UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Advanced Notice of Proposed Rulemaking:	)	
Building for the Future Through Electric	)	Docket No. RM21-17-000
Regional Transmission Planning and Cost	)	
Allocation and Generator Interconnection	)	

Comments of the R Street Institute

I. Issue Summary

On July 27, 2021, the Federal Energy Regulatory Commission (Commission) published an Advance Notice of Proposed Rulemaking (ANOPR) on potential reforms to improve generator interconnection processes, regional transmission planning and cost allocation.[1] The ANOPR outlined the potential need to reform these policies, seeking comments structured by regional transmission planning and cost allocation processes; identification of cost; responsibility for regional transmission facilities; interconnection-related network upgrades; and enhanced transmission oversight and transition.

These comments provide a summary view of the R Street Institute (RSI) and provide specific comments for the areas mentioned above.

II. Summary of R Street Position

RSI submits these comments in recognition that there will be more opportunities to provide detailed comments. These comments are intended to be strategic: aiding the Commission in validating problem statements in the ANOPR; identifying relevant issues not specifically referenced in the ANOPR; helping the Commission prioritize reform areas; and evaluating synergies between various procedural vehicles to inform next steps.

The ANOPR flags three broad policy reform areas that RSI thoroughly supports:

1. *Reforming Regional Transmission Planning and Cost Allocation Processes*. Planning processes require an overhaul to be more independent, holistic and proactive. They should use higher quality cost-benefit analysis that accounts for risk and uncertainty. Eliminating competitive

[1] 86 Fed. Reg. 15512 (July 27, 2021). https://www.govinfo.gov/content/pkg/FR-2021-07-27/pdf/2021-15512.pdf.

carve-outs than enable regulatory evasion under Order No. 1000 should be prioritized, and R Street supports the comments of the Electric Transmission Competition Coalition in this proceeding. Modest improvements to interregional planning are possible within the scope of the ANOPR questions, though realizing the potential of interregional transmission will require a fundamental shift in institutional design that is underappreciated in the ANOPR.

2. *Interconnection-related Network Upgrades*. The current system for generation interconnection is inefficient and misaligns cost allocation relative to the beneficiary pays principle. The participant funding model is the foremost concern and is without question unjust and unreasonable, especially as the evolving resource mix enhances the value of network upgrades with dispersed benefits exceeding those of the interconnecting participant. Reforming this model properly would increase systemwide net benefits and lower the aggregate cost and risk profile to consumers. The Commission should also consider additional reforms to improve interconnection queue efficiencies and reduce informational barriers to entry.
3. *Enhanced Transmission Oversight*. The ANOPR accurately recognizes the deficiency of economic oversight in the absence of competitive discipline in transmission planning and asset management. An independent transmission monitor could close this gap: overseeing transmission planning and project selection processes to ensure independence; using robust economic criteria; promoting fair competition between new entrants and incumbent transmission providers; conducting independent assessments of transmission system performance; and making transmission rule recommendations with filing authority before the Commission would all help further this initiative.

As the Commission evaluates procedural vehicles for next steps, the degree of variances in Order 1000 implementation across regions should be assessed. If underperformance is contained to laggard regions, the Commission may find it more efficacious to initiate a Section 206 proceeding under the Federal Power Act. However, rulemaking(s) may be appropriate where uniform underperformance reveals a structural policy defect.

Perhaps the greatest strategic issue confronting the Commission is whether to pursue transmission reform under the presumption of incomplete regional transmission organization (RTO) coverage and current RTO governance structures, which favor incumbent utilities.[2] For example, revising Order 719

[2] Mark James et al., "How the RTO Stakeholder Process Affects Market Efficiency," R Street Institute, October 2017. https://www.rstreet.org/wp-content/uploads/2017/10/112.pdf.

may dislodge incumbent utilities as the "first among equals" stakeholder segment and profoundly affect the incentives of market participants and RTO leadership, as well as the quality those regional interests may implement any transmission or generator interconnection reforms.[3] If RTOs were ubiquitous and stakeholders had structural and practical parity, regions left to their own devices would be more likely to implement transmission reform in an economically efficient manner. If the Commission does not foresee such conditions emerging during the implementation timeline of final rules stemming from the ANOPR—likely a two- or three-year process—it should proceed with stricter vigilance of regional stakeholder compliance discretion and strategically narrow the asymmetry in regulatory treatment between RTO and non-RTO regions.

Order 1000 had admirable objectives but underperformed in large part because it left considerable implementation discretion to regional interests that favored incumbent transmission owners (TOs). The inefficiencies of current transmission practices largely result from the influence ceded to incumbent TOs, who undermine the quality of planning processes, retain opaque operating practices and influence regional rules that insulate themselves from competition. Further, many incumbent TOs are also generation owners, which encourages them to strategically stifle transmission development in import-constrained areas where they own generation. For example, in recent years, incumbent utilities in the southern part of the Midcontinent Independent System Operator (MISO) obstructed plans to build transmission lines that would enable cleaner, lower-cost energy to flow into the region while boosting resilience from storms like Hurricane Ida.[4] In 2018, a third party won a competitive bid from MISO to build the lines, but utilities urged state lawmakers to pass a right of first refusal (ROFR) law despite objections from the Justice Department that the action would stifle competition and increase rates.

Such pervasive examples reflect the perverse incentives under cost-of-service regulation paired with an absence of competition and economic oversight. This has predictably resulted in poor economic outcomes and an unequal playing field among stakeholders. The current system favors excessively capital-intensive transmission projects, deters economical projects and stifles innovation. Altogether, this

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[3] Devin Hartman, "Plenty of low-hanging fruit: How FERC can catalyze transmission infrastructure," *UtilityDive,* April 9, 2021. https://www.utilitydive.com/news/plenty-of-low-hanging-fruit-how-ferc-can-catalyze-transmission-infrastruct/598088.

[4] Jon Schuppe, "Hurricane Ida power grid failure forces a reckoning over Entergy's monopoly in the South," NBC News, Sept. 24, 2021. https://www.nbcnews.com/news/amp/ncna1279971.

underscores why regulatory reform must pair transparency, economic oversight, accountability and competition with technocratic improvements to planning and cost allocation.

III. Regional Transmission Planning and Cost Allocation Processes

Current transmission planning is reactive, exclusionary, frequently anti-competitive and divergent from sound planning practices, rendering it unjust and unreasonable and in urgent need of reform. The Commission should consider major changes to regional transmission planning and cost allocation, as well as an institutional reconfiguration for interregional transmission planning. Comments in this section are broken into three subsections: planning benefits; cost containment and competition; and interregional planning.

<u>Planning Benefits</u>

Generally, transmission planning should increase the use of high-quality cost-benefit analysis, including more holistic and proactive approaches to benefits inputs and methodologies. Since other parties will elaborate on this perspective, R Street will focus comments to maximize value add. We promote the equivalent treatment of all available transmission solutions. We believe the Commission should incorporate risk and uncertainty analysis; improvements to benefits treatment; and co-optimization for reliability and economic benefits while integrating public policy effects more efficiently.

An economic approach to transmission planning treats all potential resource solutions on a consistent and comparable basis. A new rule should require transmission planners to evaluate all available solutions, including conventional physical infrastructure and grid-enhancing technologies.[5] Economists have noted the value of platforms that define transmission capability in cultivating competition between imperfect substitutes.[6] One option is for the transmission planner to model all resources in a comprehensive planning exercise and put the specified project out to bid; another is to have a solution-based or sponsorship model that defines system needs and lets developers compete on broader

[5] Rob Gramlich and Jay Caspary, "Planning for the Future: FERC's opportunity to spur more cost-effective transmission infrastructure," Americans for a Clean Energy Grid, January 2021, p. 11. https://cleanenergygrid.org/wp-content/uploads/2021/01/ACEG_Planning-for-the-Future1.pdf.

[6] See, e.g., David B. Patton, "Efficient Incentives for Grid-Enhancing Technologies," Federal Energy Regulatory Commission: Grid-Enhancing Technologies Workshop, Nov. 5-6, 2019, pp. 2, 4. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20191112-4027&optimized=false.

design ideas. The latter has yielded additional cost savings and more innovation, though selecting among projects with dissimilar performance profiles that carry different co-benefits can complicate project selection.[7] Currently, practices vary across RTOs and warrant deeper comparative analysis.

Economic planning also requires the incorporation of all material and relevant anticipated future conditions, including changes in the nature and extent of the generation mix. The Commission could explore a requirement for hybrid transmission approaches that incorporates probabilistic approaches for risks (potential events with known probabilities) and scenario approaches for uncertainties (potential events with unknown probabilities). For example, the Commission should seek improvement in risk parameters like load growth projections as well as high impact and unknown probability events, all of which have been poorly accounted for to date. One key variable to consider is the economics of distributed energy resources, which can profoundly affect the economics of transmission investment.

Proper risk and uncertainty analysis were staples of best practices identified in efforts to modernize state integrated resource planning rules in the post-restructuring period. This experience provides insight for the Commission in approaching best practices in cost-of-service planning.[8] A key lesson is that defining risks and uncertainties and assigning them weight requires extensive discretion—a truth which is often at the mercy of utility influence or unstable regulatory leadership change. This underscores the need to have a durable process for independent expert judgement to determine discretionary inputs in transmission planning.

The ANOPR correctly notes that a planning process limited to modeling only forthcoming generation with completed facilities studies will result in accounting for near-term generation only. This practice contrasts sharply with the multi-decade planning horizon that determines the net benefits of transmission investment. The result is a planning process that departs from proper anticipatory planning practices and will result in systemic undervaluation of transmission expansion given the projected transmission-dependent generation mix that is emerging.

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[7] Johannes Pfeifenberger et al., “Cost Savings Offered by Competition in Electric Transmission,” The Brattle Group, April 2019, p. 11. https://brattlefiles.blob.core.windows.net/files/15987_brattle_competitive_transmission_report_final_with_data_tables_04-09-2019.pdf.

[8] See, e.g., Devin Hartman, “IRP in Era of Transformation,” Center for Public Utilities Advisory Council: Current Issues 2019 Conference, April 8, 2019, p. 4. https://elcon.org/integrated-resource-planning-in-an-era-of-transformation-devin-c-hartman-current-issues-2019-conference-center-for-public-utilities-advisory-council.

All drivers of the change in generation mix—whether public policy or economic fundamentals—should be treated as exogenous inputs in the planning process. The Commission should not be making value judgments on which state public policies to include and exclude in the planning process. For example, the aggregate market for renewable energy credits is an input that affects the anticipated generation mix, irrespective of the proportion that is voluntary or mandatory. The separation of "public policy projects" under Order No. 1000 results in a suboptimal planning process and the Commission should pivot to a neutral, integrated approach to state policies by focusing on the outcomes of relevance for transmission planning inputs. However, transmission costs accrued by a given state public policy may be worth accounting for in cost allocation applications.

The ANOPR correctly implies that optimal transmission development for renewable energy—which is the foremost projected generation source—often occurs in geographic "clusters." This may require a stronger nexus between interconnection and regional transmission processes, which are elaborated on in the interconnection upgrades section. Since the ANOPR inquires as to whether the Commission should require identification of geographic zones for renewable energy development, the Commission should be careful to retain its fuel neutral designation in pursuit of such policies. This can be accomplished by requiring targeted spatial criteria in transmission planning parameters that explicitly evaluate the development of low-cost, geographically-constrained generation.

The current approach to planning for economic and reliability projects in separate siloes results in suboptimal planning. All transmission projects have economic and reliability benefits. Transmission planning that integrates both benefit categories using equivalent metrics would help optimize the process. Some projects may require a distinct planning process to accommodate an accelerated timeline given pressing reliability conditions, but the economic benefits of these projects can still roll back into adjustments in the routinized planning process.

Integrating reliability and "narrow" economic benefits requires greater scrutiny of the economic value of reliability. Some reliability processes treat reliability requirements as exogenous with an implied infinite value of lost load (VOLL). Rather, VOLL should be incorporated into integrated cost-benefit analysis so reliability benefits are considered a form of economic benefit. The Commission should differentiate VOLL estimates by the type of reliability event. For example, long-duration and widespread outages more commonly associated with "resilience" events can have a VOLL that is orders of magnitude greater than routine, short-duration outages.[9] Given the current parameterization of reliability in planning processes, it is likely that transmission planning is deficient in accounting for high-impact, low-probability events like those linked to common mode failure and exacerbated by climate change. Any attempts to promote "resilience" scenarios in transmission planning must first develop robust economic criteria. Failure to do so could result in a lack of prudency in determining if benefits exceed costs, as most attempts to define and quantify the concept have "relied upon ad hoc definitions that do not have much underlying rigor."[10]

The Commission may seek to expand benefits categories to include social costs, such as the social cost of carbon. It is imperative that the Commission remain an environmental "policy taker"—not policymaker. For example, the Commission should only incorporate social costs consistent with guidance from the Office of Management and Budget for independent agencies. Failure to do so will destabilize and politicize benefits calculations in transmission planning, which are very sensitive to abrupt adjustments between presidential administrations given the planning time. Any incorporation of social costs should prioritize consensus and durability of long-term benefits practices.

Cost Containment and Competition

Although the ANOPR focuses heavily on improving benefits in planning, better cost containment would also result in more favorable cost-benefit metrics for transmission planning. Two key mechanisms pair to instill better economic discipline: 1) greater independence in transmission planning and project selection activities; and 2) eliminating competitive loopholes under Order No. 1000 to ensure competitive processes drive regional and interregional transmission development. A paper by Ari Peskoe at the Harvard Electricity Law Initiative underscores the importance of the Commission inducing third-party controlled transmission planning to mitigate the perverse incentives of incumbent TOs dictating planning processes.[11] Given that the voluntary nature of RTO membership puts TOs in charge, the Commission should symmetrically spur independent transmission planning in RTO and non-RTO regions. Similarly, the key to achieving the proliferation of transmission competition in RTO regions is to comprehensively close competitive carve-out opportunities under Order No. 1000. The staggeringly low percentage of

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[9] Devin Hartman, "Differentiated Reliability," Future Power Markets Forum, July 22, 2021, p. 6. https://www.rstreet.org/wp-content/uploads/2021/07/Hartman-FPMF-Differentiated-Reliability.pdf.
[10] JD Taft, "Electric Grid Resilience and Reliability for Grid Architecture," Pacific Northwest National Laboratory, November 2017, p. 1. https://gridarchitecture.pnnl.gov/media/advanced/Electric_Grid_Resilience_and_Reliability.pdf.
[11] Ari Peskoe, "Is the Utility Transmission Syndicate Forever?" *Energy Law Journal forthcoming* (2021), p. 3. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3770740.

transmission projects subjected to competition is a direct result of regulatory evasion by incumbent TOs, which is enabled by competitive opt-out provisions enacted by some RTOs in Order No. 1000 compliance. Such provisions directly reflect the outsized influence incumbent TOs hold in RTO governance.

R Street thoroughly supports efforts to bolster transmission competition for regional and interregional projects, but leaves those details to its jointly filed comments with the Electric Transmission Competition Coalition in this proceeding. R Street emphasizes here that it has presented a federalist case for federal preemption of state ROFR as a necessary step to avoid imbalanced cost imposition for projects that clearly constitute interstate commerce.[12] States are increasingly resisting regionally cost allocated projects due to other states' ROFRs. This—coupled with pushback from load interests organizing out of concern for rising transmission rates and the potential for competition to save tens to hundreds of billions of dollars over the next two decades—confirms that the Commission should act to reduce anticompetitive practices, reduce controversy and accelerate economic transmission expansion in the long run.[13]

Interregional Planning

The ANOPR asks astute questions on interregional transmission but, overall, suffers from a major lack of attention to the issue. This may simply emanate from the history of Order No. 1000, which intended to improve regional planning and, once established, turn attention to interregional planning. But this plan never materialized. This leaves the Commission with two general options: incremental improvements within the Order No. 1000 paradigm; or the construction of an entirely new paradigm.

The ANOPR questions appear to probe "within the paradigm." The recommended core principle that regional transmission planning should maximize the net benefits of economic and reliability criteria jointly—while treating public policy as an exogeneous condition—could be applied to interregional planning as well. Although the ANOPR seeks comment on establishing interregional reliability planning criteria, it would have far greater impact if it also encompassed economic criteria.

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[12] Josiah Neeley, "Right of First Refusal Laws for Electric Transmission are Anti-Competitive in Interstate Commerce," The R Street Institute, June 2021, pp. 1-2.
https://www.rstreet.org/wp-content/uploads/2021/06/explainer27-1.pdf.
[13] Ibid.

Interregional planning criteria that improves the quality and consistency of benefits assessments across regions would be a start. Consistent upfront benefit methodology would reduce key discrepancies between RTOs willing to explore interregional collaboration. This would, for instance, have helped expedite recent interregional transmission collaboration between MISO and the Southwest Power Pool (SPP).

Still, the institutional design problem is too profound to expect robust interregional planning to occur within the existing Order No. 1000 framework. The political economy of RTOs discourages voluntary transmission improvements between regions, which warrants regulatory intervention.[14] Further, bilateral RTO planning can be improved through actions like planning requirements, but it is incapable of encompassing interconnection-wide or multiple interconnection planning. It is also unclear how the ANOPR concept of using one region's regional planning process to identify benefits in—and allocate costs to—a neighboring region would practically work.

As an alternative, the Commission could seek to create or use a third party to identify benefits and cost allocation across regions and modify RTO tariffs to accommodate this input. One option is for the Commission to pursue a memorandum of understanding with the Department of Energy (DOE), which possesses transmission modeling capabilities. The DOE could convene stakeholders for planning, provide technical support and file the plan at the Commission pursuant to Section 403 of the Department of Energy Organization Act. This technical input could synchronize with new interregional planning criteria established by the Commission, potentially helping to determine minimum transfer capability requirements between regions.

Any improvement over the bilateral RTO planning paradigm would still face the difficult task of overcoming state parochialism. Encouraging state participation in a collaborative interregional planning process, such as DOE convenings, may cultivate buy-in that is imperative to encourage agreement on base cost allocation and state siting approvals—the latter of which are seldom coordinated, create clear barriers to entry for transmission and have become more challenging over the past decade.[15] The Commission may want to revisit its backstop siting authority paired with consistent evaluation practices

[14] Travis Kavulla, "Efficient Solutions for Issues in Electricity Seams," *R Street Policy Study* No. 172, April 2019, p.7. https://www.rstreet.org/wp-content/uploads/2019/04/Final-No.-172.pdf.

[15] Testimony of Travis Kavulla, United States Senate Committee on Energy and Natural Resources, "Outlook for Energy and Minerals Markets in the 116th Congress," 116th Congress, Feb. 5, 2019, p. 10. https://www.rstreet.org/wp-content/uploads/2019/02/Kavulla-Testimony-Senate-ENR-Feb-5-2019-final.pdf.

and schedule discipline to establish a no-nonsense directive for state cooperation. This could dovetail with the new joint federal-state task force on electric transmission.[16]

Any interregional actions mentioned above are consistent with Commission authority under Section 206 of the Federal Power Act. The same arguments used in the DC Circuit opinion upholding FERC Order 1000's mandate for regional planning could be applied to support interregional planning, which the court concluded was consistent "with the deferential standard in step two of the Chevron analysis."[17]

Constructing a new interregional transmission paradigm will be challenging, but the payoff would be significant. Various techno-economic assessments, such as the National Renewable Energy Laboratory Interconnections Seam Study, have demonstrated favorable cost-benefit results across scenarios from interregional transmission.[18] It will take leadership to remake the institutional context to realize a fraction of this technical potential.

IV. Interconnection-Related Network Upgrades

Two research reports this year—one by Grid Strategies, LLC and the other by ICF Resources, LLC—have helped provide sufficient evidence that the current system for generation interconnection is unworkable, inefficient and misaligned regarding cost allocation relative to the beneficiary pays principle.[19] This renders the current rules unjust and unreasonable, and the Commission should prioritize reform considering the magnitude of the consequences. A Lawrence Berkeley National Laboratory study found that by the end of 2020 over 750 gigawatts (GW) of generator capacity—680 GW of which are zero

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[16] Federal Energy Regulatory Commission, "FERC, NARUC to Establish Joint Federal-State Task Force on Electric Transmission," Department of Energy, June 17, 2021. https://www.ferc.gov/news-events/news/ferc-naruc-establish-joint-federal-state-task-force-electric-transmission.
[17] *South Carolina Public Service Authority v. Federal Energy Regulatory Commission*, United States Court of Appeals for the District of Columbia Circuit, Aug. 15, 2014, p. 25. https://www.govinfo.gov/content/pkg/USCOURTS-caDC-12-01232/pdf/USCOURTS-caDC-12-01232-0.pdf.
[18] See, e.g., National Renewable Energy Laboratory, "Interconnection Seams Study," Department of Energy, last accessed Oct. 4, 2021. https://www.nrel.gov/analysis/seams.html.
[19] Jay Caspary et al., "Disconnected: The Need for a New Generator Interconnection Policy," Grid Strategies, January 2021. https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf; Vish Sankaran et al., "Just & Reasonable? Transmission Upgrades Charged to Interconnecting Generators Are Delivering System-Wide Benefits," ICF Resources, Sep. 9, 2021. https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf.

carbon—were seeking interconnection.[20] In four RTOs with available data, the average time spent in interconnection queues increased from 1.9 years in 2000-2009 to 3.5 years from 2010-2020.[21] In five RTOs examined, only 24 percent of proposed projects in the interconnection queues reached commercial operations.[22]

Existing practices present a massive barrier to entry for hundreds of gigawatts of new generation resources in at least three forms: financial, informational and processional. This fundamentally contradicts the spirit of an open access transmission system. It is time for a new and comprehensive generator interconnection policy.

The foremost issue is reforming participant funding in the generator interconnection process. The current practice allocates nearly all network upgrade costs to generation developers. This has resulted in a stark departure in cost allocation from the beneficiary pays principle. Thus, participant funding is blatantly unjust and unreasonable and should be replaced with a policy consistent with economic principles.

The ANOPR's inquiry on participant funding is especially timely as the adverse consequences of participant funding have markedly worsened, and new evidence underscores the need for reform. In past decades, generation entry was dominated by fewer central plant generators that did not have extensive siting restrictions at the regional or subregional scale. Thus, the interconnection process was workable given a manageable number of projects with limited transmission upgrade requirements and with economics that were not overly sensitive to granular variances in available transmission capacity.

Current and projected generator interconnection, however, is dominated by far more numerous and geographically-constrained resources, notably wind and solar. The economics of these resources are heavily dependent on transmission availability and upgrade costs. Altogether, this creates more co-dependencies between groups of prospective generators and transmission development, as evidenced by the tendency of numerous independent projects to develop in geographic clusters linked to transmission development. The cost and uncertainty of transmission network upgrades is a significant

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[20] Joseph Rand et al., "Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2020," Lawrence Berkeley National Laboratory, May 2021, p. 3. https://eta-publications.lbl.gov/sites/default/files/queued_up_may_2021.pdf.
[21] Ibid.
[22] Ibid.

hurdle to the development of the predominate forms of new low-cost generation resources, which is actively deterring development.[23]

It is imperative to distinguish between "pure private" upgrades and network upgrades with benefits dispersed beyond the participant. Generators with greater individual generator upgrade costs—those where the generator accrues all upgrade benefits—are natural barriers to entry that do not result in misaligned private and social benefits. However, interconnection studies for individual and groups of generators are increasingly identifying larger regional upgrades as the cost driver.[24] Regional upgrades have network benefits that extend well beyond an individual or group of generators. Thus, the evolving resource mix is amplifying the net benefits of regionally networked upgrades, but these are not efficiently planned or paid for via the interconnection process that uses individual generator assessments and participant funding.[25]

The Commission should view participant funding reform as both an equity—avoiding free-riders via cross-subsidies and ensuring beneficiaries pay their fair share—and an economic efficiency issue. Requiring developers to pay a disproportionately higher share of costs relative to total benefits means the economic system will chronically undervalue the system-wide spillover benefits. That is, the net benefits to the private party are less than the net benefits to all parties involved, which will result in private developers underinvesting in network upgrades relative to the social optimum.

It is also critical to note that a large share of generator costs imposed by participant funding indirectly increase costs on consumers. Higher costs imposed on independent power producers are at least partially passed onto consumers, such as exerting upward pressure on power purchase agreements (PPAs). It is more severe for integrated utilities, which pass full costs for generation and load-serving obligations alike to consumers. From a consumer perspective, this underscores the importance of having the most efficient policy that maximizes net benefits.

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[23] Sankaran et al. https://acore.org/wp-content/uploads/2021/09/Just-Reasonable-Transmission-Upgrades-Charged-to-Interconnecting-Generators-Are-Delivering-System-Wide-Benefits.pdf.
[24] Caspary et al. https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy-1.14.21.pdf.
[25] Ibid.

Although recent evidence makes a compelling case that participant funding is unjust and unreasonable, it is not clear what the appropriate fix is. For example, the ICF Resources study was limited in geographic scope and did not delineate the proportionate of “pure private” benefits to developers relative to that of broad system benefits. Additional analysis could greatly inform a revised policy, but the Commission should not wait for such analysis before initiating reform of participant funding. The Commission could pursue an avenue that encourages targeted research to inform optimal policy, or establish a new framework that ages well as new information becomes available.

The policy mechanism selected should be careful to direct market participant incentives toward efficient behavioral outcomes. For example, the ANOPR considers options for upfront funding of network upgrades by transmission providers or load. Presuming a greater allocation of network upgrade costs to load relative to the current practices, it will be important to make sure a project is delivered as expected so risk is not concentrated on customers. A policy like a narrower version of Order No. 2003 crediting policy could avert this by reimbursing generators for the cost of completed, useful network upgrades. Further, funding reforms that reduce regulatory uncertainty for developers will translate into lower risk premiums, which ultimately benefits consumers in the form of more favorable offtake rates or terms for new PPAs.

One challenge for any uniform policy reform will be distinguishing between upgrade types, their associated costs and benefits, and the parties they accrue to. The Commission should consider aligning incentives for geographically-constrained generation development to maximize total system net benefits. For example, wind developers should have motive to co-optimize for geographic resource quality and transmission upgrade costs, which may result in trade-offs: some premier wind areas have high transmission upgrade costs that yield lower net benefits than second-tier wind regions with far lower upgrade costs.

As the Commission prioritizes reforms surrounding participant funding, it should not lose sight of other key deficiencies in generator interconnection policy that received less attention in the ANOPR. Despite beneficial reforms in recent years, interconnection queue delays and informational barriers to entry remain evident. Often the latter exacerbates the former, as a sizable portion of projects clogging interconnection queues are not firm commitments for commercial development but speculative projects with other motivations like information seeking. Presenting alternatives to the queue to attain this information would deter speculative project entry.

In 2018, the Commission took laudable steps under Order No. 845 to improve certainty, promote more informed interconnection and enhance interconnection processes.[26] However, this failed to fully address petitioner concerns like periodic restudies requirements and the publication of congestion and curtailment information.[27] The Commission should revisit these and consider new ways to boost transparency and data access. One option to achieve this includes interactive digital platforms to provide information at a granular level for prospective developers. Additional process efficiency improvements would also prove beneficial to reduce queue backlogs.

The independent market monitor (IMM) for the PJM Interconnection recently recommended process improvements that advance commercially viable projects and remove unviable projects from the interconnection queue—reducing delays and timelines in interconnection study results and improving the probability that projects in advanced phases successfully enter service.[28] The IMM also recommends outsourcing interconnection studies to mitigate conflicts of interest, noting that incumbent TOs who conduct these studies often own generation.[29] Such circumstances are not unique to PJM. Rather, such issues receive limited attention because IMMs and other economic oversight mechanisms often overlook or disregard transmission processes.

V. Enhanced Transmission Oversight

The ANOPR is on point: enhanced transmission oversight is peremptory. Transmission may be the only domain where incumbent cost-of-service utilities often roam free of the economic regulation that is supposed to serve as a surrogate for competition. Given the lack of competition and economic regulatory oversight, poor economic discipline results. The perverse incentives of cost-of-service utilities have resulted in overly capital-intensive project selection and inefficient asset management, while

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[26] Federal Energy Regulatory Commission, *Order no. 845: Reform of Generator Interconnection Procedures and Agreements,* Docket No. RM17-8-000, April 19, 2018. https://www.ferc.gov/sites/default/files/2020-06/Order-845.pdf.
[27] "Petition for Rulemaking of the American Wind Energy Association to Revise Generator Interconnection Rules and Procedures," Docket No. RM15-21-000, Sept. 8, 2015. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20150908-5183&optimized=false.
[28] "2020 State of the Market Report for PJM," Monitoring Analytics, 2021, pp. 571-572. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2020/2020-som-pjm-sec12.pdf.
[29] Ibid.

deterring development of lower cost projects and, by extension, undercutting innovation by destroying the market value of developing grid-enhancing technologies.[30]

Establishing an independent transmission monitor (ITM) has the potential to remedy these problems, depending on its role and scope. Several functions would improve economic outcomes, transparency and accountability:

1. Overseeing regional and interregional planning to ensure independence and use of proper process and economic criteria.
2. Overseeing regional and interregional project selection processes to ensure fair and open competition.
3. Overseeing processes for local network projects with regional benefits to ensure equitable service between incumbent TO and non-incumbent loads and between incumbent and third-party transmission providers.
4. Overseeing TO asset management to determine used and usefulness of existing assets and if alternative technologies are economic.
5. Conducting assessments of the performance of transmission regions, planners and owners.
6. Making recommendations to the regions and Commission for transmission rule reform and hold filing authority before the Commission akin to the market design flaw referral mechanism for the IMMs.

It is unclear if certain roles would be necessary. For example, the ITM role would be better spent scrutinizing the competitiveness of project selection processes than scrutinizing construction cost management of individual projects. The role may also be better situated for monitoring the quality of coordination between parties rather than playing a direct role in enhanced coordination.

An ITM would be important in RTO regions, but would have the most value in non-RTO regions, which suffer from the most severe anti-competitive practices and opacity in planning and real-time conditions. One ITM per region would be workable, though an ITM for multiple regions might enable better interregional oversight. The ITM should be structured as an external body that reports directly to the Commission or regional board to ensure independence; this structure resulted in superior independence for the IMMs in RTO regions.

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[30] "Comments of the R Street Institute on Managing Transmission Line Ratings," Docket No. RM20-16-000, March 22, 2021. https://www.rstreet.org/2021/03/22/regulatory-comments-on-managing-transmission-line-ratings.

VI. Conclusion

RSI respectfully requests the Commission consider the comments contained herein.

Respectfully submitted,

/s/ Devin Hartman
Devin Hartman
Director, Energy and Environmental Policy

R Street Institute
1212 New York Ave. NW, Suite 900
Washington, D.C. 20005
(202) 525-5717
dhartman@rstreet.org

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