspective. While HVDC technology provides the ability to control flows on a minute-by-minute basis, PJM's Independent Market Monitor has been documenting that real-time flows over the HVDC ties between NYISO and PJM were inconsistent with market price differentials much of the time: during 43.4% of all hours in 2021.[134] In fact, two of the three HVDC tie lines flowed power from PJM to New York during all hours in 2021, regardless of price differences.[135] New York's market monitor has identified a similar issue, identifying a wide range of hours where flows over interfaces with other regions, including to New England and Ontario, are scheduled in an inefficient manner.[136]

The operational limitations that result in inefficient flows on existing interregional ties would prevent the realization of the full benefits of new HVDC links provided through offshore transmission facilities. The regional market monitors have pointed out these inefficiencies for a

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[133] Some regional grid operators have recently started to work on market design modification that would allow them to operationally optimize the use of region-internal HVDC lines. See, for example, NYISO Market Issues Working Group, Internal Controllable Lines, February 3, 2022; DC Line Scheduling Design, March 16, 2022; DC Line Scheduling Design: Two Settlement Examples, April 19, 2022; and Internal Controllable Lines: Market Design Concept Proposal, August 4, 2022.

[134] Monitoring Analytics, 2021 State of the Market Report for PJM, March 10, 2022, at 461.

[135] *Id.* at 460 (Neptune), 465 (Hudson).

[136] Potomac Economics, 2021 State of the Market Report for NYISO, May 2022, at A-95, table A-7.

decade.[137] They have three main causes, all of which could be avoided for interregional HVDC transmission links that are fully controllable during real-time operations:

- **Latency Delay.** The time delay between when flows over a tie are scheduled and when power actually flows (during which system conditions and real-time prices may change).
- **Non-economic Clearing.** The grid operators make decisions about which tie schedule requests to accept without economic considerations, producing inefficient schedules.
- **Transaction Costs.** The fees and charges levied by each grid operator on external transactions serve as a disincentive to engage in trade, impeding price convergence, and raising total system costs.

While some improvements, such as the introduction of coordinated transaction scheduling (CTS) have been implemented in recent years, they have not been effective in utilizing existing interregional transmission capabilities as the regional market monitors continue to show in their state of the market reports. Further enhancements to intertie market and operational protocols—such as market coupling, intertie optimization, or interregional energy imbalance markets—will be needed to take full advantage of the value provided by interregional transmission.[138]

As a result of these continuing inefficiencies, the grid operators' existing energy-market and operational protocols tend to not take advantage of the full operational capability and energy market value provided by new regional or interregional HVDC facilities. In addition, the reliability value of interregional transmission capability often is not appropriately accounted in RTOs' regional resource adequacy evaluations and planning-related determinations, further understating the resource adequacy benefits of these interties.

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[137] For example, PJM's Market Monitor Unit already noted a decade ago that: "In 2012, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for 53.3 percent of the hours for transactions between PJM and MISO and for 47.2 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market." 2012 State of the Market Report for PJM—Volume 2, Section 8 (monitoringanalytics.com) at 225.

Similarly, New York's Market Monitor similarly pointed out over $300 million in annual costs related to inefficient use of existing interregional transmission capabilities between New York and other regions. See Patton (2010), Analysis of the Broader Regional Markets Initiatives, presented to Joint NYISO-IESO-MISO-PJM Stakeholder Technical Conference on Broader Regional Issues, September 27, 2010, at 13.

[138] For a discussion of intertie scheduling enhancements, for example, see Pfeifenberger, *et al.*, The Future of Ontario's Electricity Market: A Benefits Case Assessment of the Market Renewal Project, April 20, 2017, at 53 (Figure 9).

9. Untested BOEM Permitting Process for Third-Party Transmission

BOEM does not currently have a well-defined or broadly understood permitting process for offshore transmission that is distinct from offshore wind generators' individual interconnection cables. The project-by-project approach with radial OSW interconnection facilities developed by OSW generators is driven in part by BOEM's regulations, which bundle permitting for radial export lines into the easement associated with the permitting of offshore wind generation in the respective wind lease areas.

In particular, the relationship between independent transmission and BOEM leases remains uncertain. For example, although BOEM has a permitting process for transmission in federal waters, it is not clear how BOEM could implement its regulatory process for siting rights-of-way (ROWs) for backbone transmission or meshed offshore networks, particularly from the view of states and leaseholders. For instance, BOEM has not signaled whether it will simply process unsolicited requests by issuing Requests for Competitive Interest (RFCIs)—which it has previously done with Anbaric's NY Bight proposal[139]—or whether it will drive a centralized planning process similar to how it operates lease sales for wind energy areas.

While BOEM does have a process for permitting separate transmission facilities, there is substantial regulatory uncertainty about how the leases would interact with these coordinated transmission approaches, particularly as coordination requirements increase over time in the transition to a full offshore backbone. Further, it is not clear how the presence of a separately approved ROW for transmission adjacent to a particular lease area would affect the ability of the WEA leaseholder to develop a radial export line, including whether there would be a requirement on the WEA leaseholder to utilize the independent transmission solution. For mesh-ready substations currently required in New York's and New Jersey's OSW generation solicitations, it remains unclear whether neighboring WEA leaseholders have the presumptive right to interconnect to these mesh-ready facilities or if they must go through a separate permitting process. We note, however, BOEM has already made initial steps toward revising these regulations through a recent Notice of Proposed Rulemaking, which focuses in part modernizing the regulations governing offshore transmission to facilitate a wide range of

[139] Request for Competitive Interest on Anbaric's request for a ROW grant offshore NY and NJ, Docket No. BOEM-2018-0067.

offshore transmission solutions, including meshed systems or a full offshore grid, while "maximiz[ing] the utility of land-based points of interconnection."[140]

10. Uncoordinated Processes for Lease Area Auctions, State Procurements, and Transmission Planning

The processes of lease area auctions, state procurement of OSW generation, and regional transmission planning are siloed and lack coordination. When OSW developers purchase offshore leases, it is still unknown to which state or region they will be connecting, or the size or operation date of the specific project, as several wind energy areas can be used to deliver OSW generation to several states and more than one region. When states issue solicitations for OSW generation, they do not know which lease areas will serve them (realistically, only a few generators with nearby lease areas can effectively compete in those solicitations). Any attempts to pre-build an offshore grid to address states' clean energy needs are challenging because it is not known which lease areas to target prior to states completing their OSW solicitations. This separation of leasing, procurement, and planning is inefficient and time consuming by:

- Creating delays, since neither OSW generators nor transmission developers can start planning and permitting the transmission connection until they know which region they will be serving, as determined by the outcomes of state procurements;
- Introducing challenges in planning and developing efficient transmission solutions, and adding costs to any prebuilt transmission since any chosen location of offshore collector stations may turn out to be suboptimal and lead to duplicative offshore substations; and
- Reducing competition in OSW generation procurements by limiting the number of generators that can compete in state solicitations, and potentially resulting in prebuilt collector stations that may advantage some lease areas over others;
- Limiting the opportunities for reducing the amount of offshore cabling needed by bundling multiple adjacent OSW onto fewer large shared offshore transmission links.

Addressing these challenges and inefficiencies will require a fundamental redesign of how wind energy areas are leased by BOEM, how OSW generation is procured in the U.S. by individual states, and how transmission solutions for OSW can be planned by the grid operators. These

[140] BOEM, Notice of Proposed Rulemaking, 30 CFR Part 585, un-dated pre-publication BOEM Docket No. 2022-0019, Federal Register Docket No. BOEM-2023-0005, released January 12, 2023, at 104.

efforts will also likely require new federal and state enabling legislation to fully and efficiently coordinate WEA lease auctions with state procurements.

IV. Recommendations for Planning Cost-Effective Regional and Interregional OSW Transmission that Supports States' Ongoing Procurement Efforts

This section of our report provides of roadmap of twelve specific initiatives to address the identified challenges to achieving more timely, cost-effective, and environmentally acceptable OSW transmission solutions. We recommend that state and federal policymakers, state and federal regulators, regional grid operators, and market participants collaborate on the following initiatives:

1. Increase staffing and budgets for state and federal agencies
2. Empower regional, multi-state decision-making bodies
3. Confirm the applicability of tax credits to offshore wind-related interconnection facilities
4. Proactively identify feasible, cost-effective POIs in conjunction with fast-track generation interconnection processes
5. Develop and implement network-ready standards for use in OSW procurements
6. Clarify and streamline BOEM permitting for third-party transmission and, if possible, better coordinate lease processes with state procurement and transmission planning
7. Agree on actionable cost-allocation frameworks for planned OSW transmission
8. Develop HVDC technology, operational, and compatibility standards for transmission procurements
9. Continue to improve regional transmission planning and generation interconnection processes
10. Develop effective and actionable interregional transmission planning processes
11. Develop offshore grid shared-use contracts and open-access regulations
12. Improve grid operations and wholesale market designs to take full advantage of regional and interregional HVDC capabilities

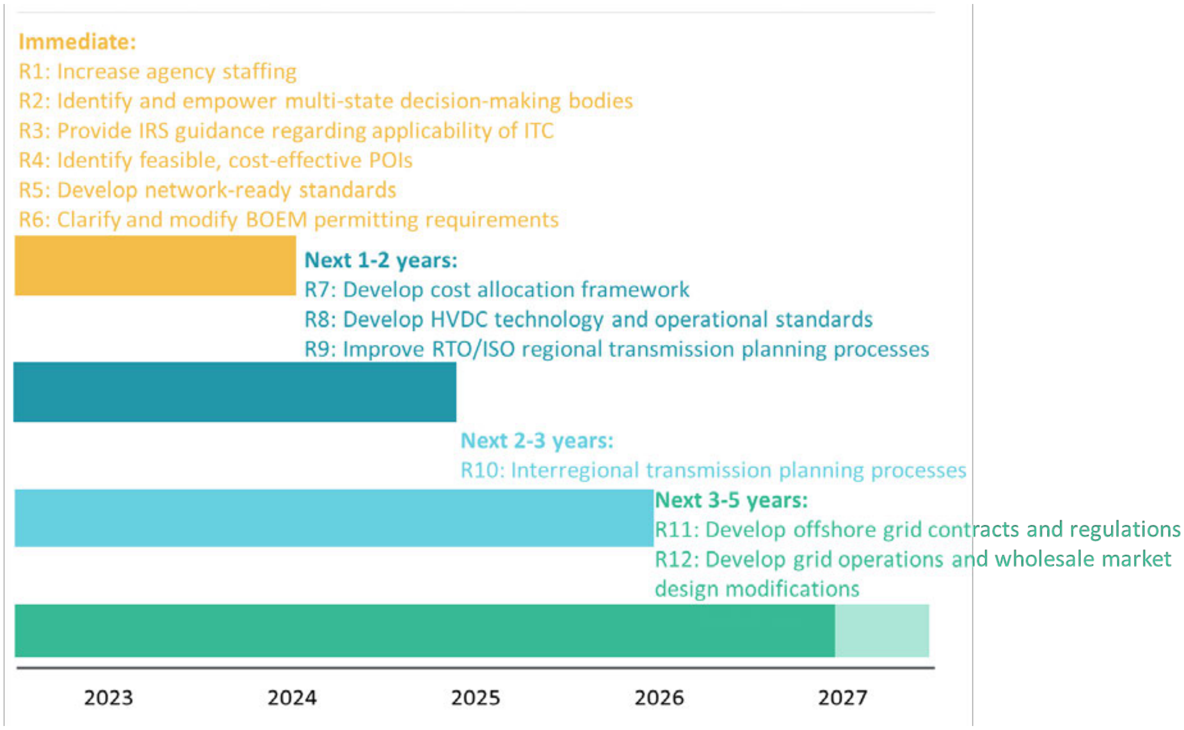
As shown in Figure 8 below, Recommendations Nos. 1 through 6 are the most urgent next steps that should be addressed **immediately within the next year**. These are all items that would make ongoing state procurement of OSW generation more future proof from an offshore transmission network development perspective.

Recommendations Nos. 7 through 9 are initiatives that should be completed **over the next one to two years** to facilitate the cost allocation of offshore transmission, the standardization of networked offshore transmission technology, and the already ongoing efforts to improve regional planning and generation interconnection processes.

The scope of Recommendation No. 10 (interregional planning) goes well beyond offshore transmission needs to include improved transmission planning between regions and nation-wide, which will realistically require **2–3 years** to develop.

Finally, Recommendations Nos. 11 and 12 focus on offshore grid usage and operational aspects, which do not need to be finalized until networked and shared-use offshore HVDC transmission facilities are placed in service. However, to provide sufficient clarity to industry participants, these items should be addressed over the next **3–5 years**.

FIGURE 8: TIMELINE OF RECOMMENDATIONS



1. Increase Staffing and Budgets for State and Federal Agencies

To address the significant number of challenges created by the ongoing clean energy transition and implement the OSW transmission-related recommendations discussed below, regulatory agencies with oversight, planning, implementation, and/or policy development responsibilities must have their funding substantially increased. This is consistent with recent recommendations by MIT researchers evaluating the regulatory challenges of the transition to a clean energy grid.[141]

Today, state and federal energy regulatory staff are subject to outdated compensation structures that do not allow states to attract or retain the necessary expertise to provide comprehensive guidance to state policymakers and effectively regulate the industry. These challenges are compounded by the lack of similar restrictions on market participants, who retain a commercial interest in attracting these staff to address the challenges, including

[141] Gruenspecht, *et al.*, Electricity Sector Policy Reforms to Support Efficient Decarbonization, MIT Center for Energy and Environmental Policy Research (CEEPR), April 2022, at 14. ("Staffing and budgets for state and federal regulatory agencies should be substantially increased to enhance these agencies' capabilities to design and implement regulatory mechanisms that can guide the transition to least-cost high-VRE systems with storage.")

through regulatory and legislative means, by acting in their own interests and not necessarily for the benefit of ratepayers.

Many of the recommendations set out below rely directly on the ability of state and federal agencies to participate in complex and often multi-state collaborations to tackle the complex challenges of achieving clean energy policies and decarbonization goals. State policy makers, legislators, and regulators will need to be at the heart of this effort. States not only drive clean energy policies in the U.S., but they also have primary responsibility under current regulatory constructs for identifying and selecting which OSW projects will be built. These OSW generation selections have historically been bundled with all necessary transmission facilities and grid upgrades, including identification of the radial export lines to shore and the funding of associated onshore upgrades. In addition, although legislation may be required, states are uniquely situated to arrange for the recovery of transmission-related costs (which already occurs for costs allocated for regional reliability and market efficiency investments). FERC's recent NOPR on transmission planning specifically identifies the ongoing and growing importance of state involvement:[142]

> "We believe that providing an opportunity for state involvement in regional transmission planning processes is becoming more important as states take a more active role in shaping the resource mix and demand, which, in turn, means that those state actions are increasingly affecting the long-term transmission needs for which we are proposing to require public utility transmission providers to plan in this NOPR."

To take on this role, state policymakers and regulators require the support of experienced staff—a scarce and valuable resource. While outside experts can assist states, internal expertise will substantially enhance the ability to engage in technical discussions and arrive at well-informed regulatory decisions. DOE, grid operators, and market participants should stand ready to provide the technical information not readily available to state agencies, but this assistance is no substitute for appropriately experienced internal staff. Without development of the relevant internal capabilities, state and federal agencies will not be effective in supporting the recommendations outlined below—to the detriment of achieving OSW and other clean energy goals and decarbonization objectives.

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[142] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 at P 301 (2022).

RECOMMENDATIONS FOR ACTION

- **State governors or senior policymakers** should make necessary changes, including passing appropriate legislation, to ensure that regulatory staff charged with leading ambitious energy and environmental policies can be retained. This may require conducting an analysis of similar compensation packages at private firms regulated by the state.
- **State agencies** should identify areas where expertise is needed and create procedures to identify, attract, and retain top talent, including from industry, to improve states' ability to develop, implement, and monitor both the programs under their direct supervision and federal regulations that directly impact the achievement of state goals.
- **The Department of Energy** should, wherever possible, utilize funding to support state agencies in their efforts to either develop, attract, and maintain key staff and internal expertise or contract to obtain the necessary expertise. For example, section 40109 of the Infrastructure Investment and Jobs Act provides $500 million in funding to state energy offices through the State Energy Program through 2026, and section 50153 provides $100 million for expenses and planning for interregional and offshore transmission lines.

2. Identify and Convene Multi-State Decision-Making Bodies

Identifying and empowering regional, multi-state decision-making bodies authorized to effectuate the development of effective, proactively planned regional and interregional transmission solutions is a critical first step toward supporting state and national offshore wind goals over the 2030–2050 timeframe. With support from the federal government, relevant state policymakers and grid operators should immediately convene to identify existing entities capable of assisting states in grid planning, or develop a new decision-making body to guide regional and interregional transmission development to address public policy and other transmission needs.

At first, these efforts will likely focus on individual regions until interregional transmission planning processes are improved to evaluate multi-value needs across regions, as discussed further in Recommendation 11. Enabled by the governors, state agencies involved in OSW generation procurement and transmission planning, including one agency for each of these purposes per state as necessary, should begin these convenings—with technical support and funding available from DOE—as soon as possible. Grid operators would be expected to provide technical expertise, including providing planning-related information unavailable to other parties, to assist states in these deliberations. States without offshore wind goals but with other public policy interests in transmission expansion should also be invited to join the regional collaborations.

These convenings will serve multi-fold purposes and provide a forum for action on many of the recommendations below. States should proceed, ideally, with support from DOE and a facilitator, to develop a binding process that would enable interested states to (1) identify policy needs to inform public policy transmission planning; (2) approve the development of identified transmission solutions; (3) agree on contracting for or cost allocations to enable the financing of the transmission investments; and (4) agree on the sharing or allocations of the clean-energy interconnection capabilities and other benefits created through the transmission planning and development effort. At a minimum, this will require multi-state agreements along with the necessary authorizations for state agencies to enter such agreements.

This effort may also benefit from the creation of regional or interregional **multi-state transmission authorities**, authorized to work directly with grid operators to procure transmission solutions and recover the cost of procured facilities, either through contracts with the transmission developers or through RTO tariff provisions. Such a multi-state transmission authority—distinct from an offshore ISO/RTO (which we caution against)[143]—could possibly be modeled after the 11-state Regional Greenhouse Gas Initiative (RGGI).[144] A multi-state decision-

[143] We caution against the creation of a new ISO or RTO for only offshore transmission because: (1) the new ISO/RTO would create additional market seams, which would make optimal use of the infrastructure even more difficult; (2) the offshore ISO/RTO would not serve any loads but would simply export all power generated to the existing ISOs/RTOs, which could prevent a reasonable market-wide optimization of generation dispatch and flows and exacerbate issues associated with offshore cost recovery; and (3) to interconnect its transmission facilities, the offshore ISO/RTO likely would still need to go through the generation interconnection process of the existing RTOs (*e.g.*, similar to merchant transmission lines interconnecting NYISO and PJM), which would make proactive planning for the combined onshore and offshore transmission needs even more challenging.

ENTSO-E recently assessed possible solutions and roles to address OSW transmission needs, similarly concluding that independent offshore transmission operations likely are less beneficial than integrated onshore-offshore operations of the transmission grid. See ENTSO-E, ENTSO-E Position on Offshore Development: Assessment of Roles and Responsibilities for Future Offshore Systems, November 2022, at 4–5.

In contrast, a multi-state transmission authority would only facilitate the development of OSW-related onshore and offshore transmission infrastructure that is regionally (and possibly interregionally) planned and operated to yield the most cost-effective solutions to support state, regional, and national clean-energy policies. The offshore facilities of the various transmission owners would still be operated independently by the respective ISO/RTO to ensure the offshore network is fully integrated with the onshore grid and offshore generation resources are optimally dispatched to yield the most cost-effective outcomes from a regional perspective.

[144] See https://www.rggi.org/. RGGI is administered by RGGI Inc, a 501(c)(3) non-profit corporation created to support development, implementation, and operations of RGGI. Other commenters have raised the idea of an interstate compact under 16 U.S.C. 824p(i), although these compacts would appear to be limited to the exercise of existing "electric energy transmission siting responsibilities of those States." 16 U.S.C. 824p(i)(1)(B).

making body could be developed by building upon and enabling the Organization of PJM States (OPSI), Independent State Agencies Committee (ISAC) in PJM, New England States Committee on Electricity (NESCOE), in collaboration with federal Power Marketing Agencies (PMAs), or through other similar state-led governance models.

These multi-state convenings could begin with a declaration of shared values and goals from participating state governors, and assign a task force of relevant state agencies, as well as outlining designated resources, state legislation, or funding to address these goals. This declaration could form the basis for beginning the convenings, where a formal multi-state memorandum of understanding (MOU) with specific goals and commitments, as well as a framework for making joint decisions, could be developed. This approach could be modeled after similar agreements reached in Europe which guide international coordination on transmission system development issues enabling OSW integration and the broader energy transition.[145] In addition, the federal administration has developed a federal-state OSW partnership[146] and FERC has created a Joint Federal-State Task Force on Electric Transmission,[147] both of which could also serve as to support a multi-state offshore transmission entity.

These authorized multi-state decision-making bodies would enable alignment of state-specific needs with regional and interregional transmission planning and development efforts, making actionable many of the recommendations underlying this effort, including: providing and certifying planning scenarios that would form the basis of developing onshore POIs (Recommendation 4); collaborating on the design of mesh-ready standards (Recommendation 5); developing a binding cost-allocation framework among states with OSW commitments (Recommendation 7); providing input to regional (Recommendation 9) and interregional (Recommendation 10) transmission planning; as well as providing input to enable the necessary improvements to regulatory and contractual frameworks (Recommendation 11) as well as grid operations and market design (Recommendation 12).

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[145] See Letter of Intent Between the German Federal Minister of Economic Affairs and Energy and The Minister of Climate, Energy, and Utilities of the Kingdom of Denmark on Cooperation on Jointly Analyzing Joint and Hybrid Offshore Renewable Energy Projects Between the Countries; The Declaration of Energy Ministers on The North Sea as a Green Power Plant of Europe.

[146] The White Hours, FACT SHEET: Biden Administration Launches New Federal-State Offshore wind Partnership to Grow American-Made Clean Energy, June 23, 2022.

[147] FERC Joint Federal-State Task Force on Electric Transmission, available at: https://www.ferc.gov/TFSOET

RECOMMENDATIONS FOR ACTION

- **State governors or senior policymakers** should identify the urgency of immediate coordinated planning for state policy including OSW through a shared declaration, and charge lead regulatory agencies with participating in a collaborative fashion with other states to accomplish this directive by collaborating on development of a statement of shared values to initiate multi-state planning convenings through a memorandum of understanding (MOU). State policy makers should also promptly identify and enact any additional authority needed (including through legislation, if necessary) to grant agencies authority to submit public policy transmission needs into a multi-state regional planning process, procure transmission needed for development of OSW and other public policy resources, and allow cost recovery of these facilities. Existing constructs for multi-state collaboration, including RGGI, the Organization of PJM States (OPSI), Independent State Agencies Committee (ISAC) in PJM, New England States Committee on Electricity (NESCOE), or others could serve as potential organizational and governance models, including for voting structures, for such multi-state efforts.
- The **Department of Energy** should convene lead regulatory agencies from each state with the goal of identifying and empowering regional multi-state decision-making bodies and developing a specific milestone schedule for future work items for the decision-making bodies. DOE studies, including the National Transmission Planning Study,[148] Transmission Needs Study,[149] and Atlantic Offshore Wind Transmission Study[150] can provide valuable insights and support to participating states as they proceed through the milestone schedule.
- **Grid Operators, FERC, BOEM, industry stakeholders** and others, possibly including federal PMAs, should be ready to provide support as necessary the multi-state decision-making effort, including by conducting planning studies and incorporating recommended OSW injections into their transmission planning processes.
- **Lead state regulatory agencies** should actively participate in these convenings with the goal of identifying, developing, and formalizing cooperation among states, including a governance or voting process to make decisions, identify transmission needs, and endorse cost allocations, wholesale market designs, planning decisions, or other recommendations.

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[148] US DOE Grid Deployment Office, Building a Better Grid, National Transmission Planning Study.

[149] US DOE Grid Deployment Office, National Transmission Needs Study.

[150] US DOE Wind Energy Technology Office and National Renewable Energy Laboratory, Atlantic Offshore Wind Study.

3. Clarify Applicability of the Investment Tax Credit to Offshore Wind-Related Interconnection Facilities

The IRS should expeditiously provide guidance to confirm the applicability of the ITC to offshore-wind related interconnection facilities that deliver to shore the output of one or more offshore wind generating plants, including those under independent third-party ownership.[151] We understand that there may be authority under the existing rules that already permits separate ownership of ITC eligible property,[152] and provides ITC eligibility in joint ownership circumstances.[153] In addition to immediate action from the IRS, Congressional action may be necessary to more explicitly expand the ITC to infrastructure necessary to bring offshore wind-generated energy to a specific point on the onshore grid, including links between offshore wind collector stations.

RECOMMENDATIONS FOR ACTION

- The **Internal Revenue Service** should provide guidance on the applicability of the ITC to all property, including export lines and other conditioning equipment, in connection with one or more offshore wind facilities in a manner consistent with CCA 201122018 (May 4, 2011) and the Bluebook released by the Joint Committee on Taxation (JCS-1-22). This guidance should make the ITC available for property necessary to deliver and condition electricity for use on the grid, such as subsea cables and voltage transformers, and for eligible equipment owned by a third party consistent with current tax authorities. The guidance should also make clear that interconnection facilities that are sized to enable future project expansion, or connection with an adjacent OSW project, are ITC-eligible; similarly, any equipment required at onshore or offshore interconnection substations to enable future meshing should also be ITC-eligible.
- If IRS guidance is insufficient, the **U.S. Congress** may need to explicitly expand the ITC to infrastructure necessary to bring offshore wind-generated energy to a specific point on the onshore grid, including links between offshore wind collector stations.

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151 For a discussion of applicable IRS rules, see Appendix C.3 of the BPU SAA Evaluation Report.

152 See *Cooper v. Commissioner,* 88 T.C. 84, 116–17 (1987) (rejecting an argument that energy property only includes "a completely functional system" in finding that ITC eligibility is not dependent on an individual taxpayer owning a complete system);

153 See Rev. Rul. 78–268, 1978-2 C.B. 10 (allowing proportionate ITC to co-owners of an electric generating facility despite their owning the facility as tenants in common with tax-exempt and municipally owned entities that are disqualified from receiving the ITC).

4. Optimize Onshore Interconnection Points for Delivering Offshore Wind

States, in collaboration with grid operators and DOE, should immediately start efforts to proactively identify feasible, cost-effective POIs with the necessary transmission corridors and onshore upgrades for all generation interconnection needs associated with forecasted new generation within each FERC-jurisdictional planning region. This work could be facilitated through the multi-state decision-making body described above. These efforts would be similar to New Jersey's recent offshore wind transmission procurement with PJM that identified POIs and necessary upgrades for an additional 6,400 MW of OSW generation but at a full, multi-state regional scale. Five New England states' recently begun transmission RFI could serve as the foundation for such coordination and optimization in the region.

Development of adequately robust POIs—and selecting POIs that reduce the necessary upgrades to the onshore grid with lower total OSW-related transmission costs—will be needed for both the interconnection of OSW generation with radial tie lines and any networked offshore transmission facilities. Interconnection rights at any state-funded POIs should be made available for state-procured OSW generation and/or transmission through a fast-track (*i.e.*, first-ready/first-served) RTO interconnection process that takes account of any state (or multi-state) investment in a particular location, similar to that already identified through FERC's generator interconnection NOPR.[154] Moreover, expeditiously incorporating these POIs into each regional transmission planning model is critical to ensuring that planning entities produce POIs that remain feasible and do not become obsolete as the grid evolves.

In addition, this effort may need to evaluate rules surrounding grid operators' single largest contingency, to determine transmission designs and operational protocols that enable reliable operations with higher-capacity HVDC-cables and injection amounts.

FERC's recent NOPR on long-term transmission planning, if finalized, would require regional planners to implement long-term planning for multi-value needs, but these long-term planning efforts would not result in sufficiently timely transmission upgrades to facilitate the development of POIs needed for the interconnection of OSW generation coming online within the next decade. This is because a final rule approved by FERC in 2023 will require years of compliance filings and planning studies before the first transmission investments would be

[154] *See Improvements to Generator Interconnection Procedures and Agreements,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 at P 260 (2022).

identified and approved. Further, the additional long-term planning processes specified in the NOPR add a 20-year long-term time horizon to regional and interregional plans, but are not intended to change the existing, near-term planning processes.[155] Additional near-term efforts, such as multi-state versions of the SAA process PJM has just completed in collaboration with New Jersey, would therefore be necessary to identify the best POIs to interconnect OSW generation needs over the next decade, while longer-term needs are identified proactively through new regional and interregional long-term planning efforts, as discussed in Recommendations Nos. 11 and 12.

Importantly, any such efforts to identify and possibly build out an optimal set of POIs to integrate the necessary amounts of OSW generation over time—to accommodate state procurement targets and the entire generation in BOEM lease areas, and considering long-term OSW needs to meet decarbonisation goals—would also need to be associated with: (1) providing interconnection rights to the specific states that fund the transmission upgrades necessary to enable the specified injections at the selected POIs; and (2) providing a fast-track path through generation interconnection processes (*e.g.*, under a first-ready/first-served framework), so generators can be interconnected at those state-funded POIs more quickly.

RECOMMENDATIONS FOR ACTION

- **States, in collaboration with grid operators and DOE** should immediately start efforts to proactively identify feasible, cost-effective POIs (with feasible transmission corridors) for all generation interconnection needs associated with existing state OSW and other clean-energy goals within each FERC-jurisdictional transmission planning region.
- The identified **multi-state decision-making entity** (possibly a multi-state transmission authority) should procure the transmission solutions (with the necessary land, transmission corridor infrastructure, and onshore upgrades) necessary to enable cost-effective POI development to support short-term goals and obtain long-term benefits of coordinated transmission.
- **Grid Operators** should, in collaboration with the states or multi-state entity, expedite the analyses necessary to identify the best set of POIs that can integrate the generation procured and projected over the coming decades, as states develop the regulatory pathways to request, allocate, select, and recover the costs of the needed transmission

[155] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 at P 3 (2022) ("We do not propose in this NOPR to change Order No. 1000's requirements for public utility transmission providers with respect to existing reliability and economic planning requirements.")

upgrades. This analytical initiative would be similar to PJM's effort in the New Jersey SAA, PJM's Offshore Wind Study (studying the integration of 75 GW of renewables needed to meet the public policy needs of PJM states),[156] and ISO-NE's Pathways Study.[157] As was the case in New Jersey's selection of POIs to meet its 7,500 MW OSW goals for 2035, these RTO-level studies will identify POI options and associated onshore network upgrade costs that will serve as the necessary input to the decision-making of states, which may then select OSW generators or independent transmission developers to use the most cost-effective and least environmentally impactful POIs for the purpose of integrating the planned amounts of OSW generation.[158] Grid operators would additionally need to streamline generation interconnection processes to make sure that generators ultimately selected through state procurements would be able to use the pre-built POIs through a fast-track (first-ready/first-served) process.

- **DOE** should continue to refine and share detailed results and insights of its ongoing studies, such as the Atlantic Offshore Wind Transmission Study[159], with states, FERC, and grid operators to assist with identification and analysis of potential POI locations from a broader interregional perspective.
- Building on its approval of the New Jersey State Agreement,[160] the policy statement on voluntary transmission development and cost allocation,[161] and provisions in the transmission planning NOPR, **FERC** should continue its efforts to enable:
  - Voluntary cost allocations agreed to by states to enable public policy transmission procurement and selection (Recommendation 6).
  - The expedited integration of public policy needs or transmission projects identified by states into grid operators' regional transmission plans under approved voluntary cost allocation provisions, prior to additional long-term transmission planning reforms being adopted under Recommendation 10.
  - Access to proactively planned and pre-built POIs provided in a fair and expedited fashion such as through approval of state agreements on preservation and utilization of created

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[156] PJM, Offshore Wind Transmission Study: Phase 1 Results, 2021.

[157] ISO-NE, 2050 Transmission Study Revision 2, November 17, 2021.

[158] See I.M.O. Offshore Wind Transmission, NJBPU Order, October 26, 2022, at 20–21.

[159] See US DOE Wind Energy Technology Office and National Renewable Energy Laboratory, Atlantic Offshore Wind Study.

[160] 179 FERC ¶ 61,024 at P 46 (2022); Rate Schedule FERC No. 49.

[161] *State Voluntary Agreements to Plan and Pay for Transmission Facilities,* 175 FERC ¶ 61,225 (2021).

POI capability funded by states through public policy transmission investments (Recommendation 9).

- **FERC** should similarly continue to pursue reforms to generator interconnection processes to create a fast-track option (*e.g.*, based on the generator interconnection NOPR's proposed first-ready/first-served approach[162]) for OSW generators assigned to the pre-planned POIs. Ideally, FERC should go beyond the NOPR's currently proposed reforms in the following areas:
  - Encourage grid operators to plan for generation interconnection needs more proactively; and
  - Encourage migrating to a "connect and manage" approach, similar to approaches adopted in the United Kingdom and Texas,[163] to address any distant network upgrades currently identified through interconnection studies through a combination of congestion management (in the short term) and multi-value transmission planning, including the use of advanced, grid-enhancing technologies (GETs) (in both the medium and long-term).

5. Develop and Implement Network-Ready Standards for Use in OSW Generation Procurements

To avoid losing the opportunity to integrate these offshore facilities into a planned grid in the future, we recommend that state procurements for OSW generation and transmission mandate “network-ready” designs for all offshore facilities—in particular, for OSW generation procurements with generator-owned radial links to shore.

A broadly accepted and future-proof network-ready standard should thus be developed immediately for standardized, modular offshore substations. This will create flexible, low-cost options to integrate radial offshore export links into a networked offshore grid in the future. This network-ready standard could then be used by states in all their future OSW generation and transmission solicitations such that the option to integrate these radial facilities into a linked offshore grid can be exercised if and when the benefit of doing so is confirmed through regional and interregional planning efforts. Offshore wind generation development will not pause until a regional or interregional offshore transmission network can be planned—which is

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162 *See* Improvements to Generator Interconnection Procedures and Agreements, Notice of Proposed Rulemaking, 179 FERC ¶ 61,194 at PP 37-160 (2022).

163 *See* J. Pfeifenberger, *Generation Interconnection and Transmission Planning*, ESIG Workshop Presentation, (August 9, 2022) at 15.

why ensuring network-ready designs that are modular and future proof (*i.e.*, able to accommodate the still uncertain future selections of evolving HVDC technologies) is critical to capture the full benefits of coordinated long-term transmission plans for 2030–2050.

This standardization effort should clearly define technical requirements that will allow the potential for future interconnections between offshore transmission platforms to enable additional benefits. The choice of technology should take into account the envisaged purpose of the future interconnections, required upfront investment, required total investment and operational costs.[164] These efforts should be aligned with similar efforts ongoing in Europe[165] and can begin domestically with technical specifications that New York and New Jersey have already identified for mesh-ready/network-ready offshore substations and that New England is exploring through its RFI.[166] However, while New York and New Jersey's mesh-ready standards are limited to HVAC links between offshore platforms, the technical specifications should be sufficiently flexible to allow for future HVDC links—although that would require standardized HVDC voltage levels and equipment to be included in mesh-ready designs as well (as discussed in Recommendation 8).

RECOMMENDATIONS FOR ACTION

- **DOE** should sponsor the selection of technical experts (such as a qualified engineering firm, or a National Lab) to develop of necessary technical standards for network-ready solutions.[167] This effort would build upon existing work on network-ready standards in Europe, New York, and New Jersey to ensure broad technical compatibility. DOE and the selected leads of this effort should work closely with an advisory committee composed of state, FERC, NERC, other relevant national lab, grid operators, utility, and OSW transmission and generation developer participants.
- Once standards are developed, **states** should expressly require the use of the jointly developed network-ready design standards for offshore substations and export cables in generation solicitations as an eligibility requirement to secure OSW contracts. State OSW

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164 See C.A. Plet, *et al.*, Offshore substation platform expandability, 2021 Cigre Canada Conference, Toronto.

165 See PROMOTioN—Progress on Meshed HVDC Offshore Transmission Networks, D12.3—Draft Deployment Plan, February 26, 2020, at Table 2, Figure 1-1, 33.

166 See 2022 Solicitation—NYSERDA (Appendix G: Meshed Ready Technical Requirements); Solicitation Documents—NJ Offshore Wind (Attachment 11: Offshore Transmission Network Preparation Requirements); and 2022 New England States Transmission Initiative Request for Information (Question 3).

167 Work on this issue has been initiated in the U.S. through DOE's HVDC standardization efforts, enabled by recent federal funding. See Department of Energy Wind Energy Technologies Office, WETO Releases $28 Million Funding Opportunity to Address Key Deployment Challenges for Offshore, Land-Based, and Distributed Wind, December 6, 2022.

procurement contracts will also need to allow for adding shared-use and open access provisions in the future (see Recommendation 9).

6. BOEM Transmission Permitting and Leasing

BOEM should clarify and modify its permitting processes quickly to provide additional specificity to enable pursuit of coordinated offshore transmission, including third-party use of offshore cable routes. This effort should include BOEM permitting of transmission, (1) between lease areas and pre-specified POIs on the existing grid and (2) between existing or newly assigned lease areas. It should also include the potential for BOEM to review and approve general activity plans to allow construction of cables in advance of offshore wind project permitting to reduce project-on-project risk, incentivize lessees to participate in offshore networks, and allow for coordination of resources such as cable-laying vessels. Permits may specifically include rights-of-way to construct competitively awarded cables by one or more entities selected by one or more states. In an encouraging first step, BOEM has recently sought industry comment on how to revise transmission permitting and leasing regulations through a recent Notice of Proposed Rulemaking, including the potential for exploring coordinated approaches to transmission, shared cable corridors, meshed systems, or the development of the offshore grid.[168]

In addition, DOE and BOEM should explore and evaluate, for possible future federal legislative action, more effective alternatives to the existing auction, lease, and permitting processes for possible future federal legislative action for better alignment with OSW generation procurements. Current processes can impede the development of coordinated transmission and more cost-effective OSW solutions because states and system planners do not know which lease areas will serve their policy needs, as discussed above. While modification to BOEM lease auction processes would likely require federal legislation and additional analysis beyond the scope of this paper, substantial incremental benefits of coordinated planning may remain unavailable without improving the coordination of wind area designations, lease area auctions, state OSW generation procurement, and BOEM generation and transmission permitting.

RECOMMENDATIONS FOR ACTION

- **BOEM** should immediately begin a planning process to identify and analyze feasible regional offshore cable routes, including to pre-specified interconnection points on the existing grid. This planning process should include development of a defined process to advance existing

[168] BOEM, Notice of Proposed Rulemaking, 30 CFR Part 585, un-dated pre-Federal-Register-publication, BOEM Docket No. 2022-0019, Federal Register Docket No. BOEM-2023-0005, released January 12, 2023, at 104.

stand-alone transmission proposals in coordination with other siting agencies, FERC, and relevant state agencies. This effort should develop a review and approval process for general activities plans to allow construction of offshore cables *in advance* of OSW projects, including multi-use ROWs and transmission facilities, to reduce project-on-project risk and incentivize lessees to participate in offshore networks. Additionally, **BOEM** should issue a request for information and/or call for information on proposed cable routes, accounting for state and federal needs, identified interconnection points, specified lease areas, environmental factors, and ocean-user conflicts (*e.g.*, fisheries, other seabed infrastructure, *etc.*). This request should build on BOEM's recently issued Notice of Proposed Rulemaking,[169] and would likely occur after onshore POIs are identified as part of Recommendation 4.

- **DOE** should engage BOEM, FERC, the Congressional Research Service, or other relevant government agencies to explore alternatives to existing lease process and any necessary federal administrative or legislative actions to allow for the planning and permitting of transmission solutions to those lease areas to start immediately, and for coordination with state solicitations of generator bids for developing the lease areas designated for such state procurement.

7. Develop an Actionable Cost Allocation Framework

States with OSW commitments should, in concert with implementing Recommendation 2, develop a methodology to allocate the costs of OSW-related transmission investments, which include onshore upgrades for multi-state generation interconnection efforts and shared radial export facilities. This methodology should ensure that allocated costs are roughly commensurate with the benefits states receive (*e.g.*, in proportion to their OSW and/or other clean energy needs). This framework can then also serve as the basis for developing cost allocations of networked regional and interregional offshore transmission, as discussed further in Recommendations 9, 10, and 11.

As a potential starting point, RENEW Northeast together with Brattle authors have developed a voluntary multi-state cost allocation framework as part of a Northeast Transmission Blueprint.[170] The recommended approach relies on simple beneficiary-pays principles and applies cost responsibility in proportion to incremental transmission capability requested by

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[169] *Ibid.*

[170] RENEW Northeast, A Transmission Blueprint for New England: Delivering on Renewable Energy, May 23, 2022 (Appendix contributors, J. Pfeifenberger and J. DeLosa III).

each state in support of its public policy needs and accounting for avoided costs.[171] Any developed cost allocation frameworks should enable a wide range of potential use cases, including contemplating clean energy resources likely needed by those states that may participate in public policy planning efforts but do not have offshore wind goals, as discussed further in Recommendations 9 and 10. We recommend cost allocation frameworks that apply to portfolios of transmission projects, rather than individually to each project. While it is critical that benefit-cost-analyses used to evaluate alternative transmission solutions consider and (if possible) quantify the full set of benefits transmission investments can provide, we recommend *against* the development of cost allocations that are formulaically based on such quantified benefits, since quantified benefits depend on study assumption and change over time—which tends to make the allocation process more contentious than simpler, voluntary cost allocation frameworks that meet the "roughly commensurate" standard.[172]

RECOMMENDATIONS FOR ACTION

- **State regulatory agencies**, as part of a multi-state decision-making entity in Recommendation 2, should develop a binding multi-state cost allocation agreement, to be filed with FERC, which enables continued discussion of procurement frameworks and selection criteria among participating states. These discussions should be informed by grid operators' analyses demonstrating that the benefits of proactive coordinated planning are roughly commensurate with allocated costs. States should also apply for transmission grants, loans, and loan guarantees from DOE to reduce costs to customers, and help to ease any cost allocation disputes.
- **FERC** should encourage this multi-state effort and provide guidance on acceptable cost-allocation frameworks. Building upon the approved New Jersey State Agreement Approach,[173] the policy statement on voluntary transmission development,[174] existing cost allocation frameworks for multi-value transmission projects,[175] and cost-allocation

[171] *Id.* at 15.

[172] See J. Pfeifenberger and J. DeLosa III, Transmission Planning for a Changing Generation Mix, OPSI Annual Meeting, October 18, 2022, at 17, 23.

[173] 179 FERC ¶ 61,024 at P 46 (2022); Rate Schedule FERC No. 49.

[174] *State Voluntary Agreements to Plan and Pay for Transmission Facilities,* 175 FERC ¶ 61,225 (2021).

[175] For example, cost allocations used for MISO MVPs, SPP's highway/byway approach, and NYISO' Public Policy Transmission Planning Process (PPTPP) may provide good starting points. See also 181 FERC ¶ 61,219 at P 50 (2022) ("…cost allocation does not need to be undertaken with exacting precision in order to be roughly commensurate with benefits … the use of a portfolio approach will help ensure that the benefits of each MVP portfolio are distributed broadly across the subregion") (citing *Illinois Comm'n I,* 576 F.3d at 477; 178 FERC ¶ 61,087 at P 30 n.42 (2022) ("Courts have held that the cost causation principle does not require costs to be allocated with exacting precision, but rather requires that costs be allocated in a manner 'roughly commensurate' with the benefits received.")).

provisions in the transmission planning NOPR, FERC should quickly approve voluntary cost allocations that enable coordinated public policy transmission development.

- **DOE** should identify funds that can be made available to facilitate the construction of coordinated offshore wind transmission facilities, either by opening a TFP solicitation dedicated to each coast's offshore wind transmission needs or otherwise identifying funding opportunities well-suited to offshore wind transmission.

8. Develop HVDC Technology and Operational Standards

Within 1–2 years, following the development of network-ready standards in Recommendation 5, DOE should develop rigorous HVDC technology compatibility and operational standards that allow for a "future proof" evolution of the offshore transmission network to meet state, regional, and interregional needs. These standards can be informed by similar work underway in Europe[176] and build on initial efforts by DOE.[177] Ahead of a national adoption of any standards, state procurements can drive standardization through collaboration and by adopting standards in their OSW procurements.

These compatibility standards should cover, at a minimum, the following aspects: system requirements (*e.g.*, voltage level, converter configuration, system protection, fault clearing strategy); functional requirements (*e.g.*, operational switching sequences, control modes, fault response, *etc.*); vendor interoperability requirements (*e.g.*, communication interface, transient and harmonic stability, *etc.*); procurement requirements (*e.g.*, responsibility for system integration, liability, performance guarantees, information exchange, *etc.*); and operational requirements.[178]

Additional challenges will be presented by the need for **floating offshore wind generation** required as the demand for OSW continues to grow and new lease areas are in deeper waters and often more distant from shore. Given the federal administration's goal of 15 GW of OSW by

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[176] See PROMOTioN—Progress on Meshed HVDC Offshore Transmission Networks, D12.3—Draft Deployment Plan, February 26, 2020.

[177] Department of Energy Wind Energy Technologies Office, Bipartisan Infrastructure Law (BIL) FOA to Address Key Deployment Challenges for Offshore, Land-Based, and Distributed Wind, December 6, 2022, at 10.

[178] The lack of an "HVDC grid code" that specifies how an offshore network should be operated, also is probably one of most important missing technical elements towards achieving interoperability of different HVDC facilities that could be integrated into a linked network. One step in this direction would be to revisit the existing NERC standards and assess to what extend and how they are applicable to DC systems, and adapt those standards where necessary.

2035[179] and the fact that state OSW generation commitments already include more than 50 GW of floating offshore wind generation,[180] technology development and standardization will have to address additional design considerations relevant to floating applications. While many of the components of the electrical design will be the same, cables connected to floating platforms must handle dynamic stresses not imposed on fixed-bottom offshore equipment due to repetitive wave motion and extreme events such as storms. A joint industry project focused on this matter is currently in early stages of developing pre-standardization requirements[181] and a number of development efforts for floating equipment have been initiated,[182] although technology maturity is still low.[183]

RECOMMENDATIONS FOR ACTION

- As a follow-on to the work in Recommendation 5, **DOE** should continue efforts, including developing the process to identify necessary technical and operational standards for HVDC technology. The continuity of this effort would ensure compatibility with any previous mesh-ready guidance developed by DOE and adopted by states. DOE and the selected technical leads should work closely with an advisory committee composed of members from states, FERC, NERC, relevant national labs, grid operators, utilities, and OSW

[179] See White House, "Fact Sheet: Biden-Harris Administration Announces New Actions to Expand U.S. Offshore Wind Energy" at https://www.whitehouse.gov/briefing-room/statements-releases/2022/09/15/fact-sheet-biden-harris-administration-announces-new-actions-to-expand-u-s-offshore-wind-energy/

[180] See Table 1 offshore wind goals and needs for California, Oregon, Washington, and Maine—with additional floating OSW plants likely off other Atlantic-coast states.

[181] DNV, 30 Partners Join DNV to Start Joint Industry Project for Floating Offshore Wind Substations, May 31, 2022.

[182] Pre-standardization for design and testing is in place since last year (*e.g.*, Cigre—TB 862—Recommendations for mechanical testing of submarine cables for dynamic applications). See also:

Hitachi ABB, "Hitachi ABB Power Grids launches new transformers for floating offshore wind power" *power transformer news*, June 8, 2021 at https://www.powertransformernews.com/2021/06/08/hitachi-abb-power-grids-launches-new-transformers-for-floating-offshore-wind-power/

Nevesbu, "Concept design of a floating offshore substation," May 10, 2022 at https://www.nevesbu.com/insights/floating-offshore-wind-substation-concept-design/

Splash 247, Saipem and Siemens Energy to design new floating substation," *Transformers Magazine,*, September 7, 2022 at https://transformers-magazine.com/tm-news/saipem-and-siemens-energy-to-design-new-floating-substation/

Ocean Grid, Floating HVDC platform at https://oceangridproject.no/research/floating-hvdc-platform

D. Cole, "Thinking inside the box with HVDC for floating offshore wind," *LinkedIn* at https://www.linkedin.com/pulse/thinking-inside-box-hvdc-floating-offshore-wind-david-cole/

Petrofac, Design, Floating substation concept development at https://www.petrofac.com/services/our-work/concept-design-floating-offshore-wind/

[183] In particular, developing and qualifying "dynamic" 525 kV HVDC cables—such that floating offshore transmission substations could be interconnected with stationary 525kV HVDC facilities (which are increasingly more likely to become an industry standard)—will be challenging and may take up to a decade to reach full maturity.

transmission and generation developers to develop these HVDC and offshore network standards.

- Once standards are developed, **states** (*e.g.*, through multi-state agreements) should utilize these standards in any coordinated onshore or offshore procurement for public policy transmission that may include HVDC facilities.
- **DOE**, with Congressional authorization if necessary, should financially support pilot projects and testing centers to demonstrate technology maturity and the economic and operational capabilities of HVAC-meshed and multi-terminal HVDC designs, including HVDC circuit breakers and vendor compatibility, to demonstrate commercial readiness of standardized technologies for use in competitive processes by offshore wind generators and transmission developers for both fixed-bottom and floating offshore wind plants. These pilot demonstration projects could rely on the advisory committee as discussed in Recommendation 5, and include engineering experts such as IEEE, and build on recent standardization efforts in Europe and conducted by the DOE described above.

9. Improve Regional Transmission Planning and Interconnection Processes

Ongoing efforts to improve regional transmission planning processes (over the next 1-2 years) to proactively address onshore and offshore renewable generation grid integration needs from a long-term, multi-value planning perspective will be key to meeting the ongoing and evolving needs of the nation's clean energy future. Initial reform efforts are already underway as part of FERC's transmission planning NOPR,[184] but that effort has not yet resulted in a final rule nor any resulting reforms. In addition, the NOPR does not propose to reform the existing near-term regional transmission planning processes, which create several challenges to efficient regional planning as discussed above, including an accelerating volume of incremental transmission investments and siloed, single-driver planning processes that pre-empt more cost-effective solutions.

Reforms to improve regional transmission planning require the review of siloed existing processes that are not sufficiently coordinated with each other to yield cost effective regional planning solutions. More holistic planning and simultaneous identification and consideration of multiple transmission needs will also be necessary to reduce the cost of necessary network upgrades triggered by generation interconnection requests. When considering a broad range of

[184] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022).

local, reliability, market-efficiency, public policy, resilience, and other drivers at the same time, regional planning processes will be able to address both near-term and long-term needs in a more cost-effective manner. A major focus should be for states and regional grid operators to formally incorporate the transmission needed to incorporate these generation resources into each region's planning process and ensure that any planning effort actually has a path to implementation within each planning region and that any future onshore grid expansion planning is integrated with OSW transmission planning.

A comprehensive framework for cost-benefit analysis needs to be adopted to ensure that all costs and benefits (system-wide cost savings and reliability improvements) of different transmission solutions can be identified and quantified transparently to inform the evaluation and selection of both regional and interregional transmission solutions.[185] Several U.S. grid planners already have significant experience with the quantification of multiple transmission-related benefits in long-term planning efforts.[186] In Europe, ENTSO-E has developed a framework with common principles and procedures for multi-criteria cost-benefit analysis for its network development plan projects.[187]

RECOMMENDATIONS FOR ACTION

- **FERC** should continue efforts in its transmission planning NOPR toward longer-term, multi-value, scenario-based proactive transmission planning, and ensure that facilities identified to meet these needs are part of least-regrets, system-wide solutions.
- **Grid Operators** should provide robust compliance filings to any final regional planning rule, including to ensure planning processes will be more responsive to the state public policy needs within their region and provide a clear path to actionable inclusion of offshore wind transmission needs into the existing transmission planning efforts.[188] Grid operators should

[185] As noted earlier, we do not recommend that cost allocations are formulaically based on quantified benefits. Rather, the costs of OSW-related transmission facilities should be allocated in a fair and transparent way that is roughly commensurate with their benefits (*e.g.*, voluntarily in proportion to states' OSW and other clean-energy needs, but considering system-wide benefits that may accrue to all loads in a region or across neighboring regions).

[186] See Pfeifenberger, Gramlich, *et al.*, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, the Brattle Group and Grid Strategies, October 13, 2021.

[187] ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, January 28, 2020.

[188] For instance, while the NOPR provides for proposed requirements that planning regions include "transparent and not unduly discriminatory criteria, which seek to maximize benefits to consumers over time…" these provisions only require "*potential selection in the regional transmission plan,*" likely allowing compliance filings that do not mandate such selection. *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 at pro-forma Attachment K (2022).

also provide more robust frameworks to work directly with states, as envisioned in the NOPR,[189] to participate in development of selection criteria for proactive, multi-value transmission planning.

- **FERC** should monitor the results of regional planning reforms to evaluate whether the revised planning processes result in identification of cost-effective solutions to address multiple transmission needs and reduce the amount of siloed planning performed in the various planning regions.
- The contemplated creation of an **Independent Transmission Monitor** could assist FERC in the ongoing evaluation and analysis of transmission needs and advise on the effectiveness of and necessary further improvements to transmission planning reforms.[190]

10. Create Effective Interregional Transmission Planning Processes

Over the next 2–3 years, efforts should continue toward improving interregional planning processes as contemplated in FERC's 2021 ANOPR,[191] including evaluating fundamental reforms to the timing and sequencing of interdependent regional and interregional transmission planning processes. While the benefits of interregional transmission have been broadly identified, critical barriers exist preventing the identification of interregional transmission needs and solutions that could more cost-effectively provide solutions to needs across regions. FERC has made initial strides in improving interregional coordination as part of ongoing efforts in the NOPR to adopt long-term transmission planning scenarios, but these coordination processes do not address interregional needs, nor do they try to evaluate whether more cost-effective interregional solutions should displace higher-cost regional solutions.[192] These efforts could be aided by DOE exercising existing authority to identify National Interest Electric

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[189] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 at P 245 (2022).

[190] See, for example, States press FERC for independent monitors on transmission planning, spending as Southern Co. balks | Utility Dive (October 27, 2022); FERC, state regulators consider independent monitors as way to boost transmission oversight 'gap' | Utility Dive (November 16, 2022); and Item No. 5 of Notice Inviting Post-Technical Conference Comments - Docket No. AD22-8-000 | Federal Energy Regulatory Commission (ferc.gov) (December 23, 2022).

[191] *Building for the Future through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022).

[192] For a discussion of interregional planning challenges and proposed solutions, see Interregional Planning Roadmap.

Transmission Corridors, which would create additional federal interregional planning and development authorities.[193]

Building on the refinements to FERC's transmission planning NOPR, additional interregional planning reform efforts should seek to improve grid resilience, lower system-wide costs, take advantage of load and resource diversity, evaluate if interregional solutions can more cost-effectively address regional transmission drivers, and analyze if offshore transmission links between regions offer the most feasible and cost-effective way to address these identified interregional needs. Existing and currently contemplated new interregional coordination efforts do not attempt to pursue this degree of planning or operational coordination between regions that could offer substantial additional system benefits.

RECOMMENDATIONS FOR ACTION

- **FERC** should continue ongoing efforts set out in its ANOPR and transmission planning NOPR that seek to improve interregional coordination. **FERC** should additionally consider future reforms to regional and interregional planning processes that would address sequencing of near- and longer-term transmission planning processes to ensure that incremental investments based on siloed existing planning processes do not preempt more cost-effective interregional transmission solutions.
- **Grid Operators** should respond to FERC's guidance with a robust interregional need identification process, including identifying needs on a multi-value basis, evaluating whether interregional solutions are more cost-effective in addressing regional needs, and if offshore transmission links offer the most cost-effective solutions to address identified needs.
- The contemplated creation of an **Independent Transmission Monitor** (as already noted in Recommendation No. 9) could effectively assist FERC in the ongoing evaluation and analysis of interregional transmission needs and advise on interregional planning reforms.

[193] 16 U.S.C. § 824p. The DOE's only designation of National Interest Electric Transmission Corridors occurred in 2007 with the designation of the Mid-Atlantic Area and the Southwest Area, see *Order Denying Rehearing,* 73 Fed. Reg. 12959 (March 11, 2008). These Corridor designations were vacated by the Ninth Circuit in *California Wilderness Coalition v. Dept. of Energy,* 631 F.3d 1072 (9th Cir. 2011); see also A. Zevin, S. Walsh, *et al.*, Building a New Grid Without New Legislation: A Path to Revitalizing Federal Transmission Authority, Columbia University Center on Global Energy Policy, December 14, 2020.

11. Develop Offshore Grid Regulations and Contract Structures

Over the next 3–5 years, and before networked or multi-use offshore facilities are placed into service, appropriate regulatory and contractual frameworks will need to be developed to enable the commercial use of shared offshore and onshore transmission facilities that are built for the purpose of enabling OSW goals.

Some progress has already been made in New Jersey's effort to develop an avenue, as recently approved by FERC, to preserve and assign POI capability created by state-sponsored network upgrades for the purpose of integrating OSW generation.[194] However, the PJM-New Jersey agreement contemplates preservation of the capability created at specific onshore POIs for one state that are then assigned to specific individual OSW generators. As ongoing efforts in the U.K. show, many additional regulatory and contractual matters will need to be addressed once offshore facilities are designed to (1) be coordinated to address the needs of multiple generators and states,[195] and (2) are linked into a shared, multi-purpose offshore network with multiple POIs in one or more market areas.[196] Offshore wind integration efforts in Ireland have addressed similar issues.[197]

These contractual and regulatory frameworks also need to be developed in the U.S. for multi-purpose use, allowing for both the delivery of OSW generation to shore and expansion of the transmission capability of the integrated grid. They should also facilitate both regional and interregional operations. While networked connections between radial transmission facilities may initially create a meshed network configuration within one region, underlying regulatory constructs should be created such that these networks can be readily expanded to enable interregional connections. This will likely require additional and related RTO market design work, including engagement with workstreams contemplated under Recommendation 12 below. These regulatory frameworks should also seek to mitigate project-on-project risks of separating offshore wind transmission development and operations from offshore wind generation development and operations, by preserving (or otherwise identifying) the capability

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194 179 FERC ¶ 61,024 at P 46 (2022).

195 See National Grid ESO, Offshore Coordination: Early Opportunities Update, May 2022 (to increase coordination for projects already under way), including discussion of "multi-purpose interconnectors" (at 9) and "next steps timeline" (at 16) of codes and standards, industry processes, stakeholder engagement, and grid operations processes.

196 See Ofgem consultation and stakeholder survey: Update following our consultation on changes intended to bring about greater coordination in the development of offshore energy networks, January 26, 2022.

197 S. Boeve, B. Vree, *et al.*, Final Report: Offshore Grid Delivery Models for Ireland, Navigant, March 31, 2020.

to be used by facilities subject to coordinated interconnection and enabling application of revised ITCs implemented under Recommendation 3.

Development of such a regulatory and contractual framework will require close collaboration among grid operators and states, possibly supported by DOE's transmission contracting capability. This framework must support evolving system designs, supporting the transition from radial tie lines to meshed radial tie lines and towards broader regional and interregional grid solutions. In addition, state engagement is critical to ensure that the ultimately developed contractual provisions can be used to enable networked offshore transmission through state-driven OSW generation and transmission procurements.

RECOMMENDATIONS FOR ACTION

- **DOE** should develop a technical forum of East Coast RTO/ISOs to begin development of regulatory and contractual models for intra- and inter-regional networking and multi-purpose use of offshore transmission facilities. This technical forum would include FERC as a critical member advising on open access precedent, states (possibly through a multi-state entity), NERC, relevant national labs, OSW generators, transmission developers, and other parties DOE finds appropriate.
- Once regulatory frameworks are developed, **FERC** should provide guidance on how RTO/ISO tariffs may need to be modified to support the necessary regulatory frameworks, encouraging or requiring **Grid Operators** to adopt these standards in compliance filings.

12. Improve Grid Operations and Wholesale Market Designs for HVDC networks

Within the next 3–5 years, and certainly before networked or multi-use offshore facilities are placed into service, DOE, in coordination with grid operators, should develop wholesale electricity operations and market design modifications that allow for the regional and interregional optimization of HVDC transmission networks.[198] These revisions to RTO operations and markets should consider the need to optimize both regional and interregional HVDC interties and the accelerated utilization of advanced technologies to address reliability needs (including MSSC concerns) and provide market benefits.

[198] As noted, NYISO has already started to work on market design modification that would allow them to operationally optimize the use of region-internal HVDC lines. See Internal Controllable Lines: Market Design Concept Proposal, August 4, 2022.

Importantly, these improvements should take full advantage of the unique capabilities of HVDC technology as discussed earlier, utilize advanced technologies and operational tools to address concerns over largest single contingencies described above, and more fully and optimally utilize both existing and new interregional transmission capability. Once fully enabled, the benefits of optimized market operations enabled by appropriately-designed regional and interregional HVDC networks—such as interregional energy transfer value, grid congestion relief benefits, the resource adequacy value of broader interregional diversification, the interregional resilience value enabled by the improved grid operations and RTO/ISO market design, and reliability benefits such as black start capability—should also be considered in the benefit-cost analyses employed in regional and interregional transmission planning processes.

RECOMMENDATIONS FOR ACTION

- Following efforts in Recommendation 8, **DOE** should continue the technical forum of East Coast RTO/ISOs to build on existing experience (*e.g.*, current NYISO efforts) and develop best practices in grid operations and market design that allow for the optimization of offshore wind-related HVDC transmission links within and across regions and the consideration of these benefits within planning processes. This technical forum would include FERC, states (possibly through the multi-state entities), NERC, other relevant national labs, and would be expanded to include market participants likely to be impacted by pricing outcomes.
- Once the improved grid and market operations standards are developed, **FERC** should encourage **Grid Operators** to adopt these improved operational, reliability, and planning frameworks in their tariff and business practices.

V. Available Federal Support

Federal support for these recommendations is now available through several funding options and programs that are relevant to evaluating, analyzing, and planning the onshore or offshore grid to enable injection of offshore wind resources. DOE administers several of these funding streams under its Building a Better Grid Initiative, which includes the Transmission Facilitation Program, the Grid Resilience Utility and Industry Grants, Smart Grid Grants, and the Grid Innovation Program, described further below.[199] In addition, DOE's Wind Energy Technology

[199] Department of Energy Grid Deployment Office, Building a Better Grid Initiative.

Office provides further funding opportunities,[200] including a recent $28 million opportunity related to address HVDC Standardization and other key wind energy deployment challenges,[201] and managing the federal administration's Earthshot™ for floating offshore wind.[202] While federal funding is very limited compared to offshore transmission investment needs—and investment tax credits are not broadly available to support offshore transmission—the available support can facilitate initiative to address the recommendations discussed above:

- Up to $100 million is available for funding for planning, modeling, and analysis is available under section 50153 of the Inflation Reduction Act (IRA),[203] including for specific purposes such as: (1) paying expenses associated with convening relevant stakeholders to address the development of transmission of electricity associated with OSW;[204] and (2) evaluating integration of clean energy into the grid, including cost methodologies to facilitate the expansion of the bulk power system, impacts of increased electrification, benefits of coordination between generator interconnection processes and transmission planning, evaluation of rights-of-way and existing transmission corridors, benefits of additional interregional or inter-interconnection transmission links, and opportunities for use of non-transmission alternatives.[205]
- Up to $760 million is available to facilitate the siting of certain interstate and offshore electricity transmission lines under section 50152 of the IRA, including for analyzing a transmission project, examining alternate siting corridors, participating in regulatory proceedings, and supporting economic development in affected communities.[206]
- Up to $2 billion is available for transmission facility financing under section 50151 of the IRA, including loan guarantees to certain transmission facilities designated by the Secretary of Energy to be in the national interest.[207]

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[200] Department of Energy Wind Energy Technologies Office.

[201] Department of Energy Wind Energy Technologies Office, WETO Releases $28 Million Funding Opportunity to Address Key Deployment Challenges for Offshore, Land-Based, and Distributed Wind, December 6, 2022.

[202] Department of Energy Wind Energy Technologies Office, Floating Offshore Wind Shot.

[203] 42 USC § 18715b.

[204] 42 USC § 18715b(b)(1).

[205] 42 USC § 18715b(b)(2)(A)–(L).

[206] 42 USC § 18715a.

[207] 41 USC § 18715.

- Up to $250 billion is available for energy infrastructure reinvestment loan financing under section 1706 of the IRA, including to retool, repower, or repurpose energy infrastructure, including transmission, to avoid or reduce greenhouse gases.[208]
- Up to $5 billion is available for resilience grants under section 40101 of the Infrastructure Investment and Jobs Act (IIJA), intended to reduce the likelihood and severity of grid disruptions, including for purposes such as weatherization technologies, monitoring and control technologies, equipment undergrounding, utility pole management, reconductoring or relocating power lines, and others.[209] Of this amount, up to $2.5 billion is available for Grid Resilience Utility Grants under section 40101(d) through Formula Grants for states, Tribes, and territories, and $2.5 billion is available for Grid Resilience Industry Grants under section 40101(c) through competitive grants and federal financial assistance.[210]
- Up to $5 billion is available under section 40103(b) of the IIJA, the Grid Innovation Program, providing states groups of states, Indian Tribes, local governments, or Public Utility Commissions funding opportunities for innovative approaches to transmission, storage, and distribution infrastructure.[211]
- Up to $3 billion is available for Smart Grid Grants under section 40107 of the IIJA, allowing for enhanced deployment of technologies to enhance grid flexibility.[212]
- Up to $2.5 billion is available on a revolving basis is available under section 40106 of the IIJA, which establishes the Transmission Facilitation Program.[213] This program allows DOE to engage in various ways to assist in the facilitation of transmission, including assisting in design, construction, operation, as well as issuing loans related to eligible projects and entering into contracts for up to 50% of the capacity of an eligible transmission project.[214]

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[208] 42 USC § 16516; 42 USC § 16517; see also Department of Energy Grid Deployment Office, Bipartisan Infrastructure Law and Inflation Reduction Act Program and Opportunities, October, 2022, at 4.

[209] 42 USC § 18711.

[210] Department of Energy Grid Deployment Office, Bipartisan Infrastructure Law and Inflation Reduction Act Program and Opportunities, October, 2022, at 5.

[211] 42 USC § 18712(b).

[212] The IIJA amended and made additional appropriations for 42 USC § 17386(a), the existing Smart Grid Investment Matching Grant Program established under the Energy Independence and Security Act of 2007, see IIJA § 40107.

[213] 42 USC § 18713.

[214] 42 USC § 18713(e)–(f).

- Up to $500 million is available for state energy offices, including for collaborative transmission siting and energy conservation plans under section 40109 of the IIJA, via DOE's State Energy Program extending to 2026.[215]
- The IRS administers several tax credits for project developers, including a 30% investment tax credit for offshore wind projects beginning construction before January 1, 2026, including direct pay provisions. Section 13502 of the IRA also includes additional tax credits for domestic manufacturing of components and installation vessels for offshore wind facilities.[216]

As several respondents to the RFI of the New England States have noted in specific recommendations for obtaining federal support and funding, these options are suitable to support offshore wind transmission efforts.[217] Four of the five New England states participating in the multi-state RFI have already sought input on how these funding opportunities may enable regional transmission goals. [218]

[215] The IIJA amended and made additional appropriations for 42 U.S.C. § 6322(c), the existing Energy Policy and Conservation Act, see IIJA § 40109.

[216] Congressional Research Service, Offshore Wind Provisions in the IRA, September 29, 2022, at 2.

[217] For example, see Anbaric, Scaling Renewable Energy (RFI Comments), October 28, 2022, at 3-4, and 6 and Eversource, Comments of Eversource Energy Service Company on behalf of The Connecticut Light and Power Company, NSTAR Electric Company and Public Service Company of New Hampshire, October 28, 2022, at 6-9.

[218] See New England States Transmission Initiative, Five New England States Announce New Regional Energy Transmission Infrastructure Initiative – Request for Information to Integrate Clean Energy Resources, December 16, 2022 Update.

Appendix A

Table A-1 provides the details of offshore wind procurements, procurement targets of the states, and projected long-term needs. The projected long-term needs are based on state or regional clean energy and decarbonisation pathways studies.

TABLE A-1: OFFSHORE WIND COMMITMENTS AND FUTURE NEEDS

Region/State	Already Procured	State Goals					Projected Long-Term Need (GW)	
	2022	2030	2035	2040	2045	2050	2040	2050
ISO-NE (MW)	**4,841**	**8,042**	**8,642-9,042**	*8,642-9,042*	*8,642-9,042*	*8,642-9,042*	**23-29**	**42-44**
Massachusetts	3,241	5,600	*5,600*	*5,600*	*5,600*	*5,600*	6.7-11	23
Connecticut	1,158	2,000	*2,000*	*2,000*	*2,000*	*2,000*	9.1-11.1	*9.1-11.1*
Rhode Island	430	*430*	1,030-1,430	*1,030-1,430*	*1,030-1,430*	*1,030-1,430*	2.7	5
Maine	12	*12*	*12*	*12*	*12*	*12*	5	5
NYISO (MW)	**4,362**	*4,362*	**9,000**	*9,000*	*9,000*	*9,000*	**9-25**	**14-25**
New York	4,362	*4,362*	9,000	*9,000*	*9,000*	*9,000*	9-25	14-25
PJM (MW)	**8,432**	**8,432**	**14,722**	**18,222**	*18,222*	*18,222*	**13-30**	**33-58**
New Jersey	3,758	*3,758*	7,500	11,000	*11,000*	*11,000*	3.5-13.5	11-26
Maryland	2,022	*2,022*	*2,022*	*2,022*	*2,022*	*2,022*	*2.0*	*2.0*
Virginia	2,652	*2,652*	5,200	*5,200*	*5,200*	*5,200*	8-15	20-30
SERC (MW)		**2,800**	*2,800*	**8,000**	*8,000*	*8,000*	**8**	**7-10**
North Carolina		2,800	*2,800*	8,000	*8,000*	*8,000*	8	7.2-10
South Carolina								
MISO (MW)			**5,000**	*5,000*	*5,000*	*5,000*	**5**	**5**
Louisiana			5,000	*5,000*	*5,000*	*5,000*	5	*5*
CAISO (MW)		**5,000**	*10,000*	*15,000*	**25,000**	*25,000*	**15**	**25**
California		5,000	*10,000*	*15,000*	25,000	*25,000*	*15*	*25*
NWPP (MW)		3,000	*3,000*	*3,000*	*3,000*	*3,000*	**2-6**	**24-30**
Washington							0	4-10
Oregon		3,000	*3,000*	*3,000*	*3,000*	*3,000*	2-6	20
Atlantic Total (GW)	**17.6**	**23.6**	**35.2-35.6**	**43.9-44.3**	**43.9-44.3**	**43.9-44.3**	**54-93**	**96-137**
Gulf of Mexico Total (GW)			**5**	*5*	*5*	*5*	**5**	**5**
Pacific Total (GW)		**8**	**13**	*15*	**28**	*28*	**17-21**	**49-55**
US Total from State and Regional Studies (GW)	**17.6**	**31.6**	**53.2-53.6**	**66.9-67.3**	**76.9-77.3**	**76.9-77.3**	**76-119**	**150-197**
Federal U.S. Total (GW)		**30**				**110**	**40-100**	**224-458**

Notes: Values in italics and grey shading are based on previous years' stated procurement targets (and linearly interpolated for CAISO).

Sources for State Procurement Targets:

Massachusetts, Bill H.5060: An Act Driving Clean Energy and Offshore Wind, July 2022, at 58.

Connecticut, House Bill 7156: An Act Concerning Procurement of Energy Derived From Offshore

Wind, 2019.

Rhode Island, S 2583 Affordable Clean Energy Security Act, 2022.

New York, New York's Climate Leadership and Community Protection Act, 2019.

New Jersey, New Jersey Executive Order No. 307, September 21, 2022.

Maryland, OSW goal see 2019 Clean Energy Jobs Act; current procurement see Maryland Offshore Wind Overview (2022). As specified in its 2019 Clean Energy Job Act, the target of Maryland is to reach 1.6 GW offshore wind by 2030 but Maryland has already procured (2022.5 MW) more than the target.

Virginia, HB1526 Virginia Clean Economy Act, 2020.

Louisiana, Louisiana Climate Action Plan, February 2022.

Oregon, House Bill 3375, 2021.

California, Offshore Wind Energy Development off the California Coast: Maximum Feasible Capacity and Megawatt Planning Goals for 2030 and 2045, August 2022.

Sources for Long-Term Needs:

Massachusetts, Clean Energy and Climate Plan for 2050, December 2022, at 24.

A. Kniska and R. Collins, 2050 Transmission Study: Preliminary N-1 and N-1-1 Thermal Result, ISO-NE, March 16, 2022, at 12.

New England for Offshore Wind - NE4OSW: States Overview.

R. Jones, *et al.*, Energy Pathways to Deep Decarbonization: A Technical Report of the Massachusetts 2050 Decarbonization Roadmap Study, Evolved Energy Research, December, 2020.

Connecticut Department of Energy and OC Environmental Protection, Integrated Resources Plan: Pathways to achieve a 100% zero carbon electric sector by 2040, October 2021.

State of Maine Governor’s Energy Office, State of the Offshore Wind Industry: Today through 2050, January 28, 2022, at 27.

R. Lueken, S. A. Newell, J. Weiss, J. Moraski, S. Ross, The Brattle Group, New York’s Evolution to a Zero Emission Power System, May 18, 2020, at 44 (14-25 GW by 2040).

New York State Climate Council Scoping Plan, December 19, 2022, at 221, Table 13 (16-19 GW by 2050).

N. Bouchez, *et al.*, Grid in Transition Study: Phase 1 Analysis, NYISO, June 28, 2022.

PJM, Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

Evolved Energy Research, New Jersey 2019 IEP Technical Appendix, November 29, 2019, at 20 and 25.

W. Shobe, *et al.*, University of Virginia and Evolved Energy Research, Decarbonizing Virginia's Economy: Pathways to 2050, January 2021, at 40, Figure 34.

B. Sergi, *et al.*, Duke Energy Carbon-Free Resource Integration Study, National Renewable Energy Laboratory, 2022, at 32.

Washington State Department of Commerce, Washington 2021 State Energy Strategy Transitioning to an Equitable Clean Energy Future, December 2020, at 37.

Evolved Energy Research, Renewable Northwest, GridLab, and the Energy Transition Institute, Oregon Clean Energy Pathways Final Report, June 15 and July 2, 2021.

Source for Federal U.S. Total:

E. Larson, *et al.*, Net-Zero America—National data, January 9, 2022, Princeton University, at 41, Table 42.

List of Acronyms

AC	Alternating Current
ACORE	American Council on Renewable Energy
ACP	American Clean Power Association
ANOPR	Advance Notice of Proposed Rulemaking
BOEM	Bureau of Ocean Energy Management
BP	Bi-Pole
BPU	Board of Public Utilities
CAISO	California Independent System Operator
CATF	Clean Air Task Force
CEEPR	Center for Energy and Environmental Policy Research
CESA	Clean Energy State Alliance
COP	Construction and Operation Plan
CTS	Coordinated Transaction Scheduling
DC	Direct Current
DOE	U.S Department of Energy
DOI	U.S. Department of the Interior
ENTSO-E	European Network of Transmission System Operators for Electricity
ESO	Electricity System Operator
EU	European Union
FERC	Federal Energy Regulatory Commission
FOA	Funding Opportunity Announcement
GE	General Electric
GET	Grid-Enhancing Technology
GIP	Grid Innovation Program
GW	Gigawatt
HVAC	High Voltage, Alternating Current
HVDC	High Voltage, Direct Current
IESO	Independent Electricity System Operator
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act
IRS	Internal Revenue Service
ISAC	Independent State Agencies Committee
ISO	Independent System Operator
ISO-NE	ISO New England
ITC	Investment Tax Credit
JTIQ	Joint Targeted Interconnection Queue Study
kV	Kilovolt
kW	Kilowatt
LBNL	Lawrence Berkley National Laboratory

LMP	Locational Marginal Pricing
LRTP	Long Range Transmission Planning
MISO	Midcontinent Independent System Operator
MIT	Massachusetts Institute of Technology
MOU	Memorandum of Understanding
MSSC	Most Severe Single Contingency
MVP	Multi-Value Project
MW	Megawatt
MW/km2	Megawatt per square kilometer (wind energy generation density)
NERC	North American Electric Reliability Corporation
NESCOE	New England States Committee on Electricity
NJ	New Jersey
NOPR	Notice of Proposed Rulemaking
NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
OPSI	Organization of PJM States
OSW	Offshore Wind
OW	Ocean Winds
PJM	PJM Interconnection
PMA	Federal Power Marketing Agency
POI	Point of Interconnection
PPTPP	Public Policy Transmission Planning Process (of NYISO)
PPTS	Public Policy Transmission Study
RENEW	RENEW Northeast
RFI	Request for Information
RFCI	Request for Competitive Interest
RGGI	Regional Greenhouse Gas Initiative
ROW	Right-of-Way
RTO	Regional Transmission Organization
SAA	State Agreement Approach
SM	Symmetrical Monopole
SPP	Southwest Power Pool
TFP	Transmission Facilitation Program
UK or U.K.	United Kingdom
U.S.	United States
WEA	Wind Energy Area

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UNITED STATES OF AMERICA

BEFORE THE

DEPARTMENT OF ENERGY GRID DEPLOYMENT OFFICE

Notice of Availability of National Transmission Needs Study and Request for Comment

[6450-01-P]

COMMENTS OF THE SOUTHERN RENEWABLE ENERGY ASSOCIATION

The Southern Renewable Energy Association (SREA) appreciates the opportunity to comment on the February 2023 Draft of the Department of Energy's National Transmission Needs Study (Needs Study). This study is an important analysis of electric transmission needs across the country. The study defines these needs as "the existence of present or expected electric transmission capacity constraints or congestion in a geographic area",[1] which are driven by a current and projected range of electricity demand, public policy, and market conditions. As an active stakeholder in regional and interregional planning efforts in the Midcontinent Independent System Operator (MISO), and the Southeast Regional Transmission Planning (SERTP) regional footprints, SREA is pleased with the Needs Study's insight and analysis. The Needs Study broadly supports conclusions that MISO, the Southwest Power Pool (SPP) and SREA as well as other stakeholders have come to regarding the dire need for improved connectivity on the national bulk electricity system. The need to share a greater amount of electricity via interregional and intra-regional connections during extreme weather events that strain individual planning areas is well documented with increasing frequency.

[1] National Transmission Needs Study, Draft for Public Comment, February 2023, pg. ii

SREA is strongly supportive of transmission planning efforts that encompass regional and interregional reliability needs and consider a multitude of benefits over a 20–40-year time horizon. Providing a broad spectrum of probable long-range outcomes in generation expansion and retirements, as well as load growth in the Needs Study is necessary, especially because not all planning areas engage in scenario-based planning. However, providing a study that is national in scope, and examines the challenges of maintaining a stable, affordable and resilient bulk electricity system into the future is directly tied to DOE's mission "to ensure America's security and prosperity by addressing its energy, environmental, and nuclear challenges through transformative science and technology solutions."[2] It is in this spirit that we wish to provide SREA's perspective as an engaged stakeholder in transmission planning within planning regions, an experienced stakeholder in state proceedings and a voice of experience that has contributed to the record on transmission planning rulemaking discussions at FERC.

I. The Department of Energy Has Jurisdiction to Develop the Needs Study

The current pace of regional and interregional transmission planning and deployment across planning areas studied by the DOE Needs Study is currently insufficient to meet both present and forecasted demands on the bulk electricity system. Expansion of the transmission system is necessary to meet not only the demands of today but also the grid of tomorrow. In that context, the Needs Study provides valuable information to transmission planners and stakeholders participating in bulk electricity system planning efforts that can facilitate reliable, resilient, and affordable access to electricity across the United States in the decades to come.

[2] United States Department of Energy. Mission. [https://www.energy.gov/mission]

The DOE is within its jurisdiction under Federal Power Act (FPA) Section 216 to carry out the Needs Study as it is directed by the FPA to conduct "an assessment of national electric transmission capacity constraints and congestion not less frequently than once every 3 years."[3] Furthermore, the study provides a much needed perspective especially as it relates to future interregional and intra-regional transmission needs which are not represented in the dominant paradigm of bottom-up transmission planning processes across the seven Regional Transmission Organizations (RTOs) and six transmission planning regions.

II. The Needs Study Scope is Appropriate and Necessary

While FERC sought to encourage interregional planning through Order 1000,[4] the resulting buildout of coordinated system planning, and deployment of interregional transmission has been piecemeal at best. Coordinated system planning between the Southeastern Regional Transmission Planning utilities (SERTP) and neighboring regions has not resulted in meaningful transmission development. In the SERTP annual process, a set of up to five "Economic Planning Studies" are proposed by stakeholders participating in the Regional Planning Stakeholders Group (RPSG), and chosen by SERTP to analyze further for the annual transmission plan. These studies only examine simulated source to sink power transfers on a regional and interregional basis that do not assess the economic benefits beyond avoided transmission costs. Further, SERTP's studies only evaluate 10 years worth of data, as opposed to a more robust longer term transmission planning process.

[3] 16 U.S.C. 824p.
[4] 141 FERC ¶ 61,044, at P 60, (2012) "(1) coordinating and sharing the results of respective regional transmission plans to identify possible interregional transmission facilities that could address transmission needs more efficiently or cost-effectively than separate regional transmission facilities; and (2) jointly evaluating such facilities, as well as jointly evaluating those transmission facilities that are proposed to be located in more than one transmission planning region.' (https://www.ferc.gov/sites/default/files/2020-05/E-1_22.pdf)

SERTP utilities stated in FERC's RM21-17 that "Rather than a failure of the SERTP Sponsors' Order No. 1000 processes, the lack of alternative transmission facilities selected for regional cost allocation demonstrate that the SERTP Sponsors' IRP/RFP-driven transmission planning, in fact, already successfully identifies cost-effective and efficient solutions."[5] However, it may be more accurately stated that by deferring to in-state IRP/RFP-driven planning, SERTP utilities simply favor a generation-centric transmission planning process over regional or interregional transmission planning. SERTP notably does not consider production cost savings in transmission planning however and does not consider the ability of transmission to mitigate congestion as a benefit. As the Needs Study points out, "Utilities in the Southeast are in the process of developing the Southeastern Energy Exchange Market (SEEM) to trade energy in real-time (SEEM 2022), an extension of the bilateral contracts currently used in that region. Notably, however, SEEM does not price or reflect congestion."[6] By not considering production cost savings in the SERTP planning process, and other benefits, utilities are unable to adequately evaluate the benefits of transmission, nor definitively state that the current system is cost-effective and efficient. It is no surprise then that the conclusion reached by SERTP utilities is that interregional transmission with their neighbors in MISO, PJM, or SPP is not needed.

SREA would like acknowledge that DOE's Needs Study provides significant value for non-RTO regions, especially the Southeast. Utilities involved in SERTP commented on the previous draft of the Needs Study that the identification of forecasted "transmission capacity constraints" are beyond the jurisdiction of the DOE defined in FPA Section 216. SREA disagrees

[5] Southeastern Regional Transmission Planning Process Sponsors' Initial Comments under RM21-17, August 17, 2022 [https://elibrary.ferc.gov/eLibrary/filedownload?fileid=B406F1B5-0F1E-C763-A2E4-82ACB4E00000], pg. 34

[6] National Transmission Needs Study, Draft for Public Comment, III.d.2, pg. 16, (February 2023)

with this perspective. The DOE Needs Study provides least fifty research papers on the forecasted changes in the generation mix nationwide, providing a range of outcomes that clearly indicate the necessity for the identification of not only historical congestion and constraints, but also likely congestion and constraints in the future. If the DOE Needs Study were to only focus on immediate and historical transmission capacity constraints and congestion, it would be negligent in identifying the reliability needs related to a rapidly evolving bulk electricity system that is widely forecasted by many studies. The studies evaluated have a wide geographic diversity, subject matter expertise, and cover a wide range of issues faced by the nation's transmission system today.

A. Integrated Resource Plans are Not Replacements for Robust Transmission Planning

SREA is heavily involved in IRP processes throughout the southeast. We have been heavily involved with IRPs in Arkansas, Georgia, Kentucky, Louisiana, Mississippi, and Tennessee. Alabama, Florida, and Texas do not have IRP requirements. Many municipal and cooperative utilities, like PowerSouth and Cooperative (Mississippi), similarly do not conduct IRPs publicly. In states where IRPs are required, those IRPs are too limited in scope to address the transmission issues identified in the Needs Study. IRPs in the south are often solely focused on *generation* planning, not *transmission* planning. No IRP in the south includes evaluation of cost-effective transmission planning in a wide, multi-state or multi-region fashion. In effect, no IRP in the south fulfills the requirements of Order 1000 that,

> (3) Public-utility transmission providers in each pair of neighboring transmission planning regions within each interconnection must coordinate to determine whether more efficient

or cost-effective transmission solutions are available within each pair of neighboring regions; [7]

In SREA's experience intervening in IRPs throughout the Southeast, the Georgia Public Service Commission (GAPSC) conducts one of the more thorough IRP processes. As SREA noted in comments on FERC's RM21-17 NOPR, in the state regulatory processes, Georgia Power presented to the GAPSC that the Company is simply unable to perform more robust transmission planning, because its software and models are unable to do so. Georgia Power witness Robinson noted under oath that the Company is opposed to assessing economic congestion of the transmission system because, "We don't have the models to do it."[8] Southern Company affiliates use Aurora planning software for IRPs, but GAPSC staff witness Leah Wellborn noted under oath that, "There is no transmission modeling in Aurora."[9] If there is no optimization of generation investment with transmission investment in IRP's, even in one of the most robust IRP processes, then assumptions feeding into regional SERTP plans are wholly centered on accommodating a cost effective transmission system buildout only as it relates to in-state generation decisions. The Needs Study fills a gap in analysis not conducted in state IRP processes.

Utility IRPs that forecast future generation capacity expansion are a useful input to transmission planning, but should not be the only input. IRPs often only forecast needs for the utility conducting the analysis, not neighboring utilities nor regions. MISO considers state IRPs, alongside state mandates and utility goals to inform their 20 year out "Futures" forecast that guides

[7] Order 1000-B, at 60 (https://www.ferc.gov/sites/default/files/2020-05/E-1_22.pdf)
[8] Georgia Power Company's 2022 Application for Approval of its Integrated Resource Plan, May 24, 2022, hearing transcript pg. 282-283, Attachment B.
[9] Georgia Power Company's 2022 Application for Approval of its Integrated Resource Plan, June 21, 2022, hearing transcript pg. 239, Attachment A.

their Long Range Transmission Plan (LRTP), but MISO's transmission planning is optimized for cost effective regional reliability and generation investment. Alternatively, the state IRPs in SERTP do not consider needs of the bulk electricity system across the Southeast, only in state reserve requirements. SERTP utilities further commented that these projected future capacity constraints are traditionally addressed through generation planning in the IRP processes in participating states, independent of transmission assessments, underscoring the inadequacy of IRPs. SERTP utilities propose in their comments on FERC's RM21-17 NOPR that production cost savings are "at their core generation-focused considerations."[10] Production cost savings are more clearly linked to transmission expansion in that it is focused on the economic dispatch and operation of generation resources, rather than capital costs.[11] Therefore, siloing production cost benefits in the IRP process, from a transmission and generation optimized approach in regional transmission planning, is ruling out potential adjusted production cost benefits of transmission that leads to more economic dispatch of resources. The DOE Needs Study addresses the limited scope of IRPs by evaluating larger regional needs.

B. SERTP is a Weak Transmission Planning Process

The Regional Planning Stakeholders Group (RPSG) in SERTP is a working group that proposes Economic Planning Studies assessing source to sink power flows between SERTP and neighboring regions 10 years into the future. Broad sets of benefits are not assessed for these projects, aside from the avoided cost of regional projects. Notably, neighboring RTO regions such as MISO and PJM do not participate in the RPSG. In 2022, the RPSG only included two members,

[10] Docket No. RM21-17, SERTP Comments, August 17th 2022, PP. 30

[11] 'Transmission Planning for the 21st Century', Brattle and Grid Strategies, PP. 33-34, (2021) (https://acore.org/wp-content/uploads/2021/10/Transmission-Planning-for-the-21st-Century.pdf)

including Santee Cooper and SREA.[12] Simon Mahan, SREA's Executive Director, noted at the FERC's Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements that "…on the SERTP website, there are registration links for stakeholder committees for FRCC, MISO, PJM, SCRTP, and SPP; however, all the links to register for the committees are broken (Error 404), generic, or outdated."[13] There is no coordinated system planning with neighboring regions that is open to stakeholders in the SERTP process. The Economic Studies in SERTP have unsurprisingly never yielded a single interregional transmission project to be constructed with neighboring regions.

III. Resilience and Reliability Challenges in the South

SREA appreciates the Needs Study's focus on resilience and reliability needs associated with transmission planning in future years. The lessons of operational challenges for the bulk electricity system during extreme cold events like Winter Storms Uri[14] and Elliott[15] and extreme heat events in CAISO[16] and ERCOT[17] in recent years highlight the challenge of maintaining reliability over multiple days relying on short term or in-state planning decisions that neglect transmission needs. Low-frequency, high-impact events challenging grid stability are becoming

[12] SERTP 2022 RPSG Sector Members. [http://www.southeasternrtp.com/docs/general/2022/2022-RPSG-Sector-Members.pdf]
[13] Simon Mahan (December 9, 2022). Speaker materials of Simon Mahan, Southern Renewable Energy Association at the Workshop on Establishing Interregional Transfer Capability on December 5-6, 2022 under Docket Number AD23-3-000. Pg. 10-11. [https://elibrary.ferc.gov/eLibrary/filedownload?fileid=cf3c0869-66e8-c152-963c-84f7b2e00000]
[14] Midcontinent Independent System Operator, The February Arctic Event, February 14-18, 2021 (https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf)
[15] ACORE and Grid Strategies, "The Value Of Transmission During Winter Storm Elliott', February 2023, (https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf)
[16] CAISO News Release "Conditions on the grid becoming more strained as heat wave intensifies' (http://www.caiso.com/Documents/conditions-on-the-grid-becoming-more-strained-as-heat-wave-intensifies.pdf)
[17] "Texas grid operator urges electricity conservation as heat wave drives up demand', Sneha Dey and Mitchell Ferman, July 10th 2022 (https://www.texastribune.org/2022/07/10/texas-blackouts-power-ercot/)

increasingly frequent, and increasingly impactful. The value of addressing resilience in transmission planning is clear. As a recent Lawrence Berkeley National Laboratory (LBNL) study states, "Extreme conditions and high-value periods play an outsized role in the value of transmission, with 50% of transmission's congestion value coming from only 5% of hours."[18] However, since there is no Locational Marginal Price (LMP) information available for non-ISO planning areas in the Southeast there was no data provided in the LBNL study to determining the value of avoided congestion during recent extreme weather events. SREA believes that recent events clearly indicate a high value of regional and interregional transmission for the Delta (MISO South), and especially the Southeast regions. Nevertheless, additional data would be helpful in assessing transmission value, such as LMPs.

A. Resilience and Reliability Challenges in the Southeast

The needs assessment suggests for the Southeast "between 2.9 and 7.5 GW of new transfer capacity (median of 4.5 GW, a 54 percent increase relative to the 2020 system) needed with the Midwest region in 2035 to meet moderate load and high clean energy futures" and "between 2.8 and 8.5 GW of new transfer capacity (median of 5.1 GW, an 86 percent increase relative to the 2020 system) needed with the Delta region in 2035 to meet moderate load and high clean energy futures." for the Southeast.[19]

There is compelling evidence supporting the Needs Study conclusion that expanded Interregional Transfer Capability between the Southeast and Midwest (MISO) regions are

[18] "Empirical Estimates of Transmission Value using Locational Marginal Prices', Dev Millstein, Ryan Wiser, Will Gorman, Seongeun Jeong, James Kim, Amos Ancell, Lawrence Berkeley National Laboratory, August 2022
[19] National Transmission Needs Study, Draft for Public Comment, pg. 13, (February 2023)

necessary even without considerations for load growth. As stated in a press release by NERC President and CEO Jim Robb after Winter Storm Elliott in 2022, “There will be multiple lessons learned from last week’s polar vortex that will inform future winter preparations. In addition to the load shedding in Tennessee and the Carolinas, multiple energy emergencies were declared, and new demand records were set across the continent. And this was in the early weeks of a projected “mild” winter. This storm underscores the increasing frequency of significant extreme weather events (the fifth major winter event in the last 11 years) and underscores the need for the electric sector to change its planning scenarios and preparations for extreme events.”[20] Four of those five events impacted the South, including:

- In 2014, the Polar Vortex event created historic winter peak demand in VACAR (Carolinas) where demand reached nearly 118% of the historical peak, and over 100% for both TVA and the Southeast. SCE&G had “controlled firm load shed” and Duke “activated a 5 percent system-wide voltage reduction”[21]
- The “Cold Weather Bulk Electric System Event of January 17, 2018,” resulted in outages and derates of 29% of TVA’s generating capacity, and 6% of the non-MISO South SERC region in the weather impacted area over two days.[22]

[20] North American Electric Reliability Council, Press Release. “FERC, NERC to Open Joint Inquiry into Winter Storm Elliott’ (December 2022) (https://www.nerc.com/news/Pages/FERC,-NERC-to-Open-Joint-Inquiry-into-Winter-Storm-Elliott.aspx)

[21] NERC, Polar Vortex Review 2014, Polar Vortex saw historic winter peak demand in VACAR reach nearly 118%, and over 100% for both TVA and the Southeast, Table 2, https://www.nerc.com/pa/rrm/January%202014%20Polar%20Vortex%20Review/Polar_Vortex_Review_29_Sept_2014_Final.pdf

[22] 2019 FERC and NERC Staff Report, “The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018’, pg. 35 (https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf)

- In 2021, Winter Storm Uri impacted the southeast, including TVA. According to a FERC/NERC investigative report, "TVA called a TLR Level 3 resulting in curtailments of non-firm power transfers from BAs east of MISO to SPP."[23]
- Then in December 2022 Winter Storm Elliott caused Duke Energy[24] to shed roughly 5-6% of their load, and TVA[25] shed load for nearly 10% of their system to preserve reliability. While there is no data in SERTP related to congestion or LMP's during these extreme weather events, the impact of these events would suggest that the value of interregional transmission would likely be high.

i. <u>Winter Storm Elliott</u>

Considering the impacts of extreme weather on the SERTP planning area system during the recent Winter Storm Elliott, there are interregional transmission planning needs that should be considered to ensure reliability and resilience. During Winter Storm Elliott, across the TVA region, Duke Energy in the Carolinas, Louisville Gas & Electric and Kentucky Utilities (LGEKU), PJM, MISO and SPP, natural gas generators failed to perform as expected. According to analysis by Bloomberg New Energy Finance "On Dec. 23, US natural gas production suffered its worst one-day decline in more than a decade, with roughly 10% of supplies wiped out because of wells freeze-offs. Output was as low as 84.2 billion cubic feet on Saturday, a 16% decline from typical levels,

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[23] FERC, NERC and Regional Entity Staff Report, The February 2021 Cold Weather Outages in Texas and the South Central United States, footnote 219, pg. 148, (https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and)

[24] "Duke Energy updates North Carolina Utilities Commission on Winter Storm Elliott Emergency Outage Event" Duke Energy Press Release, January 23, 2023, (https://news.duke-energy.com/releases/duke-energy-updates-north-carolina-utilities-commission-on-winter-storm-elliott-emergency-outage-event)

[25] "Winter storm brings power outages, rolling blackouts and frigid temps to Middle Tennessee' Kirsten Fiscus, Mariah Timms, Chris Gadd and Adam Friedman (https://www.tennessean.com/story/weather/2022/12/23/nashville-winter-storm-cold-air-wind-chill-warning-in-effect/69752558007/)

before a slow recovery started, according to BloombergNEF data based on pipeline schedules."[26] Tens of thousands of megawatts of natural gas facilities were derated or otherwise unavailable across the Eastern Interconnect.

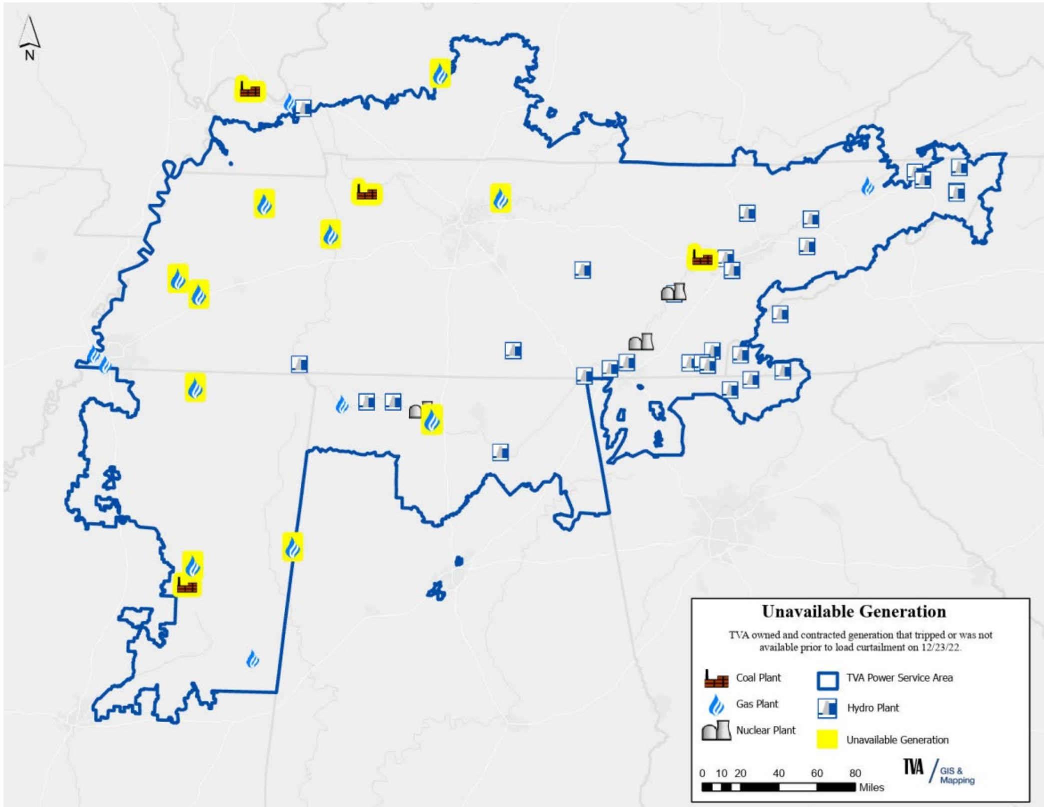
a. Winter Storm Elliott's Impact on TVA

According to local press, on December 23rd "TVA lost more than 6,000 megawatts of power generation or nearly 20% of its load at the time, with both units at TVA's Cumberland Fossil Plant offline and other problems at some gas generating units".[27] TVA experienced rolling blackouts on December 23rd, as well as December 24th, and had to cut power to at least 10% of their customers to maintain their system.[28] In addition to the frozen generators and inadequate fuel supply, utilities in the Southeast underestimated the power demand needs for their individual areas.

[26] "Deadly Winter Storm Exposes Deep Flaws of US Energy System', Gerson Freitas Jr, Naureen S Malik and Mark Chediak, Bloomberg, December 27, 2022 (https://www.bloomberg.com/news/articles/2022-12-27/deadly-winter-storm-exposes-deep-flaws-of-us-energy-system?leadSource=uverify%20wall)

[27] Dave Flessner (December 24, 2022). "Chattanooga area hit with 15-minute power outages as cold weather forces rolling blackouts," Chattanooga Times Free Press. [https://www.timesfreepress.com/news/2022/dec/24/power-outages-tfp/]

[28] TVA Press Release, "TVA Accepts Responsibility, Starts Full Review', (December 2022) (https://www.tva.com/newsroom/press-releases/tva-accepts-responsibility-starts-full-review)

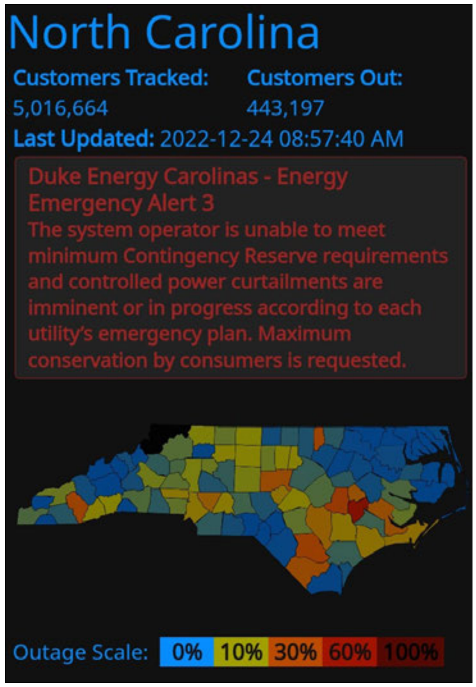


Source: TVA 2023[29]

b. Winter Storm Elliott's Impact on Duke Energy

With higher power demand needs than expected, and less generation than necessary, Duke's power outages began on December 24th at roughly 6:15AM eastern time until about 4PM later that day. Duke Energy told the North Carolina Utilities Commission in a briefing that the company's lack of generation was undermining the entire eastern interconnection's frequency.[30] Duke ultimately ended up shedding 5% of its load to maintain the system.[31] Meanwhile, portions of North Carolina in the PJM region were mostly unaffected.

[29] TVA Presentation to the Kentucky Legislature on Winter Storm Elliott, 2023. [https://apps.legislature.ky.gov/CommitteeDocuments/305/24160/Feb%202%202023%20TVA%20PowerPoint.ppt]
[30] North Carolina Utilities Commission Staff Conference, at timestamp 27:35, (January 3, 2022) (https://www.youtube.com/watch?v=xARPpMFpOA4)
[31] Duke Energy, North Carolina Utilities Commission | January 3, 2023 Briefing on Rolling Outages, slides 4-12 and 23-24 (https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=63276e03-87af-42d5-b2c2-97293fc5fe83)



Source: Poweroutage.us 2022

c. Winter Storm Elliott's Impact on LGEKU

In addition to Duke Energy and TVA, LGKEU, a Kentucky-based utility, also had load shed during Winter Storm Elliott. In a presentation to the Kentucky Legislature, LGEKU noted that the company lost about 900 MW of gas generation due to "unexpected low pressure" on a natural gas pipeline that served multiple gas units.[32]

[32] LGEKU Presentation to the Kentucky Legislature on Winter Storm Elliott. 2023. [https://apps.legislature.ky.gov/CommitteeDocuments/305/24160/Feb%202%202023%20LG&E-KU%20Presentation.pdf]

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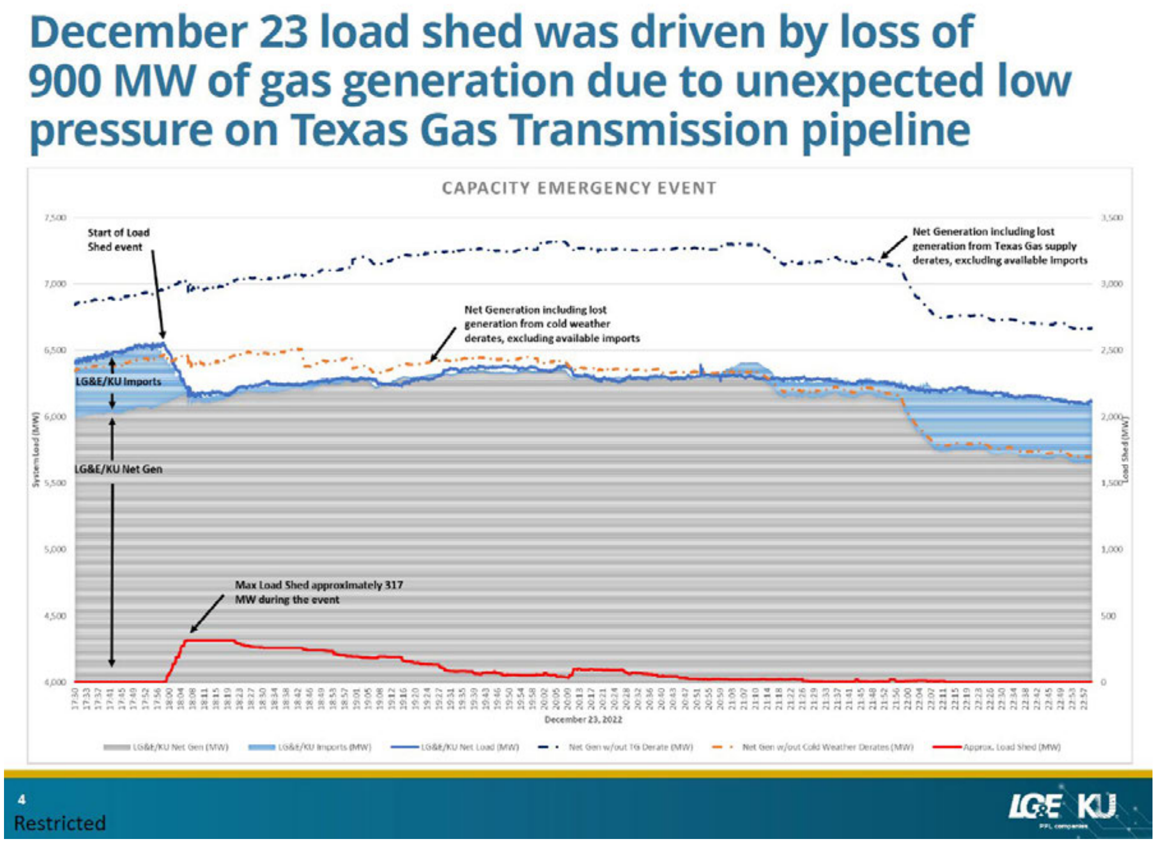

Source: LGEKU 2023[33]

d. Winter Storm Elliott's Impact on Southern Company

Southern Company did not face the same rolling blackouts that neighboring TVA and Duke Energy experienced, despite having significant generator outages. In response to PSC staff data requests, Georgia Power reported capacity reduction or loss events related to Winter Storm Elliott at Bowen 2, Gaston 1, Gaston 2, Gaston A, McDonough 3B, McDonough 4, McDonough 5, McIntosh CC 10, McIntosh CC11, McIntosh CT2, McIntosh CT5, McIntosh CT7, McManus 3B, McManus 3C, McManus 4B, McManus 4F, Scherer 3, and Yates 6.[34] Winter Storm Uri in 2021

[33] LGEKU Presentation to the Kentucky Legislature on Winter Storm Elliott. 2023. [https://apps.legislature.ky.gov/CommitteeDocuments/305/24160/Feb%202%202023%20LG&E-KU%20Presentation.pdf]

[34] Georgia Power Company, April 10, 2023. DKT 44902 STF-3 Data Request Responses. [https://psc.ga.gov/search/facts-document/?documentId=194017]

also impacted Bowen 2, McDonough 4, McDonough 5, Scherer 4, and Wansley 1.[35] SREA is unaware of other data publicly available for Alabama Power or Mississippi Power; however, it would seem unlikely that only Georgia generation units would have been effected, given TVA's own generator outages in Mississippi and Alabama. On February 2, 2023, a Georgia Power representative presented to the Georgia PSC a few details about the impacts of Winter Storm Elliott. Georgia Power did call on interruptible loads to reduce system stress, but the Company also imported significant amounts of power from MISO and Florida.[36] According to data provided to the Energy Information Administration by Southern Company, the balancing area imported about 1.7 GW of power from Duke Energy, 1.9 GW from TVA, 1 GW from Florida Power & Light, and 0.5 GW from MISO at various times during Winter Storm Elliott.[37] From December 23, 2022 to December 25, 2022, the Southern Company balancing area imported more power than it exported, underscoring the need for more robust regional and interregional transmission.

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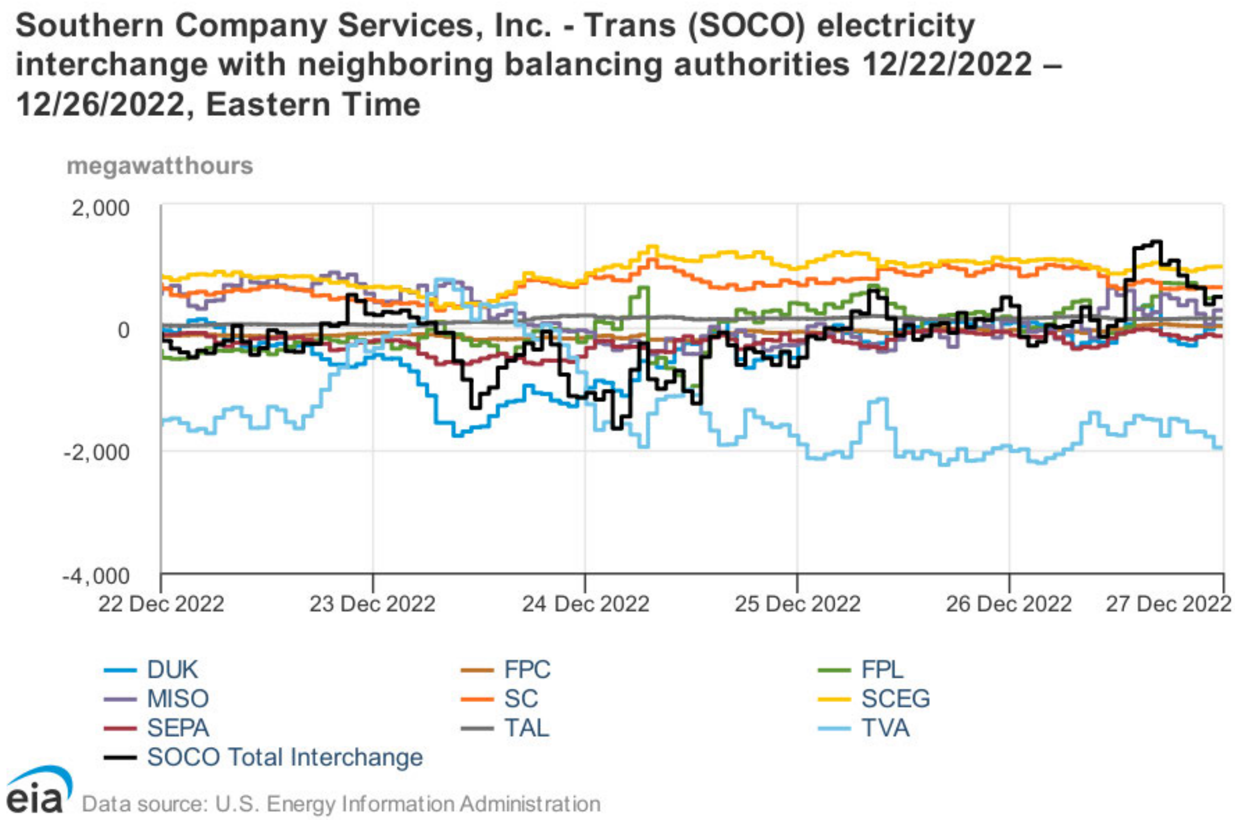
[35] Ibid.

[36] Georgia Public Service Commission, February 2, 2023. PSC Committee Hearings - 02/02/2023. [https://www.youtube.com/live/TYktpHDPBM4?feature=share&t=582]

[37] U.S. Energy Information Administration. Southern Company Services, Inc. - Trans (SOCO) electricity interchange with neighboring balancing authorities 12/22/2022 - 12/26/2022, Eastern Time. [https://www.eia.gov/electricity/gridmonitor/dashboard/custom/B9908A407CD58A5BEEFBAA06A878B5D8]



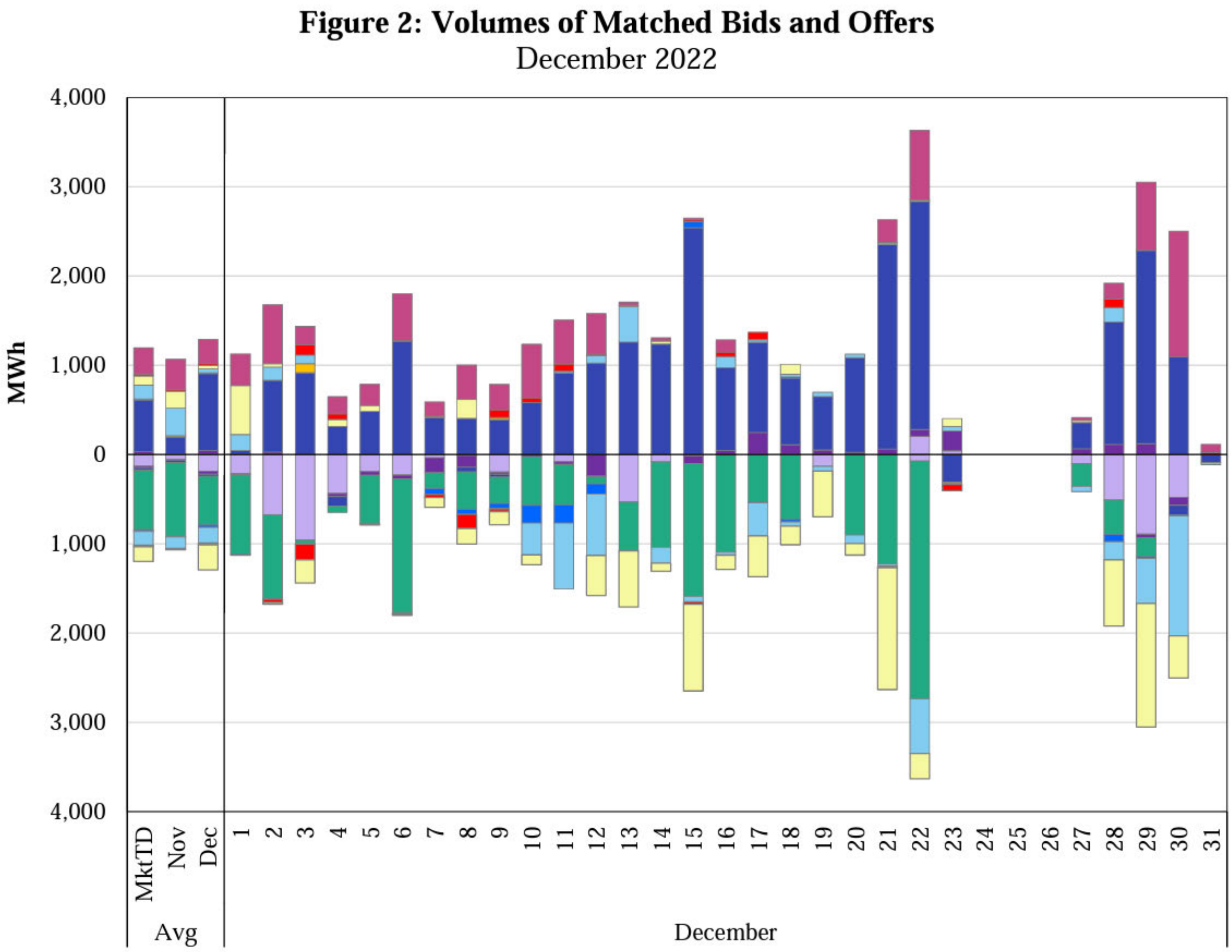
Source: EIA 2023[38]

e. Winter Storm Elliott's Impact on the Southeastern Energy Exchange Market

As noted in the Needs Study, "Utilities in the Southeast are in the process of developing the Southeastern Energy Exchange Market (SEEM) to trade energy in real-time (SEEM 2022), an extension of the bilateral contracts currently used in that region. Notably, however, SEEM does not price or reflect congestion."[39] In the December days prior to Winter Storm Elliott in 2022, SEEM volumes of matched bids and offers ranged from close to 500 MWh to over 3,500 MWh per day. However, from December 25-27, 2022, SEEM market participants conducted no

[38] Ibid.
[39] National Transmission Needs Study, Draft for Public Comment, III.d.2, pg. 16, (February 2023)

trades, highlighting a stressed southeastern power system.[40] SEEM relies on nonfirm available transmission capacity to enable trades, and as such, it is unclear if trades were impacted by lack of generation, lack of transmission, or potentially both.

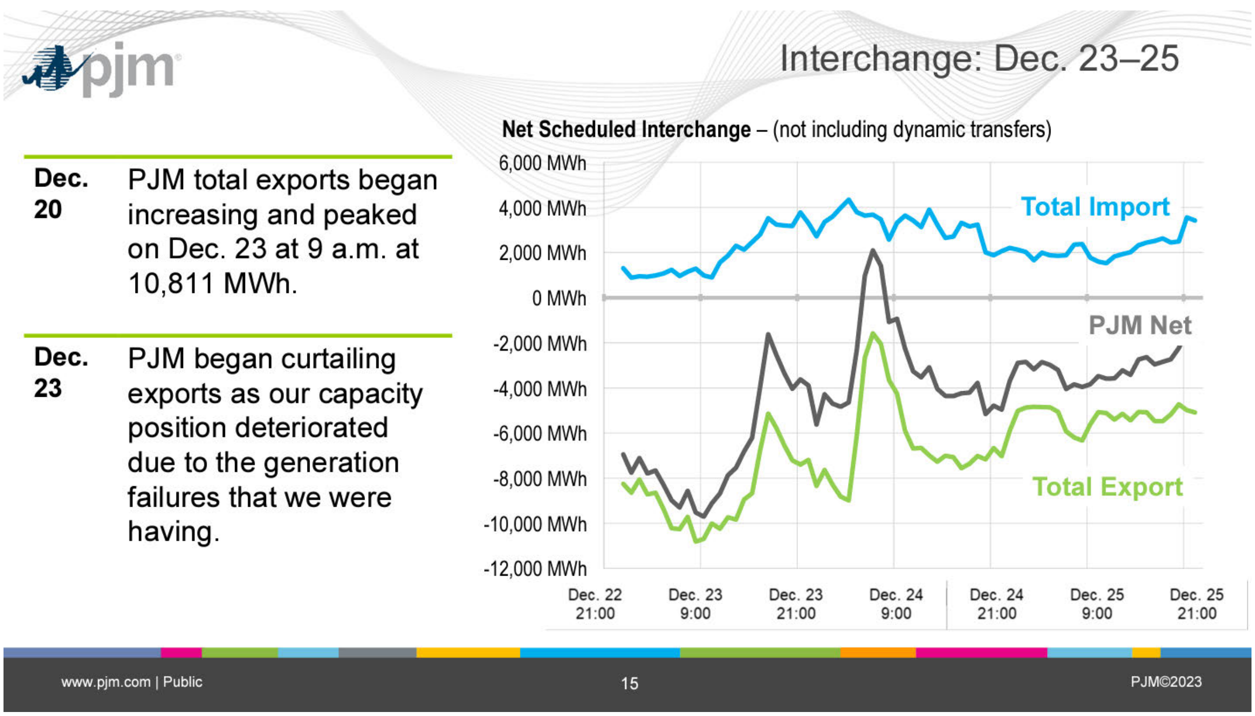


Source: Potomac Economics 2023[41]

[40] Potomac Economics, Monthly Audit Report on the Southeast Energy Exchange Market, December 2022. January 31, 2023. [https://southeastenergymarket.com/wp-content/uploads/SEEM-Audit-Report-2022_12-Final.pdf]
[41] Ibid.

f. Winter Storm Elliott's Impact on PJM

Although better equipped, neighboring PJM experienced an unavailability of 23.2% of generating capacity on December 24, 2022.[42] Nearly 6,000 megawatts of steam resources, the majority of which were natural gas generators were not available. PJM narrowly averted rolling blackouts only because of the ability to access a pool of generators and load in a wider reserve area, and through connections with neighboring MISO and NYISO. Larger balancing areas and diversified power generation fleets helped maintain stability in the MISO, PJM and SPP regions.

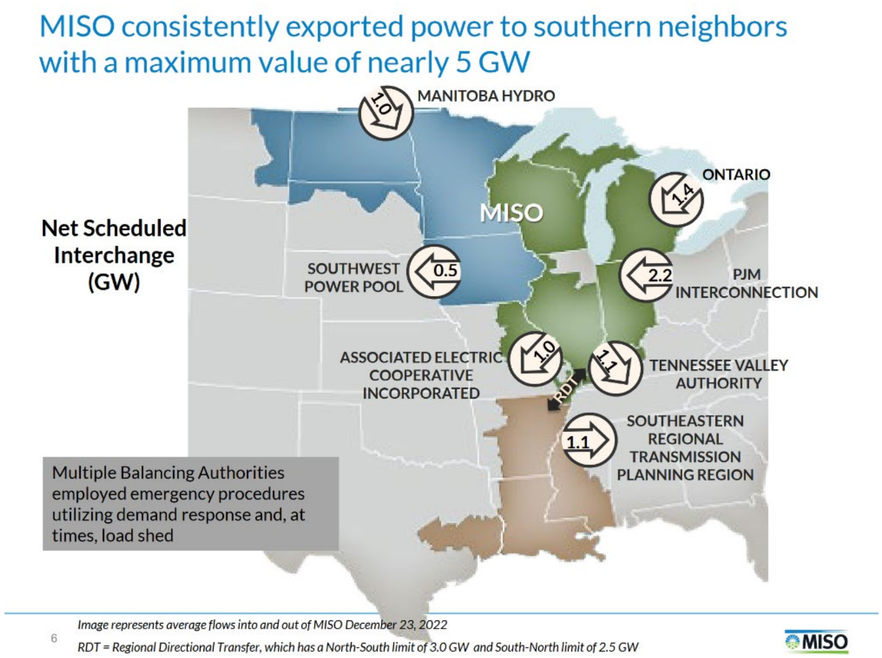


Source: PJM 2023[43]

[42] PJM Presentation, Winter Storm Elliott, Slides 11-12, (2023) (https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx)
[43] PJM, "Winter Storm Elliott", January 2023 [https://www.pjm.com/-/media/committees-groups/committees/oc/2023/20230112/item-02---overview-of-winter-storm-elliott-weather-event.ashx]

g. Winter Storm Elliott's Impact on MISO

MISO's wind farms in the north provided solid power straight through the storm,[44] and MISO's staff expertly wheeled power down into TVA and the struggling south. MISO was providing roughly 5,000 megawatts of power to neighboring regions throughout December 23rd. Clearly, this was still not sufficient to avert rolling blackouts in TVA and Duke territories, but it is likely that the additional impacts to the SERTP planning region could have been dire without this limited support from MISO. Clearly the challenges in Southeast region suggest that there is a strong resilience argument for increased connectivity with the Midwest (MISO) region.

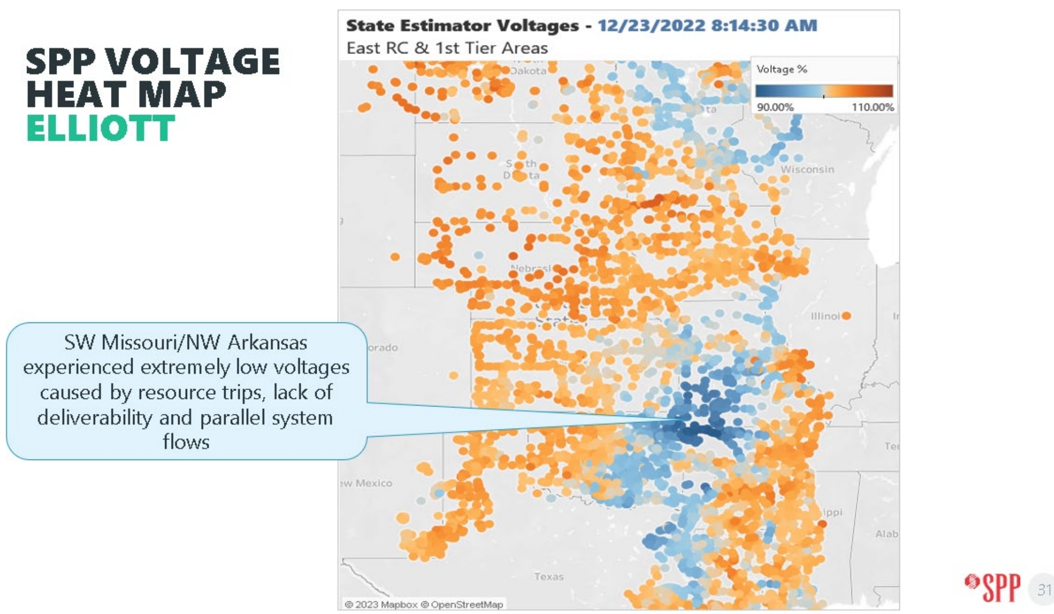


Source: MISO 2023[45]

[44] MISO, "Overview of Winter Storm Elliott December 23, Maximum Generation Event', slide 11, (January 2023) (https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf)
[45] MISO, "Overview of Winter Storm Elliott December 23, Maximum Generation Event', slide 11, (January 2023) (https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf)

h. Winter Storm Elliott's Impact on SPP

Winter Storm Elliott first impacted SPP's region beginning late in the day on December 22, 2022. Natural Gas generator outages continued steadily through December 23, 2022 and remained high for the next few days.[46] At times, natural gas generators were providing approximately 7 GW less than accredited availability, and coal units were nearly 8 GW less than accredited. According to SPP, "SW Missouri/NW Arkansas experienced extremely low voltages caused by resource trips, lack of deliverability and parallel system flows."[47] Still, SPP was able to export power for much of the event because of high wind energy output.



Source: SPP 2023[48]

[46] SPP, "December 2022 Winter Storm Elliott". February 2023. [https://spp.org/Documents/68837/SAWG%20Meeting%20Materials%2020230222-23.zip]
[47] Ibid.
[48] Ibid.

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ii. Regional Benefits of Additional Transmission during Winter Storm Elliott

A recent study from Grid Strategies found that 1 GW of transfer capability between SERTP members Duke Energy and TVA with neighboring regions to range $75-95 million in benefits during Winter Storm Elliott.[49] Grid Strategies utilizes wholesale power prices at the interfaces between TVA and Duke Energy with MISO and PJM respectively, and then applies a Value Of Lost Load (VOLL) of $9,000 to determine this value of transmission.[50] This proxy data could be an important input into considering the value of transmission during Winter Storm Elliott and other recent wide area events affecting the Southeast and the DOE Needs Study should include the analysis. In assessing needs for the Southeast, the Needs Study should consider data made available, if timely, through the joint FERC/NERC inquiry into Winter Storm Elliott initiated on December 28, 2022.

B. Resilience and Reliability Challenges in the Delta

The record is concerning regarding the reliance on ad-hoc coordination between the Joint Operating Agreement (JOA)[51] parties that utilize the interface between MISO North and South during extreme weather events that frequently have challenged the reliability of the power system in MISO South. The resilience need for an increased connection between the Midwest (MISO North) and Delta (MISO South) regions is clear and should be ranked in priority ahead of

[49] "The Value Of Transmission During Winter Storm Elliott', American Council On Renewable Energy and Grid Strategies, Michael Goggin and Zachary Zimmerman, pg. 1, February 2023 (https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf)
[50] Ibid., pg. 7
[51] 154 FERC ¶ 63,001, January 5, 2016. The Joint Operating Agreement (JOA) parties include SPP, Midcontinent Independent System Operator, Inc. (MISO), Associated Electric Cooperative, Inc. (AECI), Alabama Power Company, Georgia Power Company, Gulf Power Company and Mississippi Power Company, by and through their agent Southern Company Services, Inc. (collectively, Southern Companies), the Tennessee Valley Authority (TVA), Louisville Gas and Electric Company and Kentucky Utilities Company (together, LG&E/KU) and PowerSouth Energy Cooperative (PowerSouth). NRG Energy, Inc. (NRG) is also considered a Party for the purposes of the Settlement Agreement's Articles IV and XIV only. AECI, Southern Companies, TVA, LG&E/KU and PowerSouth

interregional planning between the Midwest to Plains and Delta to Plains suggested in the Needs Study.

SREA agrees with the comment of the Illinois Commerce Commission (ICC)[52] regarding the Needs Study's priority given to connectivity between the Delta (MISO South), Midwest (MISO North) and the Plains (SPP) regions rather than between the Delta (MISO South) and Midwest (MISO North) regions. While there are likely benefits to increasing connectivity between these two regions, there are differing market structures and current planning priorities underway in MISO that would suggest a higher priority to connect the Delta and Midwest regions before increasing connectivity between these regions and the Plains region.

During the previously mentioned "Cold Weather Bulk Electric System Event of January 17, 2018" the Delta region barely escaped implementing load shed due to a lack of extremely constrained transmission access between the Southeast, Delta and Plains regions. The JOA determining the firm contract Regional Directional Transfer Limit (RDTL) path between MISO North and South was pushed to its limit. As the FERC and NERC joint report on the event stated, "Because MISO could not reliably provide reserves from its Midwest to its South region without exceeding the RDTL, at 5:04 a.m. CST, MISO asked SPP to agree to raise the RDT north-to-south limit above 3,000 MW." Put succinctly in the report, "MISO had reserves that were stranded in its northern footprint, limited by transmission system constraints."[53] While requests were made to

[52] National Transmission Needs Study, Draft for Public Comment, Appendix A-2 at 5, (February 2023)
[53] 2019 FERC and NERC Staff Report "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018', pg. 54
[https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf]

increase the RDT, load shedding in MISO South was only narrowly averted only after requesting a temporary 700MW purchase from the the neighboring Southern Company balancing authority.[54]

In February 2021 however, the SPP, and MISO faced generation and transmission emergencies much more extreme. During Winter Storm Uri, MISO South faced several emergency load reduction events but MISO North had fewer events. MISO's report on the storm noted that MISO requested that the RDTL be increased "in an effort to transfer more energy to MISO's South region to compensate for the increased evening demand and offline generators. Unfortunately, the request could not be accommodated due to overloads in Joint Parties' neighboring systems, as TVA already had multiple constraints in excess of 100%."[55] MISO reported that there were three separate interactions, with four separate requests, where MISO staff had requested that the RDTL be increased above the 3,000 MW North to South limit, up to 3,700 MW. Three of the four requests were denied by TVA and/or SERC, citing Transmission Loading Relief (TLR) procedures that would be exceeded, or were already in a TLR procedure.[56]

During Winter Storm Elliott in 2022, the RDTL between MISO and neighboring balancing areas became a liability again once again that threatened to cause load shedding in MISO South due to the loss of nearly 2,000 megawatts of capacity due to generation unit trips and failures to start.[57] Given the record of events over the past 5 years, it is critical that there is greater

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[54] 2019 FERC and NERC Staff Report "The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018', pg. 62 https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf)

[55] MISO, The February Arctic Event, February 14-18, 2021. Pg. 18-19

[56] MISO, The February Arctic Event, February 14-18, pg. 36-37, (https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf)

[57] MISO, "Overview of Winter Storm Elliott December 23, Maximum Generation Event', slide 4, (January 2023) (https://cdn.misoenergy.org/20230117%20RSC%20Item%2005%20Winter%20Storm%20Elliott%20Preliminary%20Report627535.pdf)

connectivity between the Midwest and Delta regions. The Needs Study notes that for the Delta region there is a need for "between 1,400 and 3,900 GW-mi of new transmission (median of 1,700 GW-mi, a 49 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures."[58] The DOE should consider in their identification of needs that MISO's Long Range Transmission Planning (LRTP) Tranche 4 effort[59] proposes increased connectivity between the Midwest and Delta regions.

Better connections between MISO North and South and intra-regionally for the Delta region are an efficient way to operate the power grid even in blue sky conditions with projected solar and wind resources expected for the region. Resource and geographic diversification are key to reliability and resiliency, and the expansion of the RDTL promised to be included in Tranche 4 of MISO's LRTP effort is vitally important to maintaining system reliability and resilience in the future. Enabling complimentary access of rich wind resources from the Midwest region and robust solar resources in the Delta region should be considered a transmission need that increases flexibility and resource adequacy throughout the MISO footprint.

To fully benefit the Delta region however, an expansion connecting MISO North to MISO South, or to neighboring regions, is dependent on the success of Tranche 3 of MISO's LRTP effort.[60] This effort is focused entirely on the Delta region and is concerned with deliverability of

[58] National Transmission Needs Study, Draft for Public Comment, pg. 12 (February 2023)
[59] MISO Updated Friday, March 03, 2023 Long-Range Transmission Planning (LRTP) Tranche 2 – Frequently Asked Questions, pg. 4, (https://cdn.misoenergy.org/MISO%20Long-Range%20Transmission%20Planning%20LRTP%20Tranche%202%20FAQs627648.pdf)
[60] MISO Updated Friday, March 03, 2023 Long-Range Transmission Planning (LRTP) Tranche 2 – Frequently Asked Questions, pg. 4, (https://cdn.misoenergy.org/MISO%20Long-Range%20Transmission%20Planning%20LRTP%20Tranche%202%20FAQs627648.pdf)

power intra-regionally – which has historically been a challenge that is compounded by extreme weather events in recent years.

In the aftermath of Hurricanes Laura and Ida (2020 and 2021, respectively), power outages in the Delta region lasted for months in parts of South Louisiana and Southeast Texas. This is partially due to impacted areas being within "load pockets" or transmission constrained areas across South Louisiana and Southeast Texas. Some of these have been documented as far back as 2012 by the DOE National Electric Congestion Study - before Entergy joined the MISO footprint.[61] There are multiple load pockets in MISO South including but not limited to West of the Atchafalaya (WOTAB), Amite South and Downstream of Gypsy (DSG), Texas East and Texas West. These load pockets stretch from Southeast Texas to South Louisiana.[62] However, the impact of Hurricane Laura in 2020 on the Entergy system created a "hurricane load pocket"[63] that caused over 500MW's of load shedding after the event.[64] After Hurricane Ida within the Amite South and Downstream of Gypsy load pockets, the City of New Orleans and surrounding areas did not fully have power restored even after ten days[65] because the city effectively islanded, and without the ability to import power. Eight transmission routes connect to the Greater New Orleans area contained within the Downstream of Gypsy load pocket, and when one was effectively severed,

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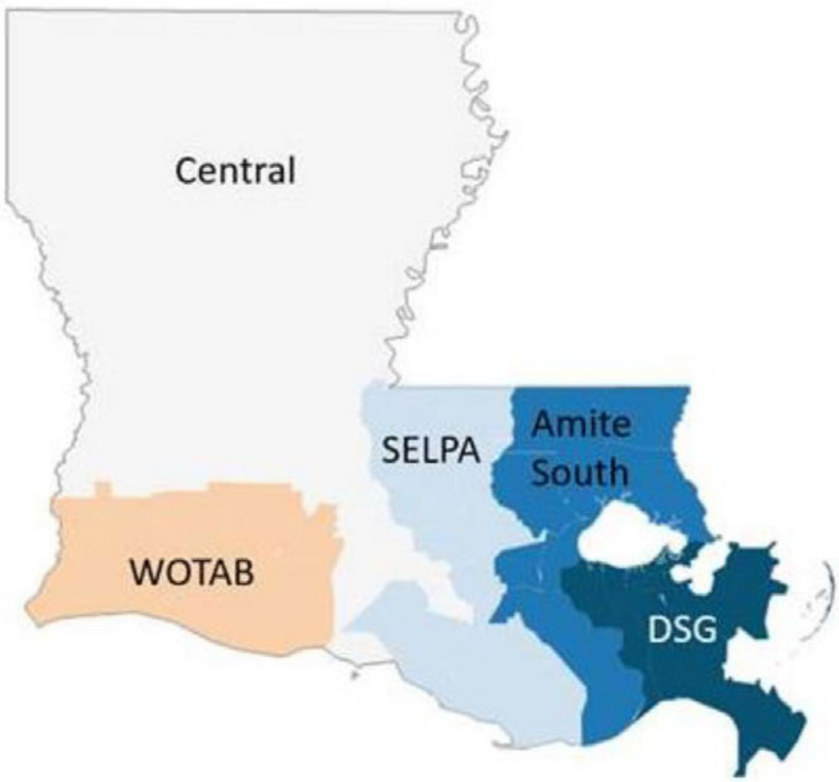
[61] U.S. Department of Energy Pre-Congestion Study Regional Workshop for the 2012 National Electric Congestion Study, slides 5,6 (https://www.energy.gov/sites/prod/files/Presentaion%20by%20Doug%20Powell%2C%20Entergy.pdf)
[62] MISO MTEP 18, Appendix D1, pg. 21 and 51, (https://cdn.misoenergy.org/MTEP18%20Appendix%20D1-South276900.pdf)
[63] MISO IMM Quarterly Report: Fall 2020, slide 17, (https://cdn.misoenergy.org/20201208%20Markets%20Committee%20of%20the%20BOD%20Item%2008%20IMM%20Quarterly%20Report499524.pdf)
[64] Entergy Regional State Committee Presentation, Hurricane Laura Recovery, November 2020, slide 12, (https://cdn.misoenergy.org/20201120%20ERSC%20Item%2006%20Entergy%20Hurricane%20Restoration%20Update495364.pdf)
[65] Anthony McAuley, September 8, 2021. "Ten days after Hurricane Ida, progress on power restoration but still more than 280,000 offline," Times-Picayune. [https://www.nola.com/news/business/ten-days-after-hurricane-ida-progress-on-power-restoration-but-still-more-than-280-000/article_6cf22eba-10af-11ec-8e5c-bfb1f54c8d08.html]

outages followed, assumedly to prevent contingencies on the remaining six.[66] As an Entergy press release states about the toppled transmission tower leading into the DSG load pocket, "When this occurred, it caused a load imbalance in the area and resulted in generation in the area coming offline."



WOTAB, Amite South and DSG (Downstream of Gypsy) load pockets, along with SELPA (Southeast Louisiana Planning Area). Entergy typically overlaps "planning areas" for generation RFP's with load pockets.[67]

The transmission constraints throughout South Louisiana and Southeast Texas are a challenge and impediment to power transfer capability, but they are also impacting the costs of

[66] Entergy Press Release, "Ida Knocks Out Transmission Sources into New Orleans', (August 2021) (https://www.entergynewsroom.com/article/ida-knocks-out-transmission-sources-into-new-orleans/)
[67] Notice of Intent to Issue a Request for Proposals 2020 Entergy Louisiana, LLC Solar RFP ()

interconnecting new resources in these states. As Lawrence Berkeley National Laboratory (LBNL) points out, interconnection costs in Louisiana and Texas are some of the highest cost per kilowatt in the MISO footprint. A summary report states that "southern states such as parts of Texas ($416/kW) and Louisiana ($306/kW) have the greatest interconnection costs among projects that are still actively being assessed."[68] Transmission constraints and congestion are already impacting the cost of interconnecting new renewable energy resources, but in coming years the challenge to connect new solar and wind resources may be insurmountable without intra-regional transmission planning in MISO South through MISO's LRTP effort.

MISO's draft projections in their revised Future 2A forecast, which include post Inflation Reduction Act assumptions about the cost, and expansion of resources in MISO, indicate the addition of approximately 80GW's of renewable energy, hybrid, and energy storage resources in the Delta Region by 2037.[69] An additional ~70GW's of solar, wind, hybrid and energy storage projects entered the interconnection queue for MISO in the MISO South footprint in the 2022 interconnection cycle.[70] Entergy Louisiana recently sought approval for 3GW's of solar,[71] which is nearly 20 times the amount of installed utility scale solar in the state.[72] These numbers are staggering, and the shift to renewable energy resources is happening very quickly in the Delta region.

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[68] "Interconnection Cost Analysis in the Midcontinent Independent System Operator (MISO) Territory', Lawrence Berkeley National Laboratory, pg. 10 (https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_2022.10.06-_miso_interconnection_costs.pdf)
[69] MISO Future 2A Expansion & Preliminary Siting Presentation, slide 8, March 10, 2023 (https://cdn.misoenergy.org/20230310%20LRTP%20Workshop%20Item%2002%20MISO%20Future%202A%20Expansion%20and%20Preliminary%20Siting628178.pdf)
[70] (https://cdn.misoenergy.org/2022%20GIQ%20Submission%20Statistics626443.pdf)
[71] "Entergy Louisiana seeks approval for 3 GW of solar', PV Magazine, Anne Fischer, March 20, 2023, (https://pv-magazine-usa.com/2023/03/20/entergy-louisiana-seeks-approval-for-3-gw-of-solar/)
[72] SEIA, Louisiana Solar Fact Sheet, Q4 2022, (https://www.seia.org/state-solar-policy/louisiana-solar)

There is an overwhelming need to address the historic and future constraints in MISO South. MISO's LRTP Tranche 3 planning effort is a clear opportunity within the MISO market to remedy ongoing and future congestion issues as well. Furthermore, transmission capacity increases in the MISO South are desperately needed to ensure any greater connectivity with MISO North or neighboring regions will be effective in mitigating present and future congestion and constraints.

C. Interregional Offshore Transmission Planning

There can be a synergistic value to transmission planning that addresses future operational challenges like transmission capacity constraints and congestion, including those that are included in the Biden Administration's Justice 40 initiative. There are increasing and innovative opportunities to engage in transmission planning that meets these standards on the Texas - Louisiana Gulf Coast where there are specially designed lift-boats, a skilled workforce, and an industrial fabrication infrastructure that is especially equipped to address the expected needs in the Delta and Texas regions for the offshore wind industry.

There is an active Bureau of Energy Management (BOEM)[73] Gulf of Mexico Intergovernmental Renewable Energy Task Force that the Governor of the State of Louisiana initiated in 2020[74] for the purpose of identifying offshore wind leasing areas in federal waters. There has been active engagement in efforts to create a thriving business environment for offshore wind, from a diversity of stakeholders that span consumer advocates and environmental NGO's,

[73] BOEM, Gulf of Mexico Activities, (https://www.boem.gov/renewable-energy/state-activities/gulf-mexico-activities)
[74] Office of Louisiana Governor John Bel Edwards, Press Release, November 9, 2020, (https://gov.louisiana.gov/index.cfm/newsroom/detail/2790)

to industry and economic development organizations. This includes partnerships between traditional fossil fuel energy companies like Shell Energy and New Orleans-based Gulf Wind Technologies[75] and utility Entergy Louisiana's partnership with RWE offshore holdings LLC.[76] In addition to these developments, the state of Louisiana's Climate Initiatives Task Force Action Plan approved a goal of 5GW's of offshore wind to be developed in the Gulf of Mexico by 2035.[77] This goal is also included in the Midcontinent Independent System Operator's (MISO) initial draft revised MTEP Futures[78] which provide a 20-year range of forecasts that inform transmission planning throughout their region, including Louisiana and Southeast Texas where initial leasing areas have been identified by the BOEM process. In this context, SREA strongly urges that offshore transmission needs for offshore wind in the Gulf of Mexico are included in the Needs Study.

The Needs Study should consider an increase in interregional capacity between Texas and Louisiana to facilitate offshore wind energy in the Gulf of Mexico. Currently there is an opportunity through the Inflation Reduction Act to respond to this need in Section 50153,[79] which

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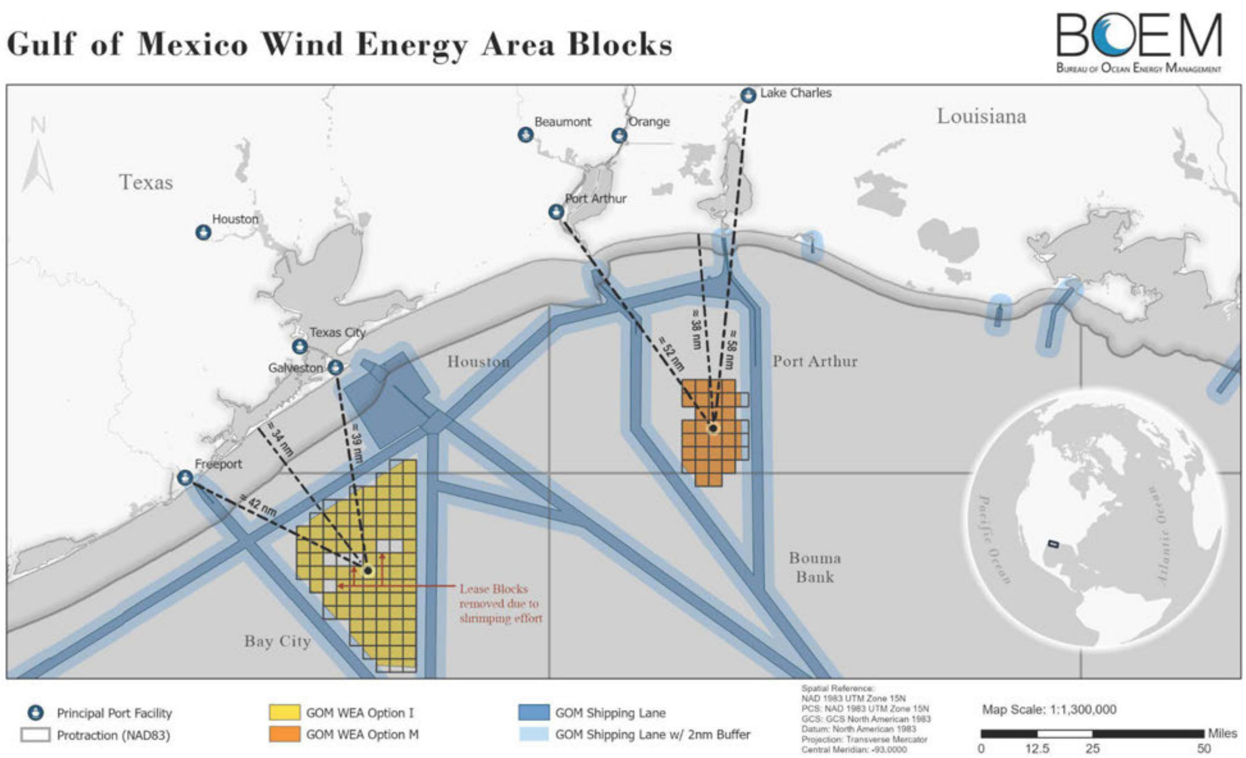
[75] Office of Louisiana Governor John Bel Edwards, Press Release, March 13, 2023, 'Gulf Wind Technology and Shell Collaborate to Establish Offshore Wind Energy Hub at Avondale Global Gateway', (https://gov.louisiana.gov/index.cfm/newsroom/detail/4014)
[76] Entergy Press Release, March 30, 2023, 'RWE and Entergy partner to define route to market for offshore wind in the Gulf of Mexico' (https://www.entergynewsroom.com/news/rwe-entergy-partner-define-route-market-for-offshore-wind-in-gulf-mexico/)
[77] Louisiana Climate Action Plan, pg. 50, Action 1.3, (https://gov.louisiana.gov/assets/docs/CCI-Task-force/CAP/Climate_Action_Plan_FINAL_3.pdf)
[78] MISO Staff indicated in meetings discussing the Future 2a forecasted expansion, that staff is including the 5GW by 2035 offshore wind target proposed in the Louisiana Climate Action. Furthermore, they indicated that this offshore wind expansion would be included in the forthcoming Future 1a and 3a expansion forecast as well.
[79] Inflation Reduction Act, SEC. 50153. INTERREGIONAL AND OFFSHORE WIND ELECTRICITY TRANSMISSION PLANNING, MODELING, AND ANALYSIS (https://crsreports.congress.gov/product/pdf/IN/IN11980)
"$100m through 2031 to convene stakeholders to develop interregional transmission on offshore wind, planning, modeling, analysis, pertaining to…clean energy integration, effects of weather, cost allocations, GI processes and transmission planning, increased electrification, power flow modeling, benefits of connections between west/east/Texas, cooptimization of renewables and storage, non transmission alternatives, economic development associated with offshore wind, planned national transmission grid for offshore wind"

could aid in developing cost effective, reliable solutions with socioeconomic benefits for the region. The need to enable offshore wind which addresses clean industrial development, reliability and resilience benefits including reduced congestion in the Texas and Delta regions, will be a growing need in coming decades in the Southeast Texas and South Louisiana coastal areas along the Gulf of Mexico.



Source: BOEM 2023[80]

Considering the Needs Study's emphasis on increased transfer capacity for Texas[81] and Delta regions with neighboring regions; increasing transfer capability between the Delta and Texas

[80] Bureau of Ocean Energy Management. Gulf of Mexico Wind Energy Area Blocks, (2023) (https://www.boem.gov/renewable-energy/state-activities/gulf-mexico-activities)
[81] The Needs Study notes on pg. 9, "between 4.3 and 12.6 GW of new transfer capacity (median of 9.8 GW, a 1200 percent increase relative to the 2020 system) needed between Texas and the Plains region in 2035 to meet moderate load and high clean energy futures. (§VI.c)" but possible an offshore HVDC connection between the Delta and

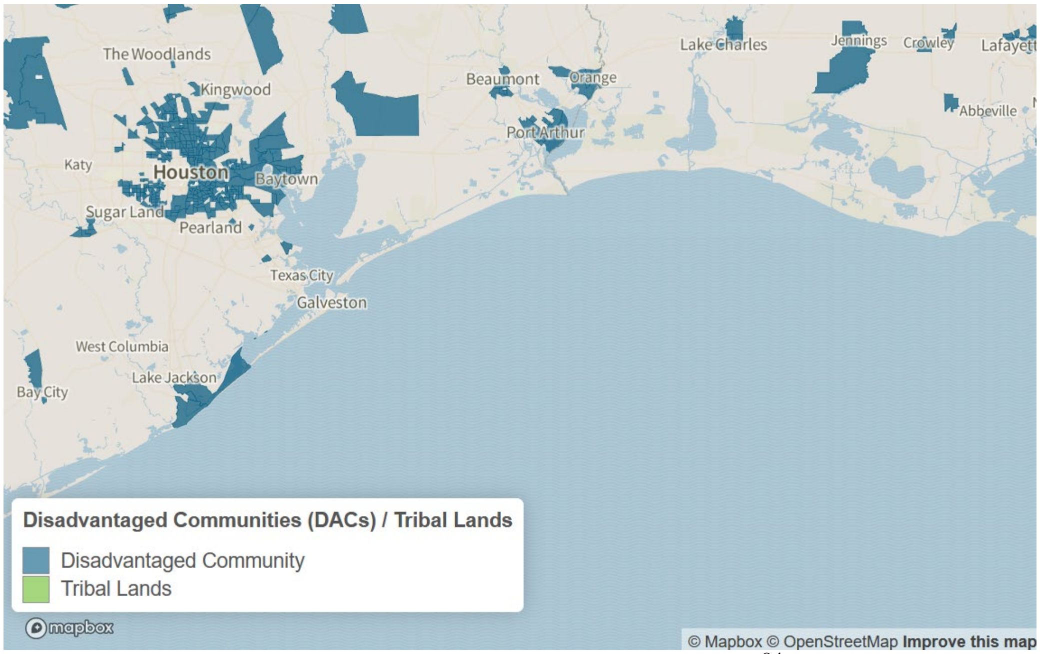
regions that facilitates offshore wind in the Gulf of Mexico could provide the additionality of power transfer between regions during resilience events, and possibly utilizing a clean resource that performs well in evening hours and during cold temperatures that have challenged grids in the very recent past. When offshore wind resources connected to load are performing, the associated evening ramp of offshore wind can supplement solar resources in both regions as they ramp down at the end of the day as well.

Greater connectivity and increased resilience during extreme weather events is a clear need. There is also a need to support the growth clean energy jobs in communities that have been historically focused on fossil fuel jobs in Southwest Louisiana and Southeast Texas. Governor John Bel Edwards of Louisiana explicitly called out this opportunity by stating, "Offshore wind provides the opportunity for us to build off our existing skill set and experiences in the offshore oil and gas industry."[82] The DOE's "Energy Justice Dashboard" which highlights Disadvantaged Communities (DACs) as defined by the Justice 40 Initiative[83] matches well with BOEM leasing areas, port infrastructure, plans for hydrogen hubs, and resource potential in the Gulf of Mexico.

Texas regions could assist in meeting these targets or alleviate congestion associated with industrial growth discussed further in these comments, while still preserving ERCOT's authority.

[82] Tulane University, "Gov. Edwards: Louisiana is "poised for success' with offshore wind energy', (https://law.tulane.edu/news/gov-edwards-louisiana-%E2%80%98poised-success%E2%80%99-offshore-wind-energy)

[83] The DOE Office of Economic Impact and Diversity identify eight policy priorities to guide DOE's implementation of Justice40: (1) Decrease energy burden in disadvantaged communities (DACs) (2) Decrease environmental exposure and burdens for DACs (3)Increase parity in clean energy technology (e.g., solar, storage) access and adoption in DACs (4) Increase access to low-cost capital in DACs (5) Increase clean energy enterprise creation and contracting (MBE/DBE) in DACs (6) Increase clean energy jobs, job pipeline, and job training for individuals from DACs (7) Increase energy resiliency in DACs. (8) Increase energy democracy in DACs.



Source: DOE Energy Justice Dashboard 2023[84]

D. Transmission Needs and Development of Green Hydrogen in the Delta and Texas Regions

There is a technical challenge in the growth of green hydrogen which is not currently considered in the Needs Study. Bolstering interest in offshore wind is a strong industry and state interest in green hydrogen spurred by the 45V tax credit for green hydrogen production[85] and a thriving green and blue hydrogen industry is the priority HALO initiative, a bipartisan three-state partnership between Governors of Arkansas, Louisiana, and Oklahoma, to compete for funding set forth in Infrastructure Investment and Jobs Act (IIJA).[86] The regional economic development group Greater New Orleans, Inc. leads 25 business partners in the H2theFuture coalition, which was awarded a $50 million federal grant from the U.S. Department of Commerce and Economic

[84] U.S. Department of Energy. Energy Justice Dashboard. 2023. [https://www.energy.gov/diversity/energy-justice-dashboard-beta]
[85] 26 U.S. Code § 45V, Section 13204
[86] "Louisiana, Oklahoma, and Arkansas Announce Hydrogen Partnership' (https://gov.louisiana.gov/index.cfm/newsroom/detail/3587)

Development Administration to support research and workforce and business development to commercially scale green hydrogen in the region.[87] Additionally, private companies like Sasol,[88] Plug Power[89] and HyStor[90] have all indicated plans to produce green hydrogen in the coming decade across the Gulf of Mexico coast in the Delta region.

In the Texas region, the Center for Houston's Future released a recent report indicating that "Demand for clean hydrogen in Texas alone could reach 21 MT by 2050 – vs. current demand of 3.6 MMT for conventionally produced hydrogen. The expected demand in 2050 comprises 11 MMT for local demand and a surplus of 10 MMT for export."[91] Importantly, there is *already* hydrogen pipeline infrastructure in place that can enable a "clean hydrogen ecosystem," "with concentrations in areas around Greater Houston, Corpus Christi and South Texas, Baton Rouge

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[87] Louisiana Economic Development Press Release "Louisiana Marks Clean Energy "Milestone' as Hydrogen Project Wins $50 Million Federal Grant' (https://www.opportunitylouisiana.gov/led-news/news-releases/news/2022/09/02/gov.-edwards-hails-clean-energy-milestone-as-louisiana-hydrogen-project-wins-$50-million-federal-grant)

[88] "Back From Brink, Sasol Gets On The Path To Greener Chemicals', Christopher Helman, Forbes, October 3, 2022 (https://www.forbes.com/sites/christopherhelman/2022/10/03/back-from-brink-coal-giant-sasol-gets-on-the-green-path/?sh=362969b5f19f)

[89] "Plug Power and Olin launch JV to construct hydrogen plant in Louisiana', Mary Bailey, Chemical Engineering, October 24, 2022, "Plug expects to produce 1,000 tons per day of liquid hydrogen by 2028' (https://www.chemengonline.com/plug-power-and-olin-launch-jv-to-construction-hydrogen-plant-in-louisiana/?printmode=1)

[90] "Hy Stor Energy Strategic Partnership with Key Gulf Coast Port Becomes First to Deliver Renewable Hydrogen Access for Manufacturing, Industrial Applications, Port Operations and Long Duration Energy Storage', Businesswire, June 29, 2022 "During the first phase of the partnership, the hydrogen hub is expected to produce an estimated 350 tons/day (320,000 kg/day) of renewable hydrogen and store more than 71,000 tons (69 million kg) of hydrogen in underground salt caverns.' (https://www.businesswire.com/news/home/20220629005311/en/Hy-Stor-Energy-Strategic-Partnership-with-Key-Gulf-Coast-Port-Becomes-First-to-Deliver-Renewable-Hydrogen-Access-for-Manufacturing-Industrial-Applications-Port-Operations-and-Long-Duration-Energy-Storage%20%20%20)

[91] Press Release, Center for Houston's Future, "Houston region is poised to become a global clean hydrogen hub, according to new report', pg. 3, (May 23, 2022) Note, the full report refers to "MT' as the abbreviation for "Million Megatons'. SREA has used "MMT' in the quote to align with DOE's adopted abbreviation. (https://static1.squarespace.com/static/5bd0cda394d71a3556faeb6c/t/629119f928ac024f71491c9a/1653676537994/HubPressRelease527.pdf)

and New Orleans, Beaumont and East Texas, and extending to Dallas and the Texas Triangle, as well as West Texas."[92]

Existing hydrogen pipeline infrastructure connecting Texas and Louisiana

Source: Center for Houston's Future and the Greater Houston Partnership 2022[93]

In addition to these more regionally focused efforts, the DOE produced a draft "National Clean Hydrogen Strategy and Roadmap" which cites a goal of 50MMT of annual clean hydrogen production in the U.S. by 2050.[94] This is a five-fold increase in the approximate 10MMT of the current annual hydrogen production in the U.S. This goal indicates a massive shift in how energy is used, and how it is produced, which will bring with it new demands throughout the country on

[92] Ibid., pg. 4
[93] Center for Houston's Future, "Houston as the epicenter of a global clean hydrogen hub", (2022) [https://www.centerforhoustonsfuture.org/h2houstonhub]
[94] DOE National Clean Hydrogen Strategy and Roadmap, September 2022, pg. 21 (https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf)

the bulk electricity system, likely creating transmission constraints and congestion that will need to be remedied.

Ensuring that hydrogen is produced with renewable energy, ensures the greatest reduction in greenhouse gas emissions. A letter endorsed by several environmental groups to the Department of Treasury urges guidelines for the 45V tax credit that include hourly verification of renewable energy production of hydrogen to qualify for the credit. It states "Using fossil-generated electricity or siphoning off renewables subsequently back-filled by fossil power to operate electrolyzers—which would occur under loose guidance—generates at least twice the carbon emissions that status-quo gas-derived hydrogen emits. Weak guidance could therefore force Treasury to spend more than $100 billion dollars in subsidies for hydrogen projects that result in increased net emissions, in direct conflict with statutory requirements and tarnishing the reputation of the nascent "clean" hydrogen industry."[95] In order to meet emissions goals in the U.S., development of green hydrogen will require the deliverability of renewable energy, which requires transmission to enable green hydrogen production.

In this context, it would be extremely helpful for the Needs Study to assess needs related to the impacts of industrial green hydrogen development using electrolyzers. Understanding that the U.S. Treasury Department is yet to deliver guidance for the 45V tax credit, plans are nonetheless in motion across the Gulf South that will have a significant influence on needs for the bulk electricity system. SREA suggests that the Needs Study include assumptions for hourly

[95] National Resources Defense Counsel, "Implementation of the IRA 45V clean hydrogen tax credits as it relates to guidelines for emissions accounting of grid-connected electrolyzers", (February 23, 2023), (https://www.nrdc.org/sites/default/files/2023-03/joint-letter-45v-implementation-20230223.pdf)

matching of hydrogen production with renewable energy as well, in order to encompass the needs associated with responsible development this nascent industry.

IV. Responses to SERTP Utilities' Comments

The DOE solicited feedback from various stakeholders regarding the draft Needs Study, including the SERTP sponsor utilities. Some of the comments provided by SERTP utilities warrant direct response and we encourage the DOE to take our recommendations into consideration.

A. SERTP #55: "Another concern with the Draft Study's conclusions on the need for significant interregional/interface facilities is that such "solutions" could allow certain regions to shift their resource adequacy responsibilities to neighboring regions, exacerbating existing resource adequacy problems and ultimately increasing reliability risks to all. For example, the Draft Study identifies several regions that are predicted to experience resource adequacy problems or that are likely to experience complications associated with not having sufficient dispatchable resources/high renewable penetration. While interregional transfer capability may temporarily, or in isolated instances, alleviate these complications, resource adequacy as a whole cannot fully and finally be resolved through transmission –it is, after all, a resource issue. If those regions do not directly address those problems internally but instead expand their interface ties, then those regions are merely exporting their problems to neighboring regions…this concern of allowing regions with resource adequacy problems to shift those problems to their neighbors appears borne out by the Draft Study's Table VI-3, which seems to indicate that current lowcost regions, such as the Southeast, would have to bear significant upgrade costs to enable its neighbors to "lean on" the Southeast. While there could be some benefits from geographic and resource diversity, it cannot come at the cost of encouraging regions to disregard their own respective resource adequacy. ….In sum, there may be better alternatives to the massive build-out of interfaces as forecasted in the Draft Study. These include regions addressing their problems with internal upgrades (which could be transmission or supply- or demand-side alternatives). The Draft Study, however, appears to give no consideration to the possibility of other, more cost-effective or efficient alternatives. For example, for the Southeast, the Draft Study specifically forecasts that 5,400-8,000 GW-mi of new transmission is needed but fails to consider whether there are more cost-effective or efficient or reliable alternatives."

SREA agrees with the SERTP Utilities that it is important to evaluate "more cost-effective or efficient or reliable alternatives" regarding transmission *and* generation planning; however, the SERTP Utilities have not provided any analysis showing that the Needs Study is inaccurate. Further, the SERTP Utilities are placing a burden on the DOE that they themselves do not follow, namely, evaluating regional and interregional transmission as an alternative to local transmission projects or generation resources. As mentioned previously, the SERTP Utilities' IRPs do not adequately incorporate reginal and interregional transmission analysis as alternatives to generation resources.

Several of the SERTP Utilities already operate in a pooling agreement, such as the Southern Company pool. Part of the justification by the SERTP Utilities themselves for operating in such a fashion is due to the benefits of "reserve sharing" and "economic dispatch". Georgia Power notes that, "Participation in the Southern Company Pool provides benefits to the Operating Companies and to their customers. Pool participation not only enhances Georgia Power's ability to provide reliable, low-cost electric service to its customers but also to achieve economies of scale in any required investments."[96] Those same principles are chastised and contradicted by the SERTP Utilities in their comments regarding the Needs Study for "…encouraging regions to disregard their own respective resource adequacy." The Duke Energy and TVA regions during Winter Storm Elliott were the worst impacted regions, and in a sense the Southeast was "exporting their problems to neighboring regions" by being heavily dependent on importing power from MISO and PJM and other regions to prevent even worse blackouts in the region. Reserve sharing and economic dispatch are valuable attributes of better regional and interregional connection and should be appropriately evaluated and measured.

The Southeast is no longer considered to be a "low cost" region. In a state-by-state data review conducted by Illinois Citizens Utility Board, the only southern state to be considered in the top 25 of states for "Overall Utility Performance" is Florida (ranked #18); all other southern states are below average. For "Affordability Rankings", Arkansas (#10), Louisiana (#15), and Kentucky (#17) receive the best marks for southern states, while South Carolina (#43 tied), Georgia (#43 tied), and Alabama (#47) receive some of the worst scores.[97]

[96] Georgia Power Company 2022 Integrated Resource Plan, Attachment G. [https://psc.ga.gov/search/facts-document/?documentId=188519]
[97] Illinois Citizens Utility Board, 2021. Electric Utility Performance, A State-by-State Data Review. [https://www.citizensutilityboard.org/wp-content/uploads/2021/07/Electric-Utility-Performance-A-State-By-State-Data-Review_final.pdf]

B. SERTP #83: "The Draft Study forecasts the need for a massive build-out of virtually all interface ties but does not give consideration to the corresponding vast amounts of local upgrades that would need to be made to accommodate expanding such ties by the projected gigawatts of capacity. To illustrate, and using HVDC lines as an example of expanded interregional capacity, such lines typically carry between 500 MW and 2000 MW of power. When transferring power across the HVDC line, the source end of the HVDC line would draw in up to 2000 MW of generation out of the system, acting like a 2000 MW load. The delivery end of the HVDC line would push 2000 MW of power into the receiving system, similar to adding 2000 MW of power, much like a large generation site. The existing transmission system is currently not designed to handle either the 2000 MW of generation being moved out of the system or the dumping of 2000 MW of generation into the system at the other end of the HVDC line. The existing infrastructure would require major, costly expansion (in addition to the HVDC line itself) of the AC transmission system to accommodate this type of large transfer. Transmission planners would have to study the impacts of each one of these proposed HVDC lines and rebuild the existing transmission system to accommodate the Draft Study's forecasts."

ESIG conducted an analysis adding a new 2 GW interregional HVDC connection between ERCOT and Southern Company.[98] The study found that, "By modeling a link between two systems made unreliable for the purposes of this study, the transmission makes both systems reliable—without adding new generation capacity on either side." ESIG noted that large scale emergency events are often ignored or heavily discounted in transmission planning processes, but such an

[98] ESIG, 'Multi-Value Transmission Planning for a Clean Energy Future', (June 2022) [https://www.esig.energy/multi-value-transmission-planning-report/]

HVDC connection "…could potentially avert $2.7 billion of unserved energy over 30 years depending on the LOLE of the system." ESIG stacked multiple benefits of such a line against the total portfolio investment (costs) and found a benefit-cost ratio of 1.66, even with limited benefits evaluated.

The SERTP Utilities' state that "The existing transmission system is currently not designed to handle either the 2000 MW of generation being moved out of the system or the dumping of 2000 MW of generation into the system at the other end of the HVDC line." If the current Southeastern system, with over 160 GW of generation[99], is unable to handle a 2 GW request (1.25% of current capacity), that in and of itself is justification for the Needs Study and an indictment of the status quo.

[99] Southeast Energy Exchange Market, May 2022. [https://southeastenergymarket.com/wp-content/uploads/SEEM-Webinar-1_Sharable-v2.pdf]

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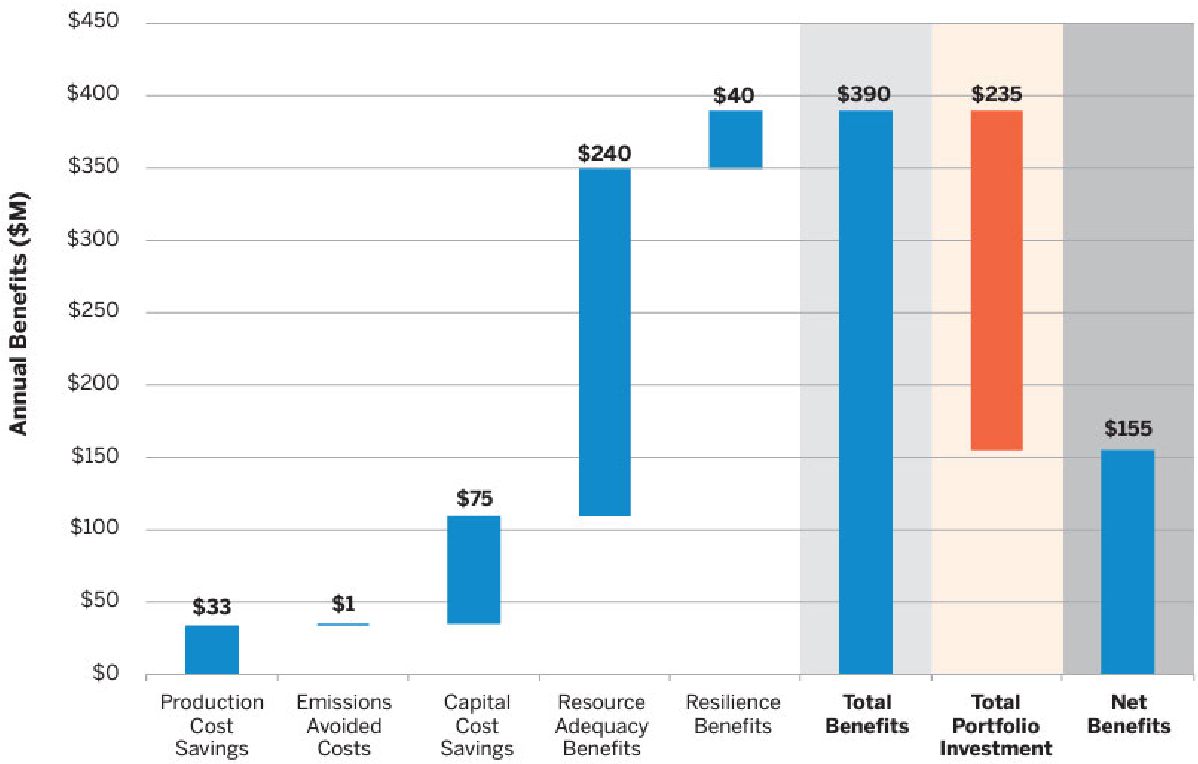
FIGURE 28
Multi-Value Benefit Stacking for the Transmission Line Connecting ERCOT and Southern Company



Source: ESIG[100]

C. <u>SERTP #97: "While the Draft Study emphasizes the value of additional transmission, since the scope of the Draft Study does not include specific cost ramifications, the Draft Study's assumed benefits are almost certainly overstated. For example, the Draft Study performs scenario analyses of several levels of renewable penetration to conclude that vast amounts of additional transmission capacity (i.e., gigawatts) are needed both internally and between transmission planning regions. The Draft Study does not, however, appear to weigh the</u>

[100] ESIG June 2022. Multi-Value Transmission Planning for a Clean Energy Future. [https://www.esig.energy/multi-value-transmission-planning-report/]

costs associated with the specific benefits asserted, thereby calling into question whether net benefits would be provided or whether there may be more economic alternatives. The apparent narrow focus of the analysis calls into question the probative value of the projected transmission needs."

The DOE responded to this comment, and others (DOE Responses 3, 11, 106), noting that additional and more specific engineering studies by the designated NERC Planning Authorities would need to be conducted to adequately measure both the costs and benefits. SREA encourages the SERTP Utilities to work with their regulators and other stakeholders to conduct long-range, scenario-based transmission analyses that evaluates multiple benefits and costs for regional and interregional planning.

D. SERTP #128: "At a high level, the SERTP Sponsors recommend that DOE make greater utilization of NERC-registered transmission planners and transmission owners that have the actual "duties to serve" and corresponding legal obligations to expand their respective transmission systems in an economic and reliable manner to meet the needs of their customers. In this regard, the SERTP Sponsors have concerns about the decision to rely solely on capacity modeling studies that use abstracted, generalized assumptions, disregarding industry-led regional studies based on actual operation of the grid. The Draft Study also relies heavily on existing studies performed by consultants, who are often funded by certain market participants. To better ground the study through the use of actual electric system forecasts, data, and established practices, the SERTP Sponsors recommend a higher utilization of the expertise afforded by the Eastern Interconnection Planning Collaborative (EIPC). The EIPC performs coordinated transmission planning among the transmission planners in the Eastern Interconnection, including both RTOs/ISOs and non-RTO/ISO transmission planners, and increased coordination with the EIPC would provide a more reliable study informed by transmission planners who have the needed experiential perspectives on the needs of the grid."

SREA agrees that the SERTP Utilities and DOE should work closer together on transmission planning analysis. SREA encourages the DOE to establish a working group with SERTP Utilities, state regulators, and other stakeholders where data transparency can enable more specific recommended needs in the Southeast. EIPC may be an additional venue for information sharing; however, EIPC does not readily include state regulators or non-utility or non-RTO stakeholders as members. A spokesperson for the EIPC delivered testimony to FERC regarding interregional transfer capacity in early December 2022, noting that, "As noted in the 2021 Grid Report referenced above, EIPC's analyses over the years have consistently confirmed that the [Eastern Interconnect] remains strong and that individual and collective transmission planning activities have yielded a system that is reliable and well-coordinated on both a regional and interconnection-wide basis."[101] Three weeks later, Winter Storm Elliott drew EIPC's assessment into question with rolling blackouts throughout the Southeast.

[101] Testimony of David W. Souder on Behalf of the Eastern Interconnection Planning Collaborative, Docket No. AD23-3-000, Establishing Interregional Transfer Capability, Transmission Planning and Cost Allocation Requirements.
[https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/639cd78a50f0d438d326b361/1671223179859/Souder+EIPC+Testimony+for+Interregional+Transfer+Workshop.pdf]

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E. SERTP #147: "DOE has expanded the scope of its studies from the statutorily mandated "transmission capacity constraints and congestion" analysis to one that is more akin to a future generation/resource study. In doing so, DOE intrudes into resource planning activities that extend well beyond the scope authorized by FPA section 216. the Draft Study could unlawfully open the way for FERC to authorize transmission projects predicated upon resource decisions made by the federal government (not the states, as prescribed in the FPA). Therefore, we recommend that DOE continue to perform a transmission assessment and not an expansive future generation study predicated upon theoretical resource assumptions. We further suggest that the accuracy of such transmission studies would be improved if DOE were to coordinate more closely with North American Electric Reliability Corporation("NERC") registered transmission planners and transmission owners. In the alternative, DOE should clarify that the Draft Study is not for FPA section 216 purposes and provide further explanations of the Draft Study's scope."

The SERTP Utilities are confusing scenario planning and resource planning. Scenario based planning is a best practice regarding both generation and transmission planning. Further, both capacity constraints and congestion exist due to generation issues, thus generation must be taken into consideration when evaluating the transmission system.

F. SERTP #148: "DOE broadly defines a transmission need to be...an upgrade to or a new transmission facility—including non-wire alternatives— that would optimally be built to... -improve reliability and resilience of the power system; -alleviate transmission congestion on an annual basis; alleviate transmission congestion during real-time operations; -

alleviate power transfer capacity limits between neighboring regions; -deliver new, cost-effective generation to high-priced demand; and -to meet projected future generation, electricity demand, or reliability requirements. The last three criteria bolded above were not within the scope of the DOE's 2020 triennial transmission congestion study, which defined "transmission constraint and congestion" to consist of essentially the first three criteria quoted above. The new criteria have apparently been added to the scope of the Draft Study based upon Congress' recent addition of the term "capacity" before the word "constraint" in FPA section 216(a)(1). The addition of this word "capacity" apparently is being used to expand the scope of the Draft Study from being focused on transmission matters (i.e., the first three criteria quoted above) to also encompass resource/generation/IRP planning matters (i.e., the last three criteria quoted above).Indeed, a review of the Draft Study establishes that It primarily concerns DOE's projection of the addition of significant amounts of renewable generation. Then, having assumed certain levels of specified generation resources based upon certain modeling scenarios, the Draft Study concludes, without any real explanation, that huge amounts (i.e., gigawatts) of additional transmission capacity are needed within and between essentially all transmission planning regions. … Rather than DOE independently performing such de facto resource/generation/IRP planning, DOE should coordinate with NERC-registered transmission planners and transmission owners to utilize their load and supply-side and demand-side forecasts that incorporate the results of state-regulated IRP and resource procurement processes. This approach would allow for an accurate assessment of "electric transmission capacity constraints and congestion" in accordance with FPA section 216 as well as being consistent with the overall structure of the FPA. Further, the Draft Study incorporates studies that are predicated upon very aggressive clean energy and renewables assumptions that are not tied to federal mandates. With the Draft Study's resource forecasts predicated upon neither state-regulated forecasts nor federal mandates, the basis upon which DOE is incorporating such assumptions is unclear. Instead of DOE independently making such determinations, the better approach would be for DOE to use the "projected future generation, electricity demand, or reliability requirements" determined to be appropriate for transmission planning purposes by NERC-registered transmission planners and transmission owners–those having the responsibilities under FPA section 215 to do so–and which incorporate the results of state-regulated IRP and resource procurement processes."

The Needs Study does not evaluate forecasted growth of renewable energy as the *only* justification for expanded transmission capacity. Instead, the Needs Study looks at multiple issues including the impact of extreme events, the impacts of which we are seeing in today's bulk power system without the need of forecasting future generation shifts. However, in light of generation changes that are occurring nationally (including the southeast), a more robust regional and interregional analysis is warranted, especially given that not all utilities perform IRPs such as utilities in Alabama, Florida, and Texas. While IRPs may be helpful data inputs, those data inputs are not the only ones to be helpful in evaluating future load, retirements, and generation changes. Still, SREA encourages the DOE to work with all utilities to gather IRP data and utility goals for additional sensitivities and studies in the future.

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G. SERTP #149: "The studies utilized by DOE predominantly use a zonal model. Compared to a nodal model, the use of a zonal model greatly underestimates the required transmission buildout that would be necessary. This characteristic means that the transmission build-out to support the Draft Study's increased inter-regional transfer capability is likely significantly underestimated."

SREA encourages the DOE to work with SERTP Utilities gain access to nodal data so that more specific transmission analysis can be conducted.

H. SERTP #150: "If a transmission needs study is to be performed, specific transmission planning studies to assess transmission expansion should be performed and not derived from a conglomeration of different types of studies. EIPC has begun discussing the preparation of a combined Eastern Interconnect study that will assess expected renewable generation and synchronous generation retirements as well as incorporating climate change transfer capability needs. This process includes: -building eastern interconnect models which include renewable generation in expected rural areas -modeling expected synchronous generation retirements identifying extreme weather events -forecasting generation requirements in areas experiencing the extreme weather event -modeling transfers of power from areas not experiencing the SAME weather event to the areas experiencing the SAME extreme weather event; this step identifies the required transfer capability for extreme weather -identifying transmission constraints resulting from modeling the required transmission transfer capability requirements -identifying transmission needs to mitigate the transmission constraints which includes non-wires solutions where appropriate SERTP respectfully submits that this type of specific, engineering-based study, rather than an abstracted, aggregated meta-study, is more appropriate to determine transmission needs."

SREA looks forward to learning more about a future EIPC study; however, there has been no mention of such a study on the EIPC website nor a timeline for when such a study may be finalized. In reviewing the Report for 2028 Summer and Winter Roll-Up Integration Cases Public Version[102], published by EIPC in 2019, the study relied on self-provided data from the EIPC members, not scenario-based planning. In 2019 for instance, the Southern Balancing Area, Duke Energy Carolinas and Duke Energy Progress, Dominion South Carolina, and LGEKU data assumed zero new renewable energy additions through 2028, while TVA only added one 60 MW facility to the model.[103] Even without a realistic view of the future, the study found that the SERC region had the highest number of overloads with N-1 contingencies in the Eastern Interconnect. Further, EIPC relied on the study utilities to provide solutions to the identified problems. Only Santee Cooper provided three solutions, while no other SERC or FRCC utility provided upgrade information to the study. Finally, the EIPC efforts only focus on NERC reliability standards, and do not evaluate the economic value of transmission.

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[102] Eastern Interconnection Planning Collaborative Transmission Analysis Working Group Report for 2028 Summer and Winter Roll-Up Integration Cases Public Version Approved by the EIPC Executive Committee August 28, 2019.
[https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/5d7bcc99ab124176b6f8ce17/1568394394545/EIPC_Roll-Up_Report_2019_public_Final.pdf]

[103] Eastern Interconnection Planning Collaborative Transmission Analysis Working Group Report for 2028 Summer and Winter Roll-Up Integration Cases Public Version Approved by the EIPC Executive Committee August 28, 2019. Appendix C. [https://eipconline.com/s/AppendixC_2019_Final.xlsx]

In EIPC's testimony to FERC in December 2022, the organization supported more robust interregional transmission analysis. EIPC's spokesperson stated:

> "There is ample record support before the Commission in the Long-Term Regional Transmission Planning proceeding, as well as strong support from the state commissions as evidenced in the record of the July 20, 2022 public meeting of the Joint Federal-State Task Force on Electric Transmission, for taking steps to examine enhancements to interregional transfer capability. Given the complexity of this task and the resources which will need to be dedicated to its development, the EIPC believes it important that the Commission indicate support for the effort proposed by the EIPC and use its convening authority to bring forward NERC, the National Labs and states to work with the EIPC on this effort before work begins. Further, the EIPC suggests that the Commission use workshops such as this one to provide for "check-ins" as to the progress of the EIPC efforts in the Eastern Interconnection. Accordingly, the EIPC urges the Commission to provide its support for this effort in the Final Order addressing the LTRTP NOPR, based on the full record developed in that proceeding to date in support of such an initiative."[104]

V. Conclusion

SREA again appreciates the important scope of the DOE Needs Study, and especially its focus on future needs. In transmission planning terms, 2035 is tomorrow. Projects can take a decade or more before there is steel in the ground and gigawatts of energy flowing on conductors.

[104] Testimony of David W. Souder on Behalf of the Eastern Interconnection Planning Collaborative, Docket No. AD23-3-000, Establishing Interregional Transfer Capability, Transmission Planning and Cost Allocation Requirements. [https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/639cd78a50f0d438d326b361/1671223179859/Souder+EIPC+Testimony+for+Interregional+Transfer+Workshop.pdf]

This current trend is not in step with the pace of renewable energy expansion. Over 50 reports cited in the Needs Study state in one form or another, that to meet the challenge of widespread decarbonization by 2035, it is critical to have a wide scale assessment of needs to facilitate an affordable and reliable bulk electricity system in the U.S. for decades into the future.

The Needs Study's role in providing an assessment that may inform the identification of National Interest Electric Transmission Corridors (NIETCs) is crucial. If the widely expected energy transition from greenhouse gas emitting resources to renewable energy is to happen affordably and at a reasonable pace, the power industry must be able to use innovative tools like NIETCs. The current draft Needs Study, with some exceptions noted in SREA's comments, havs provided a well-grounded assessment of needs related to the bulk electricity system in U.S. that are in the national interest currently, and for decades to come.

Attachment A

Georgia Power Company's 2022 IRP

Docket No. 44160

Transcript, May 24-25, 2022

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BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:

Georgia Power Company's 2022 Application for Approval of its Integrated Resource Plan	)	Docket No. 44160

In Re:

Georgia Power Company's 2022 Application for Approval of its Amended DSM Plan and Certification and Decertification of Certain DSM Programs	)	Docket No. 44161

VOLUME I

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Tuesday, May 24, 2022

The above-entitled matter came on for hearing Pursuant to Notice at 9:30 a.m.

PRESENT WERE:
TRICIA PRIDEMORE, Madam Chair
TIM ECHOLS, Vice-Chairman
FITZ JOHNSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
JASON SHAW, Commissioner

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you're saying you change it from 2.30 to 7.50 and it makes the -- the PPA clearly uneconomic. I don't think that's the case.

There's -- I mean, there's money there. I'm not going to say it doesn't matter or what have you. But in terms of the capacity payments with -- of the PPA, it's pretty small. The additional sum relative capacity payment to the PPA is pretty small.

Q Okay. While it wouldn't make it uneconomic, it would have a cost impact?

A (Witness Newsome) Oh, yeah.

Q It wouldn't make it less cost-effective?

A (Witness Newsome) Correct. Yes.

A (Witness Hayet) And it has an impact on the ratepayer.

Q And then that ratepayer has to pay the higher amount, or whatever the amount that's approved?

A (Witness Hayet) That's correct. And that's why we recommended it should be the 2.30 a KW a year value.

MR. BAKER: Thank you, panel. Thank you, Commission.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association.

MR. MAHAN: Good morning, Commission.

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CROSS-EXAMINATION

BY MR. MAHAN:

Q Good morning, panel.

A (Witness Newsome) Good morning.

Q On page 95, lines 7 and 8, you said the 1,000 megawatts of batteries evaluated by the staff and the company are uneconomic based on your analysis. But with the questions you just had with Mr. Baker, you suggested that the 1 gigawatt of batteries might be economic if paired with renewables; is that correct?

A (Witness Newsome) I don't think -- I don't think we said that.

Q Okay. But you would agree that you said it would be cheaper if paired with renewables?

A (Witness Newsome) I think the whole discussion on that was us not including battery plus solar in the analysis. So I'm not quite sure where you're going with all this, but I think that whole conversation was saying we had solar analysis, we had battery, standalone battery analysis, but we didn't have it combined.

Q Right. And, Mr. Hayet, you explained that the investment tax credit could be applied to batteries if they're conjoined with renewable resources; is that correct?

A (Witness Hayet) Yes. I think we said that it could be cheaper and it wasn't exactly modeled, but we're recommending that an RFP be conducted. And through the -- so what we're saying is that a thousand megawatts of battery storage shouldn't be approved necessarily, but it should be based on economics and knowing exactly what the costs are going to be and seeing if the IATC is going to be extended. And, therefore, doing it through the RFP is the best approach, rather than arbitrarily saying: Hey, a thousand megawatts, we think you should accept it based on no economic analysis.

Q Okay. But your testimony does say that you believe that the 1,000 megawatts is currently uneconomic; right?

A (Witness Newsome) Correct.

Q And that's based off of the Aurora capacity expansion modeling work that you did?

A (Witness Newsome) Correct. But there's also other market indications. In this capacity RFP the company just conducted where they selected the six PPAs, you know, battery plus solar was allowed to bid in. It just wasn't selected. So when you also --

Q We'll get to that in a second.

Aurora is a capacity expansion model, though; right? It's not an energy expansion model?

A (Witness Newsome) Well, it measures the energy,

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too.

Q But which one does it prioritize?

A (Witness Newsome) It does both. That's the reason it's so --

Q At the exact same time?

A (Witness Newsome) Yes.

A (Witness Hayet) Yes.

Q Okay. If you give Aurora a low-cost energy resource, it will select that resource, regardless of whether or not it provides capacity?

A (Witness Newsome) Repeat the question.

Q So if you provide Aurora with a low-cost energy resource --

A (Witness Newsome) Define low-cost.

Q $25 per megawatt-hour.

A (Witness Newsome) So it's just the energy product?

Q Sure.

A (Witness Newsome) Not capacity?

Q Yep.

A (Witness Newsome) Okay.

Q You provide that to the -- into the model, will the model select that if there's no capacity need?

A (Witness Hayet) Yes.

A (Witness Wellborn) Yes. You can set the model to make those selections. The company's resource mix study included solar with no capacity value as selectable. And it was selected.

Q Was that generally earlier or later in the model runs, in the model years?

A (Witness Wellborn) It was consistent with the economics of the inputs. The prices change over time. And so how the system is being dispatched influences what's getting selected when. I would say generally later than earlier.

A (Witness Newsome) When you say later, what -- what in your mind --

Q Post 2030.

A (Witness Hayet) It selected it prior to 2030.

Q Was that often?

A (Witness Wellborn) I might point us back to Table 19, which includes staff's Stage 1 results from Aurora. And you can see the solar selected in those model runs.

Q Okay. Can batteries act as a transmission alternative?

A (Witness Newsome) They could, yeah.

Q Does Aurora model that option?

A (Witness Wellborn) There is no transmission modeling in Aurora.

Q Can batteries provide frequency and voltage support?

A (Witness Hayet) Yes.

Q And does Aurora model that?

A (Witness Hayet) It doesn't model frequency and voltage support, no.

Q And did you run Aurora on an hourly basis or a sub-hourly basis?

A (Witness Hayet) We didn't run it on a sub-hourly basis.

Q Okay. So it was an hourly basis then?

A (Witness Hayet) Depending on the study actually, but -- but --

Q Okay. And can batteries provide services on a sub-hourly basis?

A (Witness Hayet) They can provide -- so can other resources. But, yes, batteries can provide benefits on a sub-hourly basis.

Q So is it possible, then, the Aurora runs that both the company and the staff performed doesn't consider the full value stack of battery resources?

A (Witness Hayet) Yes, I'd say that's true. But I think that you've got to consider the full value stack with batteries, as well as other resources. But I definitely agree that it doesn't account for the full value stack.

MR. MAHAN: All right. That's it. Thank you.

COMMISSIONER PRIDEMORE: Georgia Watch. Georgia Watch was missing before. Is she still missing?

There she is.

MS. COYLE: No questions. Thank you.

COMMISSIONER PRIDEMORE: No questions, okay.

All right. I believe I got everybody for this panel, except Georgia Power.

MR. MARZO: Thank you, Madam Chair. I promise this is not all for them.

COMMISSIONER PRIDEMORE: He brought a box, folks.

MR. MARZO: It's not all for you, gentlemen, and ladies.

CROSS-EXAMINATION

BY MR. MARZO:

Q First of all, Brandon Marzo on behalf of Georgia Power Company. I echo the sentiments earlier, Mr. Hayet. I hope you get better soon.

A (Witness Hayet) Thank you.

Q I appreciate the panel's patience. I do have some questions for you, though. The good part of going last is I think a number of them have already been asked.

developing a 50-megawatt project. I mean, can you designate 3 megawatts of that for the community -- if you had the demand for it, designate 3 megawatts of that generation for community solar, but get the benefit of the economies of scale by having the larger 50-megawatt project and not have it dedicated, you know, that 3 megawatts? You know, just a standalone project for the community solar?

A (Witness Cook) Yes, that's certainly -- yes, that's certainly an option, yes.

MR. BAKER: Okay. Thank y'all very much. Appreciate it.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association?

CROSS-EXAMINATION

BY MR. MAHAN:

Q Good afternoon, Commission. Good afternoon panel. I am Simon Mahan.

A (Witness Barber) Good afternoon.

A (Witness Cook) Afternoon.

Q I'm Simon Mahan with the Southern Renewable Energy Association.

Page 7, Recommendation 11, "Staff recommends that the company should not issue a North Georgia RFP for renewables but should instead require the cost of transmission upgrades" -- "require to meet the resilience for southern projects to be added to projects in the north."

Can you describe how you plan on that process working?

A (Witness Cook) So I think to the point we were making earlier about locational value, there is the production cost difference between -- and as well as necessary transmission upgrades to allow Southern Solar to provide for the reliability ease of the load in the north.

So I think along those lines, you can quantify the cost of those transmission assets or any other constraints in order to apply an evaluation benefit to one resources -- or one geographic location versus another.

Q Okay. And so what you just described, is it possible that the South Georgia to North Georgia movement of power is not just a single transmission line, it could be multiple projects in order to resolve any constraints?

A (Witness Cook) Certainly.

Q And over time; right? It's not all going to be done in one single year; right?

A (Witness Cook) Certainly. I would direct any more detailed questions about transmission to the transmission, you know -- our consultant that does transmission.

Q Sure. And transmission projects can provide

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multiple benefits, not just for solar developers. It can provide for, you know, shifting frequency in voltage around.

So it can provide multiple benefits; right?

A (Witness Cook) Certainly it provides -- yes, it does more than just carry electrons for solar, yes.

Q And so this North Georgia reliability and resilience plan that we're all kind of talking about, when we come up with some transmission solutions out of there, you're proposing that 100 percent of those costs be then applied to any North Georgia solar projects that bid into the RFP?

A (Witness Barber) Repeat your question.

A (Witness Cook) Yeah, repeat your question.

Q So all of the projects that are going to go into the North Georgia reliability transmission plan, you're going to take all of those costs and then assume all of those costs are caused because of the solar developers in the south and then you're going to apply those costs as a benefit to projects that may bid into the north; is that right?

A (Witness Cook) Okay. You're talking about the transmission projects required in the North Georgia reliability plan?

Q Yes. Yes.

A (Witness Cook) I don't believe that we're -- we're not recommending that all of the costs associated with the North Georgia reliability plan would be coalesced and attributed to those southern resources. I think that would require more of a -- a more specific study that looked more directly at the costs of bringing those electrons from South Georgia to North Georgia and -- yeah. And shoring up those reliability constraints specifically, not necessarily -- because I believe a lot of the North Georgia reliability plan also revolves around unit retirements as well that are kind of beyond that scope.

Q And so it really -- you really have to go transmission project by transmission project, line by line to figure out what costs you would then want to attribute to North Georgia renewable bids?

A (Witness Cook) That might be a little bit beyond my expertise on that. I would probably try that with John Chiles.

Q Okay. Yes, we can do that.

Have you all looked at the generation air connection queue up in the northern part of Georgia within the past six months?

A (Witness Cook) We did review it. It was part of a data request. We did see that interconnection queue, yes.

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Q Okay. And do you recall approximately how many renewable projects in northern Georgia might be able to bid into a northern Georgia specific RFP?

A (Witness Cook) That number crossed our desk. I certainly couldn't quote it for you. I know that the vast majority of projects in development, including things in the interconnection queue, are located in middle, south Georgia. It's just kind of the reality of the situation.

Q Sure. But just to boil it down. I mean, part of this recommendation that y'all are making is because you're concerned that the North Georgia only RFP will fail?

A (Witness Cook) Yes.

A (Witness Barber) Yes. And I think we put that in our testimony as well.

Q Okay. Going back to this concept of applying transmission benefit costs to northern Georgia projects, presuming there are -- we're going to presume that there's going to be a Northern Georgia renewable project that's going to bid into an RFP at some point in the future.

Would a future battery project get that same transmission benefit assigned to it?

A (Witness Cook) A battery project in North Georgia?

Q Yeah.

A (Witness Barber) Well, it can't bid in.

A (Witness Cook) Well, yeah, it wouldn't be able to bid into the renewable, but in theory if you -- in theory if we -- you know, if we develop a locational value, as we talk about in the locational value study section, then, yes, that locational value could be applied to other resources outside of the renewable RFPs.

Q Okay. So it could theoretically apply to natural gas plants?

A (Witness Cook) Yes, in theory.

Q Okay. And I don't think you want to do this, but why wouldn't you also assign that transmission benefit to existing coal units?

A (Witness Cook) In theory it could, yes.

Q Okay. And if you did that, it could potentially encourage those coal units to stay on for a very long time?

A (Witness Cook) Depending on the level of the -- the difference in cost, yes.

Q So let's go back to this hypothetical situation where we've got a renewable project in North Georgia that bids into an all Georgia RFP and you're giving that project some sort of transmission adder, benefit, you know, let's call it $3 a megawatt hour, you know, it doesn't matter what the price is; is that renewable project actually avoiding any transmission build-out in the southern part of the state, or is it just a hypothetical?

A (Witness Cook) I mean, I guess it would depend on how the analysis was done and how that -- that value was -- was determined.

I could see that some evaluation methodologies might be much more correlated with actual costs, but it also certainly depends on the level of response from North Georgia. And so it is sometimes hard to see a benefit from one generator. But, you know, we -- when we do analyses -- when we do analysis, particularly, say, in Aurora, you know, you look at 300-megawatt blocks, and so you're looking at generators in aggregate.

And so if you have a block of respondents that bid into the North Georgia -- or bid into the RFP from North Georgia, you could see those benefits.

Q But in order to do that, you would have to cancel transmission projects in the North Georgia reliability plan then?

A (Witness Cook) Yeah. I would -- I would probably kick that to John Chiles.

Q Okay. Speaking of Mr. Chiles, I presume you've read his testimony?

A (Witness Cook) Yes.

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Q Okay.

A (Witness Barber) Yes. And we -- and we discussed our recommendation with him before it got put in our testimony, so it is -- it was from his guidance.

Q Okay. Well, one of his recommendations is to create a new collaborative transmission planning process.

And you are familiar with that recommendation generally?

A (Witness Cook) Generally, yes.

Q Do you envision that collaborative transmission process occurring before the 2023 renewable RFP process?

A (Witness Barber) Not really sure. I'm not sure of the timing of that recommendation.

Q Okay. So going back to this original recommendation of if there are northern Georgia renewable projects and you want to provide a transmission adder benefit for them so they can get ranked and appropriately evaluated, but the collaborative planning process isn't completed yet, how do you expect to be able to assign some sort of transmission benefit when you don't have the number?

A (Witness Cook) That's not to say that a study couldn't be done ahead of a collaborative group.

Q But that study would presumably be run solely by Georgia Power without any collaboration involved in it?

A (Witness Cook) With staff involvement, but potentially not industry involvement.

Q Sure. Which staff specifically would be involved? Because the collaborative process that Mr. Chiles outlines mentions that staff and consultants will be involved in that process. Can you name like the specific staff that would be involved in that process?

A (Witness Barber) I don't know specifically, but it would probably be someone from electric. Blair Fink, maybe, possibly somebody from our unit as well.

Q And do you have a sense of who the specific consultants would be that would help in the collaborative process?

A (Witness Barber) No, I sure don't.

Q Okay. Generally, do you believe that the Commission staff have enough resources to evaluate these transmission alternatives and optimization of transmission of the system?

COMMISSIONER McDONALD: No?

A (Witness Barber) No. No.

MR. MAHAN: Thank you, Commissioner.

BY MR. MAHAN:

Q Mr. Chiles also recommends and discusses the North Carolina transmission planning collaborative as an example of what he'll eventually propose down here which y'all are familiar with.

Have y'all participated in that planning collaborative in North Carolina?

A (Witness Cook) No.

Q Have you spoken to anyone in North Carolina that has participated in that collaborative?

A (Witness Cook) I haven't, no.

A (Witness Barber) No, we haven't.

Q Do you happen to know if that collaborative is run by an independent entity or is it run by the utilities?

A (Witness Barber) We're not sure.

Q Okay. Let's move on to staff recommendation 13 regarding the locational value study that came out of the Docket 4822. And on page 52 of your testimony, you cited earlier testimony that y'all provided in that docket that gave an example of solar resources being built in the south providing a different value than solar resources being provided in the north.

But that's just like a generic example, that's not a specific example of the two regions that y'all anticipate to evaluate; right?

A (Witness Bower) That's right. That's just a sort of generic description of how locational -- a locational energy value would work.

Q Okay. And so there's potentially many more locations that a locational value study would or could evaluate?

A (Witness Bower) That's right.

Q Do you have a sense of how many locations or how you would divvy up those locations?

A (Witness Bower) No. I mean, I think that would have to be -- that would really depend on -- and this is what we're hoping the study would kind of, you know, figure out is where there are transmission constraints, where there are load pockets or generation behind transmission constraints that may lead to differentiated locational value of energy, and, therefore, you know, differentiated value of renewables in those regions.

But the number, that would have to be the output of the study, not something that we know --

Q Okay.

A (Witness Bower) -- at this point.

Q And do you happen to know if other utilities or regions conduct a similar locational study or forecasts like that?

A (Witness Bower) I don't know of any utilities that do studies similar to those exactly like that. I know, for example, I've reviewed the PacifiCorp IRP in the past, and they have different regions where they are -- you know, they have different -- when they're doing capacity expansion, for example, they take into account transmission constraints between regions and differing value both, you know, capital cost value but also avoided energy in different regions as part of the economic analysis.

Certainly every -- every market based region locational value is baked into energy pricing and, you know, to the extent there are different capacities on those capacity pricing as well.

Q And when you say "market," what do you mean?

A (Witness Bower) I mean like an RTO or an ISO market, an AM or MISO.

Q All regional transmission organizations include this, and it's -- is it called locational marginal pricing?

A (Witness Bower) Yes. LMP is generally what -- what that's referring to.

Q Okay. So just to be very clear, what the staff is recommending is that the company conduct a locational marginal pricing study.

A (Witness Bower) Not -- I wouldn't characterize it that way. There are ways to evaluate locational value without everything that goes into locational -- locational marginal pricing that markets use.

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So hourly LMP's by node is locational pricing. Locational marginal pricing. You can look at regions with general transmission constraints and general constraints that prevent the free flow of lowest cost energy and characterize that in a regional context rather than on a nodal, you know, point-by-point context.

So, conceptually, it's similar, but I think that you can do a lot to -- and what we are -- what we are, you know, proposing here or suggesting is that there are additional ways that you can do these studies. It is not a full LMP-based analysis, but it's more than what the company has proposed, which is only transmission capital cost focused.

Q And so what you are proposing is a less granular, less accurate version of a locational marginal price?

A (Witness Bower) Probably a less -- a less -- certainly less granular.

Q And you anticipate the study to be released on an annual basis or is it a once-in-a-three-year basis or...

A (Witness Bower) Well, I think -- I think the first step would be doing the study once, you know, to get a sense of transmission constraints on Georgia Power system, whether there is any -- any value in -- whether there is a differentiated locational value. I think that that's not necessarily a certainty until the study is complete.

Q So you only evaluate a single year then? Is that what you are proposing?

A (Witness Bower) No. You can do a forecast. You know, you can do multiple years. But, again, I think to first -- the first order of business is just do the study to determine whether those transmission constraints exist and whether the prices of renewables in different regions would have a different value.

You could do that with one-year or you could do a multi-year forecast and gain different amounts of information. But all of it would be useful in helping determine whether this is something that's worth pursuing.

Q But could you -- I mean, if you could kind of help me out here, because I think we all agree in the room that there is a difference between Northern Georgia and Southern Georgia, and that there are transmission constraints. And so kind of the -- the answers you just describe are things that we all agree on.

And so what -- what additional value is that study going to provide if it's not going to do additional granularity?

A (Witness Bower) Well, I think you can go more granular than -- I think there is a granularity level between is it north or is it south. And every single substation on Georgia Power's system, which is what really an LMP-type analysis would do.

Q But locational marginal pricing analysis from the RTOs, this is something that they have been doing for decades at this point; right?

A (Witness Bower) Yes.

Q And so your -- strike that.

Let's move on to page 53 here real quick, line 5. You explain how the Aurora model currently used by the company doesn't include transmission topology and then you suggest that the model could be used to break into, quote, "smaller zones connected by transmission links that reflect actual system transfer limits."

Again, can you give a sense of how big of a region or zone you are thinking of that the company needs to evaluate?

A (Witness Bower) I really don't -- don't have an example that I can give on, you know, physically how big those regions are. You let the transmission topology sort of determine that, rather than a, you know, square miles or anything like that.

Q Regarding the model itself, who told you that the model can do that?

A (Witness Cook) We have some experience in

Aurora. And both I and other members on staff have done some work in Aurora, going through their models, and we've demonstrated that, yes.

Q Okay. So you verified that the model can potentially do what you're asking it to do?

A (Witness Cook) Yes. Aurora can differentiate between zones, yes.

Q Okay. Wouldn't it also be helpful to do locational marginal pricing across the Southern Company territory, given that the southern pool operates as a pool?

A (Witness Cook) Certainly. I think we really operate in the context of Georgia Power here.

Q Sure. Well, but you're aware, also, that Southern Company uses Aurora planning software in Mississippi and Alabama, here in Georgia?

A (Witness Cook) Yes.

Q Would it be helpful to have that type of analysis across SERC?

A (Witness Cook) Certainly.

Q Is it possible that there are transmission solutions into Tennessee that would be better suited to fix the northern Georgia problems?

A (Witness Cook) I -- Yeah, I can't speak to that, but you might try John Chiles.

Q Okay. I did a search in the testimony regarding the Southeastern Energy Exchange Market.
Are you familiar with what this is?
A (Witness Cook) Yes.
A (Witness Barber) Vaguely.
A (Witness Cook) Vaguely.
Q Vaguely?
A (Witness Cook) We've been -- we've been watching it develop, yes.
Q Okay. The Southeastern Energy Exchange Market, did that have any role to play in fulfilling this request for your locational value study?
A (Witness Cook) I don't believe so.
Q Do you value -- do you see -- or let me -- let me rephrase.
The Southeastern Energy Exchange Market, do you believe it will provide a benefit to Georgia?
A (Witness Cook) I think that's outside the scope of our testimony.
Q Is there anyone that gave testimony regarding the Southeastern Energy Exchange Market?
A (Witness Cook) I don't believe so, no.
Q Okay. So it's entirely outside of the scope of the integrated resource plan.
Let's move on to page 33 of your testimony,

line 11. You mention in the most recent capacity RFP, the company did not allow two-hour batteries to participate.

Did staff recommend that two-hour batteries be allowed to bid into that RFP?

A (Witness Cook) Yes, I believe we did.

Q And you were overruled?

A (Witness Cook) Yes.

Q Okay. How do we resolve that deficiency in the future?

A (Witness Cook) I think in future capacity RFPs, we'll be continuing to advocate for two-hour batteries.

Q Okay. Line 38 -- or sorry. Page 38, line 8 of your testimony explains that there's about 2.3 gigawatts renewables currently under development; is that correct?

A Yes.

Q And that's all from the 2019 IRP?

A (Witness Cook) It may not be all from the 2019 IRP but most of it, yes.

Q And the company is now requesting 2.3 gigawatts of new renewables --

A (Witness Cook) Yes.

Q -- in this IRP?

And also in this IRP, the company is requesting 2.3 gigawatts of gas power purchase agreements?

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A (Witness Cook) Yes.
Q 2.3 gigawatts over and over and over. Is that -- is that a coincidence?
A (Witness Cook) I can't speak to that.
A (Witness Barber) Yeah. Not really sure.
Q Okay. Appreciate it. Thank you.
MADAM CHAIR PRIDEMORE: Georgia Power?
MR. HEWITSON: Thank you, Madam Chair.
Hello, panel.
PANEL: Good afternoon.
BY MR. HEWITSON:
Q Steve Hewitson on behalf of Georgia Power Company. I want to start with the RCB framework, and before getting into any specific components, let me ask you generally about modeling for a second.
Did staff provide any modeling results to support its testimony in this IRP?
A (Witness Barber) Can you be specific which testimony?
Q On the RCB framework.
A (Witness Bower) No.
Q Did you run any models in developing your testimony?
A (Witness Bower) No.
Q So although you have questions and concerns

We would say: This is the load at the time. What resources are going to serve that? Does the system work?

Q Thank you.

Did your analysis include any evaluation of sensitivity of transmission needs under various target reserve margin levels or scenarios?

A (Witness Chiles) No, it did not. Once again, for the reasons stated.

MR. BAKER: Okay. Thank you very much. Thank you, Mr. Thomas, for being patient.

Thank you, Commissioners.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association.

MR. MAHAN: Good morning, Commissioners. Good morning, panel.

WITNESS CHILES: Good morning.

MR. MAHAN: Simon Mahan for the Southern Renewable Energy Association.

CROSS-EXAMINATION

BY MR. MAHAN:

Q My questions today, if everyone was paying attention yesterday, are going to be directed towards Mr. Chiles.

Were you able to listen, Mr. Chiles, to the panel Barber, Bower, and Cook yesterday?

A (Witness Chiles) I did.

Q And they instructed me to ask you these questions.

A (Witness Chiles) I'm aware. And they will hear about it later.

Q Yes.

Do you have experience with the Aurora model the staff and company have referenced?

A Not with Aurora specifically, but I have worked with several production cost models in my career.

Q Do you recall the discussion regarding the locational value study that we were talking about yesterday?

A (Witness Chiles) I do recall hearing about that study.

Q Okay. Do you recall how staff said Aurora could be used to conduct that study?

A (Witness Chiles) If you could refresh me, that would be helpful.

Q They said that.

A (Witness Chiles) That's helpful.

Q Okay. It's coming back from yesterday.

Is Aurora designed to conduct locational marginal pricing on a notable basis?

A (Witness Chiles) I am not aware of if it is or not.
Q Okay. But you're aware that the proposal is that the Aurora model could be so subdivided into subzones to come up with effectively avoided costs in different parts of the state. You're familiar with that?
A (Witness Chiles) Yes, sir. I am aware of that.
Q But effectively couldn't the company gerrymander the zones to make the analysis less transparent than locational marginal pricing?
A (Witness Chiles) There's a couple of options you can look at in --
Q Yes or no?
A (Witness Chiles) -- most production cost models. So I believe the answer is yes.
Q Okay.
A (Witness Chiles) I believe you could look at, once again, a trading up model or a zonal model to give you some --
Q Do regional -- thank you.
Do regional transmission organizations use Aurora to run their market locational marginal pricing?
A (Witness Chiles) There may be some. I'm more familiar with those they use provided use -- use PSLF and GE MAPS.

Q Okay. So different models to conduct more locational marginal pricing, instead of Aurora?

A (Witness Chiles) That's correct.

Q Okay. Moving on, you're familiar with the North Georgia RFP proposal that the company has put forward; correct?

A (Witness Chiles) Yes, I am.

Q Okay. And you're familiar that the staff have recommended that Northern Georgia renewable -- that instead, that the renewable RFP should be statewide and that renewable projects that are located in the north should instead be somehow compensated for not having transmission service from the south.

Is that your understanding of that recommendation?

A (Witness Chiles) That's my understanding, yes, sir.

Q But projects in the north -- if projects do bid in to this RFP, are they definitively negating the need for transmission in the south?

A (Witness Chiles) Once again, it would depend upon location and the contingency analysis run on a power flow model for the entire state.

Q And so a northern project could potentially -- instead of providing a transmission benefit, it could actually provide a reliability benefit?

A (Witness Chiles) Once again, the power flow model is agnostic to, you know, who provides what. You know, it's a case of: Under contingency conditions, does the sum of the generation and the sum of the load result in overloads on the system?

So I'm sure, you know, multiple projects could provide benefits in various locations, depending upon the season, the contingency, and the time of day.

Q Yesterday Mr. Hewitson during cross-examination of the same panel, he asked if ERCOT uses locational marginal pricing. Did you catch that question?

A (Witness Chiles) I did.

Q Does ERCOT use locational marginal pricing?

A (Witness Chiles) Yes, it does.

Q Did the use of locational marginal pricing cause blackouts in Texas?

A (Witness Chiles) I sure hope not, no. But my understanding is is that, you know, the energy market construct and the use of pricing, once again, gives you a price signal. But it's operation of the system and outages of generation that, my understanding, has resulted in the blackout situation.

Q Okay. And so --

MADAM CHAIR PRIDEMORE: Mr. Chiles, isn't it -- isn't it fair to say that -- as even the people in Texas like to say, it was the perfect storm. So it was policy with the system and system reliability from a generation and transmission side. It was all things combined; right?

WITNESS CHILES: That's correct. If you look at -- if you look at the system and look at the number of outages, the types of outages, the location of those --

MADAM CHAIR PRIDEMORE: Yeah.

WITNESS CHILES: -- the fuel supply. You know, there were several factors that contributed to the problems in Texas.

COMMISSONER McDONALD: Mr. Chiles, do you think that the utility that this Commission regulates would find any favor by being a part of an RTO?

WITNESS CHILES: I think that's a question for this Commission to answer and not for me to answer. The only thing I would say is, you know, from a transmission perspective, my concern is: Do we have a system where the resources that the company wants to have can effectively serve the loads of the customers of the state of Georgia?

Whether that's in an RTO construct or not, I am completely agnostic to that. I just want to make sure that when mom and pop at the end of the line turn the light -- hit the switch, do the lights come on and do they stay on.

MR. MAHAN: That is a great answer.

COMMISSONER McDONALD: I can tell you this Commission has a position on it.

MR. MAHAN: And, Chairwoman Pridemore, thank you for pointing out the multiple factors that led to the blackouts in Texas.

BY MR. MAHAN:

Q To be a little bit more specific on this, did a lack of transmission connections outside of Texas contribute to the blackouts and the extremity and the length of time of the blackouts in Texas?

A (Witness Chiles) Well, certainly within this -- within ERCOT, given it's about, I think, 5- to 600 megawatts of total capability across the three DC ties, that certainly has a whole lot less interconnection capability than what we have here in the state of Georgia. So I would argue yes.

Q And so does ERCOT build transmission projects that cross U.S. state borders?

A (Witness Chiles) ERCOT does not do that.

Q Why don't they do that?

A (Witness Chiles) Because they made the decision

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back in the '70s to sever the ties to -- to the rest of the country in order to avoid the influence of the federal government under the Interstate Commerce Act.

Q All right. So ERCOT is, in effect, a single-state transmission planning entity?

A (Witness Chiles) It is a single-state independent transmission planning entity. There's about 20 percent of the state of Texas that is served by customers in the Eastern and Western Interconnect.

Q Single-state-based transmission planning analysis or a collaborative might actually miss larger-scale regional transmission solutions that could help prevent things like blackouts?

A (Witness Chiles) Once again, it depends upon the configuration of the system. You know, here in Georgia, because we're an integrated system, you know, the models which the company runs right now look at those things. The company does interface planning. The company looks at that.

So I think it's already being addressed, in terms of the other planning options that the company has. So I think that's already being covered as the previous --

Q But your testimony in general is dissatisfied with the way the company does transmission planning, isn't it?

A (Witness Chiles) I wouldn't say I'm

dissatisfied with the way they do planning, in terms of the reliability planning. I think I'm more concerned from a strategic planning long-term perspective, given the significant changes in the generation mix, in the location of that generation, you know, in the energy transition, which the Chair recognized. I think you have to look beyond our ten-year horizon and really decide, as my mother-in-law would say: What do you want to be when you grow up?

And I think that's part of -- I think that's part of the discussion, you know, of really: Where do we want to be? You know, if we want to be a state that has significant renewable generation, for example, then I think you need to build a transmission and planning for that which is going to accommodate that. Otherwise, you're chasing your tail and you run into problems where the planning lags behind the desire to move forward with generation.

Q And you think that's where we are right now?

A (Witness Chiles) I'm concerned that's where we are right now.

COMMISSONER McDONALD: So you -- we referred to blackouts and, of course, I think we were more talking about Texas and California. Do you recall blackouts in Georgia?

WITNESS CHILES: Not in the 18 years I have been here.

COMMISSONER McDONALD: Thank you.

WITNESS CHILES: The last time I saw a blackout was up in the northeast on August 14th of 2003, sir.

MADAM CHAIR PRIDEMORE: Where you were in the northeast in 2014, are they part of an RTO?

WITNESS CHILES: That was part of the PJM system. And along with MISO, and along with what was happening in Canada and transferring off of FirstEnergy system. So it was a confluence of events that caused a great deal of regulate issues, which is why we have the NERC reliability standards today.

BY MR. MAHAN:

Q On page 9 and 10 of your testimony you were describing kind of these two separate concepts of generation-centric planning or transmission-centric planning. Do you recall that?

A (Witness Chiles) Yes. Yes, I do.

Q Am I correctly characterizing that generally?

A (Witness Chiles) Yes, sir.

Q Okay. So can comprehensive transmission planning reduce overall generation costs?

Can a good transmission plan reduce costs of generation?

A (Witness Chiles) I am going to ask you to be a little bit more specific on that because the transmission system, once again, is agnostic to the prime mover. If you're talking about production costs, then I can't speak to that. If you're talking about interconnection costs and improved deliverability, I can speak to that.

Q Let me think about this a different way. So if you had a generation-centric planning system, sort of like what we have right now, it still requires transmission upgrades?

A (Witness Chiles) That's correct.

Q But in your testimony you identify that we could possibly optimize the transmission system to reduce overall costs?

A (Witness Chiles) Correct.

Q Okay. Generally could a generation-centric planning approach be concerned kind of like a bottom-up transmission planning process?

A (Witness Chiles) I usually think about bottom-up in the context of a regional transmission organization where the members of that group submit a project based upon their local needs and that gets rolled up into a common plan. Yeah, what I'm thinking about is in terms of generation.

The question is does the -- does the transmission planner have the obligation to make the system work when a company says: You're putting generation here.

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Go figure it out?

Or does the transmission planner have the option to say: Based upon the grid and the needs of the grid, these are viable locations for placing generation such that the grid can accommodate that and the grid operates more efficiently. So that's how I view those two things.

Q But there is a top-down approach?

A (Witness Chiles) There is top-down approach, that's correct.

Q Okay. Would you describe Georgia Power's current transmission planning process as a bottom-up approach or a top-down approach?

A (Witness Chiles) Probably more of the bottom-up, in terms of the -- I think the generation tends to lead the transmission more than the transmission leading the generation.

Q But they both have value, both the bottom-up and the top-down?

A (Witness Chiles) Absolutely. And if you look at most processes, most organizations have both a top-down and bottom-up for that reason.

Q And when you say organizations, what do you mean?

A (Witness Chiles) That -- it can mean utilities. It can mean state commission planning processes. It can mean regional transmission organizations. It really -- it could even be within a single company.

Q Okay. On page 14 of your testimony, you give Arizona and North Carolina as two examples of states that do joint transmission planning through some sort of stakeholder process where the commissions, quote, have oversight and a seat at the table in the strategic evaluation of the regional transmission system.

Do you believe that the Georgia Public Service Commission staff currently have oversight and a seat at the table regarding strategic evaluation of the regional transmission system?

A (Witness Chiles) Only to the extent that they participate in this integrated resource plan every three years.

Q Have you participated in the North Carolina Transmission Collaborative?

A (Witness Chiles) I have not, but I have clients who have participated in that process.

Q Do you happen to know who leads that process?

A (Witness Chiles) I do not.

Q Is it possible that's a utility-lead process?

A I do know that utilities do have seats at the table at that process. I do not know if there's an independent evaluator or not.

Q Are you familiar that that North Carolina Transmission Collaborative has a planning working group?

A (Witness Chiles) Yes, I am.

Q Did you know that the planning working group requirements require a bachelor's degree in engineering to participate?

A (Witness Chiles) Yes, I did.

Q Are there any nonutility members of that planning working group?

A (Witness Chiles) I don't know the roster.

Q You also had mentioned that there's a transmission advisory group?

A (Witness Chiles) That's correct.

Q Has the transmission advisory group ever proposed an interregional transmission project?

A (Witness Chiles) I haven't reviewed the last couple of plans.

Q Do you happen to know who bears the cost of the additional transmission solutions and studies that are recommended in that process?

A I do not.

Q Would it surprise you that it's the requester that has to pay for those costs?

A (Witness Chiles) The requester of the project pays for the entire project cost?

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Q Of the study.

A (Witness Chiles) It wouldn't surprise me that the requester pays for that study. That's similar to what happens when we talk about interconnection service. If you request interconnection service, you pay the deposit for the study.

Q Don't you think it would be cost-prohibitive for nonprofit organizations to request studies in that process if they are the ones that are going to have to pay for those studies?

A (Witness Chiles) I would think that depending upon that cost and depending upon how you -- the type of budgets you propose, I would suggest that those groups get together and form a coalition to propose a project and share those costs amongst its members.

Q Regard CEII, what is that?

A (Witness Chiles) Confidential energy infrastructure information.

Q Can you give an example of some of those?

A (Witness Chiles) Maps of the power system, power flow models would be a couple of examples.

Q And some of those things have been provided in this integrated resource plan; correct?

A (Witness Chiles) They have been provided under a confidentiality agreement and are shared.

Q Okay. So it's not uncommon for intervening parties, for instance, to be granted access to CEII data so long as they sign a nondisclosure agreement?

A (Witness Chiles) If they sign an NDA. Now, if it's a federal situation, then you would have to go through FERC and request, you know, that clearance and then the utility would grant it.

Q Okay. Do you happen to know if the North Carolina Transmission Collaborative performs both top-down and bottom-up transmission analyses?

A (Witness Chiles) I would not. My understanding is I think that the utilities present their plans and then that rolls into what the North Carolina Collaborative actually uses that as a foundation for evaluating other projects.

Q Do you happen to know how many staff from the North Carolina Utility Commission oversee that process?

A (Witness Chiles) I do not.

Q How many consultants from the utility commission oversee that project?

A (Witness Chiles) I do not.

Q Is the IRP incorporated in that process?

A (Witness Chiles) I do not know.

Q But you still believe the North Carolina process is better than the current Georgia process?

A (Witness Chiles) I believe the North Carolina process gives a framework for which better transparency and engagement exists, which ultimately, to me, it would be an improvement over the current process where we see a plan every three years.

Q Do states and regional transmission organizations have significant oversight regarding transmission planning and siting?

A (Witness Chiles) When you say states, are you referring to state commissions?

Q Yes.

A (Witness Chiles) Okay. Yes, they do. Because the -- I'll use MISO as an example. The MISO board, they approve a transmission project, but that project will go before the state commission, who will have the option to review and determine whether or not that project is useful and whether it's appropriate and prudent for the state.

Q And so state PSCs still have to approve the transmission projects that the RTOs recommend; right?

A (Witness Chiles) That is correct.

Q And state public service commissions often hire specific staff and consultants just to interact with the RTO stakeholder processes; right?

A (Witness Chiles) That is correct.

Q Do you know what the Organization of MISO

States is?

A (Witness Chiles) Yes, I do.

Q What is it?

A (Witness Chiles) The Organization of MISO States is a collective of representatives of state commissions of each of these states which are part of the MISO footprint.

Q And they have considerable oversight in the MISO process?

A (Witness Chiles) They do. They have their own budget, they have their own staff of consultants. They also have ability to file, you know, at FERC on various issues, which MISO will make submittals to the federal commission for.

Q Do you know what the Southwestern Power Pool's regional state committee is?

A (Witness Chiles) It's a very similar organization to OMS.

Q Okay. Does PJM have something similar?

A (Witness Chiles) I believe they have the Organization of PJM States.

Q OPSI?

A (Witness Chiles) I believe that's correct.

Q I love the acronym.

So which RTOs are you heavily involved in?

A (Witness Chiles) I'm most heavily involved in the Midcontinent ISO and the Southwest Power Pool. I have some involvement in ERCOT and limited involvement in PJM.

Q Do you have a favorite RTO?

A (Witness Chiles) That's like asking me if I have one of my favorite children. The answer to that would be no, in case they're listening.

Q But you love them all?

A (Witness Chiles) I appreciate the differences between them.

Q Are those RTOs, in your opinion today, better at transmission planning and stakeholder engagement than the North Carolina process?

A (Witness Chiles) I would say they provide a higher level of stakeholder participation.

Q And the North Carolina process is better than the Georgia process?

A (Witness Chiles) Once again, from a transparency standpoint, I would say that North Carolina does provide opportunities for stakeholders where the Georgia process doesn't.

COMMISSONER McDONALD: That's the second time you've asked that same question.

MADAM CHAIR PRIDEMORE: And you also know that North Carolina is 95 miles northeast of here.

MR. MAHAN: Yes, ma'am.

MADAM CHAIR PRIDEMORE: Like, we're in Georgia and this gentleman has filed this testimony about Georgia.

MR. MAHAN: Yes, ma'am. He is the sole RTO expert that we have had on any witness stand. And considering the importance of transmission planning, I'd really like to continue asking about transmission planning and --

MADAM CHAIR PRIDEMORE: But you do recognize that you're in the state of Georgia. Georgia's not in an RTO. Whether or not to be in an RTO or even repeat the acronym isn't even in this IRP, so --

MR. MAHAN: Yes. Which I agree with that.

MADAM CHAIR PRIDEMORE: You've been given a lot of leeway here, but -- but let's keep it centered. I'm sure Mr. Chiles has a lot of opinions on a lot of important things. And let's keep it centered here on his testimony.

MR. MAHAN: Yes, ma'am.

BY MR. MAHAN:

Q Would it be valuable to incorporate surrounding states in a transmission planning analysis, like Alabama and Tennessee?

A (Witness Chiles) I believe that already happens as part of the SERTP.

Q But do you think the SERTP is adequate in addressing Georgia's problems?

A (Witness Chiles) I can't speak to that. I'm not engaged in the day-to-day activities of the SERTP.

Q On page 17 of your testimony, line 13, regarding the ten-year transmission plan, you state: The company did not provide any analysis that indicated the projects were the optimal solutions with respect to cost.

Do you recall saying the exact same thing in the 2019 IRP?

A (Witness Chiles) Yes, I do.

Q How do you define optimal?

A (Witness Chiles) Optimal with respect to cost?

Q Yes.

A (Witness Chiles) It is a combination of the economic factors and the reliability factors. Once again, I can spend very little on a transmission upgrade and it may solve the problem, but it may not solve the problem for 20 years. It may solve the problem for two years.

I can spend a whole lot more money, I can have a great reliability solution, but I may have such limited flow on that line that really the line is not used and useful for other than maybe a few hours of the year. So that's what I mean by optimization with respect to cost.

Q Why would the company not automatically select the optimal transmission solution?

A (Witness Chiles) I think the company would select the optimal transmission solution. I think it's in the best interest to do so. I'm just saying in my testimony that they did not provide that analysis to us. They provided what they provide in Appendix 3 of their IRP and that's what he reviewed.

Q Is it possible that expanding the transmission system could provide more opportunities for competitors to compete against Georgia Power's existing generation?

A (Witness Chiles) That's a hypothetical. I think any time you expand the grid and you change power flows, that creates opportunity.

Q So it's possible the company may have an incentive to not find the optimal transmission solution on their own?

A (Witness Chiles) I'm not going to speak to that, sir.

Q That's fine.

So how would you recommend for the Commission and staff to be able to determine if a solution is actually optimal?

A (Witness Chiles) I think what would help, you

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know, from an evaluation standpoint is understanding better the criteria by which the company uses to define the optimal solution. And just getting an understanding of the why behind the number I think would be very helpful.

Q Would it be helpful to have some sort of independent transmission analysis completed by a third party?

A (Witness Chiles) In lieu of a process by which staff is engaged --

Q In addition to?

A (Witness Chiles) Depends on the quality of that analysis and it depends on what are the goals of that analysis. You know, I think, once again, the people that are most interested in and understanding that are probably the Commission, the staff, you know, and the company.

You know, primarily, in terms of the rates, reliability, all of that, you know, I think that, you know, those folks need to understand very clearly what are the drivers behind the selection of one project over another.

Q But there are non-RTO consulting firms that could perform this type of analysis for the Commissioners?

A (Witness Chiles) There --

MADAM CHAIR PRIDEMORE: Was that a question?

MR. MAHAN: Yes.

WITNESS CHILES: I can guarantee you there are

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consulting firms all over this country that can perform all types of things and would be more than happy to do so.

BY MR. MAHAN:

Q On page 18, line 10, you stated that the summer peak power flow cases provided by the company were reasonable. Did you only evaluate the power flow cases for the summer?

A (Witness Chiles) No. We evaluated some different seasonal cases, as well.

Q Did you evaluate all the cases provided?

A (Witness Chiles) We received over 200,000 cases. So I don't think that it would have been prudent or timely for us to evaluate every single case that the company provided. We did do a selected number of cases in our evaluation consistent with what we thought would be the ones primary for making determinations in this proceeding.

Q At the end of your testimony, or page 28 -- sorry. At the end of page 28, and to page 29 of your testimony, you stated that you hope -- or that hopefully that the company would include transmission alternatives in the North Georgia reliability and reliance action plan.

Are you aware that you have previously requested this annual -- an assessment of nontransmission solutions in the earlier IRPs?

A (Witness Chiles) I am aware of that, sir.

Q And the company still hasn't done it; provided those nontransmission alternatives to you?

A (Witness Chiles) I have not -- I mean, I have seen -- you know, I mean, obviously the battery storage projects at this point I would say are fully into that. But I don't think there has been large-scale deployment of nonwire solutions yet on the company's transmission system.

MADAM CHAIR PRIDEMORE: Can I ask you that question in a more forthright way?

WITNESS CHILES: Absolutely.

MADAM CHAIR PRIDEMORE: Did you supply this recommendation and make a data request to the company for that?

WITNESS CHILES: We supplied the recommendation as part of the 2019 IRP.

MADAM CHAIR PRIDEMORE: Okay.

BY MR. MAHAN:

Q If the Commission hired an independent consultant to conduct an independent transmission analysis, the Commission could theoretically require that consultant to conduct its analysis that you recommended, though; right?

A (Witness Chiles) I can't speak to what the Commission would require. That's their call, sir.

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Q Okay. On page 32 of your testimony, line 9 and 10, you said: Having better clarity from the renewable RFP will result in a transmission solution that is right-sized for North Georgia.

Which RFP are you talking about? Are you talking about the staff-proposed statewide renewable RFP next year?

A (Witness Chiles) Yeah. It would include that, yes, sir. Because as part of the problem is when you deal with power flow modeling, location is very important in terms of power flow models. So until you know what resources at what locations, then you're making a guesstimation on what you think is the appropriate transmission system.

You know, unfortunately, transmission models are not very forgiving. They really expect to have loads in the right spots, lines in the right spots, and generation in the right spots, and dispatched at the right setting to get the answer you want.

Q On page 8, lines 14 through 18 of your testimony, you explain that buses or substations or locations in North Georgia that were provided by the company north of I-20 were used to evaluate renewable interconnection locations.

Do you recall that component of your testimony?

A (Witness Chiles) Yes, I do, sir.

Q Did you evaluate each one of those sites specifically to see if they could actually host a 300-megawatt solar farm?

A (Witness Chiles) We did not evaluate every one of those sites.

Q Did you evaluate any of those sites?

A (Witness Chiles) Subject to check, I'd have to go back. I don't recall if we evaluated any of those or not.

Q Do you recall the company calling those the optimal sites, though?

A (Witness Chiles) I do you recall that, yes, sir.

Q If you call something optimal, but if -- even though it's not, is it truly optimal?

A (Witness Chiles) I think we're talking about an absolute versus an incremental discussion here. And, obviously, optimal would be a copper sheath. And we're not dealing with that in this case.

If it's optimal as related to other positions on the system, then I think, you know, there is a case for that.

MR. MAHAN: Okay. I appreciate it. Thank you for you patience.

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Attachment B

Georgia Power Company's 2022 IRP

Docket No. 44160

Transcript, June 21, 2022

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BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

STATE OF GEORGIA

In Re:

Georgia Power Company's 2022)
Application for Approval of its) Docket No. 44160
Integrated Resource Plan)

In Re:

Georgia Power Company's 2022)
Application for Approval of its)
Amended DSM Plan and Certification) Docket No. 44161
and Decertification of Certain DSM)
Programs)
___________________________________)

Hearing Room 110
244 Washington Street
Atlanta, Georgia

Tuesday, June 21, 2022

The above-entitled matter came on for hearing Pursuant to Notice at 9:52 a.m.

PRESENT WERE:
TRICIA PRIDEMORE, Madam Chair
TIM ECHOLS, Vice-Chairman (By Zoom)
FITZ JOHSON, Commissioner
LAUREN "BUBBA" MCDONALD, Commissioner
JASON SHAW, Commissioner

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very helpful.

MADAM CHAIR PRIDEMORE: Southern Renewable Energy Association.

If you go down this road, Mr. Mahan, you and I are going to have a challenge.

MR. MAHAN: Which road is that, ma'am?

MADAM CHAIR PRIDEMORE: Says the intervenor who has not been paying attention evidently.

COMMISSIONER SHAW: The road most traveled.

MR. MAHAN: I will not be talking about cost shifts or anything that Mr. Baker just --

MADAM CHAIR PRIDEMORE: Especially considering this isn't a rate case, but --

MR. MAHAN: Oh.

MADAM CHAIR PRIDEMORE: -- belabor my point.

MR. MAHAN: Gotcha. Yes, ma'am. No, I will not be doing that.

Good afternoon, panel.

PANEL: Good afternoon.

MR. MAHAN: Good afternoon, Commission.

CROSS-EXAMINATION

BY MR. MAHAN:

Q I'm Simon Mahan with the Southern Renewable Energy Association.

Just a few clarifying questions to begin off.

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If the IRP and stipulation are approved by the Commission, is the Commission also approving the ten-year transmission plan?

A (Witness Grubb) Yes. I believe that's one of the items in there, yes.

Q Okay.

A (Witness Robinson) That is explicitly in?

A (Witness Grubb) That is correct.

Q I just wanted to check. Thank you.

Will the Southeastern Energy Exchange -- you're familiar with the Southeastern Energy Exchange Market?

A (Witness Grubb) SEEM?

Q Yeah, SEEM.

A (Witness Grubb) Yes.

A (Witness Weathers) Yes.

Q Will that be included in the 2025 integrated resource plan?

A (Witness Grubb) So when you say "included," I mean --

Q Modeled?

A (Witness Grubb) So I don't believe so. I'll let Mr. Weathers speak to that. We've filed a letter here. I'll let Mr. Weathers speak to that.

A (Witness Weathers) Yes. I mean, primarily that the resource plan is a -- is a capacity plan, and so the

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SEEM market won't provide any new capacity for the company.

So that -- that is an energy-only product that's exchanged on a 15-minute basis. But to the extent in the future there's energy transactions that occur from that that we're able to predict on an occurring basis, we can model those in our -- in our pool modeling.

But from a capacity standpoint, it won't affect the capacity needs or capacity of the plant at all.

Q And so because it doesn't provide capacity, you can't say that the Southeastern Energy Exchange Market will improve reliability; correct?

A (Witness Grubb) In terms of capacity planning reliability, it may not. It is going to allow for --

Q Energy exchanges?

A (Witness Grubb) -- non-firm transmission of exchange, so there could be some benefits from not having to curtail some units. But, yeah, from a reliability standpoint, we're still going to plan to our specific utilities and to our specific pools.

A (Witness Weathers) Right. Yeah, we expect the benefits to be economic.

A (Witness Grubb) Yeah.

Q Sure. And will the Southeastern Energy Exchange Market cause the transmission system to be upgraded?

A (Witness Grubb) No.

A (Witness Robinson) I agree.

Q Let's move on to Stipulation No. 8 regarding the selected supporting information section of the Technical Appendix Volume I.

A (Witness Grubb) Okay. Item 8, transmission projects listed there.

Q That's right. That's the -- can we please call it the transmission retirement projects page --

A (Witness Grubb) Sure, absolutely.

Q -- because it's a mouthful?

A (Witness Grubb) I like that. Let's go with that.

Q And on that document, it contains -- does that document contain all of the transmission upgrades necessary to retire Wansley 1 and 2, Bowen 1 and 2, and Scherer 1 through 4?

A (Witness Robinson) Repeat that again. Wansley 1 through --

Q Wansley 1 and 2, Bowen 1 and 3, and Scherer 1 through 4.

A (Witness Robinson) That's -- 1 through 3 -- correct. The Scherer 4 is already decommissioned.

Q Okay. So that -- that assessment, the

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transmission retirement project page, it found one transmission project associated with retiring Bowen Units 1 and 2. The LaGrange to north -- and forgive me, I'm not --

A (Witness Grubb) Opelika.

Q -- from -- I'm not from Alabama, so -- Opelika.

A (Witness Grubb) Right.

Q Appreciate it.

A (Witness Grubb) There's enough Auburn people up here to make sure you say it right.

Q Well, forgive me for that.

A (Witness Grubb) We all have our cross to bear.

Q That's the one line associated with Bowen 1 and 2 retirement; correct?

A (Witness Robinson) Directly, correct.

A (Witness Grubb) So it's important, Mr. Robinson, directly. So we sequenced Wansley 1 and 2 and Bowen 1 and 2. So that's additional for Bowen. The others support the retirement of Bowen.

A (Witness Robinson) Right. So you can't just take Bowen 1 and 2 out of this study, have it stand up by itself, be that project only supports that decision.

Q Okay. So the other projects ahead of that that have Wansley 1 and 2 next to it, those projects are needed regardless because of the Wansley 1 and 2 retirements?

A (Witness Robinson) Correct.

Q Okay.

MADAM CHAIR PRIDEMORE: Mr. Robinson, will you clarify, though, your previous answer? It's Scherer 3 only, not Scherer 1 through 3; correct?

WITNESS GRUBB: It's all three.

WITNESS ROBINSON: It was Scherer 1 through 3.

MADAM CHAIR PRIDEMORE: It is all three.

WITNESS GRUBB: We're not seeking retirement of 1 and 2 --

MADAM CHAIR PRIDEMORE: Right.

WITNESS GRUBB: -- but we are identifying the transmission projects to allow for the retirement of those.

MADAM CHAIR PRIDEMORE: Okay.

WITNESS ROBINSON: Right. Because it was voluntary, that decision could change. We need to have the transmission projects in place for that compliance date.

MADAM CHAIR PRIDEMORE: Okay.

BY MR. MAHAN:

Q Now, that -- the LaGrange to North Opeloka --

A (Witness Grubb) Opelika.

Q Opelika.

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A (Witness Grubb) You like it. Just remember you really like it.

Q I like it. It's hard for me to like Alabama, sir.

That project crosses the Alabama state line; right?

A (Witness Robinson) That is correct.

Q Does the Alabama Public Service Commission need to approve that line?

A (Witness Robinson) Not explicitly.

Q Why not?

A (Witness Robinson) Because there is a mechanism at FERC where Alabama can charge Georgia Power for that --

COMMISSIONER MCDONALD: I can't hear you.

WITNESS ROBINSON: I'm sorry. There is a mechanism that's found at FERC where Alabama, if they don't see a need for that line, can charge Georgia Power through an affiliate transaction, so it's a transmission facility allocation cost tariff.

BY MR. MAHAN:

Q Okay. Now, that project isn't in North Georgia, though; right?

A (Witness Robinson) No, it is not. It is middle Georgia, as we would call it.

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Q Closer to Columbus?
A (Witness Robinson) Correct.
Q It's actually closer to Stewart County than it is to Plant Bowen, isn't it?
A (Witness Grubb) I don't know. Stewart County is way down there with --
A (Witness Robinson) I don't know. I would have to look at a map.
A (Witness Grubb) I don't know.
Q Maybe?
A (Witness Robinson) Maybe. Subject to check.
Q That's fine. If the Commission delays the decommissioning of Bowen 1 and 2 to 2035, just to be sure, the company is still going to go ahead with that transmission project?
A (Witness Robinson) That's the plan; correct.
Q Okay. Now, on this list, still on the transmission retirement projects list, not all of the projects are owned by Georgia Power Company. How --
A (Witness Robinson) Yes, that is correct.
Q How is cost allocation determined between non-Georgia Power Company facility owners and Georgia Power? Is that through the FERC mechanism that you described?
A (Witness Robinson) No. That is through the

integrated transmission system here in Georgia.

Q So is it on a project-by-project basis then?

A (Witness Robinson) No. It's based on a parity calculation that's done on an annual basis.

Q And is that calculation reviewed and approved by the Georgia Public Service Commission?

A (Witness Robinson) It is not.

Q Now, backing up just a little bit, Mr. Robinson --

A (Witness Robinson) But I would say the Commission is -- I would say the Commission is aware of the ITS and how we have the cost generally.

Q I believe, Mr. Robinson, you mentioned earlier the 6 gigawatts of solar by 2035. And generally, it's in the integrated resource plan.

How does that figure play into the transmission planning process?

A (Witness Robinson) Can you repeat your question?

Q Yeah. The 6 gigawatts of renewable energy by 2035, how does that number and that date play into transmission planning?

A (Witness Robinson) So if you look in the 10-year plan that's filed with the IRP, you won't find those megawatts. So those megawatts are 2,300 megawatts that Mr. Wilson is anticipating in this IRP as well as additional up to 6,000 megawatts by 2035.

And what we're working with the ITS participants on is assuming that 6,000 megawatts, assuming that the EMCs and municipalities also have renewable goals, their customers have renewable goals, the potential retirement of Bowen 3 and 4 by that date, that is strategic road map re-using the developed transmission to facilitate the retirement of Bowen 3 and 4 and the continued development of solar up to that 6,000 megawatt number.

Q Okay. So that 6,000 megawatt number is just as important today for transmission planning as the RFP numbers that we've been talking about?

A (Witness Robinson) Well, the purpose of beginning that strategic process to identify that transmission that we will bring forward in future IRPs, that number is important for us to put a bogey out there so that we can plan beyond the 10-year horizon because, typically, that's all we've done, and we've come in three-year increments with the IRP.

We see a need to be more strategic looking beyond that period of time towards that 2035 date incorporating all of that into what we call the North Georgia Reliability and Resilience Action Plan.

Q Okay. And so you will definitively then be looking past 10 years, specifically to 2035; is that correct?

A (Witness Robinson) We will -- yes. We are using that as a planning horizon for us to develop transmission as we move forward to meet not only these needs that you talk about in this chart that we just talked about but also the potential retirement of 3 and 4 and additional renewables.

Q And so if that 6,000 or 6 gigawatt by 2035 number, if it was larger and sooner, that would change the transmission solutions that y'all are going to come out with; is that right?

A (Witness Robinson) Not necessarily. Because there is a timing aspect of transmission. It could drive other projects, but you can't just take that 6,000 and say the EMCs is now 3,000. SO we're talking 9,000 by 2035. You can't take that 9,000 and just say you're going to do it in five years and get the transmission to make that happen.

Q Sure. Let's move on to Stipulation No. 9. Requiring the company to file an annual transmission update report. In that stipulation -- I will let y'all take a moment here.

Do you take that stipulation to mean that all the transmission projects in the 10-year transmission plan, or is it just the 15 transmission projects identified in the transmission retirement project list?

A (Witness Robinson) Yes. It is only the projects associated with the selected supporting information contained in Volume 1, which is the table that we just referred to.

Q And so after the last transmission project on that list gets done, either canceled or built, you will no longer do an annual transmission update to the Commission?

A (Witness Robinson) Under this requirement, that's correct.

Q Okay. Stipulation No. 9 also requires that the company identify alternative solutions and the associated costs and benefits of the alternatives.

Do you have a list of all the types of alternatives for transmission that you plan to investigate?

A (Witness Robinson) There is a list in Volume 3 of alternatives that we anticipate and that we evaluate.

Q I forgot. Does that list include battery storage as a transmission alternative?

A (Witness Robinson) Let me get out Volume 3 and check.

A (Witness Grubb) That's a big volume, so it's a lot of stuff in there.

Q 401 pages.

A (Witness Grubb) There you go.

Q If you're having trouble finding it --

A (Witness Robinson) Yeah, I'm having trouble finding it.

But we did answer a data request where we expounded on that, and we did list battery storage as one of those alternatives.

Q Okay. Yeah. And so I was going to give you an out here saying that batteries could be a transmission alternative.

A (Witness Robinson) Okay. And we did evaluate battery storage in the -- between the 2019 IRP and 2019 rate case as ordered by the Commission, and I believe Mr. Chiles had referred to that and said that we did not provide that, but we did provide that.

We did a study in between those two proceedings and provided that information to staff and Mr. Chiles on the meeting that we had on September 10th of 2019.

Q Yeah. I recall that part in your testimony where it said you evaluated battery storage, but you rejected it because it wouldn't solve TPL 0001; is that right?

A (Witness Robinson) Well, it was -- the run time was an issue. So you've got to have batteries for the length of the contingency you're anticipating. So if it's 500 KB line, 500 KB line can be out for days.

And so you would need to solve that overloaded strength for that period of time. And I believe we looked at -- subject to check -- it was a four-hour battery for an $80 million transmission project. The cost of such battery to resolve that was in the one-and-a-half billion range.

Q Right. Okay.

So in that one situation, batteries weren't a good solution?

A (Witness Robinson) Correct.

Q Regarding the benefits of the transmission alternative, so we're still regarding the Stipulation No. 9 where you're supposed to look at all the costs and the benefits of the transmission alternatives.

Do you have a list of all the types of benefits, transmission benefits to be considered?

A (Witness Robinson) There are benefits that are listed in Volume 3 as well.

Q Is that on page 23 of Appendix A?

A (Witness Robinson) A little hard to do when you are sitting in the chair. Which reference again?

Q I believe it's page 23 of Volume III, Appendix A.

A (Witness Robinson) That's correct.

Q And that's it. Those are all the benefits that you've got?

A (Witness Robinson) No. There are -- there could be other benefits as well, but these are the main benefits we looked at as it relates to alternative projects.

Q All right. Regarding the -- the benefits and how you calculate the benefits, what's the time horizon that you calculate those benefits over? Is it 20 years? 40 years?

A (Witness Robinson) It depends on the life of the project. But if we were to do a revenue requirement evaluation that's listed in here, we would -- typically a traditional transmission solution would be evaluated at a time around 40 years. Battery system would be less, because a battery system does not have a 40-year life. So we would look at the life of a system, and do that calculation as it relates to net present value.

Q Okay. So you don't have a set time horizon for the benefits; it's based on whatever specific technology you're selecting?

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A (Witness Robinson) Based on the life of the asset we're choosing; correct.
Q Okay. What if the company finds an alternative better than the projects listed in the transmission retirement projects list? How are those alternatives proposed and approved by this Commission?
A (Witness Robinson) Ultimately it would be through the rate case, ASR process, through the IRP process. But there is another approval process that those projects go through, and that's the integrated transmission system -- the planning process we have there. There are several working groups that go through an approval process and review. Those projects are well vetted, and ultimately a decision is made to put those into parity, and accept those into parity in the ITS.
Q The ITS outcomes aren't necessarily given back to the Commission for their review and approval?
A (Witness Robinson) They are through the ten-year plan.
Q And how often does the ten-year plan get approved by the Commission?
A (Witness Robinson) Every three years.
Q Okay.
MADAM CHAIR PRIDEMORE: I can already tell you -- this is going to be a lot easier. He has a

renewable in his name, but this is all transmission. So if you want to go ahead and switch places with Wilson so you can get your books out, it might be easier on you, Mr. Robinson.

WITNESS ROBINSON: Yes, I agree with that. Thank you.

MADAM CHAIR PRIDEMORE: He has "renewable" in his name, but there's nothing about his questions that have anything to do with solar or renewable energy. This is 100 percent transmission.

MR. MAHAN: Which the renewable assets need.

MADAM CHAIR PRIDEMORE: Everything is transmission, Mr. Mahan.

MR. MAHAN: I agree.

MADAM CHAIR PRIDEMORE: I would be interested to know, who -- I would be interested to know the members of your association.

MR. MAHAN: I'd be happy to give those to you afterwards.

MADAM CHAIR PRIDEMORE: Great. Thank you.

MR. MAHAN: I don't even keep track of them that closely.

BY MR. MAHAN:

Q You mentioned on page 37 of your rebuttal that the company doesn't need additional Commission or

stakeholder oversight because you participate in SERTP?
A (Witness Robinson) Can you -- what are you referencing?
Q Page 37 of your rebuttal testimony. You say that "The company doesn't need additional Commission or stakeholder oversight because you participate in SERTP."
Who is in charge of SERTP?
A (Witness Robinson) The SERTP is governed by the 12 companies and 10 planning entities that participate in that process.
Q Does SERTP have a planning horizon further than ten years out?
A (Witness Robinson) Not at the moment.
Q So how are you going to be able to take a longer than ten-year planning horizon with the North Georgia reliability projects and insert them into SERTP if SERTP can't even accept them?
A (Witness Robinson) Well, I think there's ways you can talk beyond the horizon. I think the current NOPR that's out there that FERC let a couple weeks ago, it proposes to address that horizon issue.
Q How so?
A (Witness Robinson) They propose a 20-year horizon.
Q So you would -- you're recommending following

the FERC NOPR and doing a 20-year planning horizon for transmission?

A (Witness Robinson) I did not say that. I said the NOPR that has been let, it suggests a 20-year planning horizon.

But as far as SERTP, if we saw benefits beyond ten years, and there are projects that show benefits beyond ten years, we would definitely discuss those in that forum.

Q And you're familiar with the SERTP economic planning studies process?

A (Witness Robinson) Not intimately.

Q Okay. If you go to SERTP and you were to ask to study a 6 gigawatts -- a 6 gigawatt number of solar in South Georgia, do you know if SERTP is able to study that exact scenario?

A (Witness Robinson) That exact scenario is very difficult to study. There's a tremendous amount of assumptions that have to be made to study that amount of megawatts in South Georgia, as we're going through those studies right now with our ITS participants.

Q So you probably wouldn't be able to do that through SERTP?

A (Witness Robinson) Use the same planning principles. I think you have to make some assumptions on location of solar, where it's going to be in South Georgia. A lot of it right now is in Southwest Georgia, but I think you've got to make an assumption of where those megawatts are going to be so you can plan for the future.

Q You had mentioned earlier that SERTP allows for stakeholder participation. Are you aware that SERTP limits the economic planning studies to just five studies across the entire region?

A (Witness Robinson) I'm not aware, but since none of those have been brought, I'm not sure that's an issue.

Q And did you know that just because a stakeholder requests a study to be done, that doesn't mean SERTP has to conduct that study?

A (Witness Robinson) That's correct. They can propose a study, but they don't have to take that study up.

Q And did you know then in 2014 in the SERTP stakeholder process, the Southern Environmental Law Center requested studying evaluating Southern Company's coal retirements but that study was rejected by SERTP?

A (Witness Robinson) I'm not aware.

Q You see on page 41 on the top of your testimony, at the very top, that you're opposed to assessing an economic congestion of the transmission system in the locational value study.

Why can't you perform an economic congestion component?

A (Witness Robinson) We don't have models to do it.

Q Which models do you need to do it?

A (Witness Robinson) Security constraint dispatch for one, and the models that you develop in an RTO. We're not in an RTO. We do not have those models.

MADAM CHAIR PRIDEMORE: Speak in for me, Mr. Robinson. Thank you.

BY MR. MAHAN:

Q Have you considered asking those other regions to conduct the a study for you?

A (Witness Robinson) Which other regions?

Q The RTO regions.

A (Witness Robinson) No. We have no interest in that.

A (Witness Weathers) And, Mr. Mahan, as Mr. Robinson said, we're not an RTO, and we don't plan our system in order to have economic congestion on our system, so we -- we plan our system to not have that.

So we have -- we operate our system and plan it so that we -- that the generation can be delivered from the generation source to the customers without constraints. And so the suggestion here about locational value study by including economic congestion implies no low pricing. That's an RTO-type construct. That's just not the way our market operates.

A (Witness Robinson) Right. It anticipates us having an RTO. We are not an RTO. We don't design and plan our system that way.

MADAM CHAIR PRIDEMORE: When have you ever heard the word "congestion" used in a positive framework anyway? It's congestion.

WITNESS GRUBB: Only if you made money off of it, I would believe.

MADAM CHAIR PRIDEMORE: Well, there's plenty of people at RTOs that do, yes.

BY MR. MAHAN:

Q And so is it then your testimony that there is no congestion on the Georgia Power transmission system?

A (Witness Robinson) We -- we plan our system to be reliable to address constraints that are studied in our planning process, and we have a reliable system. That's what is in this ten-year plan. We do a lot on a real-time basis to manage restraints on -- or constraints on our system on a real-time basis because of outages and changes on the system, but we plan our system to be reliable through the NERC planning process.

Q So, yes, there is no congestion problem anywhere in the Georgia transmission planning system?

A (Witness Robinson) We do not feel that there is any type of congestion. This system is very reliable.

Q But again, you've not studied it?

A (Witness Robinson) We're not an RTO.

Q Stipulation 10, please. "The company will work with the Commission staff to develop a process that facilitates the development of renewable resources in North Georgia."

Why isn't Georgia an attractive place for renewables to develop?

A (Witness Robinson) Why is it not?

Q Yes.

A (Witness Robinson) I would argue that it is.

A (Witness Mallard) Yeah, I would say that Georgia's an incredibly attractive place for renewables to develop. Top five last year.

Q All right. Don't you think it would be helpful to collaborate with renewable developers to figure out why they're not focused in on -- why they're not as bullish about North Georgia as you guys are?

A (Witness Mallard) So absolutely feedback from the market is critical to developing our RFPs in ways that the market can be successful in their response to us, and so we do that. We've talked about that a little bit already. We've got a lot of before, during, and after opportunities to communicate to the marketplace.

So what we have heard from the marketplace is what is relatively evident just by looking at the topography and geography of Georgia, and that is flatter land in South Georgia, there's a better solar resource. And so North Georgia, you're going to have to maybe work a little bit harder to find suitable sites.

Not to say that there's not going to be suitable sites, but they may be a little bit more difficult to identify and develop.

Q And so you understand --

COMMISSIONER MCDONALD: Developers are going to have to work harder, not North George. I mean --

WITNESS MALLARD: The developers will have to -- they're the ones that are out -- right now -- my assumption, Commissioner, is that once we file this request for -- for North Georgia, that significant amounts of solar developers are seeking sites in North Georgia since that time.

WITNESS ROBINSON: And we understand that there are cost issues associated. This is not a cost issue. This is a timing issue. This is a timing

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issue for us to get the transmission built so that we can continue to develop in South Georgia. That's where -- we see benefits to that as well.

And there are also, as I mentioned before, regional benefits to having renewables in North Georgia. Particularly around geographic diversity, and that's been evidenced over the last week where we've had sunny days up here and rainy days down south.

BY MR. MAHAN:

Q But isn't it more likely that projects in the northern part of the state are going to be smaller than 100 megawatts?

A (Witness Robinson) I can't say that. I know that where we've defined there are -- there are plenty of areas where there are large tracts of land, but I can't say that. I'm not a developer.

Q And so wouldn't it be helpful to get a developer's opinion about that?

A (Witness Grubb) So, again, we do absolutely depend on feedback from the development community, and that happens through our normal processes, both formal and informal communications, but all of which comply with the Commission's rules.

Q Let's move on to Stipulation No. 18 regarding the next all-source capacity RFP for 2029 to 2031.

Is that RFP dependent on retiring Bowen 1 and 2?

A (Witness Grubb) It is not. The years may shift. We've got a lot of PPAs that roll out in 2030, about 2,000 megawatts' worth. So we would expect a need in '30 even if Bowen 1 or 2 or both are extended.

Q When do you anticipate this new all-source capacity RFP to come out?

A (Witness Grubb) So we'll work with staff on that. The first thing we'll do is we'll look at our updated -- well, first, is what comes out of this IRP. We'll update those resource decisions. Then we'll get a load forecast update this fall. And we'll then look at our needs chart and work with staff on when that need is and, obviously, the timing, also, is driven by which resources you want to allow time for.

Q Okay.

A (Witness Grubb) So I think staff's testimony pointed at around seven years, which is normal, if you want to allow for a new gas construction bid. So we'll work through all that with staff once we update our numbers this fall.

Q And how big will the RFP be?

A (Witness Grubb) So it'll depend, again, on what the Commission's decision is there. But it could be anywhere from 500 to 1,500 megawatts. Just depends on what happens. We've got a lot of economic development customers looking at the state. If we land some of those as Georgia Power customers, that'll go into the load forecast.

So it'll -- it just depends on three or four different moving factors.

Q Yeah. So y'all are requesting that the Commission approve an RFP that may come out at some point for an unknown amount of megawatts?

A (Witness Grubb) Yeah. So typically, I think even back to the 2019 IRP, we just asked for a request to have an RFP. Those details will be worked through in the RFP process. So we would -- again, we would look over what the needs are and then when that RFP needs to go out and then work through the normal RFP procedure with the Commission and staff.

Q Okay. Stipulation 19. And I think I heard this panel mention earlier that any renewable project anywhere in the country could submit a bid into the renewable RFP. Did I hear that right?

A (Witness Mallard) That's right.

A (Witness Grubb) Which has always been the case; correct?

A (Witness Mallard) That's always been the case. There's a project in interconnect to Georgia Power to the ITS to the Southern Company Balancing Authority or anywhere in the United States and have the power wheeled to our balancing authority.

Q Okay. If a renewable energy project were to enter into the generation interconnection queue today, how long would it take for them to get their first study results back?

A (Witness Robinson) As far as system impact study?

Q Yes.

A (Witness Robinson) About 12 months.

Q So June --

A (Witness Robinson) 8 to 12 months.

Q June 2023. When's the 2023 renewable RFP supposed to come out?

A (Witness Mallard) So as it's scheduled right now, the RFP will come out sometime in 2023. Probably second to third quarter. Again, with CODs required by the end of '26 or the end of '27.

Q And if you issued a statewide RFP, Northern Projects, Northern Renewable Energy Projects could still bid into that RFP, though; right?

A (Witness Mallard) Yes. All projects would be --

A (Witness Grubb) We would hope they would.

Q Stipulation 29, page -- it's a big one. It's on page 8 of the stipulation, and it's towards the bottom of that stipulation.

A (Witness Grubb) So it's on page 8, bottom half of 29?

Q Yes.

A (Witness Grubb) Okay.

Q So both Stipulation 29 and Stipulation 30 both refer to adopting an effective load carrying capacity or an ELCC methodology.

Do you see those?

A (Witness Grubb) That's correct.

A (Witness Robinson) Yes.

Q Is it -- is the effective load carrying capacity that y'all are going to use, is it for all seasons, or is it just for the summer season?

A (Witness Weathers) No, It's for all seasons. I mean, you're evaluating it both for the winter and the summer seasons.

Q And the fall and the spring?

A (Witness Weathers) Yes. Yes. Generally, that -- it's captured in there. We're doing an annual study, and so we can separate the time periods, but it is -- it is -- it covers the entire annual period.

Q That's right. And is it for all resources or just renewable energy resources?

A (Witness Weathers) Well, it's for -- so the company has -- has always had an approach to produce capacity equivalency for energy limited or variable energy resources. So ener- -- you know, such as renewable resources, such as hydrogeneration, such as demand-side resources. So it would be applied across all resources.

Q Including any potential gas units?

A (Witness Weathers) Well, gas units are -- do have 100 percent, so they're -- they're dispatchable units. They don't have the -- they don't have the energy limited or variable energy aspects that renewable energy resources have.

Q So you assume gas units are 100 operational in your IRP models?

A (Witness Weathers) Well, so they had -- the capacity contribution is at 100 percent level. We do assume that they will have outages, and so that's taken into account in the model. But from just in terms of stating the capacity of the unit, we do assume that the 100 percent capacity level.

Q Okay. And so that's for all existing units as well?

A (Witness Grubb) If they -- if they don't have limitations, as Mr. Weathers mentioned. So example of a hydro facility may have a limited pool or something like that across 8 hours. So again, I think the point on the 100 percent reliability on the gas units is not that they are 100 percent always available.

It's just when you run those reliability models with a little bit of availability, they can meet more reliability needs than others. So you compare it. You kind of set that as unity and base everything off of that.

Q Okay. Stipulation 35. This -- this will be the last bit of questions I've got, regarding that Tall Wind demonstration project.

The turbines you describe in the work papers are only 4 megawatts. Are you aware that there are onshore wind turbines potentially in the 6 to 8 megawatt range now?

A (Witness Mallard) Generally aware, yes.

Q And are you aware that a larger wind generator can increase energy output?

A (Witness Mallard) Yes. Absolutely. The 3 to 4 megawatts that we teed up here in the Tall Wind demonstration project, that's based on overall project design, interacting with the new spiral well tower technology, and so that's really what the basis was for the project budget and the initial evaluation of the project.

Q Okay. And if Georgia Power were to select a generator larger than 4 megawatts, would the company need to come back to the Commission for approval?

A (Witness Mallard) Yes, absolutely. Now, the company will come back to the Commission for approval anyway of the overall project costs once we have identified the site, the EPC, have the final cost benefit done. But absolutely, if that range of megawatts were to change, that would need to be approved by the Commission as well.

MR. MAHAN: All right. That's it. I appreciate it.

WITNESS ROBINSON: Thank you.

WITNESS MALLARD: Thank you.

WITNESS GRUBB: Thank you.

MADAM CHAIR PRIDEMORE: Redirect?

MR. HEWITSON: Thank you, Madam Chair. Just a few questions.

REDIRECT EXAMINATION

BY MR. HEWITSON:

Q Mr. Grubb, you were asked some questions about

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April 20, 2023

<u>VIA E-MAIL</u>

United States Department of Energy
NeedsStudy.Comments@hq.doe.gov

**RE: COMMENTS ON THE PUBLIC DRAFT, ENTIRE STUDY
COMMENTS OF THE SPONSORS OF THE SOUTHEASTERN REGIONAL TRANSMISSION PLANNING PROCESS**

Dear Department of Energy:

The Sponsors of the Southeastern Regional Transmission Planning Process ("SERTP"),[1] a transmission planning region for purposes of the Federal Energy Regulatory Commission's ("FERC") Order No. 1000,[2] hereby provide these comments to the United States Department of Energy's ("DOE") draft for public comment of its National Transmission Needs Study (the "Draft Study" or "Study").

I. EXECUTIVE SUMMARY

The SERTP Sponsors appreciate DOE's efforts in preparing the Draft Study and recognize that its aggregation and analysis of numerous transmission studies performed by National Laboratories, universities, and consultants can prove informative. However, if the DOE's National Transmission Needs Study ("Needs Study") serves more than informational purposes, it must meet a higher bar. If, as the Draft Study seems to indicate, it is intended to form the basis for designations of National Interest Electric Transmission Corridors ("NIETCs") as provided under Section 216 (a)(1)-(2)[3] of the Federal Power Act ("FPA"), then:

[1] The "SERTP Sponsors" are: Associated Electric Cooperative, Inc. ("AECI"); Dalton Utilities ("Dalton"); Duke Energy Carolinas, LLC and Duke Energy Progress, LLC ("Duke Energy"); Georgia Transmission Corporation (An Electric Membership Corporation) ("GTC"); Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU"); the Municipal Electric Authority of Georgia ("MEAG"); PowerSouth Energy Cooperative ("PowerSouth"); Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, and Mississippi Power Company (collectively "Southern Companies"); and the Tennessee Valley Authority ("TVA").

[2] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[3] 16 U.S.C. § 824p(a)(1)-(2) (2018).

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- The Needs Study must be consistent with both the specifics of FPA Section 216(a), which include considerations of cost, as well as the overall structure of the FPA, which unequivocally leaves resource decisions to the States;
- The Needs Study should be based on best available information; and
- The Needs Study should meaningfully incorporate feedback from States[4] and experts.[5]

As the SERTP Sponsors previously noted in their comments to the consultation draft of the Needs Study ("Consultation Draft"), the SERTP Sponsors disagree with the Draft Study's conclusions on transmission need to the extent they are based on load and generation resource assumptions untethered from State forecasts, projections, and plans. In addition, because the Draft Study does not identify or consider the substantial costs to develop, construct, and integrate its projections of massive transmission expansions, it is ill equipped to support designations of NIETCs, which should carefully consider costs as well as benefits. Therefore, to ensure the Needs Study and any NIETC designations are based on best available information, SERTP Sponsors recommend that DOE coordinate more closely with the NERC-registered Planning Coordinators and Transmission Planners who perform holistic analyses that incorporate State load and resource projections and cost evaluations[6] in their transmission planning.

Based on its aggregated analysis, the Draft Study projects that essentially all regions have significant transmission needs and that all interregional interfaces need to be significantly expanded. The SERTP Sponsors do not opine on the Draft Study's conclusions about other regions. But as for the Southeast, the SERTP Sponsors do not believe DOE's Draft Study analysis supports a massive build out of the Southeastern grid and its interregional interfaces, the cost of which would likely outweigh benefits to customers. To the contrary, lower electricity costs to customers, low congestion, high reliability, and successful implementation of the energy policies of the Southeastern States all demonstrate a robust, well-invested Southeastern transmission grid, planned with care and purpose to maintain reliable, affordable service to our customers.

Finally, while the SERTP Sponsors appreciate the DOE's acknowledgement of the SERTP Sponsors' concerns raised to the Consultation Draft in Appendices A-1 and A-2 of the Draft Study, the substantive analysis presented in the Draft Study did not meaningfully address these concerns. In particular, DOE has yet to meaningfully coordinate with NERC-registered Transmission Planners or Planning Coordinators to incorporate State load and resource projections and

[4] FPA Section 216(a)(1) requires that such triennial studies be done in consultation with "affected States and Indian Tribes."

[5] Importantly, as DOE's NIETC designations may lead to FERC's assertion of "backstop siting" authority under FPA Section 216, which could preempt state siting decisions, DOE's and FERC's assertions of authority under FPA Section 216 should be construed narrowly because they are in derogation of states' historic police powers to regulate the siting of electric transmission. *See Arizona v. Inter Tribal Council of Ariz.*, 570 U.S. 1, 13 (2013) ("we start with the assumption that the historic police power of the States were not superseded by the Federal Act unless that was the clear and manifest purpose of Congress.") (quoting *Rice v. Santa Fe Elevator Corp.*, 331 U.S. 218, 230 (1947)).

[6] While cost evaluations are important, Congress's recent amendment to FPA Section 216 to add "capacity constraints" to Section 216(a)(1) emphasizes that the study must consider reliability/resilience/capacity considerations and not just economic impacts associated with congestion.

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transmission cost considerations into the Draft Study. In this regard, the SERTP Sponsors repeat their recommendation that DOE should coordinate with the Eastern Interconnection Planning Collaborative ("EIPC") to incorporate such feedback on these important matters.

II. DOE's Future Studies Would Benefit From Better Coordination With NERC-Registered Planning Coordinators and Transmission Planners and, in Particular, Through Coordination With EIPC

The FPA clearly leaves generation resources within the province of the States. A transmission needs study that ignores this requirement leads to inaccurate and unactionable identification of transmission needs. Additionally, Section 216(a) of the FPA contemplates certain considerations in designating a NIETC, which include core economic concerns that necessitate an analysis of cost. A transmission needs study that omits this core analysis cannot be relied upon to designate a NIETC. Therefore, the DOE should coordinate more closely with the Transmission Planners and Planning Coordinators who perform holistic analyses that incorporate State load and resource projects and cost evaluations into their transmission planning.

A. The FPA Leaves Resource Determinations to the States

Before turning to some of FPA Section 216's specific requirements, Section 216 must be understood as part of the FPA's larger construct, which reflects a purposeful, dual Federal-State jurisdictional divide. FPA Section 201 reserves to the States exclusive jurisdiction over the general regulation of "facilities used for the generation of electric energy,"[7] meaning (among other things) that it is the States that have jurisdiction over the "planning and resource decisions of utilities."[8] NERC-registered Transmission Planners and Planning Coordinators duly incorporate such State load and resource decisions, while the Draft Study independently makes such load and resource assumptions based upon ranges of resource predictions incorporated in various national lab, university, and consultant studies. While it is not entirely clear what basis the Draft Study used for these assumptions, State-jurisdictional resource decisions are driven by not only the cost of delivered energy, but also include various policy preferences to drive change in the resources and resource types used to provide electricity service, promote particular technologies, and achieve environmental objectives. Moving forward, the SERTP Sponsors recommend that DOE coordinate with the EIPC to incorporate those State-determined resource decisions.

B. "Value" of Transmission Should Be a *Total/Net* Valuation, Including Transmission Cost

The Draft Study projects the need for massive amounts of transmission capacity everywhere in a relatively short time horizon.[9] However, the Draft Study is clear that it does not

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[7] 16 U.S.C. § 824(b)(1).

[8] *See Entergy Nuclear Vt. Yankee, LLC v. Shumlin*, 733 F.3d 393, 417 (2d Cir. 2013) (internal citations and quotations omitted).

[9] *See, e.g.*, Draft Study at 88-102 (projecting massive transmission needs both within regions and interregionally).

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consider the associated transmission costs or siting impacts and considerations. This significant omission seriously undermines the "value" that the Draft Study attaches to its transmission needs because it is not a total/net value determination. In designating a NIETC, DOE must consider "alternatives,"[10] and may only designate areas of electric energy transmission capacity constraints and congestion that "adversely affect[] consumers."[11] Such fundamentally economic considerations are only possible with an analysis that includes the cost of transmission and not only its benefits. In other parts of Section 216 that lay out considerations for DOE's NIETC determination, economic valuations are also prominent, including whether "the designation would result in a *reduction in the cost to purchase electric energy for consumers*."[12] Such cost evaluations are part of transmission planning carried out by NERC-registered Transmission Planners and Planning Coordinators and should be considered and incorporated into DOE's Needs Study.

More robust coordination with Transmission Planners, Planning Coordinators, and planning processes like the EIPC would help DOE to sharpen focus on regions where additional transmission would be most beneficial. In this way, agency actions taken in reliance on the final Needs Study would be based on more than hypothetical transmission needs. Instead, it would include cost projections that allow for a more meaningful, holistic determination of value and resulting transmission needs/constraints/congestion, as FPA Section 216 contemplates.

The Draft Study characterizes utility planning as being "limited in scope," with the Draft Study's being a more "holistic assessment" of "multiple values of transmission."[13] Respectfully, the SERTP Sponsors believe their IRP/RFP-driven transmission planning is in fact more "holistic" in that it: i) considers all reasonably available alternatives, both transmission and non-transmission, to address system needs *on a least-cost* and reliable basis, and ii) does so through State-regulated processes (or non-jurisdictional governance board reviews for the SERTP Sponsors that are not public utilities).[14] Thus, the Draft Study would benefit from including more of the information considered in the State-regulated processes, including bottom-line impacts on customers.

[10] 16 U.S.C. § 824p(a)(2) (regarding the required reports to designate NIETCs).

[11] *See id*. § 824p(a)(2)(i).

[12] *Id*. § 824p(a)(4)(H) (emphasis added); *see also id*. § 824p(a)(4)(A)(requiring the consideration of whether "the "*economic vitality*" of the corridor and whether end markets may be constrained due to "lack of adequate or *reasonably priced* electricity") (emphasis added).

[13] Draft Study at 2.

[14] The SERTP Sponsors consist of both jurisdictional public utilities (*i.e.*, Duke Energy, LG&E/KU, and Southern Companies) and non-jurisdictional transmission owners (*i.e.*, AECI, Dalton, GTC, MEAG, PowerSouth, and TVA). When these comments reference the SERTP Sponsors' State-regulated processes, such references should also generally be construed to include the non-jurisdictional processes of the non-jurisdictional SERTP Sponsors.

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III. A Robust Collective Transmission System, Cost-Effective Electric Rates, and High Reliability and Resilience Contradict the Draft Study's Broad Conclusions About Need in the Southeast Region

A. The Investment in the Southeast's Transmission System Is Matched to the Needs of the Region

The Draft Study's generic projections of massive future transmission capacity need in the Southeastern region are not adequately supported. The Study begins by indicating that the Southeastern transmission system has suffered from relative low investment.[15] This is simply not the case. The Southeast region has in place a robust transmission system, to which it is making substantial investments to meet the reliability and resilience needs of its customers and the energy policies of its States.[16]

The level of transmission investment in the Southeast is tied to the level of transmission need (current and future), no more and no less. This is to fully meet customer needs at the least cost to ensure reliability of service and resilience of the system, all the while implementing the energy policies of the States. The Southeastern transmission grid, planned with care and purpose, is achieving:

- Lower customer cost of electricity;[17]
- High reliability,[18] with the Draft Study identifying no reliability problems in the Southeast; and
- Successful implementation of Southeastern States' respective resource decisions.

B. The Southeast's Distinctive Characteristics Shape the Definition of Transmission Need

Unrecognized in the Draft Study are certain distinct characteristics of the Southeast region, which uniquely affect the Southeast's "transmission need." Among these are:

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[15] *See id*. at 20-22.

[16] *See* Southeastern Regional Transmission Planning Process Sponsors' Initial Comments, at 8-9, Docket No. RM21-17-000 (Aug. 17, 2022) ("SERTP Initial NOPR Comments") (the SERTP has more linear miles of transmission than CAISO, MISO, New England ISO, NYISO, and SPP and is roughly equivalent to PJM); *see also* Initial Comments of Southern Company Services, Inc., at 13, Docket No. RM21-17-000 (Aug. 17, 2022) ("Southern Initial NOPR Comments") (*e.g.,* Southern invested $5.3 billion in new transmission from 2017 to 2021).

[17] *See* SERTP Initial NOPR Comments at 14 (the 2020 average total retail price for the participants in the Southeastern Energy Exchange Market ("SEEM"), which includes all of the SERTP Sponsors, was 9.58 cents/kWh compared to 11.02 cents/kWh for the combined RTO markets).

[18] *See* SERTP Initial NOPR Comments at 10-12 (noting that the Southeast is not identified in recent NERC assessments as being a region more likely to face energy shortfalls and that J.D. Power's 2021 Power Quality and Reliability Index ranks the SEEM participants higher than RTO markets).

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- Nature of long-distance transmission lines: Load centers in the Southeast have historically been more distant from each other than those in the Northeast and Mid-Atlantic due to a more dispersed population and geography. As such, the Southeast often has in place a transmission system that generally incorporates the kind of long-distance lines the Draft Study identifies as future needs in other regions.

- "Physical" transmission service: The SERTP Sponsors provide "physical" rather than "financial" transmission service, meaning that the transmission grid is expanded so that long-term firm commitments can be served with the intent of no congestion or curtailment.[19] Section 216 of the FPA calls for an examination of areas of congestion and constraints; however, the Southeast already plans for and has built a transmission system to address such congestion and constraints. This contrasts with the financial service provided in regions served under RTOs'/ISOs' tariff-based LMP/"nodal pricing" frameworks. In those RTO/ISO frameworks congestion costs (which are the costs of dispatching supply resources out of merit to alleviate physical limits) are added to the cost of transmission service in order to incentivize location of new supply resources in high-priced areas or zones. Rather than pricing congestion as a means to influence where new sources of power supply locate, the SERTP Sponsors aim to expand the transmission system so that transmission customers making long-term commitments face neither congestion costs nor physical curtailment.

- Historic pace of transmission investment: The Draft Study focuses on transmission investment from 2011-2020 and concludes that the Southeast made relatively low transmission investments in that time period.[20] However, such analysis is a snapshot in time, with the Southeast starting that period with a relative higher amount of transmission capacity.[21] Currently, as noted in FERC Staff's recently issued 2022 State of the Markets presentation, the Non-RTO Southeast exceeded all but one of the other transmission planning regions in the amount of "Line-Related Transmission Projects" in 2022.[22] The lower relative investments in that time period, and our current increased investment, demonstrate appropriate investment as needed, when needed.

The Draft Study fails to give due consideration to these important distinct characteristics, which results in erroneous conclusions about "transmission needs" in the Southeast.

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[19] *See* SERTP Sponsors, "2022 Regional Transmission Plan and Input Assumptions, at 7 (explaining the SERTP Sponsors' provision of physical transmission service), *available at:* www.southeasternrtp.com/docs/general/2022/2022_Regional_Transmission_Plan_and_Input_Assumptions_Final_Non-CEII.pdf.

[20] Draft Study at 20.

[21] *See, e.g.*, Comments of Southern Company Services, Inc., at 6-7, Docket No. RM10-23-000 (Sept. 29, 2010) (explaining, among other things, that even though SERC had only the fourth largest geographic footprint among the eight NERC Regional Entities, in 2008 SERC had the highest amount of circuit miles in the Eastern Interconnection and was second nationally only to WECC, which covered three times SERC's square mileage).

[22] FERC Staff, 2022 State of the Markets Presentation, Slide 9 (Mar. 16, 2023), *available at*: https://www.ferc.gov/news-events/news/presentation-report-2022-state-markets.

IV. The Draft Study Did Not Meaningfully Address SERTP Sponsors' Comments to the Consultation Draft

While the Draft Study summarizes in Appendix A-2 of the Draft Study some of the key issues SERTP Sponsors raised to the Consultation Draft and cross-references to DOE's somewhat relevant responses to other comments, the Draft Study does not meaningfully address these issues because they were not incorporated in the Draft Study's substantive analyses of transmission needs. Notably, the Draft Study did not include SERTP Sponsors' recommendations to incorporate State resource projections or to include cost analysis. Further, the following comments were not adequately addressed:

A. The Draft Study Seems to Inappropriately Address Resource Adequacy Problems Through Interregional Transmission Solutions

In their comments to the Consultation Draft, the SERTP Sponsors raised the concern that conclusions about the need for significant interregional/interface facilities could allow regions having resource adequacy issues to shift problems to their neighbors.[23] After all, having additional interregional transmission capabilities does nothing if there is no resource output to transmit (in emergencies or otherwise). Moreover, additional interregional transmission capabilities are neither needed nor appropriate if there are more economic/reliable non-transmission solutions within the regions. Again, the transmission planning conducted by NERC-registered Planning Coordinators and Transmission Planners that perform least-cost/reliable transmission planning incorporating State-regulated resource projections do not project the need for such massive interregional transmission expansions.

The Draft Study does not meaningfully address this important issue. The Draft Study's response to question # 55 seems to indicate that seasonal diversity exchange between regions could address this concern while warning that this "may be a challenge." In addition, the Draft Study's response to comment # 55 cross-references its response to comment # 28 where the Draft Study further discusses the benefits of transmission allowing such interregional diversity exchanges but then warns that increased transmission infrastructure will only yield resource adequacy improvements "so long as regional planners guard against shifting resource adequacy responsibilities to neighboring regions that face inter-dependent risks."[24] This response does not meaningfully address the concern that the Draft Study's projections of enormous interregional expansions could be vastly overstated and could exacerbate the shifting of resource adequacy problems to neighboring regions.

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[23] The Draft Study identifies such concern raised by the SERTP Sponsors as comment # 55 in Appendix A-2.

[24] The Draft Study's response to comment # 55 also cross-references its response to comment # 11; however, that response does not address resource adequacy but instead criticizes the planning performed by NERC-registered Transmission Planners.

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B. The Draft Study Does Not Meaningfully Address the Impacts to Lower Voltage Systems, and Using Zonal (as Opposed to Nodal) Modeling Greatly Underestimates the Requisite Amount of Transmission

Likewise, the Draft Study's recognition that it does not address the impacts to lower voltage systems does not adequately respond to the SERTP Sponsors' concern in this regard.[25] Similarly, the Draft Study's recognition that its use of zonal modeling "may underestimate total required system build"[26] does not meaningfully address the problem. Instead, this recognition in the Draft Study reinforces the need for an evaluation of the transmission costs associated with the Draft Study's needs projections.

C. For Purposes of FPA Section 216(a)(1), DOE Performed a Broad "Transmission Needs" Study Rather than the Statutorily Prescribed Study of "Electric Transmission Capacity Constraints and Congestion"

The SERTP Sponsors also repeat their concern that the Draft Study performs a much more expansive analysis of "transmission needs" rather that the statutorily prescribed triennial study of "electric transmission capacity constraints and congestion" required by FPA Section 216(a)(1).[27] Among other things, Congress in the Infrastructure Investment and Jobs Act ("IIJA") made only limited changes to the FPA Section 216(a)(1) provisions governing DOEs performance of these triennial studies, amending that section to provide that DOE "shall conduct a study of electric transmission *capacity constraints and* congestion."[28] Apparently predicated upon this slight addition of the terms "capacity constraints," DOE greatly expanded the scope of the Draft Study as compared to the much more limited scope of DOE's 2020 triennial transmission congestion study, with the Draft Study apparently driven primarily by DOE's future generation projections.[29] This new emphasis and broadened scope arguably converts the triennial studies into more of a generation planning study than the statutorily prescribed study of "study of *transmission* study capacity constraints and congestion".[30]

The SERTP Sponsors recognize that DOE points to more than FPA Section 216(a)(1) as the source for the Draft Study, but if DOE proceeds to rely upon the Draft Study's analyses to make future reports concerning NIETCs, then DOE will need to address such statutory concerns.

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[25] *See* Draft Study at 135-36, 139

[26] *See id.*, Appendix A-2, comment # 149

[27] *See* SERTP Consultation Comments at 2-6; Draft Study at Appendix A-2 comment # 43.

[28] *See* 16 U.S.C. §824p(a)(1)(IIJA amendments shown in emphasis).

[29] *See* SERTP Consultation Comments at 4 (quoting DOE's Consultation Draft Webinar dated October 25, 2022, which provides that DOE is studying, among other things, the delivery of "cost-effective generation" and "projected future generation").

[30] *Id.* at 4. As discussed previously, the FPA leaves generation planning to the States. *See supra* at 3.

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D. The Draft Study Appropriately Recognized that Additional Transmission Should Not Be Expected to Significantly Mitigate Tornado-Induced Outages but Continues to Reference Hurricane Outages

The SERTP Sponsors recognize and appreciate that the Draft Study addressed the concern in the SERTP Consultation Comments that transmission would not mitigate tornado events.[31] However, the Draft Study continues to indicate that transmission would mitigate hurricane events.[32] As explained with tornado events, hurricanes likewise destroy distribution systems and buildings, meaning that even if more transmission capacity were available, it would likely not significantly mitigate outages associated with hurricanes. Accordingly, both tornados and hurricanes should be removed from statements pertaining to the types of extreme weather events that should be expected to be mitigated by increased transmission capacity.

V. CONCLUSION

The SERTP Sponsors support DOE's transmission planning efforts and recognize that Congress has tasked DOE with numerous planning and financing activities. However, the SERTP Sponsors are concerned that DOE has not performed a study that would appropriately support its activities under FPA Section 216. Since this provision gives FERC the limited authority to preempt and override State siting decisions, which is a jurisdictional carve-out of significant import, it is extremely important that DOE perform appropriate studies as it exercises this authority.

To help address these concerns and remedy the problems identified in these comments, the SERTP Sponsors recommend that DOE better coordinate with NERC-registered Transmission Planners and Planning Coordinators, and in particular with the EIPC, as DOE prepares its final transmission needs report and then prepares the reports that may result in NIETC designations.

[31] *See* Draft Study at 143.

[32] *See id., passim.*

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Should additional information be required, please contact the undersigned so that such information can be supplied expeditiously.

Sincerely,

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TDI New England

A Blackstone Portfolio Company

VIA EMAIL: NeedsStudy.Comments@hq.doe.gov

April 20, 2023

RE: U.S. Department of Energy's *National Transmission Needs Study*
TDI New England Comments on the Public Draft

To: U.S. Department of Energy Grid Deployment Office

Champlain VT LLC d/b/a TDI New England commends the U.S. Department of Energy's (DOE) National Transmission Needs Study (Needs Study) for identifying the challenges and opportunities associated with our nation's electric transmission infrastructure. DOE has been at the forefront of facilitating new investment in transmission through the Infrastructure Investment and Jobs Act and the Inflation Reduction Act and is driving policy to improve the resilience of the national grid. These efforts will improve reliability, facilitate the delivery of new renewable resources, and reduce the overall cost of delivered energy. TDI New England looks forward to continuing to work with DOE to achieve these shared objectives.

TDI New England's comments on the Needs Study focus on the benefits that would result from additional transmission capacity between Canada and New England. The Needs Study notes that increased transfer capacity with Canada is needed to meet future load and generation growth, and that "[i]increased transfer capacity between New England and Canada will enable bidirectional flow of hydropower, wind, and solar generation between the regions, helping to meet State clean energy targets."[1] The Needs Study includes references to studies that have found that the benefits of bidirectional flow would be immediate and consequential:

> Dimanchev et al. (2020) note that meeting existing state climate policy targets in New York and New England will likely require the nearly complete decarbonization of electricity generation. To that end, consideration is being given to expanding imports of hydropower from neighboring Québec, Canada. According to their study, in a low-carbon future it is optimal to shift the utilization of the existing hydropower and transmission assets away from facilitating one-way export of electricity from Canada to the U.S. and toward a two-way trading of electricity to balance intermittent U.S. wind and solar

[1] *Needs Study* at page xv.

generation (Dimanchev et al., 2020). They find doing so can reduce power system cost by 5-6% depending on the level of decarbonization. The cost optimal use of Canadian hydropower is as a complement, rather than a substitute, to deploying low-carbon technologies in the U.S. Expanding transmission capacity enables greater utilization of existing hydropower reservoirs as a balancing resource, which facilitates a greater and more efficient use of wind and solar energy.

Jones et al. (2020) similarly note in a regional analysis conducted for a Massachusetts study that Canadian hydropower is an essential element of regional balancing. In their study, bidirectional flow of electricity enabled the Québec hydropower system to transition into the role of a 'battery' storing excess wind and solar generation for the New England region.[2]

TDI New England agrees with the Dimanchev and Jones assessments. TDI New England is developing the New England Clean Power Link (NECPL), a 1,000 MW underground, interregional, and bidirectional high-voltage direct current (HVDC) transmission line that will increase energy flows between ISO-NE and Eastern Canada. The construction of this critical clean energy infrastructure project will provide significant economic and environmental benefits to New England including the creation of new construction jobs. Studies by the Massachusetts Institute of Technology, the State of Massachusetts, and the State of Connecticut all point to increased connectivity with Quebec as the lowest cost option to maximize the value of New England's offshore wind potential.

As the cited studies note, the primary driver for this value is the creation of a "Green Battery." As New England implements its plans to develop substantial offshore wind resources, energy storage becomes critical. During periods of favorable offshore wind conditions, NECPL will enable the transmission of wind-generated electricity to Eastern Canada. This would allow Eastern Canada to avoid drawing down its hydro reservoir system (in effect, "charging" the Green Battery). When offshore wind energy production is lower than New England demand, Eastern Canada will use its reservoir system to generate and return the electricity to New England (in effect, "discharging" the Green Battery). Meeting this defined transmission need will enable New England to move to a decarbonized energy future while saving ratepayers billions of dollars. The integration of a "Green Battery" with offshore wind also will help New England avoid costly infrastructure investments that would otherwise be required to reliably integrate large amounts of offshore wind and other intermittent clean energy resources.

[2] *Id*. at 56.

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TDI New England does take issue with one of the studies cited by DOE. In Section VI.d, "International Transfers", the Needs Study asserts that "[a]ppreciable international transfer capacities between Canada and New York and New England do not arise until 2040 in Brinkman et al. (2021)."[3] TDI New England does not believe that statement is accurate. NECPL is a fully permitted transmission project that is poised to commence and timely complete construction. The Project enjoys widespread support throughout New England, and the same management team successfully developed (and is now constructing) the Champlain Hudson Power Express (CHPE) project in New York State. CHPE is a 339-mile 1,250 MW buried HVDC transmission line that will deliver clean baseload hydropower and wind power directly into New York City and will be operational in 2026. Accordingly, it is likely that there will be appreciable international transfer capacities between Canada and New York and New England a decade prior to 2040.

TDI New England appreciates the work that DOE undertook to prepare the Needs Study. It is a valuable contribution that will inform infrastructure improvements to the interstate transmission grid for the benefit of all consumers.

Respectfully,

Donald Jessome
General Manager

[3] *Id.* at 103.

State of Utah

SPENCER J. COX
Governor

DEIDRE M. HENDERSON
Lieutenant Governor

Department of Natural Resources

JOEL FERRY
Executive Director

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April 10, 2023

Submitted via electronically: NeedsStudy.Comments@hq.doe.gov

Maria D. Robinson
Director
Grid Deployment Office
U.S Department of Energy
1000 Independence Ave. SW
Washington DC 20585

RE: **Notice of Availability of National Transmission Needs Study and Request for Comment**

Dear Ms. Robinson:

The State of Utah (State), through the Public Lands Policy Coordinating Office, has reviewed the Draft 2023 National Transmission Needs Study[1] as published in the Federal Register March 6, 2023, and submits the following comments for your consideration.

The State understands that this is a national needs assessment and not a corridor designation planning process. The State understands that the corridor designation planning will subsequently occur at the regional level and will take into consideration this needs study. The State also understands that the findings of this study will be used to prioritize Infrastructure Investment and Jobs Act (IIJA) funds. Utah welcomes projects that are locally coordinated to best utilize IIJA funds in the Mountain region. The State consists of approximately 67% federally managed lands with incredible energy resource potential for geothermal, wind, solar, coal, natural gas, critical minerals,[2] and other resources necessary to promote grid resilience and reliability.

The energy industry is constantly evolving and it is a best practice to complete a national needs study every three years. It is unfortunate that State level need studies were not considered in

[1] https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf
[2] https://ugspub.nr.utah.gov/publications/circular/c-135.pdf

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the national assessment. In Utah, these studies are published by the Utah Office of Energy Development. For example, in 2021 the State released the Utah Transmission Study: A Study of the Options and Benefits to Unlocking Utah's Resource Potential.[3] As the population of Utah increases and as electrical demand increases due to additional electrification (e.g. automobiles), capacity can become an issue – especially, when temperatures are at extreme levels. The Utah Transmission Study identified "cutplanes" for locations that will likely see capacity issues in the near future (as soon as 2025), as well as for extended timelines.

Furthermore, the State participated in a Western States' Market Study that was conducted by Energy Strategies and published on July 30, 2021.[4] The summary of that study indicates that Utah would [generally speaking] not see a net benefit from joining a regional transmission organization (RTO) or an Independent System Operator (ISO). This is because Utah has some of the lowest electricity prices in the country. Utah's grid is more reliable and resilient than many of its neighboring states. PacifiCorp provides added stability to the state's energy supply by being present in multiple states and by using a wide variety of technology without adding unnecessary federal oversight or legislation. It is known that California, Nevada, and Colorado would like Utah to join an ISO, but all the variables would have to perfectly align for Utah to benefit from joining an ISO. The maps on page 30 of the needs study are somewhat disconcerting and raise the topic that Utah is a core hub and important element in the national energy success story. It appears in the aforementioned maps that energy costs increase going east from Utah and that the trend is increasing year-over-year. That leads the reader to think that new infrastructure is needed between Utah and eastern states to meet future needs eastward of Utah.

Increasing interregional transmission systems may increase or decrease local, regional, and national security vulnerabilities. Utah is committed to keeping the lights on and staying ahead of the ever-evolving cyber threats. The national needs study should identify methods to prevent and combat cybersecurity attacks nationwide.

NEPA Restraints

Looking forward, the largest hurdles that will impeded our national needs for energy transmission will be extensive and time-consuming environmental reviews to comply with the National Environmental Policy Act (NEPA). The Department of Energy (DOE) report[5] issued on June 12, 2020, stated the following:

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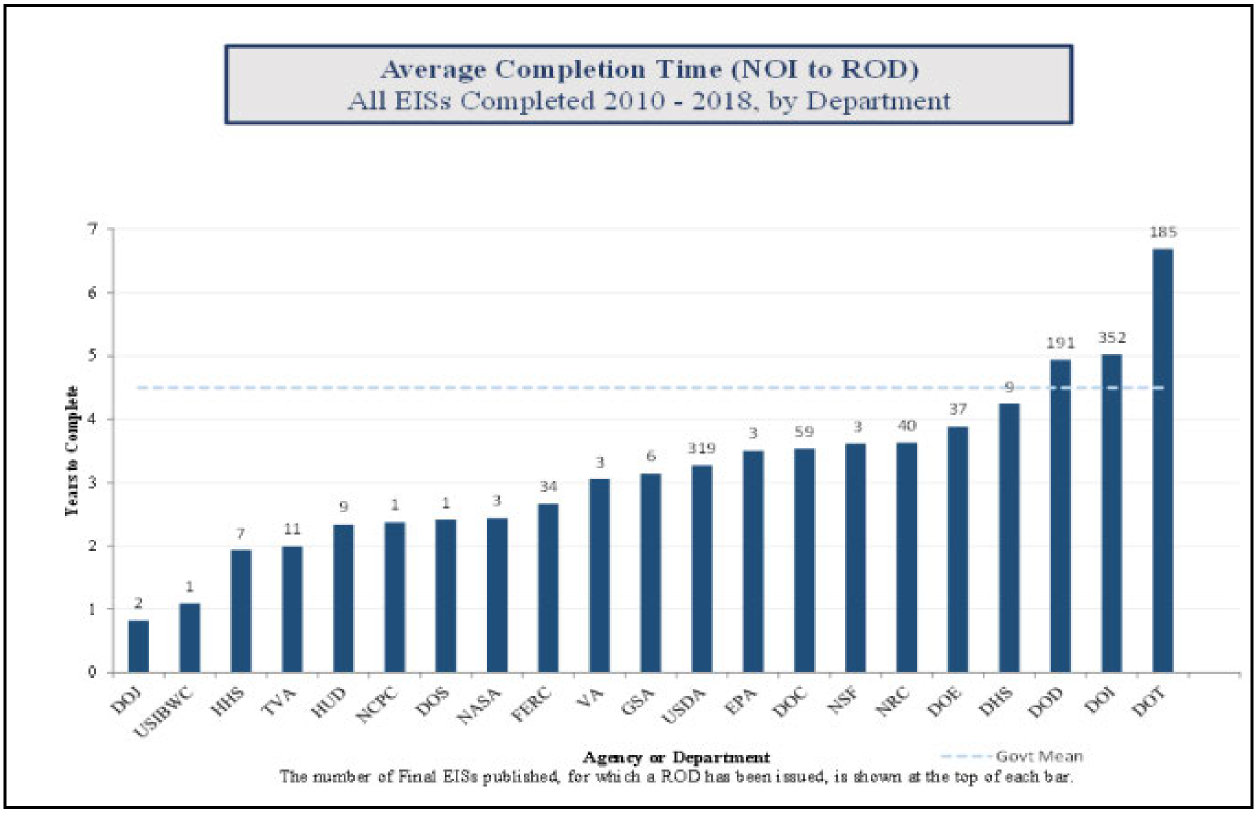
[3]https://energy.utah.gov/wp-content/uploads/2021-Utah-Transmission-Study-Technical-Report-FINAL-210121.pdf
[4]https://energy.utah.gov/wp-content/uploads/State-Study-Final-Report-1.pdf
[5]https://ceq.doe.gov/docs/nepa-practice/CEQ_EIS_Timeline_Report_2020-6-12.pdf

"To determine the time required for Federal agencies to complete EISs prepared pursuant to NEPA, the Council on Environmental Quality (CEQ) reviewed data from the following publicly available sources: (1) the Environmental Protection Agency's EIS Database;ii (2) the Federal Register;iii and (3) agency and project websites. The information provided in this document is based on 1,276 EISs for which a notice of availability of a final EIS was published between January 1, 2010, and December 31, 2018, and a ROD was issued by June 18, 2019. iv This represents 115 additional EISs with RODs compared to the 2018 Report. The data presented does not include final EISs published during the 2010-2018 period for which a ROD was still in preparation, on hold, or not planned as of June 18, 2019. To access the underlying data for this report, click here. Based on its review, CEQ found that across all Federal agencies, ***the average (i.e., mean) EIS completion time (from NOI to ROD) was 4.5 years****, unchanged from the 2018 report, and the median was 3.5 years, a decrease of .1 years compared to the 2018 report. v One quarter of the EISs took less than 2.2 years (i.e., the 25th percentile), and one quarter took more than 6.0 years (i.e., the 75th percentile); both figures are unchanged from the 2018 report. vi The period from publication of an NOI to the notice of availability of the draft EIS took on average 58.4 percent of the total time. Preparing the final EIS, including addressing comments received on the draft EIS, took on average 32.2 percent of the total time. The period from the final EIS to publication of the ROD took on average 9.4 percent of the total time."*

Furthermore, the Final Rule: Update to the Regulations Implementing the Procedural Provisions of the National Environmental Policy Act[6] for the same period showed that of the 37 DOE projects requiring an EIS from 2010 through 2018 the average number of years to complete was just shy of four years (Figure 1).

[6]https://trumpwhitehouse.archives.gov/wp-content/uploads/2020/01/20200819-FINAL-Summary-of-NEPA-Rule.pdf

Figure 1: Average Completion Time (NOI to ROD)



That same report[7] also reiterated that following point.

CEQ's 1978 regulations and guidance recommended an EIS normally be less than **150** pages, or 300 pages for actions of unusual scope and complexity, and the timeline for an EIS, even for a complex project, should **not exceed 1 year.**

It is not uncommon for an EIS to exceed 500 pages and take upwards of four years. Energy transmission projects are very complex based on the fact that they typically cross state boundaries and various terrain, such as buttes, valleys, canyons, and basins. As well NEPA requirements have become increasingly complex since the Biden Administration revised the National Policy Act Implementing Regulations on April 20, 2022[8]. This recent set of revisions made several changes to NEPA that were amended previously by the Trump Administration, including adding subcategories, including "direct," "indirect" and "cumulative impacts" into the NEPA requirements under "effects."

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[7] https://trumpwhitehouse.archives.gov/wp-content/uploads/2020/01/20200819-FINAL-Summary-of-NEPA-Rule.pdf
[8] https://www.federalregister.gov/documents/2022/04/20/2022-08288/national-environmental-policy-act-implementing-regulations-revisions

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The definition of cumulative effect is: “the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-federal) or person undertakes such other actions (40 CFR ~ 1508.7)”

In short, it takes longer to address cumulative effects for a NEPA project. Energy projects are prone to be litigated, and the ever-increasing list of layered environmental protections only adds to the complexity and extended timelines. Creating new designations such as national monuments or wilderness areas can make it almost impossible to feasibly explore, develop, and transmit energy to the grid in the future.

The State stands ready to be a cooperating agency for any transmission improvement projects or new construction in Utah. Furthermore, the State has adopted a State Resource Management Plan (SRMP) and County Resource Management Plans (CRMPs) for all 29 counties to improve coordination and consistencies across multiple jurisdictions and agencies[9]. The Utah Legislature is also supportive of improving the energy grid to keep costs low, improve reliability, and strengthen other weaknesses innate to energy transmission. As part of this equation, the State has adopted an “any-of-the-above” stance for energy production and transmission.

Additionally, the State of Utah adopted the aforementioned Utah Energy and Innovation Plan in 2022[10] with the following commitments. The federal government would be well served to adopt the same, or similar, commitments.

Utah is committed:

- to an “any of the above” energy future, supporting efforts and policies that provide a variety of tools and resources that citizens, communities, businesses, and industries can choose from to deliver or obtain affordable, reliable energy.
- to American energy independence, pursuing policies and actions that will enable more domestic energy development and enhance global energy security.
- to pragmatic, market-driven climate solutions that enable innovative energy production. This includes a focus on supporting Utah-based research and development, ensuring we stay good stewards of our environment for future generations of Utahns.
- to supporting rural communities through economic development and diversification efforts, infrastructure investment, and workforce training and development.

[9] rmp.utah.gov
[10] https://energy.utah.gov/plan/

- to supporting an environmentally responsible energy future through a strong and sensible mining program for critical minerals; investment in emerging energy technology such as hydrogen, storage, and energy efficiency; and air quality research and incentive programs.
- to collaboration with its local, regional, and federal partners to pursue infrastructure and innovation projects such as EV charging, transmission, emerging fuel hubs, and coal community support and diversification.

Renewable Energy Transition

Renewable energy will undoubtedly be part of the equation to address the needs identified by this needs study. That being said, traditional energy solutions should not be disincentivized to incentivize only renewable energy solutions. The goals, objectives, policies, and strategies of the State are outlined in the Utah Energy Innovation Plan[11] (particularly the Energy in Utah section) and in the Energy[12] section of the SRMP where petroleum, natural gas, coal, geothermal, solar, wind, hydropower, hydrogen, biomass, and nuclear energy solutions are discussed in more detail.

The State encourages the DOE to explore the goals, objectives, and policies for each of these energy solutions in all future planning efforts to ensure consistency between federal, state, and local plans. Doing so will reduce litigation risks and will expedite project completion timelines.

It is disconcerting that this needs study does not consider large scale transmission lines like Energy Gateway South and TransWest– nor does it address the need for substations and supporting infrastructure to accommodate the rapid increase in solar, wind, and geothermal renewable energy developments. It is troublesome to have transmission lines cut through the state, yet not be able to tie into those lines or economically benefit local communities in the long-term from their existence. The goal of increasing renewable energy and creating a reliable baseload is always hindered by a lack of infrastructure that is either inaccessible or very difficult to access. Take for example Fervor Energy[13] and their geothermal project near Milford, Utah. They are part of a "Cluster Study" with PacifiCorp to access its infrastructure– but, every time a partner drops out of the study, the study essentially starts over, increasing Fervor's risk of failure due to funding restraints and extended timelines. Geothermal projects are not incentivized by the federal government in the same way as wind or solar. Geothermal operations are eligible for state tax credits at the state level in Utah. In looking at the needs of the nation, expediting access to public lands for exploration and development must be coupled with the ability to expeditiously connect new power generation locations to the grid in a timely manner. In this example, geothermal is a

[11] https://energy.utah.gov/plan/
[12]https://storymaps.arcgis.com/collections/81d4406668e34acca4d98275ee41cd07?item=8
[13] https://fervoenergy.com/

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superior baseload resource and could help stabilize the grid and account for intermittency caused by wind and solar.

Draft National Transmission Needs Study - Mountain Region Specific

Utah is part of the "Mountain" region as identified on page V of the Draft National Transmission Needs Study.

- **NEED: Improve system reliability and resilience.**

The need to improve reliability and resilience in the study was identified for the mountain region due to:

Extreme heat and wildfires can result in power outages. These reliability concerns are increasing as extreme heat and wildfires become more prevalent due to climate change.[14]

The extreme risks associated with 100 years of fire suppression in the western United States cannot be overstated. Natural fire regimes have been completely violated and are very difficult to restore. Some restoration efforts are underway in Utah including efforts implemented by the Watershed Restoration Initiative[15] (WRI) and the Shared Stewardship Program[16] (SS).

For the years 2006 through 2022[17], WRI has completed 2,570 projects, improved 2,269 miles of streams, and restored 2.4 million acres (36% fire rehabilitation, 19% proactive measures; 66% federal lands, 19% state lands, and 15% private lands). Additionally, WRI has completed 673,701 acres of new class III cultural resource inventories and located 9,616 culturally significant sites that have been added to the historical record. These cultural efforts are invaluable when planning new corridors and restoration efforts to reduce fire risk across the landscape.

Shared Stewardship is a cooperative approach to managing Utah's forests. Utah's Shared Stewardship agreement provides a framework for Utah, the U. S. Forest Service (USFS) and the Natural Resource Conservation Service (NRCS) to work together to identify forest health priorities that focus on restoration projects. Since 2019, 80,000 acres have been treated, 30 million dollars have been invested, and 150 partners have coordinated to make the program a

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[14] https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf
[15] https://watershed.utah.gov/sgmitigation/
[16] https://utah-shared-stewardship-utahdnr.hub.arcgis.com/
[17] https://watershed.utah.gov/wp-content/uploads/2023/03/Since-2006-through-FY22-WRI-by-the-numbers-infographic-Final-Web.pdf

success. Unfortunately, due to funding limitations, the 125 high priority watershed projects have yet to be rehabilitated.

Although the WRI and Shared Stewardship programs do not focus specifically on utility corridors, the programs do reduce wildfire risk and catastrophic or uncharacteristic wildfire, which caused damage to infrastructure during the fire and after the wildfire, soil erosion. The Dollar Ridge Fire is a good example of what can happen to energy infrastructure caused by a wildfire. The incessant wildfires in California further illustrate the importance of active forest management. This is particularly true in proximity to energy corridors.

Additionally, wildfires release large amounts of carbon into the atmosphere. For example, as illustrated in an article published in the Los Angeles Times, "Researchers estimated that about 127 million metric tons of carbon dioxide equivalent were released by the [California] fires [in 2020], compared with about 65 million metric tons of reductions achieved in the previous 18 years."[18] If one fire season can off-set almost double what was accomplished by 18 years of emission reductions in just one state – we need to rethink our air quality goals as a nation and focus on forest health and restoring natural fire regimes.

These concerns were further identified and explained in the Utility Corridor[19] and Pipeline and Infrastructure sections that were added to the SRMP in 2022 and have been added to most of the CRMPs statewide in 2023.

Utility Corridor objectives and policies Identified in the SRMP:

- (Objective) Support Bureau of Land Management instruction memorandums (e.g. Utah IM-2021-004) that allows utility companies to have additional flexibility to access infrastructure and utility corridors for maintenance purposes and to reduce the risk of wildfire impacts on the utility.
- (Objective) Maintain and update wildland fire protection plans to reduce the risk of wildfire in utility corridors.
- (Policy) Federal agencies shall recognize and aid utilities in implementing wildland fire protection plans required of qualified utilities under Title 54-24-201 of the Utah Code.
- (Policy) Every effort should be made to ensure that wildland fires are not caused by utility providers.
- (Policy) The State will support utility companies in being able to maintain vegetation near and around utility corridors to mitigate risks that could potentially cause wildland fires.

[18]https://www.latimes.com/california/story/2022-10-20/california-wildfires-offset-greenhouse-gas-reductions
[19]https://storymaps.arcgis.com/collections/81d4406668e34acca4d98275ee41cd07?item=26

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- **Need: Alleviate unscheduled flows on three Qualified Paths within the region**:

Transmission paths 30, 31, and 36, which align with Colorado's borders to the west, south, and north, respectively, are Qualified Paths.

Per the Federal Energy Regulatory Commission (FERC) glossary online, "loop flow" is unintended or unscheduled flow of electricity through a line or system. Path 30 connects Colorado and Utah. Accepted by FERC in March 2016, the WIUFMP monitors real-time flows on selected transmission paths where congestion is significant and could affect grid reliability and uses control devices and curtailment to manage congestion and unscheduled flows on the grid. The Western Interconnect Unscheduled Flow Mitigation Plan[20] was included in this need study for the first time as referenced on page 7. Thank you for including this plan. As new transmission lines come online, there will be a need to update this plan and adapt proactively.

- **NEED: Increase in transmission deployment to meet projected generation and demand growth.**

Anticipate between 2,500 and 4,500 gigawatt-miles (GW-mi) of new transmission2 (median of 3,100 GW-mi, a 90 percent increase relative to the 2020 system) needed in 2035 to meet moderate load and high clean energy futures. Current utility plans for transmission development in the combined Mountain and Northwest region do not meet anticipated need.

The Bureau of Land Management (BLM) has been working on the Western Solar PEIS.[21] That effort has primarily focused on removing criteria #1 and #2 from the "exclusion criteria" based on new technology since the original six state PEIS was adopted in 2012. The Solar PEIS is also looking at adding five additional western states to the PEIS. The idea of a PEIS is to identify utility corridors and expedite the NEPA process for established zones. The State supplied comments on that scoping request and requested that the PEIS be divided into two separate PEIS processes so the 2012 PEIS can be amended in a timely manner in order to increase not only solar installations, but the more important component of improving existing infrastructure to accommodate new energy generated by solar energy. There has never been a solar project completed in Utah on BLM parcels identified in a Solar Energy Zone (SEZ) or through the "exception" process. The identification of SEZ's is fundamentally not appealing to the private sector who prefers to build on private lands or state lands where NEPA does not impede progress and where assumed risks are significantly lower. In Utah, the vast majority of new renewable

[20] https://www.wecc.org/Reliability/FERC%20Accepted%20WIUFMP%20March%2011%202016.pdf
[21] https://eplanning.blm.gov/eplanning-ui/project/2022371/510

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energy projects are built on State Institutional Trust Lands Administration[22] (SITLA) parcels. SITLA has the directive to generate revenue for their beneficiaries – primarily the children of Utah. The energy goals identified in this "need" to increase gigawatt-miles to support increased generation are going to require working with state and local governments, including agencies like SITLA, to achieve these goals and promote traditional and renewable energy production necessary to meet national requirements.

In the western United States, the vast majority of transmission lines are sited on public lands administered by the BLM and the U.S. Forest Service (USFS). State and local governments work diligently to establish cooperative relationships that encourage federal coordination and consistency with relevant plans, documents, and procedures. These efforts are also in-line with the requirements listed under FLPMA, NFMA, and NEPA.

These relationships are frequently stretched and tested when directives, policies, and procedures are passed down from the federal government and presidential administrations, which changes direction every four to eight years. These constant changes and lack of coordination from the nation's Capital in Washington D.C., to State Offices, to state governments, and to local governments tends to be the overarching issue leading to distrust between governments and even energy companies. The State requests frequent communication that should occurs early and often. Taking these necessary steps will expedite the federal goals to increase giga-watt miles and support the anticipated increase in energy production that will be required in the future nationwide.

Also, it is not uncommon to site transmission lines in or near critical habitat for threatened and endangered species. For this reason, the State requests that transmission lines be sited in the same previously disturbed corridors whenever possible. This has been particularly troublesome in Sage-grouse Management Areas. The needs study does not adequately address working across state lines to promote species planning, habitat enhancements, and reducing disturbances.

Conclusion

In conclusion, the State requests that the DOE's 2023 Transmission Needs Study be amended to account for planned and projected renewable energy resources and transmission infrastructure that are being built, or will be built, in the next 3-5 years. DOE should consult with states early and often to ensure compliance with state and local goal, objectives, and policies identified in state plans and state code. NEPA should be expedited and policies should be implemented to promote timely connection to the grid for new energy projects. This is

[22] https://trustlands.utah.gov/

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particularly important for energy sources that are not intermittent and that provide readily available and dispatchable energy.

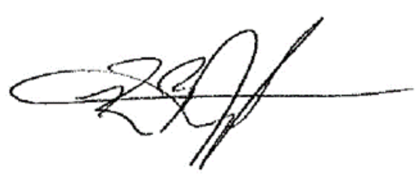
Wildfires are a huge risk in the mountain region and the State supports partnerships and all other efforts to ensure that vegetation near utility corridors are managed routinely and that utility providers have immediate access to repair their infrastructure. The goal is to have zero fires started by powerlines. Utility providers have plans to reduce these risks, but frequently are delayed by permitting with federal agencies for even routine maintenance. Programs like WRI and Shared Stewardship can further these efforts. The State requests on-going federal funding to further the efforts of these programs.

Unscheduled flows on qualified paths need to be mitigated and future issues need to be avoided to the maximum extent possible.

To increase the giga-watt miles, we need to work collectively and collaboratively across state lines to expedite NEPA review, facilitate necessary conversations, mitigate impacts to endangered and threatened species, and strategically plan for our future needs as a region and as a nation. The future of the United States and the Nation's power grid depends on the federal government's ability to expeditiously permit utility corridors and transmission lines on public lands in the mountain region.

The State appreciates the opportunity to review and submit comments on the proposed Draft National Transmission Needs Study to provide information about capacity constraints and congestion on the nation's electric transmission grid. Please call or email our office if you have further questions.

Sincerely,



Redge B. Johnson
Director

The Case for A National Transmission Grid for North America

By Vijayasekar Rajsekar (Raj)

The February 2021 power outages in Texas has triggered an avalanche of articles, opinions, social media coverage, suggestions and inquiries about the inability of Electric Reliability Council of Texas known as Ercot to accurately forecast and prevent the power blackouts. Like other transmission grid operators, Texas's power coordinator did their job to initiate load shed to prevent the massive state grid from total collapse. It was a textbook load shedding procedure to prevent total blackout in entire Texas state. As per Ercot CEO's statement, nearly 35 gigawatts of capacity became out of operation from Ercot's power grid overnight on Feb 15, 2021. As Wall Street Journal reported, "Just before 2 a.m. that night, the frequency of the grid fell significantly below the normal level of 60 hertz. The system stayed below 60 hertz for longer than 4 minutes until Ercot ordered additional blackouts". The Ercot Control Room Dispatchers and Engineers deserve a special kudos in avoiding a major power disaster. We can leave the investigation part to Texas Public Utilities Commission and FERC to find out the root cause of Texas blackouts. The investigators will publish a comprehensive set of recommendations which will be adopted by Ercot and other Transmission Operators (TOs). It is certain that one of the main recommendations would be creating more interconnections between Ercot and East/ West transmission regions. The other probable recommendations might be winterizing gas fired power plants, ability to accurately forecast wind/ solar generation, beefing up the capacity market system and few other changes.

The stalled Tres Amigas Superstation project in Clovis, New Mexico, shown in Figure 1, was going to enable the connection of America's three primary interconnections (Western Electricity Coordinating Council-WECC, Eastern and Ercot) while integrating substantial renewable energy sources. The New Mexico Independent stated “It may well be the answer to getting energy from renewable sources like wind and solar, flowing around the U.S. with greater ease. In short, the Tres Amigas project in Clovis, NM may help connect the U.S. three energy grids”.

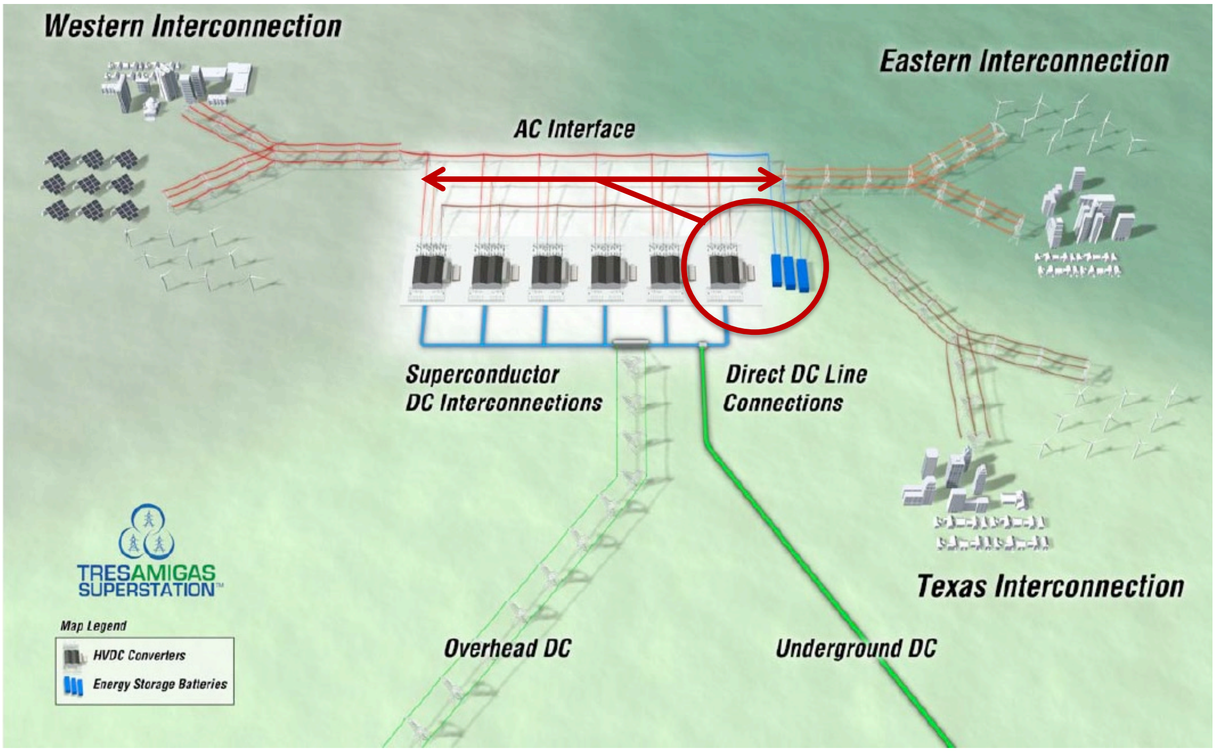


figure 1: Proposed Tres Amigas Superstation located in Clovis, New Mexico (Courtesy: TresAmigas LLC.,)

One of the preliminary analysis of the Texas blackout which was performed by a panel of IEEE Smart Grid specialists, concluded that rolling blackouts would have occurred even if Ercot had interconnections to neighboring transmission operators. As per the IEEE Smart Grid Panel, the Midwest ISO had their supply tapped out, Southwest Power Pool’s demand exceeded supply while Southwest region has less usable reserve to share with Texas grid

The Ercot grid was literally saved by the action of their Dispatchers and Engineers within a span of few minutes by resorting to massive load shed, as indicated in Ercot’s frequency graph in

Figure 2. Ercot Engineers collectively performed all actions like distressed aircraft pilots when they knew that their airplane was about to crash. They resorted to multiple emergency maneuvers including dumping fuel and shutting alternate engines to reduce the impact from a crash but eventually managed to get the plane up in the sky. Captain Sullenberger who managed to save the lives of 150 passengers by performing the “Miracle on the Hudson” water landing is another example. Similarly, Dispatchers and Engineers in California Independent System Operator (CAISO) performed such a feat on August 14-15, 2020 when lightning induced wildfires knocked out nearly 8,000 MW of renewal generation capacity. As per a Final Root Cause Analysis report published by CAISO, considering 35 years of weather data, the extreme heat wave experienced in August 2020 was a 1-in-30 weather event in California.

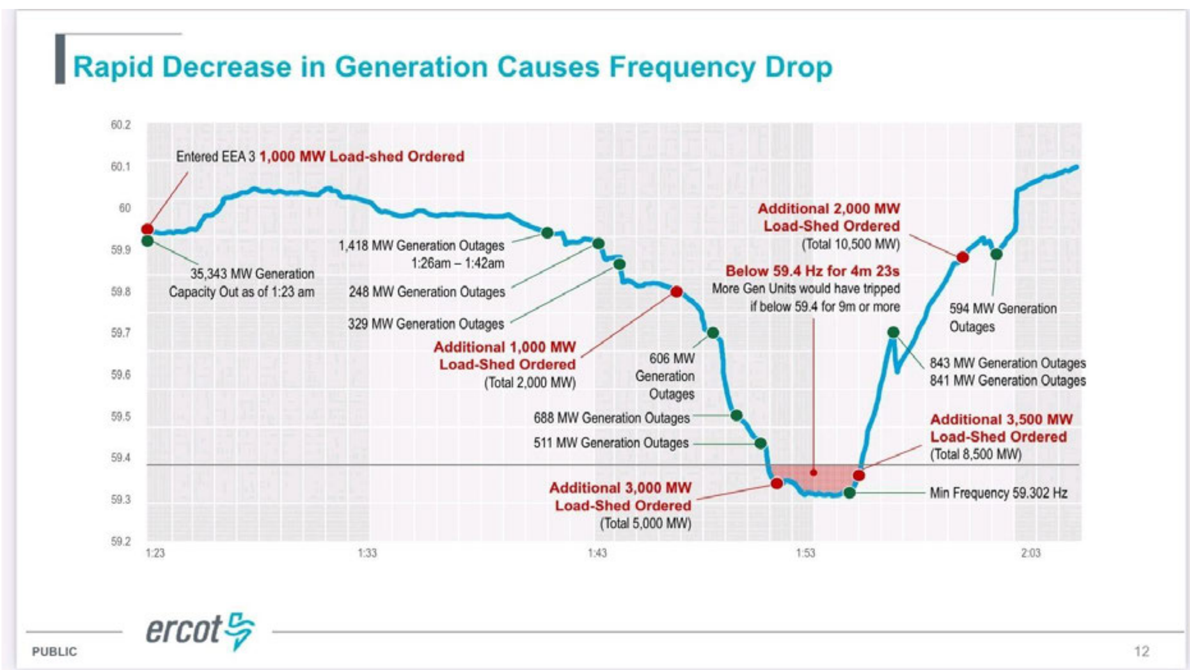


figure 2: Rapid Decrease in Generation in Ercot region during extreme cold weather event (Courtesy: ERCOT Board of Directors meeting document published in ERCOT website)

Prominent US national labs like National Renewable Energy Lab (NREL), University academic experts and industry specialists in the past have recommended to strengthen the US electric grid and creating more regional interconnections to Ercot. The Interconnections Seam Study authored by NREL and partners recommended creating an integrated power grid which would link the three regions of US power system – the Western Interconnection, the Eastern Interconnection and Ercot. Now, all three regions operate almost independent of each other. Moreover, US does not have adequate transmission lines to effectively transfer power across all three regions.

Let us take a step back from the US grid interconnection issue for a moment and look at similar efforts of integration in other industry domains of United States. The Dwight D. Eisenhower Interstate Highway system, shown in Figure 3, is a classic example of how different corners of our country from San Diego to Portland, Maine and Miami to Seattle is interconnected by highways. The interstate highways are major catalyst for the US economy to seamlessly move goods and services. The US freight railroad system is another example where coal from North Dakota is transported to power plants in mid-western states. The famous California Aqueduct moves water from Northern Sierras to water starved Central Valley and eventually to Southern California. Most global industries including in United States have adopted a vast network of supply chains to move parts/ components required to assemble products. The Tesla electric sedan is assembled in Fremont, California using parts manufactured in different parts of US and world. The Boeing Dreamliner aircraft is assembled in Everett, Washington and Charleston, South Carolina using components build in several countries. We can give many such examples where interconnected supply chains play an important role in business continuity. Imagine if US had three systems of Interstate highways for West, East and Central which were not directly connected. A shipment from San Francisco to Philadelphia would be transported into different containers across three regional boundaries in order to continue the journey. The total shipment time would increase by 2-3 times as compared to the same truck if it were able to ply between the cities with no changeover. The same principle can be applied to electric grid and interconnected power systems.

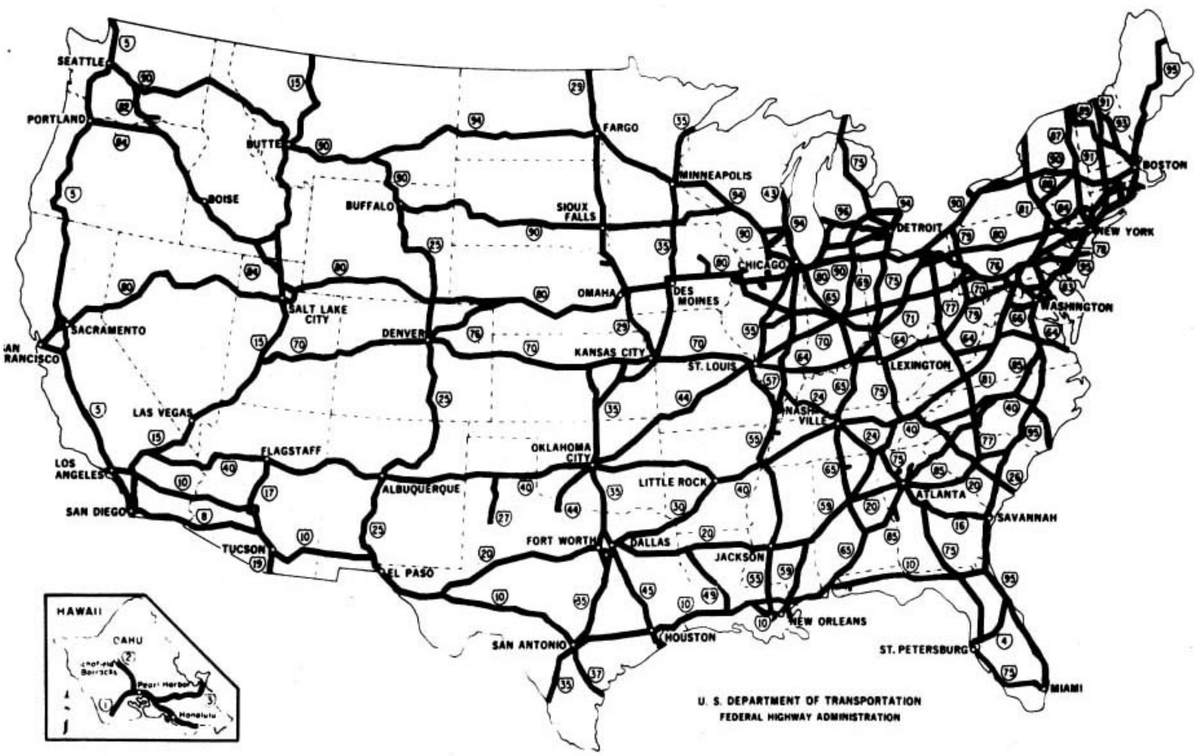


figure 3: The Dwight D. Eisenhower System of Interstate and Defense Highways

Major power system incidents like the Texas cold weather outages, California brownouts in 2000-01, East coast blackout in 2003, San Diego blackout in 2011, India national grid outages, and various outages in Europe with the most recent one occurring on Jan 6, 2021 always trigger a healthy debate among power professionals and industry partners to look closely at root causes of the problem. The recommendations from these incidents have far-reaching implications on the reliability and performance of electric grid. The results after implementing the recommendations has created a more robust and reliable electric grid. Many countries like India, China, Mexico, UK, European Union and Canada have setup an integrated National Grid to seamlessly move power across different regions. Our North American grid, especially United States does not have such an interconnected system. Let us not delve into the reasons why US did not implement such a system even after the major North-East blackout of 2003. Certain regions of US are well interconnected between themselves like Western and Eastern region. San Diego and Los Angeles load centers receive power from British Columbia and Bonneville Power Authority in Washington via high voltage transmission lines. The Sandy Point High Voltage Direct Current (HVDC) converter substation in central Massachusetts and operated by National Grid since 1990 was one of the earliest import points for southern New England load centers. Texas had surplus power generation from coal, gas, wind and solar generation which helped the Ercot region to continue operating with very few interconnections to adjacent regions. The February 2021 winter storm in Texas literally shutdown thousands of gigawatts of electric power which was expected to continue with no disruptions. A similar situation occurred in Texas during February 2011 Super Bowl weekend in Texas when extreme cold weather disrupted gas power generation triggering a load shed of 4,000 MW affecting nearly 3.2 million customers, as per FERC report. We can expect similar grid disturbances to occur more often given the frequent occurrences of natural disasters like California wildfires, Atlantic hurricanes, snowstorms in east and northern states, cold snaps in south and mid-west. Other unexpected incidents like tornadoes, flooding, terrorist attacks and earthquakes must also be considered.

How can we create a Unified National Grid for North American power grid?

To start with, the new US Department of Energy and Federal Energy Regulatory Commission (FERC) leaders could review the recommendations from The Interconnections Seam Study which was completed in October 2020. Four transmission designs under eight scenarios were developed and studied to estimate costs and potential benefits as part of the Seam study. The US has some of the brightest power professionals and utility operations leaders who have decades of experience in designing, operating and maintaining transmission systems covering large geographic areas. From a communication and control systems perspective, majority of the

U.S. power system network is managed by Supervisory Control and Data Acquisition (SCADA) and Energy Management System (EMS) computer systems/ applications supplied by big four vendors in the world – GE Digital (former Alstom Grid), Hitachi ABB Power Grids (former ABB Network Management), Siemens Spectrum Power and OSI (now part of Emerson). GE also supplied a SCADA/ EMS platform called XA/21 which has a large installation base in US, Europe and Asia, prior to acquiring France based Alstom Power and Grid in 4Q 2015. A collaboration team of top power professionals, national labs engineers and SCADA/ EMS vendors could effectively design and implement the best scenario for the US National Grid system. Most of the control systems and telecommunication infrastructure do currently exist in order to create a National Grid. The communications infrastructure needed for telecontrol and data communications must be upgraded to latest 4G or 5G standards.

The most prevalent international standard from International Electrotechnical Council (IEC) is called IEC 60870-6/ Telecontrol Application Service Element (TASE.2), also known as Inter Control Center Communications (ICCP) protocol which is used worldwide by almost all major transmission operators, power pools and Generators. The ICCP protocol allows seamless interconnection of control system networks between multiple utilities and operators over wide area networks. Moreover, Supervisory controls is supported by ICCP by implementing Block 5 function which would facilitate remote operation of critical tie-switches across different regions based on security constraints. A separate physical transmission network of high voltage AC and DC (HVAC/ HVDC) systems must be constructed or upgraded in capacity to facilitate bulk transfer of power between different regions of US. ICCP protocol also helps in consolidation of satellite control centers maintained by utilities as a result of acquisition/ mergers between companies. Recently, Exelon Utilities completed their consolidation of SCADA/ EMS Grid Control Centers across their territories under three geographic regions. In Asia, the Indian electric grid was completely unified over a period of several years by implementing a hierarchical architecture and establishing a National Load Dispatch Center in New Delhi in addition to regional Load Dispatch Centers (LDCs) in North, South, West, East and North-East regions. The European Network of Transmission System Operators for Electricity (ENTSO-E) represents 42 electricity transmission system operators (TSOs) from 35 countries across Europe. On Friday 8, January 2021 at 14:05 CET, the Continental Europe Synchronous Area was separated into two areas (the North-West area and the South-East area) due to cascaded trips of several transmission network elements. This situation was caused, on one hand, by warm weather in the Balkan Peninsula as well as the Orthodox Christmas holiday on January 6 and 7, leading to an overall lower demand than usual in some of these countries. Immediately after the incident occurred, European TSOs started to resolve the problem and resynchronized the continental Europe power system at 15:08 CET. Due to the fast and coordinated approach, there were no major loss of load or damages in the power system. The engineers of ENTSO-E performed a "Miracle on Hudson" maneuver to prevent a complete collapse of the European grid.

The following simplified implementation approach might help US to create an effective National Transmission Grid:

- ❖ **Phase I (Interconnecting Control Centers through WAN)** – Implement/ strengthen ICCP links across three regions of U.S., followed by Canada and Mexico. Many TOs use ICCP to exchange power system information between Control Centers and Canada/ Mexico. From a control systems perspective, the big four SCADA/ EMS vendors (GE, Hitachi ABB, Siemens and OSI) have computer systems and software applications functioning in these regions for controlling the grid and running market systems. Establishing ICCP links and overseeing the grid information from Regional Grid Control

Centers (RGCCs) would greatly help in improving situational awareness of national grid from all corners of the country. A national Grid Monitoring Center could be established at FERC or North American Electric Reliability Corporation (NERC) headquarters where national power systems parameters could be monitored. Three RGCCs could be setup within existing ISO/ TO framework and physical premises. The Western RGCC could be setup within CAISO, the Central RGCC within SPP or Ercot and Eastern RGCC within New England or PJM. Similarly, ENTSO-E, China, Mexico and India National Grids have setup such operating power structures to provide hierarchical business continuity besides getting oversight of the grid. Existing ISOs and RTOs in North America is shown in Figure 4. The proposed National and Regional GCCs is shown in Figure 6.

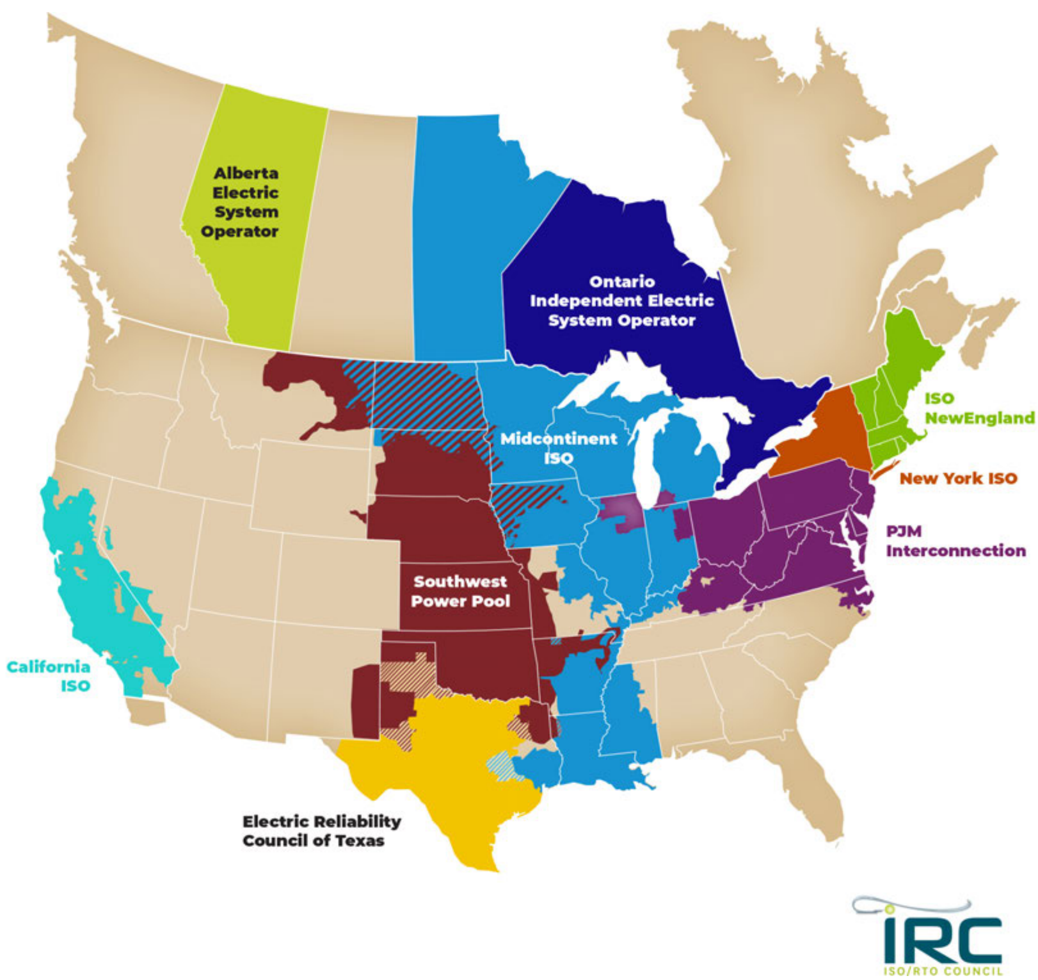


figure 4: Transmission Operators in North America (Courtesy: ISO/ RTO Council)

- **Phase II (Expand Synchrophasor deployment across three regions)** - Under Phase II initiative, the TOs can expand the sharing of Synchrophasor data between different regions. Synchrophasors are precise grid measurements available from monitors called Phasor Measurement Units (PMUs). PMU measurements are taken at high speed (typically 30 samples per second, over 100 times faster than conventional SCADA technology). Each measurement is time-stamped according to a common time reference using Global Positioning System (GPS). Timestamping allows measurements from different locations and utilities to be time-aligned (synchronized) and combined providing a precise and comprehensive view of the entire interconnection. Synchrophasor measurements can be used to indicate grid stress and to trigger corrective actions to maintain reliability. The North American Synchrophasor Initiative (NASPI) is a collaborative effort funded by US Department of Energy with support from Pacific Northwest National Laboratory and the Electric Power Research Institute. PMUs and latest high-speed relays/ Remote Terminal Units (RTUs) work more effectively when network latency is reduced. These devices require near real-time monitoring communication speed which should be at least 114 kilobits per second. This is the speed of General Packet Radio Service (GPRS). The next generation Enhanced Data GSM Evolution (EDGE) communications use 384 kilobits per second. This is referred to as 2.5 G network. The newer 3G and 4G cellular network would increase the bandwidth and communication speed from/ to the RTUs, Relays and PMUs. Many large utilities still employ legacy communication network with speeds ranging from 1200 bauds to 9600 bauds for SCADA and Teleprotection. FERC and DOE shall mandate that all legacy network infrastructure for transmission devices be upgraded in a time-bound manner.

- **Phase III (Develop Unified Power System Network Model)** – This work could be started by leveraging existing power system network models which is maintained at respective Reliability Coordinators, Balancing Authorities, ISOs and Investor Owned Utilities. As an example, the existing West wide System Model (WSM) which used to be maintained by Peak Reliability Coordinator in WECC could be expanded to cover other regions. Alternately, existing network models from other regions could be merged or expanded to create a national power network model. We don't have to start from basics to build a national network model. This exercise requires active collaboration between different regions/ entities before proceeding to conduct periodic model updates for a national grid. The network model data is currently exchanged using Common Information Model (CIM) XML format between entities. All big four SCADA/ EMS vendors have the capability to help in developing and maintaining such large network models. The national network model must include critical data from PMUs and large DERs in order to improve situational awareness for regional dispatchers. A dispatcher sitting in New England ISO could possibly detect a congestion or disturbance occurring in San Diego or Oklahoma City.
- **Phase IV (Establish HVDC/ HVAC interconnections between regions)** – Implement the best scenario/ design from NREL's The Interconnections Seam Study to interconnect the U.S. grid. The possible resurrection of now stalled Tres Amigas project must be explored to make it fully operational. Interconnecting the three regional U.S. grids via AC or DC systems, as shown in Figure 5, shall be undertaken as a top priority by DOE and FERC. A political will is required to implement a truly interconnected grid which could be quickly executed by ISOs and National Labs. The American Recovery and Reinvestment Act of 2009 was a fiscal stimulus plan which seeded the foundations for hundreds of Smart Grid projects in US including Smart Meter rollouts and implementation of many

Advanced Distribution Management Systems (ADMS)/ Distribution Automation (DA) programs. Since 2010, several large scale ADMS/ DA programs were completed and being deployed in US. Having a state-of-the art SCADA/ EMS combined with ADMS/ DA systems would truly make the electrical grid “Smart”. The existing electric grid is nearly equivalent to early flip phone design with 2.5G communication network and capability. Upgrading the present electric grid to an integrated Smart Grid by deploying EMS/ ADMS/ DA along with latest 4G or 5G capable networks would elevate the grid up to latest standards and capabilities. The ADMS provides several benefits to integrated utilities where they can seamlessly monitor and control the transmission and distribution infrastructure including Distributed Energy Resources like solar, wind and battery storage systems. The ADMS facilitates initiation of surgical load sheds on individual distribution feeders/ loads whenever a major load relief is required like recent Ercot and CAISO incidents. This setup requires installing feeder reclosers to sectionalize distribution feeders thereby reducing the number of customers who might be impacted by rolling blackouts. High risk customers like hospitals, nursing homes, elderly care facilities, fire stations, police precincts and homeless shelters could be spared from rolling blackouts when selective and surgical load shedding is implemented

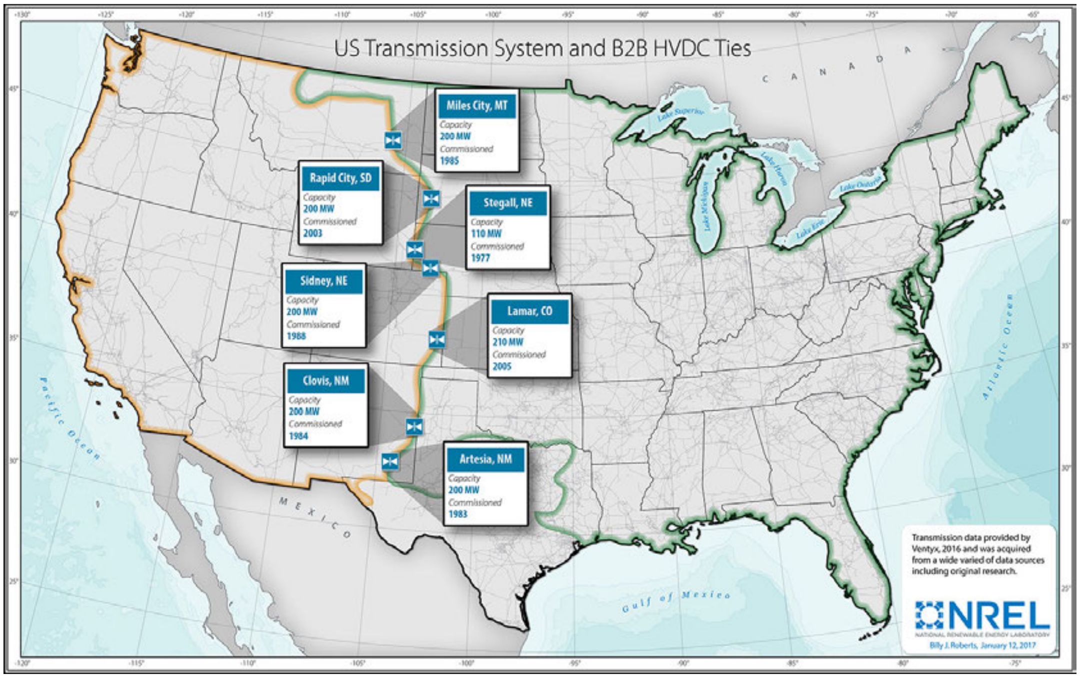


figure 5: Back-to-Back HVDC Ties (Courtesy: NREL, Billy.J.Roberts, January 2017)

❖ **Phase V (Interconnect Canada and Mexico with US grid)** – The last phase could be implemented after successfully completing earlier phases and taking enough time to conduct different power systems analysis on the new National Transmission grid. After that, US/ FERC can decide to strengthen existing interconnections to Canada and Mexico to create a North American National Grid. The RGCCs may be extended to Canada where North RGCC could be established. The North RGCC may be co-located within IESO or BC Hydro systems. The South RGCC could be established within Mexico's National Grid Operator CFE in Mexico City.

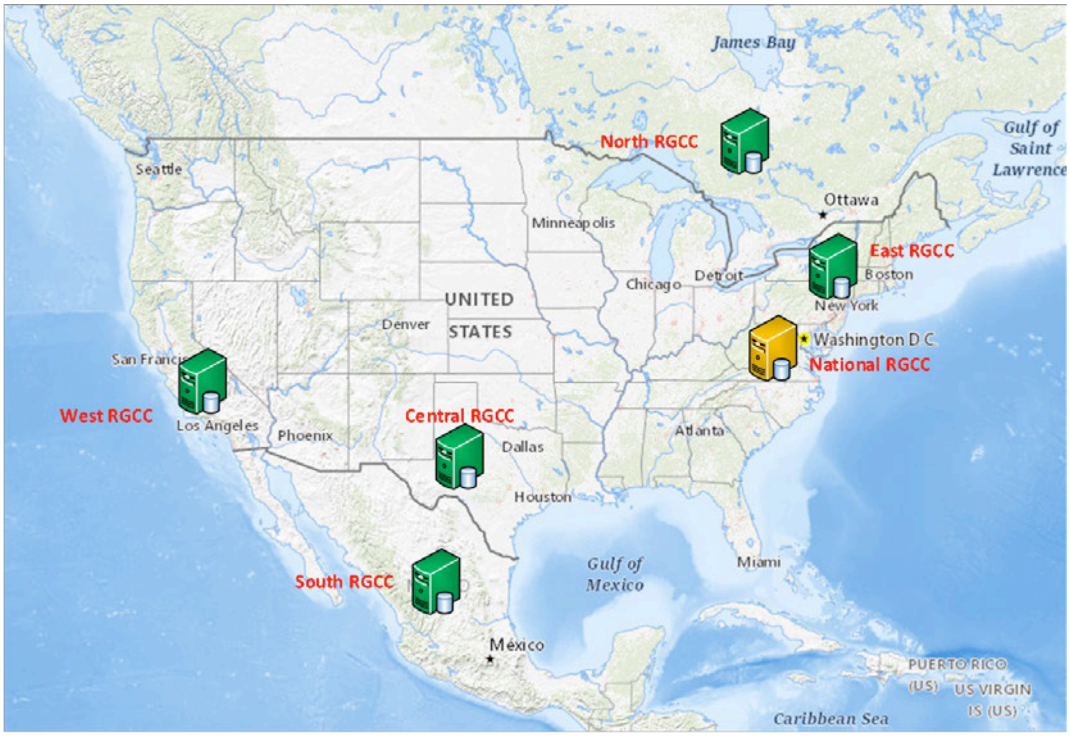


figure 6: Proposed National Transmission Grid Control Centers by Author

(Map courtesy: U.S. Department of the Interior - usgs.gov)

The US Energy department under the new leadership of Energy Secretary, Jennifer Granholm and FERC Chairman might want to look at the feasibility of interconnecting the U.S. electrical grid and create a National Grid where power transfer between regions would prevent the next Texas, North-East or California rolling blackout. The proposed National Infrastructure Plan by the new federal administration can earmark funds for implementing a National Transmission Grid for US and North America.

Disclaimer: The opinions expressed in this article are solely the author's and do not reflect the opinions and beliefs of Pacific Gas & Electric Company, San Francisco, CA.

For Further Reading

- The National Renewable Energy Laboratory (NREL), "Interconnections Seam Study" Available at: https://www.nrel.gov/analysis/seams.html

- Electric Reliability Council of Texas (ERCOT) Board of Directors Meeting Available at: *http://www.ercot.com/content/wcm/key_documents_lists/225373/2.2_REVISED_ERCOT_Presentation.pdf)*
- Electric Reliability Council of Texas (ERCOT) letter to Members of the Texas Senate and the Texas House of Representatives regarding Generator outages during February 2021cold weather event, dated March 4, 2021 available from Ercot website
- Report on "Outages And Curtailments During The Southwest Cold Weather Event Of February 1-5, 2011, Causes and Recommendations" Prepared by the Staff of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, August 2011
- European Network of Transmission System Operators for Electricity (ENTSO-E) – Interim report on "Continental Europe Synchronous Area Separation on 8 January 2021, Publication date: 26 February 2021 available from ENTSO-E website.
- Jean Kumagai, IEEE Spectrum Magazine, December 2015, "The U.S. May Finally Get a Unified Power Grid".

Biography

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RE: Draft National Transmission Needs Study Request for Public Comment – WATT Coalition Response

April 20, 2023

I. Introduction

The Working for Advanced Transmission Technologies (WATT) Coalition appreciates the opportunity to share comments on the Draft Transmission Needs Study (Needs Study) with the Department of Energy (DOE). The Needs Study confirms that significant transmission capacity expansion is vital to America's energy future. The Needs Study highlights the brief window to create this capacity in alignment with the Biden Administration's commitment to domestic clean energy growth.

The WATT Coalition encourages the DOE to increase their focus on Grid Enhancing Technologies (GETs) and their capabilities to increase transmission capacity quickly and at lowest cost. In the following comments, WATT proposes several additional resources to cite in the report that elucidate the roles of GETs towards clean energy goals.

The WATT Coalition has commissioned new research this month that specifically quantifies the synergistic relationship between GETs and transmission expansion. The report *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts*, is appended to these comments. It is available for download at https://watt-transmission.org/wp-content/uploads/2023/04/Building-a-Better-Grid-How-Grid-Enhancing-Technologies-Complement-Transmission-Buildouts.pdf

II. About the WATT Coalition

The WATT Coalition is a trade association focused on facilitating the adoption of advanced technologies on the US electric transmission system that improve reliability, lower costs, and accelerate decarbonization—benefiting American citizens and businesses. The WATT Coalition represents GETs vendors and companies that support broader deployment of GETs in the renewable energy, energy finance and transmission industries.

GETs are active hardware, software and sensors that increase the capacity, efficiency, and/or reliability of transmission facilities at a fraction of the cost of tradition grid upgrades. Grid operators use Dynamic Line Ratings (DLR), Advanced Power Flow Control, and Topology Optimization to access more usable grid capacity, more flexibility, and greater situational awareness. GETs reduce congestion costs, enable low-cost generation to interconnect to the grid, and maximize the value of new transmission investment.

III. Specific considerations for valuing Grid Enhancing Technologies in transmission expansion plans.

WATT recognizes that GETs were not explicitly modeled in the research that the Needs Study is based on. Existing research that could be cited in Section V is described in item IV.c of these comments.

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Findings from *Building a Better Grid: How Grid-Enhancing Technologies Complement Transmission Buildouts*, published April 2023, are highlighted below.

The report referenced above has three major findings:

1. *Before construction, GETs can reduce congestion by 40% or more, and can be deployed in weeks or months.*

The Needs Study identifies necessary transmission capacity expansion at an unprecedented scale and speed. GETs can be deployed in months, with little or no outage time, while conventional transmission upgrades are being planned. If GETs are part of the national and state clean energy strategies, the benefits of expanded transmission capacity will be available, in part, much faster than is possible with new lines. When new lines are in service, GETs can be redeployed to offer improvements to other areas of the grid, or mitigate downstream constraints that emerge when new transmission infrastructure is operational. GETs can also be part of long-term transmission planning, and their inclusion could help planners identify the highest-value transmission investments.

2. *During construction, outages can be avoided or ameliorated, with similar reductions in congestion costs of 40% or more.*

With GETs in service on a much faster timeline than new transmission, renewable energy projects can proceed while construction is underway. Interruptions of service that come with reconductoring, rebuilding, or building new transmission lines can be reduced through applications of GETs such as:

- Rerouting power along alternative circuits with Advanced Power Flow Control or Topology Optimization
- Increasing the capacity of other lines with DLR.

Real-world examples are described in the appended report. Deployments of GETs to address outages had net benefits of over $20-40 million per year in examples described in the report.

3. *After construction, utilization of new lines can increase by 16%, improving the benefit to cost ratio of the new lines.*

The Brattle Group analyzed the results of a 2021 study that modeled the deployment of GETs over the SPP transmission system in the year 2025 and included various planned transmission upgrades. With GETs, those upgrades and the existing high-voltage network saw 16% higher loading than without them. This increased utility implies that transmission lines that are narrowly below a cost-benefit threshold could comfortably exceed it if they were evaluated with strategic GETs deployments.

These results show that GETs will support the necessary grid expansion at every stage of the process, and that GETs should be included in transmission expansion plans from start to finish to maximize ratepayer value and reduce total investment cost and risk.

IV. **Recommendations for study revisions**

a. **Note regarding III.d.3 - Specialized Congestion Management Practices Used in Real-Time Operations**

The WATT Coalition appreciates the inclusion of the Transmission Loading Relief processes in the study, and we emphasize that these processes are used for reliability concerns only. Federal policymakers should look for ways to encourage similar processes to be used for economic reasons to reduce congestion and improve the deliverability of renewable energy resources. As the U.S. moves forward on its path towards decarbonization, transmission operators must recognize the flexible and dynamic capabilities of the grid, and update their processes to make use of the untapped capacity for economic benefits.

b. **Section IV**

The report on transmission investment does not note the growing adoption of Grid Enhancing Technologies by U.S. utilities. The WATT Coalition has gathered a list of representative case studies of GETs deployments across the country, available for download at this link: https://watt-transmission.org/wp-content/uploads/2023/04/US-GETs-Case-Studies.xlsx

c. **Section V**

i. **V.c Clean Energy should cite *Unlocking the Queue with Grid Enhancing Technologies***

The 2021 study *Unlocking the Queue with Grid Enhancing Technologies*, published by the Brattle Group, found that Dynamic Line Ratings, Advanced Power Flow Control and Topology Optimization could enable twice as much renewable energy capacity to connect to the existing grid, based on a case study of the Kansas and Oklahoma grids and the SPP interconnection queue. This is a relevant result quantifying how grid infrastructure can support expanded clean energy, and we recommend citing the report, available at this link: https://watt-transmission.org/wp-content/uploads/2021/02/Brattle__Unlocking-the-Queue-with-Grid-Enhancing-Technologies__Final-Report_Public-Version.pdf90.pdf

ii. **V.i Barriers to Transmission Development should also include barriers to transmission optimization.**

A 2019 paper by Rob Gramlich and Bruce Tsuchida describes the incentive misalignment for the use of Grid Enhancing Technologies. For-profit transmission owners rely on a business model of return-on-equity, which rewards them for large investments but not for improvements in the value or efficacy of those investments. To meet the nation’s transmission needs, this barrier to the most efficient and effective use of the current and future transmission infrastructure should be addressed. We recommend citing Mr. Gramlich and Mr. Tsuchida’s research, available at this link: https://watt-transmission.org/wp-content/uploads/2019/06/brattle-grid-strategies-paper-improvingtransmissionoperationwithadvancedtechnologies.pdf

d. **Section VI**

i. **Selection of Future Scenarios**

The report notes that the moderate load-growth and moderate clean energy penetration scenarios are made largely obsolete by the passage of the Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022. Given that the programs and incentives under these acts are being implemented, the assumptions of these studies no longer hold and their results should not be used to determine likely future needs. We recommend increasing the emphasis on the findings with higher renewable energy growth assumptions.

ii. **VI.a.2. Treatment of non-wire alternative transmission solutions**

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The WATT Coalition strongly supports this finding in the report: “When capacity expansion models find that new GW or GW-miles of transmission capacity is needed in a particular region, this could be met, at least in part, by increasing the carrying capacity of existing grid infrastructure already within the region.” By adding citations to the appended report from the Brattle Group, as well as the two studies cited above in items IV.c.i and IV.c.ii of these comments, this point can be better quantified.

V. Conclusion

We recommend adding language to the Needs Study that affirms the value of GETs in rapid capacity expansion, reducing the interim cost of transmission congestion while large upgrades are underway, and improving the value of large-scale investments. Thank you for your consideration.

Respectfully submitted,

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Building a Better Grid:

HOW GRID-ENHANCING TECHNOLOGIES COMPLEMENT TRANSMISSION BUILDOUTS

PREPARED BY

T. Bruce Tsuchida
Linquan Bai
Jadon M. Grove

The Brattle Group

APRIL 20, 2023

Brattle

WATT COALITION
Working for Advanced Transmission Technologies

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NOTICE

This white paper was prepared for the WATT Coalition. All perspectives and opinions are the authors and do not necessarily reflect those of The Brattle Group, its clients, or other consultants. However, we are grateful for the valuable contributions of many consultants of The Brattle Group, including John Tsoukalis as a peer reviewer.

The authors would like to thank the WATT Coalition and their members for providing their insights, experience, and data on the corresponding technology options, which were invaluable in developing this whitepaper.

Where permission has been granted to publish excerpts of this white paper for any reason, the publication of the excerpted material must include a citation to the complete white paper, including page references.

Please direct any questions or comments to T. Bruce Tsuchida: Bruce.Tsuchida@brattle.com.

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Executive Summary

> *Without transmission, our clean energy mission is stuck in neutral.*
> (Jennifer Granholm, Secretary of Energy).

The U.S. energy industry is going through a massive transition, partially driven by decarbonization initiatives that significantly increase renewable generation resources. The preferred locations for many of these new resources are often in remote areas far from consumption. The emergence of clusters of these remote resources inevitably leads to the need for more transmission.

Various studies, including the draft study titled "National Transmission Needs Study" released from the U.S. Department of Energy ("DOE") in February 2023, indicate an unprecedented need for transmission buildouts that effectively double or triple the existing transmission grid over the next 10 to 20 years. This equates to, at a minimum, tripling the level of transmission investment of today (estimated to be ~$25 billion a year) for the foreseeable future. There will likely be challenges, including the physical ability (e.g., logistical challenges, including supply chain and human resources) and economic feasibility (e.g., impact on rates), especially if the focus is limited to the traditional transmission projects (or "wires options").[1]

When developing transmission expansion strategies to achieve these ambitious goals, Grid-Enhancing Technologies ("GETs") should be part of the solution.[2] These technologies represent a new model for increasing grid infrastructure by unlocking additional capacity on the existing transmission system, and can be developed much faster and in a modular least-regrets manner at a small fraction of the cost of traditional transmission projects. Furthermore, they complement transmission buildouts by enhancing the utility of transmission infrastructure instead of eliminating or replacing it. GETs also magnify the capabilities provided by and the cost effectiveness of new transmission investments. The complementary benefits of GETs emerge ***before*** traditional transmission projects are developed, activate ***during*** construction of the transmission projects, and continue ***after*** the newly developed transmission projects are put in

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1 Most of these studies focused on the traditional "wires options" for building transmission, and while some recognize non-wires options, including Grid-Enhancing Technologies ("GETs"), they are not considered as part of the solution.

2 GETs considered in this white paper are limited to Dynamic Line Ratings ("DLR"), Flexible Alternating Current Transmission Systems ("FACTS") for flow control, and Topology Control.

service. This white paper illustrates these effects through actual GETs examples, and quantifies, where possible, the complementary benefits in monetary terms.

The benefits of GETs start _before_ traditional transmission projects are developed. Planning for and building new transmission typically takes five to ten years or longer. Many GETs can be installed in under a year to alleviate congestion and help integrate more resources before the new transmission projects are put in place. Furthermore, examples discussed in this white paper demonstrate that the payback period on GETs investment are minuscule, measured in months, rather than years. GETs are scalable and their deployments are reversible—unlike other capital-heavy investments, they can be removed (and relocated) if the need is no longer there. The portability, scalability, reversibility, and comparatively smaller investment size of GETs provide flexibility to address transmission issues *before* new transmission is built. This option is particularly effective when there is uncertainty about the future, for example with the pace of load growth, or changes in flow patterns. Examples of GETs deployment include Topology Control and Dynamic Line Ratings ("DLR") to reduce congestion, and multiple GETs [DLR, Topology Control, and Flexible Alternating Current Transmission Systems ("FACTS") devices for flow control] at a regional level to integrate more renewables. In addition, GETs that provide immediate solutions to existing grid issues could allow more time to develop traditional transmission solutions, and simultaneously delay capital investments.

The complementary benefits of GETs continue _during_ the construction of traditional transmission solutions by reducing the impact of outages or avoiding outages entirely. Installing GETs as the solution (in particular, DLR and Topology Control) often does not require transmission outages, or only require a shorter outage. When the preferred solution is to build new (or reconductor existing) transmission, GETs could help alleviate the impact of transmission outages needed for upgrading existing lines and interconnecting the new line(s) into the existing grid. Examples of GETs mitigating congestion or reducing outage needs discussed in this white paper include Topology Control and FACTS devices for flow control. During the outage planning process, Topology Control software can be used to identify options that minimize the impact of outages.

GETs can further help increase the value of new traditional transmission projects _after_ they are put in service. For example, GETs can increase the utilization of the existing system [which will include the newly added line(s)], hence increasing the Benefit to Cost ratio of any given transmission project.[3] This could allow for more transmission projects to pass the selection threshold (the Benefit to Cost ratio is one of the key metrics used), potentially increasing the number of validated transmission projects. Previous analysis of the Southwest Power Pool ("SPP") system has shown that GETs will increase the utilization level of existing 345 kV lines by 16%. GETs can also be deployed after the fact to mitigate unanticipated consequences triggered by the new line(s). For example, if energizing the new line(s) results in unintended congestion, such as those on the underlying lower voltage lines, GETs could be quickly deployed to address it. Finally, GETs can contribute to system resiliency under extreme conditions as they provide means for situational awareness and operational remedies. Examples included in this white paper are for severe weather conditions.

The complementary nature of GETs will help the unprecedented transmission buildout in multiple ways. *First*, combining GETs and transmission **enhances the value of the transmission projects**. Previous analysis of the SPP system shows GETs increasing the utilization level of 345 kV lines by 16%. This allows for a larger pool of transmission projects to pass the Benefit to Cost ratio threshold and be considered as part of the solution. *Second*, combining GETs and transmission will **reduce the overall amount of transmission needed and contribute to a lower overall cost of the transmission buildout**, as this combination could significantly increase the amount of renewable integration—the aforementioned SPP analysis shows adding GETs doubled the amount of renewables integrated, thereby suggesting transmission needs could be reduced by half. The same SPP analysis indicated investment cost reduction of more than 45%. *Third*, deployment of GETs nationwide **will reduce congestion costs**, which exceeded $13 billion in 2021. This may become even more important as the prospect of a historic buildout of new transmission (and upgrades) over the next 10 to 20 years implies a significant increase in congestion during construction-related outages. Examples reviewed in this white paper suggests 40% or more of congestion can be mitigated by GETs. Congestion mitigation alone, even if partial, will likely pay for the GETs. Mitigation of outage related congestion, in particular those that occur *during* construction of new transmission projects, will further facilitate new transmission projects because their Benefit to Cost ratio improves. And *fourth*, the combination of lower costs and deployment flexibility (scalability and reversibility) of GETs **reduces the risks faced by**

[3] Transmission needs documented in various studies, including DOE's National Transmission Needs draft report, are typically based on economic models. The needs identified represent the transmission buildout that gets to the most cost-effective electricity system. Therefore, a higher transmission cost (i.e., higher than assumed) will lead to lower buildouts as the optimal solution. If transmission costs are lower, the optimal solution will recommend more transmission. Since GETs will reduce the cost of adding transmission, they will more often make transmission the more cost effective solution, and the economic models would suggest a solution with higher levels of transmission.

transmission developers and owners, especially during the dynamic transition period we are facing.

Overall, it is prudent to consider GETs as part of the solution to two key challenges of the energy transition: the physical ability of the system (e.g., logistical challenges, including supply chain and human resources) and economics of the transition (e.g., impact on rates). Incorporating GETs into transmission expansion will also align well with the recent Notice of Proposed Rulemaking ("NOPR") titled "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" (RM21-17-000) issued on April 2022 by the Federal Energy Regulatory Commission ("FERC"), which proposes to require that public utility transmission providers more fully consider GETs in their planning.

> *"We have to figure out as regulators at both the state and federal level how we can help utilities take advantage of this opportunity. It's real and it's exciting - we can take these big old clunky not-smart wires and turn them into more dynamic assets on the system. It will save customers money, and now is the time to do it as we are thinking about larger investments in bigger, more expensive backbone transmission."*
> [Allison Clements, FERC Commissioner, at the 2022 National Association of Regulatory Utility Commissioners ("NARUC") Annual Meeting and Education Conference]

I. Introduction

The U.S. energy industry is going through a massive transition, partially driven by decarbonization initiatives that often trigger and determine targets for increasing renewable generation resources, along with the economic competitiveness of these resources (over other resources.)[4,5] Large-scale (i.e., utility-scale) renewable resources typically have lower costs than those of smaller scale (i.e., distributed energy resources, such as rooftop solar panels) and are usually built in remote areas. The emergence of clusters of remote resources, combined with load growth (which could also accelerate with decarbonization initiatives electrifying load), inevitably leads to the need for more transmission.

4 As of the end of 2022, 29 states and Washington DC had Renewable Portfolio Standards and six states had Clean Energy Standards.

5 Today, renewable generation resources are best represented by wind and solar, though the makeup is expected to evolve as new resources emerge.

The exponential growth of planned new renewable resources has exacerbated the need for more transmission infrastructure. The recent study from the Lawrence Berkeley National Laboratory ("LBNL") titled "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022" ("LBNL Queued Up Study") suggests there are more than 10,000 projects adding up to greater than 2,000 GW of new resources (1,350 GW of generation and 680 GW of storage) awaiting interconnection to the transmission grid.[6] This includes nearly 950 GW of solar and 300 GW of wind, which when combined, roughly equals the installed nameplate capacity of the entire U.S. power plant fleet today.

Various studies estimate the U.S. will need to double or even triple its electric transmission capacity within the next few decades as the nation shifts toward a grid dominated by variable renewable energy resources.[7]

> *"The current power grid took 150 years to build. Now, to get to net-zero emissions by 2050, we have to build that amount of transmission again in the next 15 years and then build that much more again in the 15 years after that. It's a huge amount of change."*
> (Jesse Jenkins , Princeton University study coauthor)

A Princeton University study titled "Net-Zero America: Potential Pathways, Infrastructure, and Impacts" looks at five different pathways for the U.S. to achieve net-zero emissions and envisions expanding the U.S. electric transmission grid 60% by 2030.[8] The study further suggests the U.S. grid may need to triple in size by midcentury.

The National Renewable Energy Laboratory ("NREL") study titled "North American Renewable Integration Study" estimates that the U.S. is projected to need roughly two to three times more transmission delivery capacity to accommodate a surge in renewable energy development amid efforts to fully electrify the power, transportation and industrial sectors.[9]

Similarly, NREL finds in its "Interconnections Seam Study" the need for 40,000 to 60,000 GW-miles of alternating current ("AC") and up to 63,000 GW-miles of direct current ("DC")

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6 Lawrence Livermore National Laboratory, Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2022, April 2023.

7 Most of these studies focused on the traditional "wires options" for building transmission, and while some recognize non-wires options, including Grid-Enhancing Technologies ("GETs"), they are not considered as part of the solution.

8 Study is available at: https://netzeroamerica.princeton.edu/?explorer=year&state=national&table=2020&limit=200

9 Study is available at: https://www.nrel.gov/analysis/naris.html

transmission to be added—by comparison, the U.S. has approximately 150,000 GW-miles in operation today.[10]

The Massachusetts Institute of Technology ("MIT") study titled "The Value of Inter-Regional Coordination and Transmission in Decarbonizing the U.S. Electricity System" suggests a roughly 90% increase in transmission capacity. The authors conclude this is in line with other studies showing that roughly a doubling in installed transmission capacity is required to be cost-optimal for electricity decarbonization in the U.S. and the European Union ("EU").[11]

The February 2023 draft study released from the U.S. Department of Energy ("DOE") titled "National Transmission Needs Study" estimates that the transmission system will need to grow by 57% by 2035 (compared to today) to comply with enacted policies (including the bipartisan Infrastructure Investment and Jobs Act of 2021 and the Inflation Reduction Act of 2022).[12] This suggests transmission needs to grow by almost 5% every year through 2035. DOE estimates that a higher load growth (driven by load electrification) scenario will require to effectively double today's transmission by 2040. This scenario would require an average growth of slightly above 5% every year through 2040. In addition to these new needs, a large share of the existing transmission facilities are approaching the end of their economic life and will require upgrades, if not replacement. This compounds the need for even more transmission.

> *"Accelerating our transition to a renewable energy economy necessitates significant investment in our nation's antiquated transmission infrastructure."*
> (Greg Wetstone, CEO, American Council on Renewable Energy)

And yet, recent investment in transmission has been far below this level. The North America Electric Reliability Corporation ("NERC") estimates in its Transmission Availability Data System ("TADS") data and State of Reliability Reports that the total transmission system (for 100 kV and larger) of today is about 500,000 miles.[13] Comparing the 2021 and 2022 publications of the State of Reliability Report suggests the annual transmission addition (for 100 kV and larger) to be around 7,500 miles, or 1.5% of today's existing 500,000 miles. Comparing the 2015 and 2021

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10 Study is available at: https://cleanenergygrid.org/wp-content/uploads/2018/08/NREL-seams-transgridx-2018.pdf, https://www.nrel.gov/analysis/seams.html

11 Study is available at: https://www.cell.com/joule/fulltext/S2542-4351(20)30557-2?_returnURL=https://linkinghub.elsevier.com/retrieve/pii/S2542435120305572?showall%3Dtrue

12 Department of Energy, Draft National Transmission Needs Study, February 2023.

13 2022 State of Reliability Report shows 511,099 miles of lines rated at >100 kV. The report is available at: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2022.pdf. The 2021 State of Reliability Report shows 503,551 miles of lines rated >100 kV. The report is available at: https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2021.pdf.
The TADS data is available at: https://www.nerc.com/pa/RAPA/tads/Pages/default.aspx ?

vintages of the TADS data suggests the annual transmission addition (for 100 kV and larger) to be less than 9,000 miles, or 1.8% of the total transmission that exists today. NREL estimates in its "Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035" report that in 2013, about 4,100 miles of transmission above 230 kV were completed, and that this was the most in a single year between 2010 and 2020. The TADS data reveals that about half of all transmission additions are at voltage levels lower than 200 kV. Combining the NREL observation and TADS data suggests roughly 8,000 miles of new additions annually, or 1.6% of the total transmission that exists today. Finally, NERC's Long-Term Reliability Assessment ("LTRA") projects approximately 15,500 miles of new transmission to be built over the next ten years. This indicates an average annual increase in the size of the bulk transmission system of 0.3%.[14] In all cases, in order for the pace of transmission buildout to approach the aforementioned 5% level, the buildout needs to be three times of what we observe today.[15] The magnitude and pace, further combined with other logistical limitations (e.g., manufacturing of equipment, and skilled labor) and regulatory policy implications (e.g., environmental justice issues, capping increase in electricity rates and protecting consumers) that may exist, make the task of expanding transmission capacity even more challenging, especially if the solution is limited to the "wires options" ("traditional transmission").

In addition, uncertainty surrounding transmission buildouts has increased. Renewable and storage assets can be built quite quickly, sometimes in less than a year. The aforementioned LBNL Queued Up Study shows that over 60% of the projects [73% of solar (695 GW), 69% of storage (472 GW) and 48% of wind (145 GW), adding up to 1,262 GW of total capacity in the generation interconnection queue] have proposed online dates by end of 2025. Many projects are not expected to realize—LBNL discusses historical observations showing that only 21% of all projects (14% of capacity) proposed between 2007 and 2020 reached commercial operation by the end of 2022 while 72% of all projects were withdrawn.[16] Furthermore, flow patterns observed are generally expected to become more complex and variable as more renewable resources are built and load profiles change with energy efficiency, demand response, distributed energy resources,

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[14] NERC's 2022 LTRA shows a cumulative level of 15,495 miles of transmission (>100 kV) in construction or stages of development for the next 10-years, and suggests that level to be near averages of the past five years. The report is available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf,

[15] Increasing transmission at the rate of 5% a year will grow the transmission system by 50% over the next ten years, and double the transmission system over the next 20 years. This is not enough to double today's transmission by 2040, as the DOE National Transmission Needs Study suggest would be needed under high load growth.

[16] This rate was even lower for wind (at 20%) and solar (at 14%).

electrification, and further diversified consumer behaviors. This change contributes to additional uncertainty and the potential risk of stranded assets for transmission owners.

When developing strategies to address the urgently needed transmission capacity expansion, Grid Enhancing Technologies ("GETs") should be considered as part of the solution.[17,18] First, these technologies can increase transfer capabilities of the existing grid. When compared to the traditional transmission buildout options, GETs—taking advantage of recent technology improvements in electronics, communications, computational power, and optimization algorithms—can be implemented much faster for a small fraction of the cost. And they are portable, making the changes scalable and reversible. If deploying GETs at a given location did not work as anticipated, it could be removed—akin to a portable Global Positioning System ("GPS") that you can replace without impacting the function of the car. Second, these technologies are complementary to the traditional transmission investments—they can be used to enhance the capability of the existing grid as well as magnify the capabilities provided by and the cost effectiveness of new transmission investments. GETs, as their name suggests, enhance transmission, not replace (or eliminate) it. In fact, GETs offer complementary benefits at all stages of transmission planning, construction, and operations. Third, utilizing GETs as part of the solution could help alleviate some of the other project risks and uncertainties (e.g., scheduling, logistics, and budget) indicated above.

II. Complementary Benefits of GETs at Different Stages of Transmission Expansion

Expanding transmission capacity is akin to expanding roads. When there is congestion (traffic), adding new transmission (roads) could help alleviate that congestion. However, similar to the network of roads, transmission capacity does not rely solely on the physical transfer capability of the individual lines added. Rather, it varies by where and how the new lines are added, and often

[17] The Federal Energy Regulatory Commission ("FERC"), in its Notice of Proposed Rulemaking ("NOPR") "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection" (RM21-17-000, issued April 22, 2022), discusses GETs. Specifically, the NOPR proposes to require that public utility transmission providers more fully consider dynamic line ratings and advanced power flow control devices in regional transmission planning.

[18] Federal Power Act Section 219 (b) 3 added by the Energy Policy Act of 2005 ("EPAct") specifically points to "encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities."

depends on the underlying system (i.e., other system elements) to accommodate the new transfers. Just as a poorly designed highway off-ramp may cause unintended congestion on the highway, transmission transfer capability will also depend on where and how new lines are connected to the rest of the system—this is the topology of the transmission network (including the points of injection and withdrawal of energy). Both the transfer capability of lines (and other components of the grid) and network topology determine how, where, and the quantity of the power flows.[19] Many GETs are built on either of two applications to increase transfer capability: one that explores enhanced and flexible application of the pre-determined transfer capability; and the other that focuses on flexible and dynamic control of transmission systems.[20]

Examples of GETs discussed in this white paper are limited to three representative technologies, namely Dynamic line rating ("DLR"), Flexible Alternating Current Transmission Systems ("FACTS"), and Transmission Topology Control. DLR is a representative application that tries to better address the individual line's transfer capability. FACTS—a common category of power-electronics-based devices that allow for flexible and dynamic control of transmission systems—are examples of hardware solutions focusing on controlling the flow, and is functionally similar to Phase Shifting Transformers ("PST"), also known as Phase Angle Regulators ("PAR"). Transmission Topology Control is an elegant software alternative to these flow control hardware—it controls the flow by adjusting the system topology (for example, by opening or closing circuit breakers) and hence changing the flow distribution that is defined by Kirchhoff's Law to achieve operational objectives. There are various other technologies—many which have been shown to be robust and effective—that this white paper does not discuss and could be considered as well.

The comparative advantages of GETs include their portability and scalability (i.e., they can be added in phases without committing to a larger project), speed to deploy (i.e., they can be put into service much faster), and lower costs (i.e., they can be deployed often for a small fraction of the cost). GETs rarely replace transmission, rather, they enhance transmission—and their complementary benefits start ***before*** the traditional transmission projects are being developed, continue ***during*** construction of the transmission projects, and ***after*** the newly developed transmission projects are put in service.[21] The remainder of this section discusses the

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19 The mainstream practice of transmission planning today is to maintain the flows within pre-determined line limits, which are often developed under a very conservative set of assumptions, and assume the topology is fixed.

20 Other technologies that the authors are aware and some consider as GETs include (but not limited to) batteries and storage devices, and advanced cables and conductors.

21 Exceptions may include GETs deployment in occasions when reconductoring, or replacing lines are difficult, as sometimes observed on radial lines, transmission paths with limited rights of ways, or geographical consideration, such as terrains that make construction difficult and expensive.

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complementary benefits GETs can provide for these three periods. GETs benefits under extreme conditions (provided through situational awareness and operational remedies) are discussed later in *Section III. B. GETs Under Severe Conditions*.

A. Before Construction

Building new transmission typically takes five to ten years or longer. Many GETs can be installed in under a year to quickly help address existing or emerging issues, including congestion, ***before*** the new transmission projects are put in place. Furthermore, GETs are reversible—unlike other capital-heavy investments, they can be removed or relocated easily as needed. The portability, scalability, reversibility, and comparatively smaller investment size of GETs provide versatility to address transmission issues before new transmission is built. Some of the remedies could be planned as (or later become) permanent solutions. This option is particularly effective when there is uncertainty about the future, for example with the pace of load growth, or changes in flow pattern. In addition, GETs that are used to immediately ease existing grid issues could allow for delaying the traditional transmission solution development, which leads to more time to develop such projects and defers capital investments.

We discuss six examples of GETs proactively addressing transmission issues (e.g., alleviate congestion and integrate larger amounts of renewable resources) before the new transmission projects aimed to address the issues are put in place here.

CASE 1: TOPOLOGY CONTROL FOR SPP CONSTRAINTS

In 2022, NewGrid (a Topology Control software vendor) studied several SPP constraints and evaluated potential reconfiguration options. These constraints include the Osage to Webb Tap 138 kV line (for the loss of Sooner to Cleveland 345 kV line) and the Cimarron 345/138 kV transformer. The Osage to Webb Tap 138 kV line has been very heavily loaded and the constraint was breaching or binding in over 28% of all market intervals in April 2022. SPP had identified the constraint as "overlapping Reliability and Economic need" in its 2020 Integrated Transmission Planning ("ITP") Assessment Report.[22] A reconfiguration enabled 10% to 20% of increased flow on the Osage to Webb Tap 138 kV constraint. The Cimarron 345/138 kV transformer was breaching or binding over 5% of all market intervals in April 2022, leading to increased costs for load in Oklahoma City. SPP identified this constraint as the top "Operational Need" in the 2020 ITP Assessment Report. Reconfiguration reliably enabled 13%

[22] SPP, 2020 Integrated Transmission Planning Assessment Report, October 27, 2020, p. 66. Available at: https://www.spp.org/documents/63434/2020%20integrated%20transmission%20plan%20report%20v1.0.pdf

to 23% increased constraint throughput under congested conditions. SPP has implemented the reconfiguration solution identified for the Cimarron 345/138 kV transformer at times to prevent severe overloads of this constraint during summer peak (the constraint had an average real-time congestion shadow price of $80/MWh in 2022, binding more than 20% of all hours, adding to more than $30 million in annual real-time congestion costs).[23]

CASE 2: TOPOLOGY CONTROL FOR MISO CONSTRAINTS

NewGrid also addressed the constraint on the Lime Creek to Barton 161 kV line (for the loss of Quinn to Blackhawk 345 kV line), which has been a standing constraint recognized by the Midcontinent Independent System Operator ("MISO") for past years. NewGrid identified, and MISO implemented a reconfiguration of the Quinn 345 kV bus in May 2022. After this mitigation solution, between June 2022 and February 2023, this constraint bound only about 108 hours. Analysis indicates that over the same period, the constraint would have been binding more than 220 hours without the reconfiguration, suggesting a mitigation rate of over 50%.

CASE 3: TOPOLOGY CONTROL FOR ALLIANT ENERGY

On a larger, regional scale, NewGrid has been conducting a topology optimization pilot with Alliant Energy. The pilot identifies and analyzes beneficial reconfigurations, and requests and tracks their implementation to mitigate congestion costs affecting Alliant's customers. Interim study findings for congestion between October 2021 and May 2022 suggest that over 40% of the realized congestion costs (summing to more than $100 million for this period) could be avoided through reconfiguration.[24] Reconfigurations implemented so far using the ad-hoc request process have yielded about one fifth of the potential savings. With the implementation of the MISO reconfiguration request process, it is estimated that the relative impacts will increase.[25]

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[23] P. A. Ruiz, P. C. Ochoa, M. Myhre, R. Donaldson, X. Li, Congestion and Overload Mitigation using Optimal Transmission Reconfigurations – Experience in MISO and SPP, FERC Tech. Conf. on Increasing Market and Planning Efficiency through Improved Software (Docket No. AD10-12-013) Washington, DC, June 23, 2022. Available at: https://www.ferc.gov/media/congestion-and-overload-mitigation-using-optimal-transmission-reconfigurations-experience

[24] The impacts were calculated ex-post based on analyses of state estimator cases published by MISO and of historical market data. *Id.*, p. 16.

[25] Currently there are no established processes for requesting reconfigurations. Some of the solutions have not been requested due to the lack of such process.

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Reconfiguration solutions discussed in the three examples above are identified through a Topology Optimization software, which has very small incremental costs for additional usage. NewGrid, based on discussions with transmission owners, switching device manufacturers, and service providers, estimate the actual cost of reconfiguration is around $100 per switching action. Thereby, the cost of applying Topology Control is minuscule, when compared to the congestion cost savings measured in millions of dollars.

CASE 4: DLR FOR PPL 230 KV LINES

Ampacimon (a DLR vendor) installed DLR systems on three 230 kV lines (Harwood to Susquehanna lines #1 & #2 and Juniata to Cumberland line) in the PPL territory as a proactive remedy to avoid $23.5 million of annual congestion costs projected in 2025.[26] DLR, which provides 20% capacity gain above static ratings for 90% of the time (and cleared PJM's market efficiency window for the application), was selected because of the lower costs (less than $1 million for DLR compared to $20 million for reconductoring, and $40 to $60 million for rebuilding transmission), and speed of installation (less than 1 year with no outages for DLR compared to 2 to 3 years with extended outages for reconductoring, and 3 to 5 years with extended outages for rebuilding transmission). The investment cost ($1 million) is significantly smaller, representing only about 4% to 5% of the estimated congestion cost (of $23.5 million) for a single year.

CASE 5: DLR FOR UPSTATE NEW YORK

LineVision (a DLR vendor) installed DLR systems on two double-circuit 115kV lines in upstate New York, where the utility is experiencing strong growth in wind and solar generation. This DLR project, along with five miles of circuit rebuilds, is projected to reduce renewables curtailments by over 350 MW while further increasing the transfer capacity of the circuits by an additional 190 MW. The DLR project will avoid the need to rebuild 26 miles of transmission lines. With an estimated cost of $3.2 million, the project budget is less than the average cost of rebuilding just a single mile of a 115 kV line in the area, and will provide substantial cost savings for rate payers.

[26] PPL Electric Utilities (H. Lehmann, E. Rosenberger, and B. Elko), *Dynamic Line Ratings Operations Integration*, presented at PJM DLR Task Force Meeting, December 12, 2022 at https://www2.pjm.com/-/media/committees-groups/task-forces/dlrtf/2022/20221212/20221216-item-04---ppl-dlr-presentation.ashx

These examples demonstrate the speed and cost-effectiveness of DLR systems. Investment can be recouped within months, if not weeks. DLR further increases system awareness for the operators, which is a benefit that is not quantified.

CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP

In 2021, The Brattle Group released a study titled "Unlocking the Queue" that discussed how GETs (DLR, Topology Control, and FACTS together) can integrate twice the amount of renewables in the Kansas and Oklahoma region of SPP.[27] Observing over 9,000 MW of renewable projects that had already signed Interconnection Agreements (as of 2020) but had yet to proceed forward, the study analyzed how much of those projects could be integrated by 2025 (accounting for system changes, including planned transmission upgrades of approximately $1 billion) with and without GETs. The year 2025 was selected as it is not far enough to build significant transmission to accommodate more renewables. The case with GETs showed that over 5,200 MW can be integrated, while the case without GETS enabled less than 2,600 MW. The study also showed that the production cost benefits by these renewables alone would pay for the GETs investment costs of $90 million in six months.[28]

The six examples above illustrates how GETs can proactively address the pressing concerns (e.g., alleviate congestion and integrate larger amounts of renewable resources) before the new transmission projects aimed to address the issues are put in place. In addition, GETs that provide immediate solutions to existing grid issues could push back the traditional transmission solution development and provide benefits of allowing for more time to develop such projects and delayed capital investments. These benefits are not quantified in this white paper.

B. During Construction

GETs can minimize impact ***during*** construction by avoiding an outage altogether, or preventing congestion caused by transmission outages that occur while interconnecting the new projects. Topology Control software could also be used to identify the least impactful outage options.

The aforementioned DLR case for PPL (CASE 4: DLR FOR PPL 230 KV LINES) is an example where using GETs avoids any transmission outages associated with the upgrades. Where GETs

[27] The study is available at: https://watt-transmission.org/unlocking-the-queue/

[28] Other benefits identified in the study included carbon emission reduction and local tax and jobs. Expanded nation-wide, the study showed that GETs (with a $2.7 billion one-time investment) could lead to over $5 billion dollars in annual savings while reducing more carbon than those of all new cars sold in the US.

installations do require outages, they are much shorter than those required by traditional transmission projects. The following example shows how deploying GETs reduced the required outage.

> *"We are committed to providing reliable access to clean electricity to consumers at an efficient cost, and to playing our part in the energy transition. Technologies like this help us solve grid congestion and maximize the use of our existing grid, reducing, in some cases, the need for new infrastructure."*
> (Andrés Moreno Múnera, VP of Transmission and Distribution of Energy, EPM)

CASE 7: FACTS AND RECONDUCTORING COMPARISON

Empresas Públicas de Medellin ("EPM") of Colombia has identified high congestion across three transmission lines that would limit the output of distributed hydro in future years in a metropolitan area where electricity demand is forecast to strongly grow.[29] EPM needed a grid upgrade option that could quickly resolve the congestion at lowest cost to consumers and with minimal impact on local communities. EPM evaluated several network options, including reconductoring the transmission corridor, which though they would increase the capacity of the transmission corridor, could be costly and would further take several years to complete, including the lengthy permitting processes. This option would also have negative impacts, including reduced grid capacity during its construction as the line would be out of service. EPM estimated two to two and a half years for reconductoring depending on outage coordination. EPM decided to use Smart Wires' (a vendor of modular FACTS devices) Static Synchronous Series Compensators ("SSSC"s) at two substations, providing the capability to push power off the overloaded line and pull power onto underutilized lines. Construction of the SSSC is estimated at nine months with outage time for commissioning of less than a week. EPM recognizes the benefit of scaling up the deployments or relocate the SSSCs to an alternate location as system needs change over time.

The following three examples illustrate how GETs can help mitigate outages caused by traditional transmission projects.

CASE 8: FACTS FOR OUTAGE REMEDY

In 2015, Smart Wires analyzed the potential benefits of modular FACTS devices to support construction of new transmission lines. The utility needed to upgrade two 60 kV lines to two

[29] See: https://www.electricnet.com/doc/empresas-publicas-de-medellin-epm-announces-successful-effort-leveraging-modular-facts-0001

115 kV lines. Given the length and location of the lines (70 miles over a difficult terrain) and the need to replace the towers (from wood poles to steel towers), the estimated construction period was 3.5 years. Removing the two 60 kV lines required redispatch of generation, particularly in the summer season, to avoid overloading other nearby lines. The study identified that the redispatch could be avoided by installing modular FACTS devices that could reroute the flow from these otherwise overloaded lines. The annual costs of the modular FACTS devices were estimated to be between $1.5 million and $4 million, and the savings induced by avoiding redispatch were estimated to be over $20.5 million a year, therefore suggesting a savings of over $70 million (net-savings of $61.5 million to $69.7 million) over the construction duration period of 3.5 years (depending on when the construction starts). The $1.5 to $4.0 million investment is significantly smaller than (between 2% to 6% of) the avoided $70 million of congestion costs.

CASE 9: TOPOLOGY CONTROL FOR OUTAGE REMEDY

In 2021, NewGrid studied several topology optimization options to alleviate the impact of transmission outages, and the system operator (MISO) implemented them. One was for the outage of Helena to Scott Co 345kV line (located near Minneapolis) to rebuild the line. This rebuild required extended outages from February 2021 through October 2021. As a result, the Chub Lake 345/115 kV transformer (for the loss of the Chub Lake to Hampton 345 kV line) constraint faced severe congestion. For the first three months (between February and April 2021) of the Helena to Scott Co 345kV line outage, the Chub Lake 345/115 kV transformer constraint was binding for more than 260 time intervals (12% of all hours), adding up to over $13 million in congestion costs. After MISO implemented a reconfiguration solution identified by NewGrid at the beginning of May, the constraint did not bind at all. The reconfiguration successfully and reliably increased throughput by up to 56% in the area. Conservatively assuming a similar amount of congestion (typically congestion would increase during the summer with higher loads), the reconfiguration is estimated to have saved about $40 million in regional market costs during the nine months-period.

While not directly associated with transmission outages for line upgrades, NewGrid also identified a reconfiguration solution to remedy severe congestion observed on the Raun to Tekanah 161 kV line (for the loss of Beaver Creek to Grimes 345 kV line) when the Ft. Calhoun to Raun 345 kV line faced a month-long forced outage from February 12, 2022 through March 12, 2022. NewGrid's proposed reconfigurations (one reconfiguration of a substation and one opening of a transformer) were implemented and reduced the constraint binding down to 19 hours, from an estimated 114 hours, a mitigation rate of over 80%.[30]

The examples above illustrate how GETs can mitigate the impact of outages specifically during construction. Similar benefits are expected for other outages as well, even after the new transmission project is put into service, as discussed in *Section II. C. After Construction*. It is generally assumed that more than half of congestion observed today are from transmission outages. As a reference, SPP's 2016 Regional Cost Allocation Review ("RCAR") report assumes there are about 7,000 transmission outages per year in SPP.[31]

C. After Construction

GETs can increase the value of the transmission projects ***after*** they are put in service in several ways. First, they can increase the utilization of both the new line(s) and the existing system, which increases the Benefit to Cost ratio of any given transmission project. This could allow for more transmission projects to pass the selection threshold (such as the Benefit to Cost ratio), and potentially enlarge the pool of potential transmission projects to be built. The complementary character of GETs is not limited to traditional transmission, but also with other GETs, which could further increase the benefits for transmission. This could allow for more transmission projects to pass the selection threshold (such as the Benefit to Cost ratio), and potentially increase the count of transmission projects to be built. Second, if energizing the new line results in unintended congestion, such as those on the underlying lower voltage lines, GETs could be quickly deployed to address it. This section discusses examples of each of these types here.

CASE 6 (REVISITED): GETS FOR INTEGRATING MORE RENEWABLES IN SPP

While very few new high-voltage lines have been built in recent years, SPP has built a network of 345kV lines. The aforementioned "Unlocking the Queue" study, which modeled SPP, shows that GETs could enable 2,600 MW more of renewables. The study accounts for the projected 2025 system conditions, including transmission projects scheduled to be in service by then. The results showed that the value of these transmission projects increased as GETs enabled more renewables and lowered production costs. A post-study analysis of the study material

[30] The substation reconfiguration was implemented for a single day on February 15th, and the transformer opening was implemented on February 16th for the duration of the outage. Post-analysis indicates that if both reconfiguration suggestions were implemented, the constraint would not have bound.

[31] RCAR report is available at: https://www.spp.org/documents/46235/rcar%202%20report%20final.pdf

found the average utilization of the 345 kV lines in Kansas and Oklahoma (including the newly added lines) with GETs (DLR, Topology Control, and FACTS together) to be 16% higher than the case without GETs. This observation illustrates how GETs can increase the value of newly added transmission projects.[32] Combining GETs may allow for more new transmission projects to pass the Benefit to Cost ratio threshold, leading to more validation and realization of transmission projects.[33]

CASE 10: FACTS AND DLR

In 2023, Smart Wires studied the combined capabilities of its FACTs device (digital power flow control technology) and DLR to increase grid capacity for 110 kV and 220 kV lines in Latin America for a set of scenarios. The study area projected high levels of renewable curtailment occurring in the study year (2024) and had high probability of new wind and solar generation seeking to interconnect into the area. Without any GETs, the available capacity on surrounding circuits would be 350 MW—which is significantly lower than the nominal system capacity. Congestion on three 220 kV circuits limited the output of existing and new generation resources in the area. Applying DLR alone increased transfer capability on this path by 100 MW. Adding flow controlling FACTs devices in two locations further increased the transfer capability by another 150 MW, resulting in a combined increase of 250 MW. When the control of the two GETs was harmonized (through software), over 300 MW of capacity was unlocked, increasing the total flow limit from 350 MW to 650 MW. This example shows how the combination of multiple types of GETs can complement each other and further increase the benefits.

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32 While the increased utilization was observed everywhere, the level did vary by project portfolio. The increase for the Balanced Portfolio (five 345 kV projects) was at 22% while it was 15% for the newly added 345 kV lines. This is likely because the renewable resources assumed in the study were those with Interconnection Agreements already signed today, indicating developers planned around the existing grid, rather than the future grid with additional upgrades. Yet, it does show positive benefits, even for the newer lines.

33 This example illustrates how GETs could increase the Benefit to Cost ratio of existing transmission assets. While a direct comparison to the original Benefit to Cost ratio is not possible, a 16% utilization increase, which is driven by more renewables, would likely increase the Benefit portion of the Benefit to Cost ratio by a similar amount, if not more. This indicates that a project that originally showed a Benefit to Cost ratio of 1.0 will now show 1.16, while a project that originally showed 1.25 will now show 1.45. A project that originally showed a Benefit to Cost ratio of 0.87 may now exceed 1.0, which is the decision threshold in some jurisdictions. The higher benefits brought by GETs would increase the number of traditional transmission projects to be permitted for construction within each jurisdiction.

CASE 11: DLR AND OFFSHORE WIND CURTAILMENT

In 2022, LineVision installed its DLR platform for National Grid U.K. on a 275 kV circuit connecting Penwortham and Kirkby in Cumbria (north of England). This line has been experiencing congestion and curtailment as a result of surplus offshore wind generation. The project is estimated to provide an increase in capacity averaging more than 45%, which will allow 500 MW more renewable power to be carried. National Grid U.K. estimates the project will save £1.4 million (roughly $1.75 million) in network operating costs.

Other examples from *Section II. A. Before Construction* (see CASE 1: TOPOLOGY CONTROL FOR SPP CONSTRAINTS, CASE 2: TOPOLOGY CONTROL FOR MISO CONSTRAINTS, CASE 3: TOPOLOGY CONTROL FOR ALLIANT ENERGY, CASE 4: DLR FOR PPL 230 KV LINES, CASE 5: DLR FOR UPSTATE NEW YORK), and *Section II. B. During Construction* (see CASE 7: FACTS AND RECONDUCTORING COMPARISON, CASE 8: FACTS FOR OUTAGE REMEDY and CASE 9: TOPOLOGY CONTROL FOR OUTAGE REMEDY) illustrate similar applications of GETs mitigating congestion without waiting for more transmission builds to remedy the situation.

GETs can be utilized in ways beyond simply mitigating congestion. One example is using the Topology Control software to estimate the impact of outages.

CASE 12: TOPOLOGY CONTROL FOR OUTAGE SCHEDULING

NewGrid's Topology Control software could be used in ways other than identifying reconfiguration options for mitigating congestion. The software technology, designed to analyze changes in topology, can be used to analyze the impact of adding or removing a line or a group of lines. This ability provides unique applications of the software, such as evaluating the impact of transmission outages (for outage planning), identifying critical elements of the system (for general protection, to minimize load shedding caused by the loss of any elements, or to develop storm response and/or restoration orders), and evaluating the benefits of new lines (effectively "reconfiguring" the topology by adding a new line).

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III. GETs as Part of the Solution

As the previous section discussed through examples, GETs are complementary to traditional transmission projects and help enhance their value. The complementary nature of GETs is ideal to support the unprecedented transmission buildout (as discussed in *Section I. Introduction*), where the industry is seeking to *more than triple* the amount of transmission that is being added to the system annually over the next decade or two.

> *"Optimizing our existing transmission grid infrastructure to utilize its full capacity will prevent unnecessary costs and investment, leading to lower prices for consumers and faster deployment of new clean energy resources."*
> (Lisa Jacobson, President, Business Council for Sustainable Energy)

A. GETs for Future Planning

Figure 1 shows historical and projected estimates of the annual transmission investments for the U.S. The figure shows annual transmission investments to be around $25 billion in recent years.[34] If we assume investments need to triple, that would imply $75 billion of investments per year for the foreseeable future. This pace and magnitude of transmission buildout can lead to two types of challenges. The first is a question of logistics and supply chain—will there be enough resources (e.g., equipment and labor) to pursue it? Second is the cost—who would bear the cost of these upgrades that will continue every year for two decades (or more)? Investments of $75 billion per year would raise the average electricity rates by almost $3/MWh every year.[35,36] The increase could be even worse, if costs go up, or if the credit ratings of the utilities drop because of the

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[34] Historical transmission investment data is based on FERC Form 1 Plant in Service Addition data for each RTO. EEI projections are based on investment figures obtained from the EEI Transmission Capital Budget & Forecast Survey, supplemented with data from company 10-K reports and other investor presentations. See: Hitachi Powergrids, Velocity Suite: https://www.eei.org/resourcesandmedia/Documents/Historical%20and%20Projected%20Transmission%20Investment.pdf

[35] The Energy Information Administration ("EIA") data shows U.S.-wide generation from utility-scale resources in 2019 to be approximately 4,100 TWh. $75 billion in investment, assuming a 15% carrying charge, would lead to $75 billion * 15% / 4,100 TWh = $2.74/MWh increase in rates every year.

[36] DOE's draft National Transmission Needs report observed that regional entities spent, on average, around $1.88 per MWh of annual load on new transmission in the past decade (with regional variations between $0.19 and $5.29 per MWh). Using the same metrics would calculate $6.25 per MWh for the $75 million investment.

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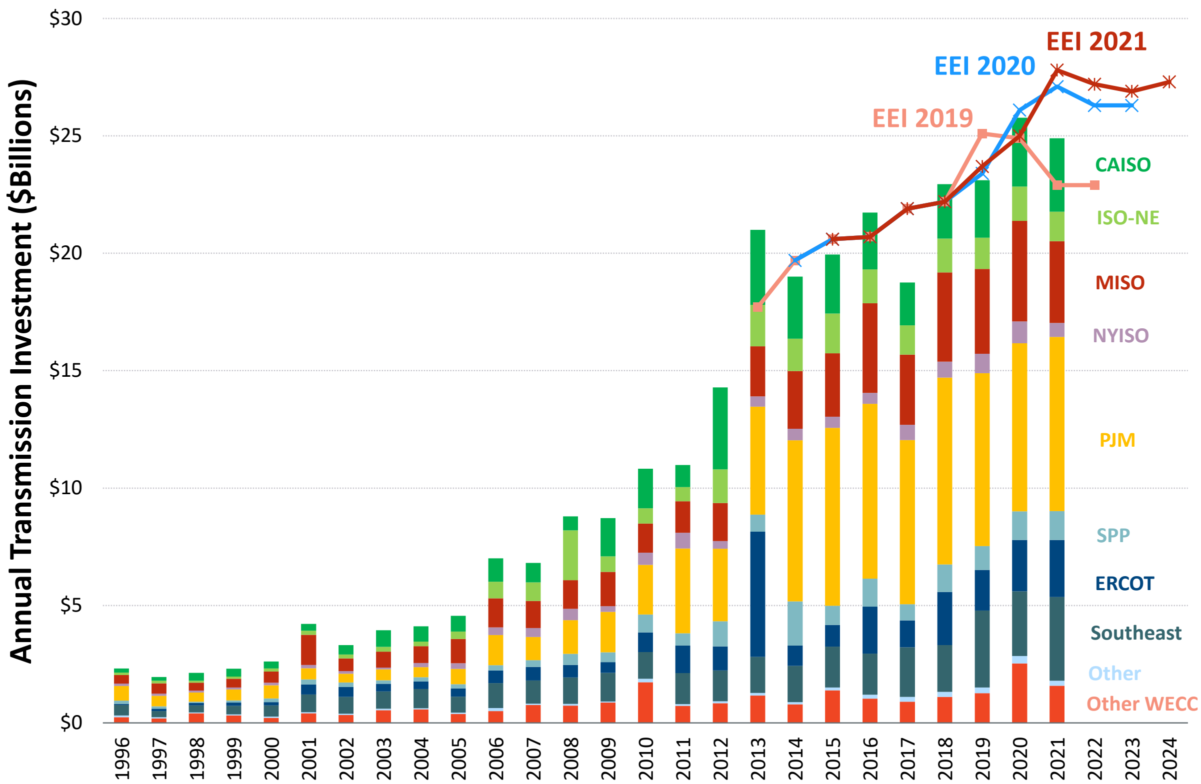
large amount of debt.[37] Regulators will have to make decisions regarding rate increases, and steps towards optimizing the transmission system should be welcome.

FIGURE 1: HISTORICAL AND PROJECTED ANNUAL TRANSMISSION INVESTMENT IN THE UNITED STATES



Source: FERC Form 1 Data, EEI "Historical and Projected Transmission Investment" most recent accessed here: https://www.eei.org/resourcesandmedia/Documents/Historical%20and%20Projected%20Transmission%20Investment.pdf

Including GETs can help expand transmission capacity in shorter timeframes and at lower costs.

First, GETs will lower the overall amount of transmission needed, as combining transmission projects with GETs could significantly increase the amount of renewable integration. CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP illustrates how adding GETs doubled the amount of renewables integrated, thereby, suggesting transmission needs could be reduced

[37] The Los Angeles Department of Water and Power estimated that a change in credit ratings by two notches could impact retail rates by roughly 20%. This impact is in addition to the rate increase associated with the new investments. See: Los Angeles Department of Water & Power Customers First, *Financial Considerations for LA100 Investments*, June 13, 2019 at https://www.ladwp.com/cs/idcplg?IdcService=GET_FILE&dDocName=OPLADWPCCB681897&RevisionSelectionMethod=LatestReleased

by half if GETs are co-planned with traditional transmission projects. CASE 5: DLR FOR UPSTATE NEW YORK shows co-planning GETs with traditional transmission projects is already happening.

Utilizing GETs will contribute to a lower overall cost of the transmission buildout thanks to their significantly lower cost compared to traditional transmission.[38] CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP suggests GETs could reduce investment cost by more than 45% to achieve similar renewable integration.[39]

It is perhaps note-worthy that GETs, once deployed widely, will likely pay for themselves through active congestion management. The savings from actively reducing congestion can vary greatly by the system and location. Congestion can be from multiple causes, including those triggered by outages during construction/interconnecting of a new lines. The prospect of a historic buildout of new lines (including upgrades) over the next decade or two implies a significant increase in outages and associated congestion.[40]

As the various examples from *Section II. Complementary Benefits of GETs at Different Stages of Transmission Expansion* illustrate, GETs can help mitigate, if not eliminate, congestion in many hours. CASE 8: FACTS FOR OUTAGE REMEDY shows FACTS completely eliminating congestion caused by transmission outages. CASE 9: TOPOLOGY CONTROL FOR OUTAGE REMEDY discusses two examples of Topology Control mitigating congestion caused by transmission outages—one example eliminated congestion completely while the other example mitigated it by over 80%. A recent study from MIT that analyzed the Electric Reliability Council of Texas ("ERCOT") suggests DLR can reduce congestion by 77%.[41] CASE 3: TOPOLOGY CONTROL FOR ALLIANT ENERGY shows Topology Control mitigated 40% of the congestion. These examples are

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38 For example, Topology Control solutions are software solutions and the incremental cost of software is considerably smaller than installing hardware. For DLR and FACTs associated solutions that involve hardware, examples (CASE 4: DLR FOR PPL 230 KV LINES, CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP, and CASE 7: FACTS FOR OUTAGE REMEDY) illustrate the comparatively lower costs, oftentimes around 5% or less of the congestion cost that is being tackled. In many cases the cost of GETs can be smaller than the range of estimates for traditional transmission solutions.

39 Future transmission projects added up to $1 billion (slightly above) and GETs costs were at $90 million. The case without GETs integrated less than 2,600 MW of renewables while the case with GETs integrated more than 5,200 MW. Assuming a linear correlation another $1 billion is needed to integrate 5,200 MW of renewables without GETs. This indicates integrating 5,200 MW of renewables can be done by adding $2 billion of traditional transmission projects, or $1.09 billion ($1 billion of traditional transmission projects and $0.09 billion of GETs)—the cost difference is more than 45%.

40 In general, roughly half of the annual congestion is thought to be caused by planned transmission outages.

41 "Impacts of Dynamic Line Ratings on the ERCOT Transmission System" available at: https://arxiv.org/pdf/2207.11309.pdf

for a single technology, and as CASE 10: FACTS AND DLR shows, combining GETs could perhaps mitigate congestion even further. [42]

A recent study released by Grid Strategies titled "Transmission Congestion Costs in the U.S. RTOs" estimates the US-wide congestion costs for 2021 to be $13.4 billion.[43] This value is quite higher than previous years with annual congestion estimated to be in the $6 to $9 billion range.[44] The report, while recognizing the impact of Winter Storm Uri, discusses how congestion rose in the northeast regions by 72% in 2021 from 2020, driven by two factors: load rebounding from COVID-19, and transmission development not keeping up with renewable energy growth.

Assuming 40% of this congestion could be avoided by GETs (from CASE 3: TOPOLOGY CONTROL FOR ALLIANT ENERGY where Topology Control can mitigate 40% of the congestion), the avoided congestion costs benefits would add to more than five billion dollars a year. In the many examples, the ability of GETs to mitigate congestion is much higher, especially if they are to be combined. CASE 6: GETS FOR INTEGRATING MORE RENEWABLES IN SPP calculates the cost to deploy GETs nation-wide to be about $2.7 billion, which indicates a half-year payback period.

Apart from the monetary value indicated here, GETs mitigating congestion triggered by transmission outages will also facilitate new transmission buildouts because reducing the negative impact caused by the outages would improve the Benefit to Cost ratio.

The uncertainty surrounding future market conditions warrants considering GETs. GETs are modular and scalable, allowing owners to adjust the size of the installments over time, rather than having to commit upfront. The example below compares the benefits of this feature.

CASE 13: FACTS AND PST COMPARISON

Smart Wires used real options analysis to compare two power flow control technologies—PST and modular Static Synchronous Series Compensators ("m-SSSC")—to find the optimal solution to resolve congestion on a 275 kV network. The difference between the two options is that m-SSSC devices are a flexible and scalable technology that can be easily expanded or relocated as system needs evolve over time. PSTs cannot be easily expanded, so the full solution needs to be built on day one. Accounting for unknowns and uncertainty associated

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[42] The various examples reviewed in this white paper suggests GETs costs would be a small fraction of the annual congestion costs, often around 5% or less.

[43] The study is available at: https://gridprogress.files.wordpress.com/2023/04/transmission-congestion-costs-in-the-us-2021-update.pdf

[44] The 2021 value certainly does include the impact of Winter Storm Uri. The impact of this storm is estimated to be about a quarter of the annual congestion cost for MISO (~$750 million).

with future projection, the m-SSSC option was shown to deliver greater benefits (higher risk-adjusted Net Present Value) compared to the PST as it enabled the transmission owner to adapt the solution size depending on which scenario became the reality. This modularity and flexibility advantage would be ideal to be used in addressing the unintended congestion discussed above, especially because the magnitude of the unintended congestion may evolve over different seasons, or years.

Finally, the speed of deployment is another reason to consider GETs. GETs being modular and scalable can be installed much faster, as various examples, including CASE 4: DLR FOR PPL 230 KV LINES and CASE 7: FACTS AND RECONDUCTORING COMPARISON, show.

When combined with the lower costs and reversible deployments, this flexibility significantly lowers the risk of deploying GETs.[45] In addition, as CASE 4: DLR FOR PPL 230 KV LINES illustrates, the lead-time for installation is much shorter, and often does not require transmission outages. Finally, unlike many other capital-heavy assets, GETs are portable and can be removed once the need goes away. All these characteristics (portable, scalable, reversible, and low cost) point to GETs having very low risk in deploying. It would be ideal for utilities that are cash-strapped but still need to grow their transmission.

B. GETs Under Severe Conditions

GETs can serve system operators well during extreme situations, also offering another benefit to the existing and future transmission system. GETs, especially DLR systems, will naturally increase the situational awareness of the weather and asset conditions by location at a much more granular level than is currently available. Second, some GETs provide means to control the flow for purposes exclusively to address extreme conditions, providing resiliency benefits. This section introduces four examples.

> *"The information we are collecting is helping us better balance strong resiliency while holding down costs."*
> (David Quier, VP of Transmission and Substation, PPL, on DLR)

[45] The logistical/supply chain uncertainties and bottlenecks (including resource availability and scheduling delay) discussed briefly earlier, should be less severe if GETs are included as part of the solution.

CASE 14: DLR AND EXTREME WEATHER

The value of DLR was demonstrated during the 2018 "bomb cyclone" when a 13-day cold snap between December 25, 2017 and January 8, 2018 constrained a large portion of the Northeast U.S. grid.[46] During this extreme event, which featured higher loads triggered by colder weather, ISO New England ("ISO-NE") issued an abnormal conditions alert to address both the weather and supply concerns. ISO-NE also increased their transmission line ratings (made possible by the cold conditions, which helped to improve thermal transfer capability), including the scheduling limits on the AC ties into New York (from 1,400 MW to 1,600 MW), which helped avoid large congestion costs.

CASE 15: FLOW CONTROL DEVICES AND EXTREME WEATHER

Flow control devices also played a major role during the same 2018 cold snap. During this event, the New York Independent System Operator ("NYISO") saw a 50% to 100% increase in downstate prices (in particular, Zone J: New York City, in comparison to the Western region, Zone A: West), and initiated several NERC Transmission Loading Relief ("TLR") alerts. The two Ramapo PARs enabled NYISO to direct flows from PJM into eastern New York using its 500 kV path. NYISO has publicly acknowledged the reliability benefits that their PARs have previously provided: "The control capability provided by the two Ramapo PARs increases operational flexibility for NYISO. Power injections can be directed where needed for reliability."[47]

CASE 16: TOPOLOGY CONTROL AND EXTREME WEATHER

The Brattle Group supported a utility in the upper Midwest to mitigate congestion and overloads under the extreme weather conditions during the Polar Vortex event of 2014. This weather event led to record-setting high loads in MISO due to extreme cold weather coupled with substantial number of unplanned generation outages triggered by the low temperatures. The very high loads and generation outages combined with extended 230 kV planned transmission outages led to severe post-contingency 115 kV transmission congestion and overloads affecting transmission utilities in the upper Midwest. The heavy congestion and overloads resulted in increasing the cost of electricity in the affected areas by over $15 million in the first 10 weeks of 2014. The Brattle Group performed a topology optimization analysis for one of the utilities impacted and identified reconfiguration solutions that relieved much of the congestion and overloads. These solutions were implemented by MISO after validation

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[46] See ISO-NE, Cold Weather Operations: December 24, 2017–January 8, 2018, January 16, 2018

[47] W. Yeomans, NYISO, Ramapo Phase Angle Regulator Cost Recovery, May 31, 2017, p. 8.

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and discussion with the transmission owners in the area. The opportunity for improved performance with topology optimization under those severe conditions illustrate the resilience benefits of flow control technologies.

CASE 17: TOPOLOGY CONTROL TO AVOID ICING

In 2018, SPP studied the opportunity to apply flow control using topology control to heat lines and avoid icing during severe winter conditions.[48] The study was performed for the January 2017 Winter Storm Jupiter conditions, which led to multiple transmission outages caused by ice accumulation. The challenging conditions for restoration did not allow all outages to be addressed within the day. The study identified two reconfiguration solutions that could have prevented or significantly relieved the ice buildup on selected critical lines, while meeting reliability criteria. The estimated savings of hypothetical avoided outages of these critical lines were $10 to $17 million, in addition to the avoided costs of system restoration.[49]

While the occurrence (frequency, duration, magnitude) of these events and benefits of the remedies are difficult to project, these examples illustrate that one event would likely more than pay for the costs of the GETs.

IV. Conclusion

The recent advancements in power electronics, communications, computer processing power, and optimization algorithms have led to the development of various new technology options designed to enhance the efficiency of the transmission grid. These new technologies, commonly known as GETs, include those that enable optimal and flexible application of the available transfer capacity, represented in this white paper by DLR, and those that focus on flexible and dynamic control of transmission systems, represented in this white paper by flow controlling FACTS devices and Topology Control software. When compared to major new transmission investments, GETs can be implemented much faster and often for a small fraction of the cost. As

48 This was a well-known practice many decades ago, see H.B. Smith, and W.D. Wilder, "Sleet-melting practices—Niagara Mohawk system," *Transactions of the American Institute of Electrical Engineers. Part III: Power Apparatus and Systems*, Vol. 71, Issue 3, Aug 1952, pp. 631–634.

49 See Ruiz P., *et al.*, "Transmission topology optimization: pilot study to support congestion management and ice buildup mitigation," SPP Technology Expo, Nov 2018.

indicated by the cases above, the benefits of GETs accrue ***before***, ***during,*** and ***after*** the construction of new transmission lines.

- Before construction, GETs can reduce congestion by 40% or more.
- During construction, outages can be avoided or ameliorated, with similar reductions in congestion costs of 40% or more.
- And after construction, utilization on new lines can increase by 16%, improving the Benefit to Cost ratio of the new lines.

These technologies are highly complementary to transmission expansion through new lines. They can magnify the cost effectiveness and capabilities provided by new transmission investments. They provide short-term solutions to temporary operational challenges, such as during transmission outages or the construction of new lines, and bridge gaps until permanent expansion solutions can be put in place. They also are realistic alternatives for long-term solutions, particularly where building transmission makes less economic sense. GETs enhance transmission investments, rather than eliminating them, acting more as a tool to augment, akin to a GPS or tire air pressure sensor making driving easier—not by themselves replacing the car.

The needs for these technologies will only increase as the pace of the energy transition accelerates and necessitates doubling or even tripling of grid capacity over the next ten to 20 years. The pace and magnitude of this challenge requires an unprecedented effort and it is unlikely to succeed if transmission owners and planners only focus on the traditional transmission development approach. It is prudent to consider GETs—a complementary technology to transmission—as part of the solution for expanding future transmission.

> *"….from a Belgium perspective what I can say 10 years ago for dynamic line rating I mean we're talking about this internally, the system engineers are just looking at us like crazy guys, what are you speaking about. This is a gadget you want to install on the transmission line? It's just crazy, we're really against it, totally against these, the usual. And now 10 years later they're just asking for more. They just complain when there is congestion, and there no passing the line, and the customers, there are many other technologies probably as good as this, it's just complying and saying you should install more."*
>
> (Victor LeMaire, Operational Planning, Elia, during the 2021 FERC technical conference "Workshop to Discuss Certain Performance-based Ratemaking Approaches.")

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Glossary

AC	Alternating Current
DC	Direct Current
DLR	Dynamic Line Ratings
DOE	Department of Energy
EIA	Energy Information Administration
EPAct	Energy Policy Act of 2005
EPM	Empresas Públicas de Medellin
ERCOT	Electric Reliability Council of Texas
EU	European Union
FACTS	Flexible Alternating Current Transmission Systems
FERC	Federal Energy Regulatory Commission
GETs	Grid-Enhancing Technologies
GPS	Global Positioning System
GW	Giga-Watt (1,000 mega-watts, 1,000,000 kilo watts, or 1,000,000,000 watts)
ISO-NE	ISO New England
ITP	Integrated Transmission Planning
kV	Kilo-Volt (1,000 volts)
LBNL	Lawrence Berkeley National Laboratory
LTRA	Long-Term Reliability Assessment
MISO	Midcontinent Independent System Operator
MIT	Massachusetts Institute of Technology
MW	Mega-Watt (1,000 kilo-watts, or 1,000,000 watts)
m-SSSC	Modular Static Synchronous Series Compensators
NARRUC	National Association of Regulatory Utility Commissioners
NERC	North American Electric Reliability Corporation
NOPR	Notice of Proposed Rulemaking
NYISO	New York Independent System Operator
PAR	Phase Angle Regulators
PST	Phase Shifting Transformers
RCAR	Regional Cost Allocation Review
SPP	Southwest Power Pool
SSSC	Static Synchronous Series Compensators
TADS	Transmission Availability Data System
TLR	Transmission Loading Relief
TW	Terra-Watt (1,000 giga-watts, 1,000,000 mega-watts)

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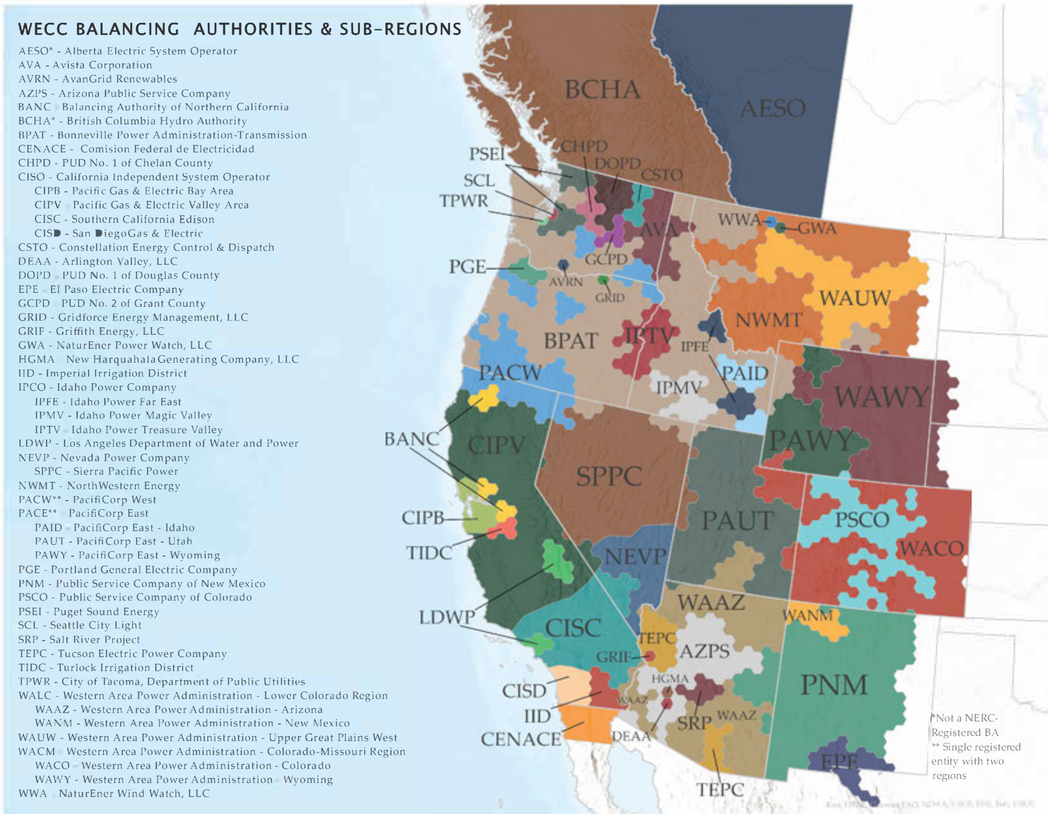
WECC BALANCING AUTHORITIES & SUB-REGIONS
AESO* - Alberta Electric System Operator
AVA - Avista Corporation
AVRN - AvanGrid Renewables
AZPS - Arizona Public Service Company
BANC - Balancing Authority of Northern California
BCHA* - British Columbia Hydro Authority
BPAT - Bonneville Power Administration-Transmission
CENACE - Comision Federal de Electricidad
CHPD - PUD No. 1 of Chelan County
CISO - California Independent System Operator
CIPB - Pacific Gas & Electric Bay Area
CIPV - Pacific Gas & Electric Valley Area
CISC - Southern California Edison
CISD - San DiegoGas & Electric
CSTO - Constellation Energy Control & Dispatch
DEAA - Arlington Valley, LLC
DOPD - PUD No. 1 of Douglas County
EPE - El Paso Electric Company
GCPD - PUD No. 2 of Grant County
GRID - Gridforce Energy Management, LLC
GRIF - Griffith Energy, LLC
GWA - NaturEner Power Watch, LLC
HGMA - New Harquahala Generating Company, LLC
IID - Imperial Irrigation District
IPCO - Idaho Power Company
IPFE - Idaho Power Far East
IPMV - Idaho Power Magic Valley
IPTV - Idaho Power Treasure Valley
LDWP - Los Angeles Department of Water and Power
NEVP - Nevada Power Company
SPPC - Sierra Pacific Power
NWMT - NorthWestern Energy
PACW** - PacifiCorp West
PACE** - PacifiCorp East
PAID - PacifiCorp East - Idaho
PAUT - PacifiCorp East - Utah
PAWY - PacifiCorp East - Wyoming
PGE - Portland General Electric Company
PNM - Public Service Company of New Mexico
PSCO - Public Service Company of Colorado
PSEI - Puget Sound Energy
SCL - Seattle City Light
SRP - Salt River Project
TEPC - Tucson Electric Power Company
TIDC - Turlock Irrigation District
TPWR - City of Tacoma, Department of Public Utilities
WALC - Western Area Power Administration - Lower Colorado Region
WAAZ - Western Area Power Administration - Arizona
WANM - Western Area Power Administration - New Mexico
WAUW - Western Area Power Administration - Upper Great Plains West
WACM - Western Area Power Administration - Colorado-Missouri Region
WACO - Western Area Power Administration - Colorado
WAWY - Western Area Power Administration - Wyoming
WWA - NaturEner Wind Watch, LLC
BCHA
AESO
PSEI
CHPD
DOPD
CSTO
SCL
TPWR
AVA
WWA
GWA
GCPD
PGE
AVRN
GRID
WAUW
NWMT
BPAT
IPTV
IPFE
PACW
IPMV
PAID
WAWY
BANC
CIPV
PAWY
SPPC
CIPB
PAUT
PSCO
TIDC
NEVP
WACO
LDWP
WAAZ
WANM
CISC
TEPC
GRIF
AZPS
CISD
HGMA
PNM
IID
WAAZ
SRP
WAAZ
CENACE
DEAA
EPE
TEPC
*Not a NERC-Registered BA
** Single registered entity with two regions

WECC

Electric Reliability and Security for the West

Draft DOE Transmission Needs Study
WECC Public Comments
April 10, 2023

Introduction

WECC is thankful for the opportunity to provide further feedback on the Department of Energy (DOE) draft 2023 Transmission Needs Study.

Please reach out to support@wecc.org with any questions about the comments below.

Links

- On page 32, the "WIUFMP FERC tariff" link produces a server error. The related "Unscheduled Flow Mitigation Plan (WIUFMP)" published in 2019, which may be a useful, contemporary reference for inclusion or replacement: https://spp.org/Documents/62460/081919%20WIUFMP%20Tariff.pdf

- On page 35, there is a paths map with a link referencing a "2013 WECC Paths Report." WECC published the following "2023 Path Rating Catalog," which includes updated maps and path ratings: https://www.wecc.org/Reliability/2023%20Path%20Rating%20Catalog%20Public.pdf

Map of Western Interconnection Balancing Areas

The map of Balancing Breas (BA) in the Western Interconnection on page 37 has been updated. Please see attachment.

Names

- Please note that the "Northwest Power Pool (NWPP)" was re-named the "Western Power Pool (WPP)" in 2021.

- The WECC footprint is not a market. The recommended term is "Western Interconnection" in the three instances where other nomenclature is used. Two instances occur on page 47, in the second paragraph, and a third occurs on page 75 (in the second paragraph, to replace "WECC region").

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From: [redacted]
To: NeedsStudy.Comments
Subject: [EXTERNAL] Comments on the Public Draft: Entire study
Date: Tuesday, March 21, 2023 5:45:31 PM
Attachments: Comments on the Public Draft from William Driscoll.pdf

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The public draft does not consider flexible demand as a means to increase transmission utilization and reduce the need for new transmission.

The benefits of flexible demand are described in the following news stories:

> https://pv-magazine-usa.com/2022/06/15/real-time-pricing-that-balances-renewables-could-save-33-billion-per-year-study-finds/
>
> https://pv-magazine-usa.com/2022/07/22/california-rulemaking-to-pursue-demand-flexibility-through-dynamic-pricing/

These comments are copied into an attachment.

Sincerely,

William Driscoll, MPA, J.D.
Arlington, VA
William.L.Driscoll@gmail.com

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Xcel Energy comments on the National Transmission Needs Study

Xcel Energy appreciates the opportunity provided by the Department of Energy (DOE) to review and offer feedback on the National Transmission Needs Study. Xcel Energy believes that proactive planning to identify beneficial transmission expansion is a key element in the transition to the clean energy future in a safe, reliable, and affordable manner. Based on our extensive experience in large scale transmission expansion efforts, we understand the value of coordination, especially between those companies and regulatory bodies representing the customers and landowners directly impacted by these efforts. We greatly value any opportunity to further develop collaboration as is being sought in this request for feedback.

Through our efforts to achieve the most cost-effective outcomes for our customer, Xcel Energy has been a leader in developing many of the innovative efforts referenced in this and other independent study efforts.

Examples of efforts within the RTOs in which Xcel Energy has been a leader

- Upper Midwest Transmission Development Initiative
- Buffalo Ridge Incremental Generation Outlet projects
- CapX2020
- MISO 2011 Multi-Value Project Portfolio
- SPP Balanced Portfolio and Priority Projects
- MISO Renewable Integration Impact Assessment
- CapX2050 Transmission Vision Report
- MISO's Long-Range Transmission Plan

Examples of efforts outside of RTO processes:

- NREL Western Wind and Solar Integration Study, Interconnection Seams Study
- Partnership with NREL and Panasonic to develop and test distributed technologies to optimize a mixed-use neighborhood demand profile
- Colorado's Power Pathway

Our work as part of these efforts has solidified Xcel Energy as leader in the clean energy transition while ensuring a safe, reliable and affordable transmission system. Despite the notable efforts referenced, this list does not represent an exhaustive list of efforts undertaken by Xcel Energy to achieve our goals of carbon free electricity by 2050, or earlier in some areas.

Through our tireless efforts, one aspect remains constant – a focus on our end use customer. The coordination among utilities, customers, and the regulatory bodies overseeing these efforts has to occur transparently such that the true value of the project can be consumed by the least involved member of the public. This is imperative because utility customers, landowners and the public ultimately carry the burden of any grid expansion in their bills. This effort by DOE, shows significant progress towards this goal, but we believe the report is targeting an audience

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that is not involved in the day-to-day work planning the grid of the future, but instead, intended to educate and show the real value of proactive planning over a wide geographic area in a way that the public can comprehend. We feel the information currently included in the draft report contains the details needed, but with reasonable effort, could be modified to provide greater value. Given our extensive experience in such efforts, Xcel Energy stands ready to assist in those changes, given the approach is adopted.

To move this effort forward, Xcel Energy offers the following questions, concerns, and suggestions:

General Questions:

- The scenarios in the material reviewed covered a wide range of planning scenarios which is excellent. Additionally, there are a number of current efforts underway which may address some of the conclusions reached through this study. Accordingly, we recommend addressing current planning assessments, known projects, and depicting the outcomes as a gap and needs assessment.
    - More clarity on how these plans line up with the scenarios analyzed would provide significant value in determining realistic paths forward.
    - Regional transmission plans, Integrated Resource Plans and other utility-driven analyses may be able to better inform this comparison.
- Is it possible to broaden the technology assumptions used for the generation resource mix to analyze the benefits of dispatchable clean energy resources?
    - There seems to be a bias to a very heavy renewable energy future rather than a more comprehensive set of resource types, like inclusion of green hydrogen and advanced nuclear technologies.
    - Many states are advancing studies to explore new technologies including geothermal resources, long duration battery storage, advanced nuclear, and hydrogen resources.
    - Does the study incorporate DOE funding of various hydrogen hubs throughout the country and the likely propensity of hydrogen adoption in CT and CC technologies?
- The report states that there may be more value pairing increased connectivity between the northern portion of the Plains region and the Midwest combined with greater connectivity between the southern portion of the Plains region with the Delta region as opposed to greater connection between the Midwest and Delta regions.
        - Xcel Energy recommends additional analyses of this issue to determine the value of that could be provided by reducing policy limitations and hurdles to coordinated market operations on top of increased transmission capacity as described in the study.

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        - Options such as eliminating hurdle rates or joint planning and market operation may alleviate these constraints at an overall lower cost
- Has the DOE reviewed utility developed reports?
    - The studies reviewed are primarily developed by third parties that do not represent the rate-regulated entities that are required to show the cost-effectiveness of the plans as proposed.
    - The CapX2050 Transmission Vision Report is one example of material that could be referenced.
- How do the authors view risk and usefulness of assets?
    - Xcel Energy has found similar results to the stated result showing 50% or more of the value of an asset can be realized in the worst 5% of hours. To better clarify this issue, Xcel Energy recommends a deeper dive into the causes of the 5% of hours driving benefits and the probability of those system conditions presenting themselves over the life of new transmission assets. Increased risk will be an inevitability when proceeding to a clean energy future, but proper accounting of those risks allows for the most informed decisions be made.
        - Solutions to these risks will likely include a much larger set of options than just transmission expansion.

General comments on the draft report:

- The report states specific solutions are not included.
    - Xcel Energy reiterates that this effort could provide more value by discussing the value of increase connectivity rather than providing generic solutions between areas.
    - While not specific solutions, Xcel Energy views the findings of a range of transmission capacity expansion levels and discussion of non-wires alternatives as providing solutions.
        - Xcel Energy doesn't view this as a negative as we have identified the value of both proactive transmission expansion as well as the implementation of non-wires alternatives. In this case, we feel the generalized nature of the solutions provided offer little incentive to move forward to implementation of this study's findings.
- Transmission development to increase transfer capability on various seams is difficult to justify without much more detailed evaluation of benefits and consensus on assumptions:
    - FERC Order 1000 stopped short of requiring more than just interregional coordination of transmission plans. Some regions, such as MISO and SPP, saw the value of a more defined process and exceeded the minimum requirements of

that order but still have yet to see any major increase in interregional transmission capacity.

        - Lack of consistent interregional coordination, and lack of consistency in regions that did implement a more detailed process, have resulted in a failure to produce productive interregional transmission projects. As stated above, a coordinated view of the future is a cornerstone to transmission expansion. To date, lack of this coordinated view has been a primary hurdle to transmission development.
    - If we can ensure a coordinated interregional planning process, cost allocation remains a significant concern that needs to be resolved first before studies even begin—the cost allocation development process is long enough that studies risk becoming stale if projects are developed prior to cost allocation determination.
        - Xcel Energy recommends further discussion on how to either leverage existing cost allocation mechanisms, or to identify the gaps that need to be addressed in those mechanisms to ensure costs incurred implementing the findings of this study are just and reasonable.
- If we were to initiate a successful project development effort expanding on the findings of this draft report, how would the transmission needs be implemented?
    - How do the authors envision the development process working?
    - What is the group of stakeholders to be engaged?
        - Very broad group of stakeholders can be difficult to manage and achieve consensus, whereas too narrow of a stakeholder group may fail to provide any value
    - In this project development analysis, how would disputes be settled?
    - What would success look like? General achievement of reduced emissions, or specific implementation of transmission capacity increases?
- How would these transmission needs be aligned with state regulatory entities?
    - Any transmission needs should be aligned with state regulatory goals/positions, those states on seams that do not benefit should not be required to carry the burden of the project costs.
- In terms of cost responsibility, how would cost allocation be developed?
    - This issue has resulted in the failure of several interregional projects shown to be beneficial
- Xcel Energy was pleased to see that the set of benefits analyzed expanded to include the value of geographic diversity in resource needs, but also including the caveat that this alone is not the solution if local resource adequacy is not maintained.
    - Several areas discuss the need to reduce curtailment, but do not mention the various reasons why resources may be curtailed outside of transmission constraints, or the value that could be realized by reduced curtailment

        - A better definition of the causes of curtailment, both transmission and non-transmission related would add value.
        - In a future more dependent on variable resources, we feel that some level of curtailment should be expected as the most economic solution instead of attempting to drive that curtailment to zero.
            - MISO's RIIA indicated that renewables operating below the available output (referred to as 'headroom' in the analysis) can improve system stability. This could be considered an added value of curtailed energy output.
    - More context showing the marginal value provided by the relieving of transmission constraints as additional constraints are mitigated will increase understanding of the cost to benefit balance.
        - In my analysis of congestion relief, there is a point in which relief of a constraint is less cost effective than just incurring the cost of the congestion. This reducing impact should be better defined in the report.
- Discussions on queue levels and reform
    - Xcel Energy believes that Queue Reform alone will not fix the issues when moving to increased reliance on clean energy resources. An efficient queue process that can quickly differentiate between interconnection requests needs to be part of a larger, proactive planning process.
    - Several areas point to historically high queue levels being justification that we need transmission expansion. As can be seen below, queue levels are lumpy and more dependent on near-term activity, like Integrated Resource Plans and release of environmental goals, but is less aligned with long-term resource shifts. These requests are generally more focused on taking advantage of available transmission capacity rather than finding the most cost-effective locations. Utility-driven plans, company goals and local, state and federal energy policies are significantly more indicative of a clean energy transition.

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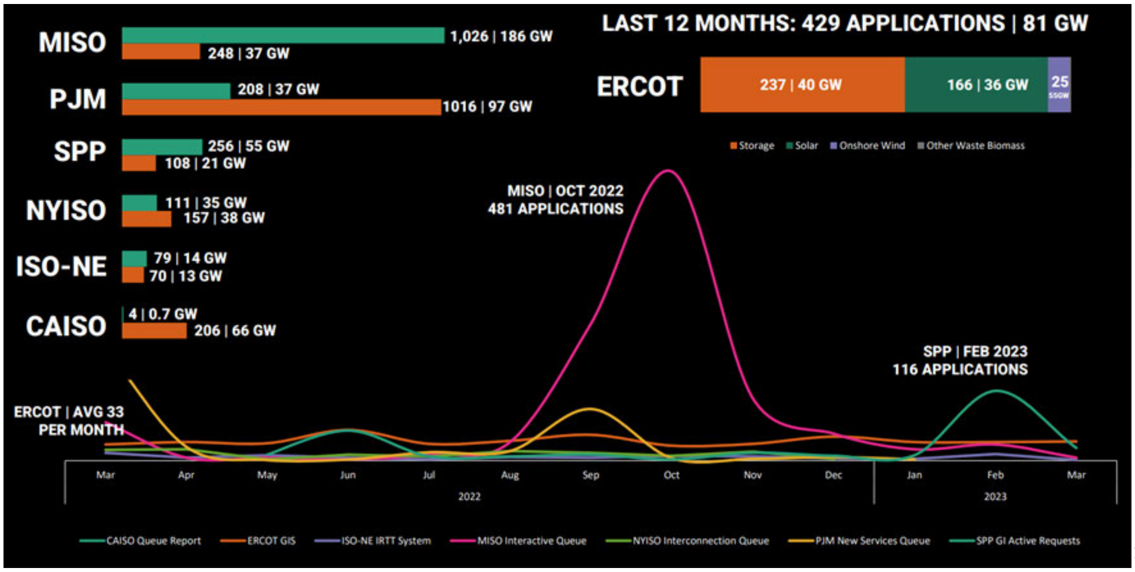

[1]

Comments related to results discussed in assumed regions:

- Mountain
  - The analysis makes several conclusions, specifically around the ability to transfer power between Colorado and the rest of the Western Interconnection, but also states that the eastern portions of the Western Interconnection would benefit with better transfer capability with areas further east.
    - The balance of coordination in the eastern part of the Western Interconnection needs further analysis to compare the value of greater connections east or west.
      - Comparatively simple solutions, such as moving away from contractual pathways and implementing new approaches to facility ratings may provide significant value without the need for incurred transmission costs. Any transmission developed to achieve additional value beyond those more policy-based mitigation would then represent a more optimal solution.
    - Consideration was given connecting the Southwest region with the Texas region. Would similar value be found if there were greater connection between the Mountains and Texas regions, allowing greater transfer capability between the west and southern SPP or ERCOT?
- Southwest
  - The draft results indicated the transfer capacity over the seam between Southwest and Texas needs to be increased to increase reliability and resiliency

[1] 1Q23 Queue Analysis Report, NPM NPM's 1Q23 Queue Analysis Report

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    - Southwestern Public Service (SPS), an Xcel Energy Operating Company serves the portion of the Plains region between these two areas.
    - Depending on the intended method of increasing transfer capability, there may be unintended consequences to be mitigated in Plains area. While this study is not intended to identify such interaction, this would need to be fully understood in a project development focused planning effort to satisfy this finding.
  - Given the events leading to system impacts in this area, is a transmission solution the right solution or would additional investment in cold weather protection be more cost effective?
- Plains
  - Xcel Energy feels the Plains/SPP region seems understudied compared to others.
    - Most of the recommendations are generic which presents a more difficult path forward only using this study effort.
  - The stated conclusion that average prices have been increasing compared to neighbors region-wide seems largely unsupported and could be solved in a number of ways, not just interregional transmission as the study recommends.
    - A more detailed accounting of the drivers of LMP trends would add value in determining the appropriate solution to such a change.

End of Comments