UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Building the Future Through Electric	)	**Docket No. RM21-17-000**
Regional Transmission Planning and Cost	)	
Allocation and Generator Interconnection	)	

COMMENTS OF THE INSTITUTE FOR POLICY INTEGRITY AT NEW YORK UNIVERSITY SCHOOL OF LAW

Pursuant to the Federal Energy Regulatory Commission's (FERC or the Commission) April 21, 2022 Notice of Proposed Rulemaking (NOPR),[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, the Institute for Policy Integrity at New York University School of Law (Policy Integrity) respectfully submits these comments.[2] Policy Integrity is a non-partisan think tank dedicated to improving the quality of government decisionmaking through advocacy and scholarship in the fields of administrative law, economics, and public policy. Policy Integrity's staff has deep expertise in cost-benefit analysis and regulatory economics, and has participated in numerous proceedings before the Commission, regional transmission organizations and independent system operators (RTOs/ISOs), and state public utility commissions regarding the socially efficient pricing of energy resources—including transmission resources.

Long-term regional transmission planning, when done properly, can help transmission planners understand the potential benefits that would flow from identification and selection of long-distance, high-voltage regional transmission projects. It has long been clear from an

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022) [hereinafter NOPR]; *see also* Notice on Requests for Extension of Time, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Docket No. RM21-17 (May 25, 2022) (extending deadline for comments).

[2] These comments do not necessarily reflect the views of NYU School of Law, if any.

engineering and economic perspective that using a variety of long-term scenarios that better match the useful life of assets will allow transmission planners to identify and select projects that can serve short- and medium-term needs while building in flexibility and option-value to meet needs that arise due to changes in the resource mix and demand in the future.[3] The value of such long-term planning is even greater in light of the passage of the Inflation Reduction Act. With new federal policy supporting renewable energy production, the pace of transition will intensify, and the next twenty years will unequivocally look significantly different than the last. As such, long-term regional transmission planning will be needed to ensure necessary transmission development to support the change in resource mix—specifically new capacity coming online—that will be driven by the Inflation Reduction Act.[4]

The NOPR takes the important step of requiring planners to engage in proactive long-term planning activities to identify more efficient and cost-effective solutions. However, it appears that not all stakeholders have the same understanding of long-term scenario planning and what it means to plan transmission over a 20-year time horizon. At a high level, the Commission should clarify that the goal of this long-term planning process should be for planners to consider what is going to be needed *over* the next 20 years (not *starting in* Year 20).

These comments also recommend that the Commission provide minimum uniform requirements on model specification and scenario planning based on best practices. Specifically, the Commission should provide greater direction (and even standardization) on modeling

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[3] *See* Comments of the Inst. for Pol'y Integrity at N.Y.U. School of Law at 27 n.89, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Docket No. RM21-17 (Oct. 12, 2021) [hereinafter Policy Integrity ANOPR Comments] (listing academic literature evidencing benefit of a proactive approach that co-optimizes transmission and generation investment decisionmaking).

[4] *See generally* PRINCETON UNIVERSITY ZERO LAB, PRELIMINARY REPORT: THE CLIMATE AND ENERGY IMPACTS OF THE INFLATION REDUCTION ACT OF 2022 (Aug. 2022), https://perma.cc/JTZ4-5RH8 (modeling the likely change in generation mix and new capacity coming online as result of the Inflation Reduction Act).

techniques, scenario construction and selection, and various features of planning like time horizons, appropriate use of historical data, inputs, and model specifications. Further, the Commission should require that planners use more, not less, than four scenarios. The Commission can look to European planners and the U.S. Department of Energy for example.

Additionally, these comments recommend that if the Commission moves forward with allowing planners to reinstate a conditional right of first refusal (ROFR), it should institute administrative guardrails to help protect transmission customers from excessive costs.

Finally, these comments reiterate the need for the Commission to mandate a uniform set of core benefits that all planning entities must consider. Harmonizing and coordinating the benefits considered will better facilitate identification and selection of efficient and cost-effective transmission solutions and will allow comparison across planning regions and even nationally.

While requiring long-term regional planning is a significant step toward proactive planning for the grid of the future, we urge the Commission to move forward quickly with an interregional transmission planning rule. The process proposed in this rulemaking is essential, and it can and should be improved, but progress in developing necessary and cost-effective transmission projects will continue to be modest without a rulemaking that ensures interregional coordination.

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I. The Long-Term Scenario Planning Requirement Is an Important Step, but Requires Clarification and Improvement

The proposed rule took an important step forward by requiring transmission planning entities to conduct proactive long-term scenario planning. The use of scenarios aligns with recommendations of engineers and economists, and best practices of transmission planners. However, the final rule should clarify and improve on how to conduct scenario planning over a long time horizon and provide greater direction on aspects of such a planning exercise.

A. The Commission Needs To Provide Clarification About Long-Term Scenario Planning

In the NOPR, the Commission mandates that planning entities undertake a long overdue and necessary long-term scenario planning exercise. Before turning to more technical improvements, these comments highlight a problem observed in various stakeholder meetings: There appears to be some confusion about what planning over a 20-year time horizon entails. The Commission must be clear about what it is asking planning entities to undertake.

Specifically, in some RTO/ISO stakeholder meetings this long-term scenario planning requirement has been understood to mean planning for what to build *in* Year 20. This view of long-term planning would consider only what construction should begin *starting* in Year 20. While one could plan this way, it is not an efficient or useful means of planning for the problems the NOPR intends to address, and the Commission should clarify that transmission planners should not understand the exercise in this way. Such a fundamental misunderstanding of how to conduct scenario planning over a 20-year time horizon would undermine the Commission's goals in promulgating this rulemaking.

Instead, the goal of planning over a long time horizon should be for planners to consider what is going to be needed *over* the next 20 years and how to ensure that projects built in the short- and medium-term (which have useful lives that may extend over and through the 20 year time horizon) can best allow flexibility to meet the needs of the future in the most efficient and cost-effective manner.

B. The Commission Should Ensure Minimum Standards for Model Specification and Scenario Planning, Consistent with Best Practices

A common criticism of modeling is that assumptions on inputs will determine the output of the model. Put differently, letting the modeler decide freely which inputs and methods to use will give the modeler a large amount of influence over the results. Where planning entities exercise strategic modeling behavior—selecting inputs that will bias the results of the model—transmission planning may not yield the most efficient or cost-effective transmission solutions, undermining the regional planning process. To mitigate strategic modeling behavior, the Commission should ensure minimum standards for model specification and scenario planning based on best practices.

In particular, the Commission should (1) ensure use of appropriate modeling techniques able to produce robust and cost-effective results in the face of an uncertain future; (2) provide direction for how planners construct and select scenarios; (3) better standardize certain features of scenario planning, such as the time horizon, how historical data will be used, basic input assumptions, and model specifications; and (4) require more, not less, than four scenarios, along with sensitivity analysis.

1. The Commission Should Ensure Use of Appropriate Modeling Techniques

By its nature, transmission planning must deal with many uncertainties. These uncertainties could arise from various factors, including policy, cost, economic trends, climate change, strategic behavior of market participants, or technological parameters. Unless these uncertainties are considered in modeling, transmission planning might not lead to cost-effective or efficient outcomes, leading to unjust and unreasonable rates for consumers. Importantly, some modeling techniques can handle uncertainty better than others. Therefore, it is important for the Commission to encourage the use of best available methods for transmission planning and provide greater direction to planning entities on appropriate modeling techniques in the final rule.

In the proposal, the Commission noted that probabilistic transmission planning or stochastic techniques could be used by planning entities to meet the requirement to account for a high-impact, low-frequency event, but did not mandate the use of such modeling techniques for this requirement or to address uncertainty in planning more broadly.[5] However, stochastic programming[6] and robust optimization[7] models are considered the state-of-the-art techniques for dealing with uncertainty. Both techniques seek to take a proactive approach to planning and may be able to better account for and deal with the uncertainty about anticipated future states of the world.[8]

Although stochastic programming and robust optimization methods are designed to deal with the stochastic nature of these uncertainties, they may be computationally expensive and may not (yet) be part of every planner's standard toolbox. Instead, many modelers use deterministic

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[5] NOPR, *supra* note 1, at P 124.

[6] Venkat Krishnan et al., *Co-Optimization of Electricity Transmission and Generation Resources for Planning and Policy Analysis: Review of Concepts and Modeling Approaches*, 7 ENERGY SYS. 297 (2015); Francisco D. Munoz et al., *An Engineering-Economic Approach to Transmission Planning Under Market and Regulatory Uncertainty: WECC Case Study*, 29 IEEE TRANSACTIONS ON POWER SYS. 307 (2014).

[7] *See, e.g.*, Álvaro García-Cerzo et al., *Robust Transmission Network Expansion Planning Considering Non-Convex Operational Constraints*, ENERGY ECON., June 2021; Cristina Roldán et al., *Robust Transmission Network Expansion Planning Under Correlated Uncertainty*, 34 IEEE TRANSACTIONS ON POWER SYS. 2071 (2019); Raquel García-Bertrand & Roberto Mínguez, *Dynamic Robust Transmission Expansion Planning*, 32 IEEE TRANSACTIONS ON POWER SYS. 2618 (2017).

[8] AHARON BEN-TAL ET AL., ROBUST OPTIMIZATION xv (2009) ("[B]oth Robust and Stochastic Optimization are aimed at answering the same question (albeit in different settings), the question of building an uncertainty-immunized solution to an optimization problem with uncertain data; . . ."). In stochastic programming models, some or all input parameters are assumed to be uncertain, but their probability distributions are known. Proponents of robust optimization argue that its primary advantage over stochastic programming is that it does not require knowledge of the probability distribution of uncertainties, which is difficult to obtain in practice, just a range of variation of the uncertain parameters. *See* R.A. Jabr, *Robust Transmission Network Expansion Planning with Uncertain Renewable Generation and Loads*, 28 IEEE TRANSACTIONS ON POWER SYS. 4558, 4559 (2013).

models and use sensitivity scenarios to check the robustness of the results under uncertainty.[9] Within a deterministic framework, however, the result of the planning studies critically depend on the number of sensitivity scenarios and how these scenarios are constructed. Given that the Commission is not requiring the use of techniques addressing uncertainty, it is important for the Commission to direct planners to use proper sensitivity analysis and provide guidelines about how to curate these scenarios.

2. The Commission Should Provide Direction About Scenario Construction and Selection

Scenario planning is a critical element of transmission planning for addressing various uncertainties involved in future outcomes. Proper construction and selection of scenarios is therefore crucial for ensuring that scenario planning yields meaningful results. If the scenarios used are not reasonably representative of the future states of the power system (e.g., if the scenarios consistently underestimate the demand at a certain location or overestimate the cost of a technology), then transmission planning might not lead to cost-effective or efficient outcomes. Furthermore, a harmonized and coordinated approach towards scenario construction and selection (and modeling broadly) across planning regions is particularly relevant for computing and comparing region-wide or national benefits.[10]

Given the importance of proper scenario construction and selection to effective scenario planning, the Commission should be more prescriptive about how planning entities choose the scenarios to be used. Ideally the Commission would prescribe the use of a uniform set of scenarios by all planning entities, but the Commission could also improve upon the NOPR by

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[9] JOHANNES PFEIFENBERGER ET AL., BRATTLE GRP., GRID STRATEGIES, TRANSMISSION PLANNING FOR THE 21ST CENTURY: PROVEN PRACTICES THAT INCREASE VALUE AND REDUCE COSTS 85 (2021).

[10] *See, e.g.*, Ioannis Konstantelos et al., *Coordination and Uncertainty in Strategic Network Investment: Case on the North Seas Grid*, 64 ENERGY ECON. 131 (2017) (explaining that market integration and cross-zonal coordination result in significant operational and capital expenditure savings).

laying out best practices for scenario construction and selection that planning entities are encouraged to use.

The Commission should look to other U.S. agencies and international transmission planners for developing best practices for choosing scenarios. One best practice the Commission should consider laying out in a final rule is the need for scenarios to capture the interactions between gas and electricity systems. The Commission could look to European planners as example. The European Network of Transmission System Operators for Electricity *and* the European Network of Transmission System Operators for Gas jointly curate and harmonize future scenarios that are used to support the selection process of the European Commission's infrastructure "projects of common interest," which are projects that could help the European Union to achieve its energy policy and climate objectives.[11] They seek to do so by using scenarios that consider both the gas and electricity system. Given the growing interconnection between the sectors,[12] scenarios used for electric transmission planning should not ignore (and should meaningfully integrate) consideration of the gas sector.

Additionally, the Commission should emphasize the importance of accounting for uncertainty in a detailed manner. The Department of Energy has begun work to develop scenarios to be used in its National Transmission Planning study,[13] which will provide useful example. The study is set to account for approximately 100 scenarios for their capacity expansion models.[14] The scenarios will, for example, differ in assumptions about the pace of

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[11] *Key Cross Border Infrastructure Projects*, EUROPEAN COMM'N, https://perma.cc/4U6X-Q2WN (last visited Aug. 9, 2022).

[12] Policy Integrity ANOPR comments, *supra* note 3, at 40–41.

[13] *See National Transmission Planning Study,* U.S. DEP'T OF ENERGY, https://perma.cc/P2KT-9CJE (last visited Aug. 9, 2022).

[14] *See* U.S. Dep't of Energy et al., Presentation on National Transmission Planning Study at the Modeling Subcommittee Meeting, at slide 21 (June 7, 2022), https://perma.cc/MEJ5-9JE6 [hereinafter DOE June 7 National Transmission Planning Study Presentation].

decarbonization and electrification, and about the cost of transmission and generation.[15] In order to best account for uncertainty, scenarios should reasonably capture possible future states of the world.

3. The Commission Should Better Standardize Certain Features of Scenario Planning

Even if the Commission is wary of being overly prescriptive, it should still provide greater direction (or even mandate) certain features of scenario planning that planning entities must undertake. Each of these ingredients for building scenarios, selecting sensitives, and formulating and running a model deeply affect the results that scenario planning will yield. Requiring greater standardization of these basic features can prevent strategic modeling behavior by planners and facilitate comparison of results.

Planning and Modeling Time Horizon: The Commission should stick to requiring modeling 20 years ahead because shorter timeframes can result in suboptimal investments in the long run. As discussed in Section I.A., it is crucial to model what is going to be needed *over* the next 20 years and how to ensure that projects built in the short and medium term can best allow flexibility to meet the needs of the future in the most efficient and cost-effective manner. The further we look into the future, the greater the uncertainty about the future state of the world. Nonetheless, in the context of long-lived transmission assets that (i) will likely to be around for more than 20 years, and (ii) have long lead times to be constructed, a long time horizon is reasonable. The Commission should also require planning entities to conduct a sensitivity analysis with respect to the time horizon: We recommend a 30-year planning horizon for that

[15] *See id.* (showing DOE plans to use four transmission topologies, nine variations on emissions, and fourteen sensitivities considering drivers like high transmission costs, high distributed PV adoption, constrained renewable energy siting, among others).

sensitivity analysis. That is, planning entities should run each of the 20-year time horizon scenarios with a 30-year horizon and compare the results.

Appropriate Usage of Historical Data: The Commission should provide direction on how to use historical data to construct forward-looking baseline scenarios, as well as how to account for the increased frequency and severity of extreme weather events. In general, it may be appropriate to use scaled and adjusted historical weather/climate data to compute temporal and spatial capacity factors of wind, solar, and other weather-dependent supply (e.g., non-dispatchable hydro) and demand resources when constructing the baseline outlook for the future.[16] The advantage is that this data is readily available for at least the last 20 years. This data can then be scaled appropriately and used to construct a baseline scenario based on estimated future trajectories of demand growth, as well as of wind, solar, and weather-dependent resources.

However, there is a critical downside to using historic data: The future may look very different considering climate change and extreme weather events, as well as innovation in demand-side or storage technologies, which would add flexibility to the market. Hence, future demand and weather-dependent supply will likely be very different from historical demand and supply. Specifically, demand-side participation is likely to increase, that is, more elastic demand able to shift load from one period to another will show up.[17] Similarly, an increased amount of storage capacity will also shift demand across time and space.[18] Furthermore, the increased

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[16] For example, DOE plans to use historic renewable energy profiles in its national transmission study. *See* U.S. Dep't of Energy et al., Presentation on National Transmission Planning Study at the Technical Review Committee Meeting #1, at slide 62 (May 20, 2022), https://perma.cc/Q96K-HUJY.

[17] *See, e.g.*, EMI BERTOLI, INT'L ENERGY AGENCY, DEMAND RESPONSE: MORE EFFORTS NEEDED (Nov. 2021), https://perma.cc/6SP8-MMYX ("There were many positive demand-response regulation and implementation developments in 2020 and 2021. Favourable policies in several countries, such as Australia, Belgium, and the United States, addressed some of the barriers to widespread demand-response deployment in power markets, while the number of capacity market auctions increased and prices broke records.").

[18] MASS. INST. OF TECH., THE FUTURE OF ENERGY STORAGE xi (June 2022), https://perma.cc/WW5E-42BD ("Energy storage enables cost-effective deep decarbonization of electric power systems that rely heavily on wind and solar generation without sacrificing system reliability."); *id.* at 2 ("Increased penetration of VRE generation

likelihood of extreme weather events will lead to increased electricity demand for heating and cooling, as well as reduced output from some supply technologies.[19]

There are multiple ways to deal with these changes. On an ad-hoc basis, expected temporal and spatial changes in future locational demand profiles or non-dispatchable supply profiles could be addressed by replacing a few historic "normal years" with data from historic extreme weather years. This replacement would change the mix of the future spatial demand projections as well as weather-dependent supply projections by increasing the frequency of extreme years in a 20-year look-ahead sample. However, this approach may still not fully represent the true locational extreme weather distributions or demand distributions because future events may be more severe than what we have observed in historical data. Another option for addressing the likely discrepancy between historical and future conditions would be to change the frequency or duration of these events based on guidance from academic literature.[20]

In any case, the Commission should provide greater direction to planning entities on whether and how to use historical weather/climate data. A higher degree of prescription on such data usage is needed to ensure that scenarios used in long-term transmission planning reasonably capture future conditions so that uncertainties can be accounted for in the comprehensive sensitivity analysis.

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makes storage more attractive because VRE generation is intermittent: Its output is variable over time and imperfectly predictable. One approach to coping with intermittency is to use storage to perform energy arbitrage—that is, to move electric energy availability from times when it is abundant (lower price) to times when it is scarce (higher price).").

[19] Todd Levin et al., *Extreme Weather and Electricity Markets: Key Lessons from the February 2021 Texas Crisis*, 6 JOULE 1, 2 (2022).

[20] For example, planners could look at models from the climate sciences, meteorological sciences, and hydrological sciences. A summary of these models is provided in the 6th Intergovernmental Panel on Climate Change Report. *See* Sonia I. Seneviratne et al., Intergovernmental Panel on Climate Change (Working Grp. 1), *Weather and Climate Extreme Events in a Changing Climate*, *in* CLIMATE CHANGE 2021: THE PHYSICAL SCIENCE BASIS 1513 (2021), https://perma.cc/UEN9-XKHR.

Assumptions on Modeling Inputs: The Commission should provide direction on appropriate (or even standardize) assumptions for major transmission drivers such as macroeconomic data, electrification, cost, and technology performance characteristics.[21] These assumptions could significantly affect the cost and benefits of transmission lines, and hence affect the planning outcomes. For example, a recent Lawrence Berkeley National Laboratory study computed marginal values of transmission in relieving congestion in 2012-2021 and found that extreme conditions (both weather-related and non-weather-related stressors, like concurrent generator outages) 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."[22] Furthermore, the report explains that modelers understated the benefits of regional and interregional transmission when extreme conditions and high-value periods are not adequately considered, highlighting the importance of input assumptions.[23] Without greater standardization, the long-term planning required by the NOPR may not provide the best results.

Model Formulation and Setup: Finally, the Commission should also provide direction on what models should be used for evaluating transmission projects by planners. Power system models come in different granularities and the Commission should ensure that these models are as realistic as possible by using consistent model formulations and physics-based constraints. The Commission should standardize certain model specifications, such as: (1) the extent to which the transmission network is modeled and what assumptions on grid-enhancing technology, e.g., topology optimization, are made; (2) how dispatchable units are modeled, for example, are

[21] For a full list of important transmission drivers, see Comments of the U.S. Dep't of Energy to Advance Notice of Proposed Rulemaking at 12–13, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Docket No. RM21-17 (Oct. 12, 2021).

[22] DEV MILLSTEIN ET AL., LAWRENCE BERKELEY NAT'L LAB'Y, EMPIRICAL ESTIMATES OF TRANSMISSION VALUE USING LOCATIONAL MARGINAL PRICES 3, 30 (Aug. 2022), https://perma.cc/AA8Q-6RTL.

[23] *Id.* at 33

units aggregated by type or are they modeled at the resource level including their operational characteristics; (3) how flexibility on the demand side, storage, and net imports are accounted for; and (4) whether electricity infrastructure and gas infrastructure are jointly co-optimized, given these two sectors are already coupled and are expected to be more so in the future.[24]

4. The Commission Should Require Use of More, and not Less, than Four Scenarios

Ideally, planners would compute sensitivity scenarios for a variety of exogeneous parameters. However, combinations of even a low/medium/high scenario for a few parameters could easily lead to a large number of scenarios. (For example, all combinations of low/medium/high scenarios of five parameters would lead to 3^5= 243 different scenarios to compute). And it is understandable for the Commission to worry about the feasibility of such analyses and want to limit the required number of scenarios.

However, using only four scenarios, as the Commission requires in the NOPR,[25] may not be sufficient for a task as complicated as forward-looking transmission planning. Planning critical infrastructure 20 years ahead is not a trivial task and, as mentioned above, the risks and uncertainties in energy markets are vast. These uncertainties are especially important in a setting with an increasing share of weather/climate-dependent production technologies under the threat of increasingly frequent and more severe extreme weather events. Given the Commission's recognition of the uncertainty that exists in conducting long-term planning,[26] to mitigate the risk and ensure effective long-term planning, the Commission should require the use of more

[24] For large volumes of energy to be transported over long distances, pipelines may be more economical than transmission lines. Whether it will be economical to convert low-cost electricity into hydrogen or other sources will depend on the conversion costs. *See, e.g.*, Daniel DeSantis et al., *Cost of Long-Distance Energy Transmission by Different Carriers*, ISCIENCE, Dec. 2021 (comparing relative cost of long-distance *energy* transmission).

[25] NOPR, *supra* note 1, at P 121. The Commission leaves open the possibility that planners may use more, but only mandates the use of four scenarios.

[26] *See, e.g., id.* at PP 71, 88, 93.

scenarios. Example planning efforts have used more than four scenarios, and thus best practice counsels against reducing the number of required scenarios.[27]

Furthermore, some of the risks might be positively correlated or a combination of risks might lead to compounding events, as the processes that cause extreme events often interact and are spatially and/or temporally dependent.[28] In such circumstances, traditional risk assessment methods, which typically use only historical data and consider one driver at a time, would lead to the underestimation of risks.[29] For example, a long heat wave might increase electricity demand while reducing water availability for electricity generation from hydroelectric units. Thus, instead of mandating only a minimum number of scenarios, the Commission should also require sensitivity analysis of critical drivers of transmission with a sufficient number of scenarios.

For the cases in which sensitivity analysis might be overly burdensome, the Commission should offer guidance on how to group different parameters into scenarios, as curating scenarios is not a trivial exercise in transmission planning. First, because of complicated power system dynamics, how a parameter would affect the need for transmission is not always intuitive *ex-ante*. For example, adding low-cost generation resources at one location might lead to higher congestion in another.[30] Second, different factors might have countervailing effects on outcomes,

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[27] For example, DOE's National Transmission Planning Study will use approximately 100 scenarios. *See* DOE June 7 National Transmission Planning Study Presentation, *supra* note 14, at slide 21. ERCOT has previously used 5 scenarios. *See* ERCOT, REPORT ON EXISTING AND POTENTIAL ELECTRIC SYSTEM CONSTRAINS AND NEEDS 10 (Dec. 2020), https://perma.cc/JGS4-9VH7. In academic work, economists looking at CAISO transmission have used 17 scenarios. *See* Mohamed Labib Awad et al., *Using Market Simulations for Economic Assessment of Transmission Upgrades: Application of the California ISO Approach*, *in* RESTRUCTURED ELECTRIC POWER SYSTEMS: ANALYSIS OF ELECTRICITY MARKETS WITH EQUILIBRIUM MODELS 241, 255 (Xiao-Ping Zhang ed. 2010).

[28] Jakob Zscheischler et al., *Future Climate Risk from Compounded Events*, 8 Nature Climate Change 469, 469, 474 (2018).

[29] *Id.*

[30] *See, e.g.*, Hans Schermeyer et al., *Understanding Distribution Grid Congestion Caused by Electricity Generation from Renewables*, *in* SMART ENERGY RESEARCH: AT THE CROSSROADS OF ENGINEERING, ECONOMICS, AND COMPUTER SCIENCE 78, 78 (2016) ("In various countries with a strong growth of RES-E this causes an increasing amount of grid congestion both on the transmission and distribution level, for example in Germany.").

meaning how they are grouped into scenarios might lead to different outcomes.[31] For example, as a stand-alone demand parameter a higher EV penetration might necessitate increased transmission capacity. However, higher EV penetration combined with increased rooftop solar PV, which can be used to charge those EVs during the day, might reduce the need for transmission capacity. Similarly, a large-scale solar PV park in the dessert might be complemented with a large transmission infrastructure upgrade able to transport the generated electricity to load centers. However, in combination with a storage technology, the seasonal and daily variation of solar generation can be smoothed out which can lower the demand for the transmission upgrade. The Commission might also encourage planners to use scenario clustering techniques that can reduce the number of scenarios but still ensure scenarios meaningfully represent uncertainty.[32]

Without a common framework for handling assumptions and sensitivity scenarios, transmission planners might rely on vastly different and incompatible assumptions, risking inefficient outcomes.

C. The Commission Should Clarify Minimum Data Transparency Standards

A commonly used acronym in the modeling community is GIGO: Garbage In, Garbage Out. It means unrealistic input data, for example about future states of the world, will lead to unsatisfactory modeling outcomes. Hence, using the best available and realistic input data will be key in successful planning. The NOPR recognized the importance of the data used and the need

[31] Yury Dvorkin et al., *Comparison of Scenario Reduction Techniques for the Stochastic Unit Commitment*, at 1 (2014) ("However, the computational burden increases rapidly with the number of scenarios considered. Scenario reduction techniques are, therefore, used to manage the amount of computing time required. Such a reduction unavoidably results in a less accurate representation of uncertainty and may produce generation schedules that require expensive corrective actions for some uncertainty realizations.").

[32] *See generally, e.g.*, Sangwoo Park et al., *Comparing Scenario Reduction Methods for Stochastic Transmission Planning*, 13 IET GENERATION, TRANSMISSION & DISTRIBUTION 1005 (2019); Mingyang Sun et al., *An Objective-Based Scenario Selection Method for Transmission Network Expansion Planning with Multivariate Stochasticity in Load and Renewable Energy Sources*, 145 ENERGY 871 (2018).

for an open and transparent approach to determining the data to be used in the planning process. As such, the NOPR requires the use of "best available data," which, among other qualities, is (1) "developed using diverse and expert perspectives"; and (2) "adopted via a process that satisfies the transparency planning principle."[33] This transparency process require planners to "reduce to writing and make available the basic methodology, criteria, and processes used to develop transmission plans" and "make sufficient information available to enable customers and other stakeholders to replicate the results of transmission planning studies."[34]

The NOPR's "best available data" requirements are crucial for protecting against strategic modeling behavior and in line with best practices of European transmission planners for how to achieve transparency, make input data available, and curate data and assumptions.[35] European planners update scenarios every two years,[36] which is more frequent than, but similar to, the Commission's three-year requirement.[37] Additionally, they get feedback from stakeholders at various stages to continuously improve their approach to transmission planning.[38]

The Commission can improve upon the NOPR's data transparency requirement by adding detail to the requirements above. As part of the requirement that the data be developed using expert perspectives, the Commission should encourage planners to involve independent researchers in the process to ensure that the latest modeling and computational developments will not be missed. This might include creating an academic advisory group or board on modeling or having third party experts inspect the planning work, reproduce results, and suggest

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[33] NOPR, *supra* note 1, at P 130.
[34] *Id.* at P 123 n.226.
[35] *See* EUROPEAN TRANSMISSION SYS. OPERATOR FOR ELEC. EUROPEAN TRANSMISSION SYS. OPERATOR FOR GAS, TYNDP 2022 SCENARIO REPORT (Apr. 2022), https://perma.cc/QL6J-64TJ [hereinafter EUROPEAN TRANSMISSION PLANNING SCENARIO REPORT].
[36] *Id.* at 10.
[37] NOPR, *supra* note 1, at P 93.
[38] EUROPEAN TRANSMISSION PLANNING SCENARIO REPORT, *supra* note 35, at 16–19.

improvements. There must be some external vetting of the data used by those who do not have a stake in planning outcomes.

Furthermore, an open stakeholder process may limit the power to influence outcomes of certain dominant market players. Because input assumptions and modeling techniques could change outcomes significantly, some stakeholders may try to influence scenarios in their favor. Besides holding public consultations events, the European transmission operators also publish a list of meetings with external stakeholders.[39] They also generally respond to all comments and feedback received during public consultation.[40] Such transparency creates confidence in the results. The Commission should ensure that stakeholder meetings are open to the public, including outside experts, and that planners meaningfully consider and respond to feedback.

II. If the Commission Chooses To Move Forward with Allowing Reinstatement of a Conditional ROFR, It Should Include Guardrails to Minimize Anticompetitive Effects

As the Commission recognizes, Order 1000 has resulted in limited investment in regional transmission facilities.[41] Given the broad number of exemptions from Order 1000 and ROFR elimination,[42] investment has been focused on local facilities not subject to competition.[43] To

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[39] *See, e.g.*, *Download*, EUROPEAN TRANSMISSION SYS. OPERATOR FOR ELEC. EUROPEAN TRANSMISSION SYS. OPERATOR FOR GAS, https://perma.cc/6GEV-M4RF (last visited Aug. 12, 2022) (providing list of external stakeholder meetings related the Transmission Scenario Report).

[40] *See, e.g.*, *id.* (providing ENTSO-E and ENTSO-G's official responses to consultation comments).

[41] *See* NOPR, *supra* note 1, at P 344.

[42] *See* Ari Peskoe, *Is the Utility Transmission Syndicate Forever*?, 42 ENERGY L.J. 1, 44–46 (2021) ("The evaluation and selection process principles outlined in Order No. 1000 apply only to projects that the planner determines have regional benefits and are therefore paid for through regional cost allocation. Order No. 1000 does not apply to facilities located within an IOU's state-granted service territory that are paid for by that utility's ratepayers. Local development remains at the IOU's discretion, constrained only by the procedural requirements of Order No. 890. Regional planning is thus the exception, not the rule. Transmission development continues to be driven by IOUs in IOU-specific planning processes."); *see also* NOPR, *supra* note 1, at P 342 (discussing exemptions/exceptions to elimination of the ROFR); Comments of Elec. Transmission Competition Coal. at 13–14, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generation Interconnection*, Docket No. RM21-17 (Oct. 12, 2021) [hereinafter ETCC ANOPR Comments] (describing Order 1000's exclusions from the competitive process).

[43] NOPR, *supra* note 1, at P 344. Here, we use local facility or project to refer to transmission development wholly within an incumbent transmission developer's retail service territory or footprint.

address this problem, the Commission has proposed to partially reinstate the federal ROFR. While the Commission's intent of encouraging transmission build-out is commendable, a ROFR will generally lead to anticompetitive behavior because it will give more bargaining power to the incumbent transmission developer. Under the proposed Conditional ROFR, where the incumbent transmission developer partners with a non-utility transmission developer,[44] it is likely that the partner will have little bargaining power in practice. As such, the proposed "condition" is unlikely to limit anticompetitive behavior and the associated consequences.

The Commission should carefully consider other options for facilitating greater regional transmission development, including closing the loopholes that allow transmission developers to divert investment to local projects not subject to competition to address the problem.[45] If the Commission does choose to move forward with the proposed Conditional ROFR, it is important that it supplements the policy with guardrails that can encourage more competitive outcomes and prevent excessively costly transmission development. However, these guardrails can only limit, and not *eliminate*, the anticompetitive outcomes that will result from ROFR reinstatement.

A. The Commission Should Clarify that the ROFR Should Be Exercised Only After a Regional Plan Is Developed

The Commission should clarify that the ROFR is being reinstated only for projects that will be built as part of a regional transmission plan. In proposing reinstatement, the

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[44] This concern is particularly great where the incumbent partners with a non-utility developer, i.e., the first category of "non-incumbent transmission developer" as defined by the Commission, rather than a developer who, while not the incumbent for the relevant project location, does have a service territory elsewhere. *See id.* at P 337.

[45] *See, e.g.*, Peskoe, *supra* note 42, at 58 (arguing FERC should discipline IOU local transmission spending); ETCC ANOPR Comments, *supra* note 42, at 15–19 (arguing the Commission should close these loopholes by establishing a clear and objective bright line for when a project is eligible for competition); Reply Comments of Public Interest Orgs. at 13, *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generation Interconnection*, Docket No. RM21-17 (Oct. 12, 2021) ("FERC must modify its transmission planning regulations to require regional transmission planning processes that plan for local transmission needs as part of the regional transmission planning process. And it must do so in a way that eliminates the loopholes that allow utilities to plan most transmission through opaque and balkanized local processes.").

Commission's goal is to spur regional transmission development that is not currently being built.[46] However, the Commission should ensure that reinstatement does not result in further diversion of investment to local projects. Reinstatement should be carefully designed to ensure that exercise of the ROFR results in the development of the regional projects the U.S. needs to support the resource mix and demand of the future. Therefore, the Commission should be clear that a regional plan must be developed *first*, and incumbents may exercise their rights to build *only* projects that result from that planning process.

Further, as part of this clarification, the Commission should confirm that the principles of Order 1000 and this new rulemaking apply to projects built by incumbents exercising the ROFR. For example, the Commission should confirm that these projects require a proper cost-benefit analysis, robust consideration of alternatives, including Grid-Enhancing Technologies (GET), and data transparency. While the project will be built by the incumbent without competition, other important reforms from Order 1000 (and those that come from the final rulemaking) should continue to apply.

B. The Commission Should Clarify "Meaningful" Participation and Investment

The Commission should clarify the definition of "meaningful level of participation and investment in proposed transmission facilities"[47] in a way that gives it substance. The result of reinstatement and exercise of the ROFR depend heavily on many factors, and so the Commission must be clear about the level of investment and participation that is required of the partner-developer. That level must ensure true bargaining power for the partner. The current proposal, which only vaguely requires the partner's involvement to be "meaningful" is insufficient to protect against anticompetitive outcomes in which the incumbent can dictate the terms of the

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[46] NOPR, *supra* note 1, at P 349.
[47] *Id.* at P 358.

partnership. The Commission should clarify whether the "meaningful" requirement applies to development, ownership, operation, or a combination thereof. It should also clarify the timeline of involvement: if the project has a 20-year useful life, for example, must the partner be meaningfully involved for all 20 years of operation? Finally, the Commission should consider whether the requisite level of involvement might differ depending on the type or size of the project.

C. The Commission Should Require Competitive Processes for Partners or Projects

To stimulate competition when the Conditional ROFR is exercised, the Commission should require a competitive partner selection process. In this setting, non-incumbent transmission developers would make proposals on projects and FERC could require objective selection criteria to be used in the selection process, for example that the project be net beneficial from a societal perspective. To prevent gaming by the incumbent, those criteria should be curated by either FERC or the planning entity, and the planning entity should be charged with selecting the winning bid.

D. The Commission Should Either Limit Partners to Non-Utility Transmission Developers or Provide Stricter Guardrails for Incumbent-Incumbent Partnerships

The NOPR's proposed condition requires the incumbent to partner with another developer in order to exercise the ROFR and does not limit those partners to non-utility or merchant developers. Instead, the incumbent must simply partner with a "non-incumbent transmission developer." That "non-incumbent," however, could be a developer without *any* retail distribution service territory or footprint, but also could be a developer who, while having such a service territory or footprint elsewhere, is not the incumbent for purposes of the proposed facility.[48] Thus, so long as the entities are unaffiliated, an incumbent transmission provider may partner with another incumbent transmission provider.[49]

A more effective way to limit the anticompetitive outcomes that will inevitably result from reinstatement of the proposed Conditional ROFR would be to require incumbents to partner with non-utility transmission developers in order to exercise the ROFR. The decision to allow incumbent-incumbent partnerships was part of the balance struck by the Commission to facilitate its goal to spur regional transmission development.[50] However, the Commission should be mindful that a condition that allows incumbents to partner, each with significant market power, is unlikely to limit the anticompetitive results of reinstatement.[51] As such, if the final rule allows incumbent-incumbent partnerships, the Commission should be stricter about the guardrails it puts in place when the ROFR is exercised in such a way. Where incumbents partner together, the likelihood of anticompetitive outcomes is higher and demands a greater level of scrutiny from the Commission.

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[48] *Id.* at P 337.

[49] *Id.* at P 358.

[50] *See id.* at P 353 ("We believe that it may be possible that allowing public utility transmission providers to propose conditional federal rights of first refusal consistent with the proposal below may help public utility transmission providers address potentially flawed investment incentives that may be restraining otherwise more efficient or cost-effective regional transmission facility development.").

[51] While not fully analogous to the transmission sector, the airline industry mergers can provide some insights into the potential implications of allowing incumbent-incumbent partnerships for regional projects, as the industry is also a network industry with a few dominant firms, many of which are almost monopolies in their own smaller local markets. Given that setting, empirical evidence shows that airline mergers increased prices for customers when the mergers included potential competitors. *See generally, e.g.*, Ying Shen, *Market Competition and Market Price: Evidence from United/Continental Airline Merger*, 10 ECONS. TRANSP. 1 (2017); John Kwoka & Evgenia Shumilkina, *The Price Effect of Eliminating Potential Competition: Evidence from an Airline Merger*, 58 J. INDUST. ECONS. 767 (2010).

E. The Commission Should Require Planning Entities To Impose Cost-Containment Measures on an Incumbent's Exercise of the ROFR

The Commission should require that planning entities impose a cost-containment measure when incumbents exercise the ROFR.[52] Such a measure would impose a price ceiling on the incumbent's proposal and would be set by the planning entity based on a competitive benchmark. This would limit the cost implications of giving the incumbent additional bargaining power through the ROFR by incentivizing the incumbent and its partner to submit an offer that is at or just below the cost cap. The goal is to protect transmission customers who ultimately foot the bill from excessive costs given the anticompetitive nature of the ROFR.

Such measures are already in use in multiple regions. For example, MISO has previously included binding cost-containment provisions in their competitive bidding process. These included a cost cap estimate provided by MISO, a return on equity cap, equity percentage cap and a schedule guarantee.[53] Similarly, developers in PJM's recent offshore wind solicitation process also submitted various cost containment measures, including a project Cost Cap, Annual Transmission Revenue Requirement Cap, Return on Equity Cap, Equity Ratio Cap, and an Operation & Maintenance Cap.[54] These examples show that cost containment measures would not prevent participation and at least add some competitive pressure for the incumbent to keep costs in check.

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[52] R. P. O'Neil, *Transmission Planning, Investment, and Cost Allocation in US ISO Markets*, *in* TRANSMISSION NETWORK INVESTMENT IN LIBERALIZED POWER MARKETS 175, 186 (Mohammad Reza Hesamzadeh et al. eds., 2020) ("All projects in the transmission planning process should have cost caps and be evaluated at the cost caps. Cost caps for projects change the standard transmission development process by transferring some of the risk of overruns from the ratepayers to the builder who is in the best position to control costs.").

[53] Press Release, Midcontinent Indep. Sys. Operator, MISO First Competitive Transmission Project Completed: New member Company Republic Transmission Energized their First Line this Month (June 11, 2020), https://perma.cc/2QHV-YMEH.

[54] PJM, Presentation to Transmission Expansion Advisory Committee on 2021 SAA Proposal Window to Support NJ OSW, slide 42–43 (July 18, 2022), https://perma.cc/7UE6-J5RK.

F. The Commission Should Use Performance-Based Regulation To Incentivize Incumbents To Find More Efficient Solutions

A cost-containment measure, like a cost cap, sets only an upper limit but does not incentivize any additional effort from developers to reduce costs below the cap even when it is efficient to do so from a social welfare perspective. To increase the incentives of the incumbent transmission provider to reduce costs even further, performance-based regulation schemes may be necessary when a project is built through the exercise of the Conditional ROFR. Performance-based regulation provides financial incentives for the achievement of performance goals, rather than costs expended.[55] Such regulatory schemes can incentivize the incumbent to exert effort to find cheaper solutions while ensuring that the project leads to efficient transmission development consistent with policy objectives.[56]

FERC has already begun discussing performance-based regulation in the context of GETs.[57] For example, the WATT Coalition Incentive Proposal, suggests that a portion of the project savings from mid-size GET projects should be paid out as incentives to the developer.[58] FERC can implement similar designs for the Conditional ROFR to protect customers from the monopoly power of the incumbent and benefit customers.

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[55] *See generally* David E. M. Sappington et al., *The State of Performance-Based Regulation in the U.S. Electric Utility Industry*, 14 ELEC. J. 71 (2001).

[56] *See* Comments of Inst. for Pol'y Integrity at N.Y.U. School of Law at 20–21, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket No. RM20-10 (July 1, 2020) (discussing benefits of performance-based regulation in transmission context).

[57] *See, e.g.*, Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 & AD19-19 (Apr. 15, 2021) (convening workshop on "performance-based ratemaking approaches, particularly shared savings, that may foster deployment of transmission technologies").

[58] *See* WATT Coalition and AEE Shared Savings Proposal, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 & AD19-19 (Sept. 3, 2020).

G. The Commission Should Consider Designing the Transmission ROFR To Better Align with a "Traditional ROFR"

The Commission could also design the Conditional ROFR to look more like a traditional ROFR. The "traditional ROFR" grants the holder a right to meet the terms of a third party's best offer—for example, the right of a leaseholder to purchase a property so long as they can match the offer made by another buyer.[59] Under Order No. 888, incumbent transmission customers seeking to renew service have the right to match new customers' terms and exercise a priority.[60] The federal ROFR in the transmission development context, however, works differently: It provided a right for the incumbent to develop and own transmission facilities necessary to serve the service territory, notwithstanding the ability or willingness of a non-incumbent to do so on better terms.

Designing the federal ROFR for transmission development to align with a traditional ROFR more closely would instill some competitive forces by requiring the incumbent to match the terms of competitors before being able to exercise its rights. The Commission could require that, along with a partner, there will be a competitive solicitation and the incumbent plus its partner have the right to match the terms of the best offer.

While a ROFR mechanism that gives the incumbent and its partner the right to match the best offer could lead to more competitive outcomes, there are at least two challenges. First, the incumbent transmission developer could potentially (even likely) match any bid from competitors, which would disincentivize merchant transmission providers to make offers because the risk of not being awarded the project would not justify the cost of preparing and submitting a

[59] *See* RISHI GARG, NAT'L REGUL. RSCH. INST., WHAT'S BEST FOR THE STATES: A FEDERAL IMPOSED COMPETITIVE SOLICITATION MODEL OR A PREFERENCE FOR THE INCUMBENT? STATE ADOPTION OF RIGHT OF FIRST REFUSAL STATUTES IN RESPONSE TO FERC ORDER 1000 AND THE DORMANT COMMERCE CLAUSE 3 (Apr. 2013) (providing an overview of the right of first refusal).

[60] *See id.* at 3–4 (discussing Order 888 and the U.S. Court of Appeals for the D.C. Circuit's decision on this ROFR).

proposal. Second, the applicability and usefulness of a "traditional ROFR" design may be restricted to the competitive bidding model where the RTO asks market participants to bid on a specific project with clear parameters. In that case, all bids can be easily compared, whereas comparing bids is more difficult under the sponsorship model, where market participants submit solution ideas to the RTO. From a transmission developer's perspective submitting a project under this regime seems significantly more elaborate and letting the incumbent match the offer might seem unfair. It would also be difficult to understand what it would even mean for an incumbent to "match the terms," given that it is not just the cost at issue, but also the design solution (which may also be submitted confidentially).

However, performance-based regulation could resolve these two challenges. For example, in the WATT Coalition proposal mentioned above, if the developer were not the incumbent, then the incumbent would be given the opportunity to exercise its ROFR and undertake the project. If the incumbent declines, then the developer is awarded the project and receives the incentive. If the incumbent exercises the ROFR to build the project, then it would do so subject to full rate-based cost recovery, but shared savings incentives still go to the developer. That is, even though the developer who designed the project does not get to build and own it, they still receive a share of the revenue. If the developer gets a sufficient share of the net project savings, regardless of who wins the bid, they will have an incentive to submit a proposal. And those proposals that would increase competitive pressure on the incumbent transmission provider.

The Commission should consider whether designing the Conditional ROFR in a way that retains some competitive forces, like those of a traditional ROFR, could prevent anticompetitive outcomes and protect against high costs. Using such a design, the Commission could also add competition for cost-containment measures. Proposals would include cost caps that the incumbent would be required to meet, adding extra protection against high costs.

III. The Commission Should Require Consideration of a Uniform Set of Minimum Benefits by all Planning Entities

The Commission presented a non-mandatory, non-exhaustive list of Long-Term Regional Transmission Benefits in the NOPR.[61] In the final rule, the Commission should take the additional step of requiring a minimum set of core benefits that all planners must consider.

Transmission infrastructure that is fit for the 21st century has advantages besides economic efficiency. These are, for example, a reduction in both greenhouse gas and local pollutant emissions assuming that less renewable energy would be curtailed if it could be transported to load centers. Furthermore, reliability as well as resilience might be increased by having more options to balance out weather/climate-dependent locational supply and demand.[62] How these benefits are distributed can have important consequences for environmental and energy justice.

A harmonized approach that uses a uniform set of minimum benefits minimizes the risk of cherry-picking metrics that make projects look less or more favorable than they are. For example, a network upgrade project that counts only production cost savings and reduced congestion may be a severe understatement of the true value of the project because other factors as described above are not accounted for in the calculation. Alternatively, a project with significant production cost savings might lead to increased congestion and emissions in other regions, leading to a net costly project from a societal perspective. Importantly, defining a uniform set of minimum benefits would ensure comparability of transmission expansion projects

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[61] NOPR, *supra* note 1, at P 185, tbl.1.
[62] *See* Policy Integrity ANOPR Comments, *supra* note 3, at 36–40, 43.

across different RTOs, which will be particularly useful given the need to improve interregional transfer capability.

In addition, the Commission should recognize that the set of listed benefits is not exhaustive and explicitly encourage planners to include additional categories in their planning analysis and take on a more holistic assessment of project benefits. Even if the Commission does not include them in the core set of minimum benefits, it should encourage planners to consider (1) the benefit of meeting decarbonization goals set by state government, and (2) equity concerns, that is, the benefit of achieving fairness and balance in bearing the cost of electricity as well as bearing the harm of pollution from thermal power plants. As an example, the Commission might look to the Electricity System Operator in Great Britain, which recently has holistically analyzed four objectives when considering the connection arrangements for offshore wind farms. Its holistic network design approach accounts for (i) cost to consumers, (ii) deliverability and operability, (iii) impact on the environment, and (iv) impact on local communities.[63]

Conclusion

The NOPR is a significant step for bringing U.S. transmission planning into the 21st Century. For the first time, the Commission asks planning entities to proactively consider future changes in the resource mix and demand in identifying transmission needs and solutions. It also reaffirms the importance of regional transmission planning and the benefits of long-distance, high voltage transmission. The Commission should move forward with its long-term transmission planning reforms with the improvements recommended above.

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[63] NAT'L GRID ELEC. SYS. OPERATOR, PATHWAY TO 2030: A HOLISTIC NETWORK DESIGN TO SUPPORT OFFSHORE WIND DEPLOYMENT FOR NET ZERO 6 (July 2022), https://perma.cc/883M-6B9Q.

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Dated: August 17, 2022