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BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Staff-Led Workshop on Innovations and Efficiencies in Generator Interconnection	**Docket No. AD24-9-000**

PRE-WORKSHOP COMMENTS OF JOHN MICHAEL HAGERTY INNOVATIONS PANEL 1: INTEGRATED TRANSMISSION PLANNING AND GENERATOR INTERCONNECTION

My name is John Michael Hagerty and I am a Principal at The Brattle Group based in Washington, D.C. I appreciate the invitation to participate in the Workshop on Innovations and Efficiencies in Generator Interconnection on the Innovations Panel 1: Integrated Transmission Planning and Generator Interconnection and the opportunity to submit written responses to the questions related to this panel.

I submit the following responses to the four questions for Innovations Panel 1. The responses are based in part on the new report, *Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid* (August 2024), which I have co-authored with colleagues at Grid Strategies and The Brattle Group.[1]

Question 1: ***Can efficiencies be gained through closer integration of generator interconnection processes with transmission planning processes? If so, how? What considerations need to be taken into account? What are the advantages/disadvantages, including impacts on consumers, to closer integration of these processes?***

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[1] Grid Strategies and The Brattle Group, Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid (August 2024), *available at* https://blog.advancedenergyunited.org/reports/unlocking-americas-energy, and also submitted in pre-workshop materials filed by Advanced Energy United in this docket on August 26, 2024 (hereafter "Unlocking America's Energy")

Yes, closer integration of generator interconnection and transmission planning processes will result in a more efficient buildout of the electricity grid. The vast majority of transmission upgrades today are identified through siloed processes, based on grid reliability studies (with limited consideration of future resource needs) and generation interconnection studies. Proactive transmission planning processes that holistically account for both future projected demand and changes in the future generation resource mix and consider a comprehensive set of transmission benefits will identify the upgrades that reduce total customer costs and allow new resources to efficiently enter the system through the generator interconnection process.

Proactive transmission planning will reduce customer costs by:

- Avoiding upgrades that are identified through siloed reliability studies (that primarily account for electricity demand growth), but are no longer required when changes to the future generation resource mix are included;
- Identifying more cost-effective upgrades that provide access to a greater quantity of new resources, compared to upgrades identified incrementally through the interconnection process;
- Identifying cost-effective upgrades that support multiple future transmission needs, including maintaining reliability, reducing congestion, and accessing low-cost new generation, that would not be identified or built through the siloed existing reliability planning and interconnection studies;
- Maximizing utilization of existing transmission corridors by increasing the capacity of (often aging) existing lines to meet the long-term needs of the system instead of short-term needs identified through the current planning processes;
- Building transmission facilities in the near-term that provide low-cost options to increase capacity when needed in the future, such as building single-circuit lines on double-circuit towers or building HVDC-ready transmission facilities that are initially operated as HVAC facilities.

Several recent studies demonstrate the cost savings of increasing integration between transmission planning and interconnection processes:[2]

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[2] The examples of proactive planning cost savings are documented in Pfeifenberger, J., et al., The Benefit and Urgency of Planned Offshore Transmission: Reducing the Costs of and Barriers to Achieving U.S. Clean Energy Goals, January 24, 2023, pp. 31-33.

- *PJM's Offshore Wind Transmission Study* highlights the difference in generation interconnection costs if long-term interconnection needs are planned proactively. A previous PJM study showed that under their interconnection process at the time 15.6 GW of individual offshore wind plants would require $6.4 billion in upgrades to the onshore grid, or *$413 per kW of renewable generation*.[3] In contrast, the 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 would require only $3.2 billion of onshore system upgrades to facilities above 100 kV, resulting in interconnection costs of only *$43 per kW of renewable generation*, a nearly 90% reduction in the cost of major onshore upgrades (before adding the cost of lower-voltage transmission upgrades).[4]
- *The PJM-New Jersey State Agreement Approach (SAA)* proactively addressed the generation interconnection needs for 6,400 MW of additional OSW, resulting in substantial savings compared to pursuing interconnection incrementally through PJM's conventional process. PJM and the New Jersey Board of Public Utilities approved onshore transmission upgrades 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 procurements.[5]
- *MISO's and SPP's Joint Targeted Interconnection Queue Study (JTIQ)* demonstrates the benefits of proactive planning, even if focused solely on generation interconnection needs. 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. These upgrades will reduce interconnection costs by over 50% (from $117/kW under the system operators' individual interconnection processes),

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[3] Business Network for Offshore Wind and Grid Strategies LLC, Offshore Wind Transmission Whitepaper, 2020, p. 11.

[4] PJM, Offshore Wind Transmission Study: Phase 1 Results, 2021, pp. 14, 18.

[5] Pfeifenberger, J., Hagerty, J., and DeLosa III, J., New Jersey State Agreement Approach for Offshore Wind Transmission: Evaluation Report, October 26, 2022. 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.

while also reducing congestion and fuel costs of MISO and SPP customers by approximately $1 billion.[6]

- *MISO's Long Range Transmission Planning (LRTP)* utilizes a scenario-based long-term planning approach that addresses multiple transmission needs (including generation interconnection, regional reliability, congestion relief, and public policy needs) and offers substantial overall cost savings to electricity customers. MISO's LRTP Tranche 1 study assessed transmission needs to facilitate 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. The Tranche 1 process resulted in the approval of a $10 billion "least regrets" portfolio consisting of 18 multi-value transmission projects in MISO's Midwestern Subregion. MISO estimated that the transmission investments will reduce other MISO costs by $37 billion to $54 billion over the same timeframe, reducing the total costs to MISO Midwest customers.[7]
- *California Independent System Operator (CAISO)* has recently approved several portfolios of upgrades through their annual planning process to support interconnection of new resources and is integrating the system deliverability created by those upgrades into its interconnection study process. The 2022-2023 Transmission Plan includes $5.5 billion in upgrades that are "needed to meet the renewable generation requirements established in the CPUC-developed renewable generation portfolios," with a focus on increasing deliverability of solar and out-of-state wind into load centers in southern California.[8] The 2023-2024 Transmission Plan includes $4.6 billion in new transmission to support resource additions including an initial tranche of 1,700 MW of Humboldt OSW in northern California.[9] The approved design includes a new HVDC line that initially operated as AC with the ability to scale up the design to accommodate significantly more OSW as needed in the future.

Proactive transmission planning to reduce the costs of generator interconnection should consider several items summarized in a report titled *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs* that my colleagues and I and co-authors at Grid Strategies submitted into the FERC transmission planning ANOPR process:[10]

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6 Tsuchida, B., Proactive Planning for Generation Interconnection A Case Study of SPP and MISO, August 17, 2022, p. 9.

7 MISO, LRTP Tranche 1 Portfolio Detailed Business Case, June 25, 2022, pp. 57–58.

8 CAISO, 2022-2023 Transmission Plan, May 18, 2023, p. 6.

9 CAISO, 2023-2024 Transmission Plan, May 23, 2024, p. 6.

10 The Brattle Group and Grid Strategies, Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs, October 2021.

1. Proactively plan for future generation and load by incorporating realistic projections of the anticipated generation mix, public policy mandates, load levels, and load profiles over the lifespan of the transmission investment.
2. Account for the full range of transmission projects' benefits and use multi-value planning to comprehensively identify investments that cost-effectively address all categories of needs and benefits.
3. Address uncertainties and high-stress grid conditions explicitly through scenario-based planning that takes into account a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.
4. Use comprehensive transmission network portfolios to address system needs and cost allocation more efficiently and less contentiously than a project-by-project approach.
5. Jointly plan across neighboring interregional systems to recognize regional interdependence, increase system resilience, and take full advantage of interregional scale economics and geographic diversification benefits.

Specifically for integrating transmission planning and interconnection processes, transmission planners need to account for the long-term uncertainties associated with projecting the future resources technologies, locations, and capacity through a scenario-based approach. Planning for multiple future scenarios that accounts for a range of projected resource costs, resource availability constraints (technology development, land use, etc.), policy and customer generation needs, and resource adequacy requirements can support the identification of least-regrets upgrades that reduce costs across most, if not all, future scenarios. The scenarios should include several combinations of resource types and locations and focus on identifying backbone upgrades that will serve future needs when resources seek interconnection of specific technologies at specific locations.

Transmission planners should consider both the near-term (5–10 year timeframe) and long-term (15–20 year) system needs, including future generation interconnection needs, when identifying proactive upgrades. Projecting long-term needs will allow transmission planners to (1) avoid inefficient under-sizing of upgrades to address near-term solutions without considering longer-term needs; and (2) identify opportunities to build expandability into the design of near-term upgrades, where applicable, to reduce the costs of future upgrades to accommodate higher injections.

Beyond reducing the total costs of transmission upgrades, the advantages of a proactive, integrated transmission planning and generator interconnection process include maximizing the benefits (i.e., cost savings) of transmission upgrades, reducing the timeline and schedule and cost risks of the interconnection process, and allowing customers to benefit from the cost and reliability benefits of faster interconnection of new resources.

However, there are potential disadvantages if the integration of transmission planning and generator interconnection processes is poorly implemented. The implementation challenges for integrating planning with interconnection that should be addressed when developing new processes include:

- Inadequate scenario development and analysis that considers too narrow a set of future market conditions, i.e., limited scenarios modeled or limited variation in resource types, capacity, and locations across scenarios, may result in transmission upgrades that are not fully utilized in the future;
- Focusing on a narrow set of drivers of future transmission needs instead of a comprehensive set of cost savings and other benefits that transmission could provide will result in higher costs to customers;
- Overreliance on traditional upgrades to existing facilities or new greenfield facilities over viable and feasible low-cost transmission solutions in the planning process, including dynamic line ratings (DLRs), simple Remedial Action Schemes (RAS), and other grid-enhancing technologies (GETs), may increase customer costs;
- Overreliance on near-term planning that does not consider long-term needs, which yields incremental upgrades to address near-term needs that preempt more efficient longer-term solutions, leading to higher overall costs.
- Poorly designed cost allocation of the planned network upgrades may result in costs being misaligned with the beneficiaries of the upgrades.

Notably, on the last item, proactive planning does not require a specific approach to cost allocation for the new transmission upgrades. Identifying a reasonable cost allocation approach that aligns costs with beneficiaries will be an important step in implementing an integrated planning and interconnection process. Regions that assign network upgrade costs to generators could retain this cost allocation approach even if the method of determining the costs for generator interconnection change. That is, instead of paying 100% for a theoretically smaller set of upgrades (and for a large one when a transmission limit is exceeded even on a large regional transmission facility), generators would instead fund a smaller percentage of a larger suite of transmission upgrades developed for their use.

Reforms will also be necessary to the interconnection process to efficiently utilize proactively planned upgrades. The recently-released report I co-authored, *Unlocking America's Energy: How to Efficiently Connect New Generation to the Grid*, includes several specific reforms to continue to improve the interconnection study process through greater integration with transmission planning and other aspects of generator interconnection:[11]

- *Reform 1: Adopt an interconnection entry fee for proactively planned capacity* to provide interconnection customers significant interconnection cost certainty and addresses cost allocation of the upgrades identified through proactive planning processes. This reform allows projects to move forward with upfront certainty by specifying in advance the cost information in exchange for taking on some of the cost of planned transmission buildout.
- *Reform 2: Implement a fast-track process to utilize existing and already-planned interconnection capacity* to implement an efficient process to quickly utilize existing and planned system capacity. In combination with Reform 1, these reforms create a fast-track process that opens up available transmission headroom for full utilization and prioritizes its use by "most ready" generator projects.
- *Reform 3: Optimize the interconnection study process* by targeting improvements to the study process that will increase the system headroom considered to be "available" for interconnecting new resources through existing and new fast-track processes. It also identifies reforms necessary to make the study process more efficient. In combination with Reforms 1 and 2, interconnection requests should proceed through the study process more quickly.
- *Reform 4: Speed up the transmission construction backlog* to address growing constraints to constructing network upgrades needed to bring new resources online after completing the interconnection study process.

<u>Question 2</u>: How might transmission providers more proactively, rather than reactively, identify zones where new transmission capacity could most efficiently accommodate proposed generating facilities?

[11] Unlocking America's Energy, p. 10.

Projections of the future locations of new resources is an important assumption for proactively planning the transmission system for new resource additions. Transmission providers and their stakeholders will need to develop a process that considers multiple inputs for identifying locations and specifies the amount of new resource additions. This process will need to identify which types of resources are likely to enter, how much will enter to meet the system's needs, and where those resources will enter. The process for identifying the upgrades should include (1) reviewing the drivers of new resource additions in their region, (2) collaborating closely with state policymakers on the types and locations of future additions where state policies are driving entry, (3) identifying the best available market data to inform future entry (e.g., resource costs, capacity limitations, interconnection requests, land-use availability, etc.), and (4) completing long-term capacity expansion simulations of new resource additions that reflect the relevant economic, reliability and policy drivers for entry.

Regional transmission organizations (RTOs) and other transmission providers have used different approaches to do so:

- In CAISO, the California Public Utilities Commission (CPUC) provides CAISO specific resource portfolios to model in their annual planning studies. The CPUC uses capacity expansion modeling to identify the amount and types of new resources necessary to meet future reliability and policy needs at least cost to ratepayers. Those portfolios then go through a detailed "busbar mapping" exercise led by the California Energy Commission (CEC) to identify the zones within California that have the most attractive locations and then the nodes in which the resources will be modeled in the transmission planning study. Their busbar mapping analysis considers four factors: commercial interest of generation developers, distance to transmission and transmission capability, land use considerations, and alignment with previous studies.[12]
- In MISO, the future resource mixes and locations for transmission planning are developed through the MISO Futures process that includes consideration of the interconnection queue, IRPs, and state policies. MISO completes capacity expansion analysis and then follows a pre-determined criteria for all resources along with resource-specific considerations for

[12] CPUC, Proposed Electricity Resource Portfolios for the 2023-2024 Transmission Planning Process, October 20, 2022, pp. 33 – 46.

developing preliminary siting assumptions.[13] MISO posts the results and requests stakeholder feedback to refine the siting assumptions.[14]

- In ERCOT, the development of the Competitive Renewable Energy Zones (CREZ) lines was based on outreach to wind developers to seek their input on the locations that were most attractive for development.[15]
- In support of Illinois' Renewable Energy Access Plan, my colleagues developed an approach that relied on overlaying grid interest with areas of environmental concern, likely resource retirements, existing grid access, and renewable potential to identify zones where future renewables would likely be sited to enable Illinois active participation in PJM regional planning.[16]

In non-RTO regions, transmission providers can use the most-recently developed portfolios from Integrated Resource Planning processes for transmission planning studies. For example, Duke Energy is proposing to use two portfolios of resources from their recent Carolinas Resource Planning study process to identify the amount and type of new resources that will enter and generation resources that will retire for their inaugural Multi-Value Strategic Transmission (MVST) planning process.[17] To determine, the locations of those resources, Duke is proposing to rely primarily on the current interconnection queue and seeking comment from developers on whether that approach reflects future development zones. They will also be studying a scenario with the same resource mix but with an alternative distribution of the resources to identify least-regrets upgrades.

***Question 3*: What mechanisms may be appropriate for transmission providers to use to determine the cost responsibility for such proactively planned network upgrades? Is it appropriate for any such costs to be allocated to load and if so, why? If it is appropriate, how should such costs be allocated between load and interconnection customers both: a) in regions that use participant funding, i.e., where interconnection customers are directly assigned**

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[13] MISO, MISO Futures Report: Series 1A, November 1, 2023, pp. 49-52.

[14] MISO, Future 2A Energy Adequacy & Siting, April 28, 2023.

[15] ERCOT, Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas, December 2006, pp. 5 – 6.

[16] Illinois Commerce Commission, Illinois Renewable Energy Access Plan: Enabling an Equitable, Reliable, and Affordable Transmission to 100$ Clean Electricity for Illinois, May 30, 2024.

[17] Carolinas Transmission Planning Collaborative, 2024 Multi-Value Strategic Transmission (MVST) Study, August 16, 2024.

network upgrade costs and b) in regions that do not use participant funding, i.e., where load is assigned network upgrade costs? What are the advantages/disadvantages, including impacts on consumers, of varying approaches to cost responsibility?

As noted above, proactively planning transmission upgrades does not require the use of a specific cost allocation method, as long as the cost allocations are consistent with Commission requirements. Several reasonable cost allocation methods can be applied, depending on region-specific considerations and the drivers for the upgrades.

For proactively planned upgrades that are primarily intended to support deliverability of future resources, the costs should primarily be allocated to interconnecting generators. In some cases, at least portion of these types of upgrades could reasonably be allocated to the load, if it is clear that load will also benefit from the upgrades (such as New Jersey offshore wind State Agreement Approach, NYISO public policy projects, or CAISO policy-driven transmission upgrades).

The challenge for allocating costs becomes more significant when proactively planned upgrades address a broader set of transmission needs and associated benefits to the market and electricity ratepayers (i.e., beyond the deliverability of new resources). For example, in the New Jersey State Agreement Approach, 6,400 MW of offshore wind injections in New Jersey required upgrades along the Pennsylvania–Maryland border, which recently has experienced significant congestion and also required reliability-driven transmission upgrade. To the extent that future upgrades—like those from a SAA for OSW—provided benefits to the rest of the PJM system by avoiding other reliability upgrades or reducing congestion (or other benefit metrics), it would be reasonable to allocate a portion of the upgrade costs to load so that allocated costs remain roughly commensurate with benefits from those upgrades.

Finally, proactive, holistic transmission planning studies that accounts for multiple drivers of future system needs, including needs driven by generation additions, load growth, congestion, aging infrastructure, retirements and congestion, may require a more comprehensive cost allocation approach, since upgrades required to deliver new resources will often be intertwined with upgrades for other needs. Several potential approaches could be used to allocate those costs between different loads on its system and generation resource additions such that the cost allocation is roughly commensurate with the beneficiaries of the upgrades. Transmission providers will need to consider whether to isolate the costs and the benefits of the upgrades specifically intended to support new generation resources to inform the cost allocation approach, or develop estimates of the relative scale of the benefits (such as from avoided incremental transmission costs) accruing to new generation and load growth and allocate costs based on the share of total costs that is roughly proportional to benefits received.

As an example, PJM's Tariff specifies an approach for allocating the costs of multi-driver projects that could be utilized for identifying the costs of proactive upgrades to be allocated to interconnection customers via an entry fee. The Proportional Multi-Driver cost allocation method enables PJM to determine "the extent to which each such driver contributes to the size, scope, and estimated costs of such Proportional Multi-Driver Project" by relying on an estimate of the avoided cost of projects that would have served each need in the absence of a multi-driver project.[18] This approach is particularly well-suited to a future where transmission providers will need to determine the portion of multi-driver facilities that should be assigned to interconnection customers through an entry fee.

***Question 4**: Where the costs exceed estimates for such proactively planned network upgrades, what are some approaches transmission providers could use to address concerns regarding ensuring adequate funding? For any given approaches proposed to ensure adequate funding, would these mechanisms increase or decrease the time and/or costs required to interconnect new resources, and how would this impact interconnection customers?*

There are two primary risks for cost recovery when allocating costs to new generation resources. The most significant risk is that the capacity projected to enter and pay for a portion of the upgrades does not materialize or materializes later than projected. Limited interest in pre-planned capacity may occur due to higher than expected planning-related costs allocated to new generation projects (reducing demand for a location on the system) or due to poorly designed scenarios in the planning studies that overbuilds transmission capacity. In either case, the

[18] PJM Tariff, Sch. 12 § (b)(xiv)(A)(1). ("The percentage contribution of each driver shall be based on the ratio of the estimated cost of each project that the Multi-Driver Project replaces to the total of the estimated costs of all projects combined into the Multi-Driver Project.")

transmission developers building the upgrades will require sufficient assurance of cost recovery prior to construction of the line, requiring transmission providers to create a backstop cost-recovery path that allocates costs to load until the generation resources seeking to interconnect to the system submit their interconnection request, sign their interconnection agreement, and begin collecting payments for accessing the available capacity.

The second risk is that the realized costs for the upgrades exceed the initial estimates. An entry fee approach for allocating costs of planned upgrades to generators must provide a high degree of cost certainty to provide an efficient path for interconnection. Ensuring adequate funding under this approach will require transmission providers and transmission owners to: (1) improve planning stage cost estimates for the upgrades that will set the entry fee by including the full scope of costs in the cost estimates, projecting likely increases in costs due to project-specific issues, and accounting for projected rates of cost escalation; (2) implement cost controls that, for example, share the risks for cost overruns between transmission developers and load or generators,[19] and (3) include a one-time, capped "true-up" to the entry fee paid by generators that accounts for differences in realized inflation, interest rates, and other cost escalation from the initially-projected costs.

As proposed in *Unlocking America's Energy*, the network upgrade true-up to the entry fee should be based on a pre-set formula that relies on publicly-available indices for macro-economic variables such as inflation and interest rates.[20] The report also proposes other potential approaches to share the cost risks of planned upgrades amongst the transmission developer, interconnection customer, and load.[21]

These approaches should have limited impact on the schedule for interconnection customers completing the interconnection process, as long as the pre-planned upgrades are built on schedule and transmission providers clarify how the transmission developers will recover their costs. These changes though may introduce some uncertainty into the costs that are ultimately allocated to generation, especially if there is a high cap on the "true up."

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19 Pfeifenberger, J., Ensuring Cost-Effective Transmission in Support of a Clean Energy Transmission, presented to NESCOE, August 9, 2024.

20 Unlocking America's Energy, p. 32.

21 Unlocking America's Energy, p. 33.