UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Interregional Transfer Capability Study: Strengthening Reliability Through the Energy Transformation	)))	Docket No. AD25-4-000

Initial Comments of the R Street Institute

I. Background and Summary

On June 3, 2023, President Joe Biden signed the Fiscal Responsibility Act into law.[1] That law required the North American Electric Reliability Corporation (NERC), as the nation's Electric Reliability Organization, to "conduct a study of total transfer capability as defined in section 37.6(b)(1)(vi) of title 18, Code of Federal Regulations, between transmission planning regions."[2] On Nov. 19, 2024, NERC submitted to the Federal Energy Regulatory Commission (FERC, or the Commission) the required Interregional Transfer Capability Study (Study). On Nov. 25, 2024, FERC issued a Notice of Request for Comments on the Study.

The result of NERC's Study is clear: Our country's current electricity system is inadequate to reliably meet customer demand going forward. NERC's efforts underscore this insufficiency on a reliability basis.[3] However, what remains to be seen are the opportunities to cost-effectively expand our interregional transmission capabilities. Said differently, Congress did not ask NERC, and NERC did not study, whether building or using interregional transmission could lower retail electric bills or meet demand in a more cost-effective manner.

NERC's Study did confirm the validity of Congress's interest and concerns and should prove helpful as lawmakers and regulators seek to address legal and regulatory barriers to regional and interregional transmission development. The study also buttresses the sagacity of Congress's preference to not initially mandate uniform interregional transfer capabilities.[4] As the report notes, a uniform approach to regional transfer capabilities would be "inefficient and ineffective."[5]

II. Benefits of the Study

The Study's ability to provide the public with the bimodal state (winter and summer) of transfer capabilities in the near future helps underscore the work that has been done to date and

---

[1] Fiscal Responsibility Act, H.R. 3746 (2023).
[2] *Id*.
[3] North American Electric Reliability Corporation Interregional Transfer Capability Study as Directed in the Fiscal Responsibility Act of 2023 (Hereinafter, "Study,"), FERC Docket No. AD25-4-000, Pleading, p. 5.
[4] Josh Siegel, "The Power Transmission Compromise That Could Unlock Energy Permitting Deal," *Politico*, May 25, 2023. https://www.politico.com/news/2023/05/25/transmission-compromise-energy-permitting-deal-00098826.
[5] Study Pleading, p. 3.

the relative inadequacy of capabilities in certain parts of the country, or in certain seasons. NERC was fairly clear that its "recommendations should be considered as a starting point, prioritizing those areas where the study suggests significant reliability improvements."[6] This level-setting is helpful in identifying the current state of the bulk power system and should serve to best inform solutions to actual, rather than perceived, shortcomings of our national grid. Although it provides a great starting point to discern the work that awaits the industry, the Study does not provide the complete picture needed to support a massive buildout of transmission infrastructure across the nation. Initially, as NERC makes clear, its "prudent additions" are technical in nature, and not based on economic justifications.[7]

Thankfully, the study identified dynamic line ratings (DLRs) as a practical and available tool to increase transfer capability.[8] Many commenters, including the R Street Institute, have conveyed to the Commission in other proceedings how cost-beneficial grid-enhancing technologies, including DLRs, can be in meeting customer demand.[9] Regretfully, "DLRs have been, and will continue to be chronically underutilized because of [transmission providers'] perverse incentives under cost-of-service regulation."[10] The Commission must do more to remedy this perverse incentive, and R Street requests that the Commission move efficiently on issuing a notice of proposed rulemaking on the subject, based on the record created in Docket No. RM24-6-000. As fixed transmission ratings were used for the Study, the robust implementation of DLRs should have a direct effect, even if only marginally in certain instances, on transfer capabilities.[11]

III. Critiques

The Study noted that future work on transfer capabilities could include "exploring alternative resource mixes" or that "[f]uture studies can offer more nuanced insights into how to optimally balance local generation with transfer capability."[12] NERC's pleading stated that "[m]ore transfer capability and a carefully planned resource mix are desirable to address […] identified challenges."[13] Respectfully, it is beyond the purpose of this Study and beyond current congressional authority for anyone at the federal level to determine a national or interregional "carefully planned resource mix," nor is a "carefully planned resource mix" likely to be efficient.[14] Given inherent information asymmetries; shortcomings of current planning and

---

[6] Study Appendix A, p. xix.
[7] Study Appendix A, p. 11. See also, Study Pleading, p. 14, noting that "NERC looked to the standard used in Commission precedent in electric utility ratemaking proceedings, which provides that "prudence" means a determination of whether (1) a reasonable entity (2) would have made the same decision, (3) in good faith, (4) under the same circumstances, and (5) at the relevant point in time."
[8] Study Appendix A, p. 134.
[9] Initial Comments of R Street Institute, FERC Docket No. RM24-6-000, Implementation of Dynamic Line Ratings Advanced Notice of Proposed Rulemaking, Oct. 15, 2024. https://www.rstreet.org/outreach/initial-comments-of-the-r-street-institute-before-the-federal-energy-regulatory-commission-on-implementation-of-dynamic-line-ratings-advance-notice-of-proposed-rulemaking.
[10] *Id*.
[11] Study Appendix A, p. 13.
[12] Study Appendix A, p. 138.
[13] Study Pleading, p. 5, citing Appendix A, p. 1 and Chapter 11. Study Appendix A refers to this seemingly preferred resource mix as being "strategically planned," Study Appendix A., p. vii.
[14] *Id*.

regulatory processes; incumbent interests; and the knowledge problem, regardless of how "carefully planned" a resource mix is, it is guaranteed to not be optimal.[15] Herein lies the benefit of wholesale competition; to the degree a resource mix is not optimal, competitive providers on the supply and demand side are either motivated to act to efficiently address needs, or are the ones that take losses on misallocated capital. "Planned" systems where the costs and risk are shouldered exclusively by customers through cost-of-service regulation are anything but "desirable." Attempting to finely tune transmission planning to accommodate a predetermined "optimal" resource mix effectively hard-codes that those resources will be built, but because future customer demands and changes in technology are impossible to project with any certainty, that predetermined resource mix will prove to be anything but "optimal."

It is important to note that NERC's study breaks some Order 1000 regions down into subregions, considering transfers across them to be "interregional." However, current "regional" processes exist today to address inadequacies between some planning regions used by the NERC study. For instance, PJM and MISO both have robust Order 1000 regional planning processes and were broken up into three and four regions, respectively, for the purposes of this Study. The success of transmission planning within these Order 1000 regions is demonstrated in NERC's Study, especially relative to the paucity of transfer capability in the Southeastern Regional Transmission Planning (SERTP) region. With the exception of MISO South, regions within MISO and PJM have significant transfer capability in the winter or summer analyses.[16] MISO South is, of course, a notable letdown when it comes to Order 1000 implementation.[17] Similarly, given its failure to meaningfully implement Order 1000 and "provide any real regional transmission planning solutions" over the past decade, it is unsurprising to see such low import capabilities across the SERTP region.[18] It is therefore past time that the Commission recommit to the principles and requirements of Order 1000 and ensure that utilities faithfully adhere to their obligations under current rules.

IV. Issues the Study Did Not Address

As previously noted, NERC's Study did not conduct economic assessments of transmission, indicating that "economic analysis, cost-benefit evaluation, or financial modeling were not factors in determining prudent recommendations. The focus was strictly on improving energy adequacy."[19] A core principle of regional planning—maximizing the net benefits of economic and reliability criteria jointly—is equally applicable to interregional planning.[20]

---

[15] J. Laffont and J. Tirole, "The Dynamics of Incentive Contracts," *Econometrica* 56:5 (September 1988); *See* F.A.Hayek, "The Use of Knowledge in Society," *The American Economic Review* 35:4 (September 1945).

[16] Study Appendix A, p. xi.

[17] A. Durnish Cook, "Tensions Boil Over MISO South Attitudes on Long-Range Transmission Planning," RTO Insider, Sept. 26, 2022. https://www.rtoinsider.com/28719-tensions-miso-south-long-range-transmission-planning.

[18] Simon Mahan, "Gridlocked: Planning Failure With The Southeastern Regional Transmission Planning Process," Southern Renewable Energy Association, Dec. 20, 2023. https://www.southernrenewable.org/blog/gridlocked-planning-failure-with-the-southeastern-regional-transmission-planning-process.

[19] Study Appendix A, p. viii.

[20] Comments of the R Street Institute, Docket No. RM21-17-000, Advanced Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, p. 8, Oct. 12, 2021. https://www.rstreet.org/outreach/r-street-comments-on-electric-regional-transmission-planning-and-cost-allocation-and-generator-interconnection-before-the-federal-energy-regulatory-commission.

Economics and reliability work hand in glove in this arena. Regardless, other studies exist that evince the profound negative economic impact to customers within RTOs caused by inadequate or insufficient intraregional (or for purposes of this Study, interregional) transmission transfer capability. For instance, inadequate transmission infrastructure within RTOs in the Midwest, namely MISO and SPP, drives inefficiencies to the tune of billions of dollars each year.[21] These regions have mature Order 1000 processes and a track record of successful intra- and interregional transmission planning, likely understating the cost impacts of inefficiencies in other parts of the country, and, in particular, non-RTO areas.[22] Incumbent interests and disparate state processes drive many of these largely unnecessary costs.

Insufficiencies of state- and regional-planning processes are clearly shown in the Study's findings. In many states that require integrated resource planning, utilities fail to holistically integrate transmission and resource planning within their own footprint, let alone on a state- or region-wide basis as the Study suggests.[23] The inability or unwillingness of utilities and state public utility commissions (PUCs) to consider the possibility of cost-effectively meeting energy adequacy in conjunction with other utilities or states leads to inefficiencies and, as the Study notes, could unreasonably subject their consumers to reliability risks. Although the current bulk power system may show sub-regional energy adequacy, regional and interregional transmission provides a likely candidate for cost-effectively meeting forecasted customer demand. In addition to congressional action to address some shortcomings in the regional and interregional transmission world, states should consider amending current—or creating new—state-level processes to ensure customers' needs are met in an efficient and effective manner. If nothing else, PUCs with utilities that conduct their own resource adequacy planning should take heed of NERC's suggestion to participate in wide-area planning and also actively participate in Order 1000 and Order 1920 regional processes to ensure that their customers are not unduly penalized by self-interested utilities' preferences.[24]

R Street does appreciate NERC's mention, if only in passing, of some of the barriers that exist today in planning and building transmission that would ultimately improve transfer capability in the future, including siting and permitting and cost allocation. As R Street has noted before, "[c]onsistent upfront benefit methodology would reduce key discrepancies between RTOs willing to explore interregional collaboration."[25] State interests pose a barrier for siting and permitting and for cost allocation. Encouraging state participation in a collaborative, interregional planning process, such as a convening run by the Department of Energy, could cultivate the buy-in needed to encourage agreement on cost allocation and state siting

[21] Catherine Hausman, "Power Flows: Transmission Lines Allocative Efficiency, and Corporate Profits," National Bureau of Economic Research, Working Paper 32091, January 2024, Revised January 2025. https://www.nber.org/system/files/working_papers/w32091/w32091.pdf.
[22] *Id*. at 40.
[23] Study Appendix A, p. 136.
[24] Whether through an integrated resource plan or otherwise.
[25] Devin Hartman, Comments of the R Street Institute, Docket No. RM21-17-000, Advanced Notice of Proposed Rulemaking: Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection, Oct. 12, 2021, p. 9. https://www.rstreet.org/outreach/r-street-comments-on-electric-regional-transmission-planning-and-cost-allocation-and-generator-interconnection-before-the-federal-energy-regulatory-commission.

approvals—the latter of which are seldom coordinated, create clear barriers to entry for transmission, and have become increasingly challenging.[26]

As it relates to truly interregional transmission (between markets), R Street still believes that the Commission should take efforts to investigate removing barriers to merchant high voltage direct current (MHVDC) development.[27] Although MHVDC developers face barriers to intra- and interregional development, they have largely led on interregional transmission activities.[28] But depending exclusively on this merchant model to build interregional transmission runs the risk that development will ultimately be inefficient because many benefits cannot be captured by the developer.[29] Regardless, MHVDC has advantages over cost-of-service regulated facilities, where questions of cost allocation and rate recovery (including transmission incentives) are not at play, given the voluntary nature of subscriptions and the market revenues available in arbitraging prices between regions. However, these facilities have to overcome numerous significant hurdles, including:

- The lack of eminent domain authority and parochial state and local interests complicate the development process;[30]
- Due to its operational characteristics, MHVDC acts similarly to generation, thus posing a competitive risk to incumbent generators. There exists an opportunity and motive for incumbent transmission operators that own generation to act in ways that complicate MHVDC development;[31]
- Vertically integrated utilities have a financial incentive to build generation rather than subscribe to MHVDC capacity because they earn a return on the former but not the latter;
- Market integration is poor;[32] and

[26] 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.

[27] Michael Giberson and Devin Hartman, Comments of the R Street Institute on the Request for a Technical Conference on Merchant High Voltage Direct Current Facilities, FERC Docket No. AD22-13-000, Interregional High Voltage Direct Current Merchant Transmission, March 8, 2023. https://www.rstreet.org/outreach/comments-of-the-r-street-institute-on-the-request-for-a-technical-conference-on-merchant-high-voltage-direct-current-facilities.

[28] Zach Hale, "Merchant Developers Fill 'Void' in US Interregional Grid Build-out," S&P Global, Oct. 6, 2023. https://www.spglobal.com/market-intelligence/en/news-insights/articles/2023/10/merchant-developers-fill-void-in-us-interregional-grid-build-out-76447354.

[29] Paul Joskow and Jean Tirole, "Merchant Transmission Investment," *The Journal of Industrial Economics* LIII:2 (June 2005). https://economics.mit.edu/sites/default/files/2022-09/Merchant%20Transmission%20Investment.pdf.

[30] Jeffrey Tomich, "Illinois Court Strikes Blow Against Grain Belt Express Power Line," E&E News, Sept. 12, 2024. https://www.eenews.net/articles/illinois-court-strikes-blow-against-grain-belt-express-power-line.

[31] Federal Energy Regulatory Commission, Order Approving Stipulation and Consent Agreement, Docket No. IN21-5-000, Public Service Electric and Gas Company, Dec. 5, 2024. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241205-3039&optimized=false; Federal Energy Regulatory Commission, Opinion No. 566, Docket No. EL15-79-001, TranSource, LLC v. PJM Interconnection, LLC, Aug. 26, 2019. https://www.ferc.gov/sites/default/files/2020-06/20190826181640-EL15-79-001.pdf.

[32] Johannes P. Pfeifenberger et al., "The Operational and Market Benefits of HVDC To System Operators," Brattle Group and DNV, September 2023. https://acore.org/wp-content/uploads/2023/09/The-Operational-and-Market-Benefits-of-HVDC-to-System-Operators.pdf.

- Regional interties are not optimized, leading to incorrect price signals that are in conflict with prevailing energy flows.[33]

V. Suggestions for FERC's Recommendations to Congress

While the Commission should investigate the barriers to interregional and MHVDC development—separately or in conjunction—it should also amplify to Congress NERC's suggestion to "consider mechanisms to address existing challenges associated with siting/permit approvals" in order to maintain, and potentially increase, transfer capabilities.[34] The Commission should suggest to Congress that permitting and siting for regional and interregional transmission should be equalized with local transmission for multistate projects. Equalization of permitting alongside Commission efforts on the quantification of interregional transmission benefits could provide states where transmission "passes through" an interest in working toward durable solutions to projects, as they could have a role that allows them to successfully address their concerns.[35]

/s/ Kent A Chandler
Kent A Chandler
Resident Senior Fellow, Energy and Environmental Policy
R Street Institute
1411 K Street N.W., Suite 900
Washington, D.C. 20005
(202) 525-5717
kchandler@rstreet.org

/s/ Devin Hartman
Devin Hartman
Director, Energy and Environmental Policy
R Street Institute
1411 K Street N.W., Suite 900
Washington, D.C. 20005
(202) 525-5717
dhartman@rstreet.org

[33] *Id.*; Johannes P. Pfeifenberger et al., "The Need for Intertie Optimization," Brattle Group and Wilkie Farr & Gallagher LLP, October 2023. https://www.brattle.com/wp-content/uploads/2023/10/The-Need-for-Intertie-Optimization-Reducing-Customer-Costs-Improving-Grid-Resilience-and-Encouraging-Interregional-Transmission-Report.pdf.
[34] Study Pleading, p. 20.
[35] Robin Allen, "Let's Make a Deal: High Capacity Transmission Edition," Niskanen Center, June 14, 2024. https://www.niskanencenter.org/lets-make-a-deal-high-capacity-transmission-edition.