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) July 15, 2021 Advanced Notice of Proposed Rulemaking (ANOPR),[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.

Current approaches to transmission planning and cost allocation are failing to capture the large potential benefits that would flow from identification and selection for development of the most efficient and cost-effective transmission investment options. These processes should be reformulated in order to better carry out the Commission's fundamental duties under the Federal

[1] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 176 FERC ¶ 61,024 (2021) [hereinafter ANOPR].

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

Power Act (FPA) to ensure that rates are just, reasonable, and not unduly discriminatory or preferential,[3] and to ensure reliability in the bulk power system.[4] Two key points underpin the need for reform.

First, empirics and modeling both indicate that the nation would reap tremendous net benefits from well-placed additions to existing regional and interregional transmission capacity.[5] Crucially, "regional and interregional" transmission spans RTOs/ISOs and crosses RTO/ISO or state boundaries, while "local" transmission projects are generally undertaken outside of competitive processes and often within the bounds of a single utility's service territory.[6] Regional and interregional projects—often long-distance and high-voltage—are likely to be more efficient and cost-effective than local projects, but are much less likely to be built.[7] Second, barriers to building this kind of transmission capacity are significant, well-understood, and embedded in the regulatory landscape created by the rules that govern transmission planning and

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[3] Federal Power Act §§ 201, 206.

[4] Federal Power Act § 215.

[5] *E.g.*, MICHAEL GOGGIN, GRID STRATEGIES, TRANSMISSION MAKES THE POWER SYSTEM RESILIENT TO EXTREME WEATHER 4 tbl.1 (2021); FERC, REPORT ON BARRIERS AND OPPORTUNITIES FOR HIGH VOLTAGE TRANSMISSION; A REPORT TO THE COMMITTEES ON APPROPRIATIONS OF BOTH HOUSES OF CONGRESS PURSUANT TO THE 2020 FURTHER CONSOLIDATED APPROPRIATIONS ACT 6–10 (2020); AARON BLOOM ET AL., NAT'L RENEWABLE ENERGY LAB'Y, THE VALUE OF INCREASED HVDC CAPACITY BETWEEN EASTERN AND WESTERN U.S. GRIDS: THE INTERCONNECTIONS SEAM STUDY (PREPRINT) 8 (2020) ("The results show a robust benefit-to-cost ratio ranging from 1.2 to 2.5 over different HVDC designs and different conditions, indicating significant value to increasing the transmission capacity between the interconnections and sharing generation resources for all the cost futures studied."); SCOTT MADDEN & WIRES GRP., INFORMING THE TRANSMISSION DISCUSSION: A LOOK AT RENEWABLES INTEGRATION AND RESILIENCE ISSUES FOR POWER TRANSMISSION IN SELECTED REGIONS OF THE UNITED STATES 274–75 (2020); JOHANNES PFEIFENBERGER & JUDY CHANG, BRATTLE GRP., WELL-PLANNED ELECTRIC TRANSMISSION SAVES CUSTOMER COSTS: IMPROVED TRANSMISSION PLANNING IS KEY TO THE TRANSITION TO A CARBON CONSTRAINED FUTURE 16 (2016).

[6] JOHANNES PFEIFENBERGER, JUDY CHANG & MICHAEL HAGERTY, BRATTLE GRP., COST SAVINGS OFFERED BY COMPETITION IN ELECTRIC TRANSMISSION EXPERIENCE TO DATE AND THE POTENTIAL FOR ADDITIONAL CUSTOMER VALUE 25 (2019) ("The introduction of competitive processes coincides with substantial increases in locally-planned transmission that are outside the full regional planning processes."); *Today in Energy: Utilities Continue to Increase Spending on Transmission Infrastructure*, U.S. ENERGY INFO. ADMIN. (Feb. 9, 2018), https://www.eia.gov/todayinenergy/detail.php?id=34892.

[7] *See infra* Part I.B.

cost allocation. These barriers are hindering the capacity expansion needed to interconnect and integrate far-flung but low-cost renewable resources. Addressing these barriers requires ambitious reforms of the Commission's prior rules on transmission and the processes they establish.

These comments recommend several reforms to enhance transmission planning and cost allocation to address the barriers preventing the build-out of high-voltage, long-distance transmission. They are organized as follows: Part I summarizes the relevant background, including the fundamental principles espoused in previous orders and the problems that persist for regional and interregional planning despite those orders; Part II describes why adopting a national perspective on transmission is a necessary precursor for other reforms and identifies options for taking this step; Part III encourages the Commission to require that transmission planning involve the use of future scenarios and modeling that appropriately account for anticipated future generation; Part IV encourages the Commission to require the use of standardized cost-benefit analysis by all entities responsible for transmission project selection; and Part V argues that the costs arising from broadly distributed and difficult to quantify benefits that accrue to all grid stakeholders, such as emissions reductions and resilience to disruptive events, should be allocated using a postage stamp method.

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I. Prior Commission Orders Lend Support To Undertaking Major Reforms Now

The Commission's ANOPR marks the latest round of reexamination and reform of its approach to transmission. For the past 25 years, the Commission has, through a series of interventions, sought to foster and (where necessary) impose transparency, coordination, and openness on the closely related processes of transmission planning and cost allocation. The Commission should use this ANOPR to build on its previous findings to promote efficient and cost-effective transmission planning. Prior orders recognized the need for Commission intervention to enhance competition, to better align planning entities' and transmission owners' incentives with society's interests,[8] and to take advantage of economies of scale in transmission in order to efficiently bridge historically separate utility service areas.[9] Further reform is necessary to advance these goals. While the advent of RTOs/ISOs limited market participants' opportunities to wield market power and tilt the competitive field in their own favor, the lack of mandatory, uniform rules continues to impede competition. And, while Order 1000 has resulted in meaningful regional transmission planning in RTO/ISO regions, local projects continue to dominate the planning process in restructured and vertically integrated planning regions alike, and interregional projects are non-starters. Yet, the Commission's landmark transmission orders provide firm ground for further reforms that would impose a forward-looking, national perspective on transmission planning and cost allocation and thereby cultivates a grid that is better able to ensure just and reasonable rates and reliability.

[8] *See infra* notes 73–80 and accompanying text.

[9] *See infra* notes 22–31 and accompanying text.

A. Prior Orders

In Order 888, issued in 1996, FERC laid the "legal and policy cornerstone" for its subsequent measures aimed at "remedy[ing] undue discrimination in access to the monopoly owned transmission wires that control whether and to whom electricity can be transported in interstate commerce."[10] FERC ordered the "functional unbundling" of utilities' generation and transmission assets and the opening of access to transmission facilities, so that transmission owners would no longer be able to use monopoly power to restrict generators' access for the benefit of some generators and at cost to others.[11] The centerpiece of FERC's remedy in Order 888 was a pro forma Open Access Transmission Tariff (OATT), designed to bring uniformity to the "patchwork of closed and open jurisdictional transmission systems," and to prevent the discriminatory use of "monopoly power over transmission."[12] As FERC explained: "Non-discriminatory open access to transmission services is critical to the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition."[13] At the heart of the OATT was a form of the "comparability standard" adopted by FERC to ensure that the services transmission owners provide to others is comparable to service provided to their own generation assets.[14] Order 889, issued concurrently with Order 888, lent support to this aim by directing utilities to publish transmission system information related to the sale or purchase of electricity, in real time.[15] That information would

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[10] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 75 FERC ¶ 61,080, at p. 1 (1996).

[11] *Id.* at p. 57.

[12] *Id.* at p. 4.

[13] *Id.* at p. 50.

[14] *Id.* at pp. 35–41.

[15] *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, 75 FERC ¶ 61,078, at p. ii (1996).

be made accessible through the Open Access Same-time Information System (OASIS), newly established by the Commission.[16] This, the Commission said, amounted to "opening up the 'black box' of utility transmission system information" and thereby "allow[ing] transmission customers to determine the availability of transmission capacity."[17] Together these orders clearly and unequivocally established FERC's commitment to ensuring transmission services are subject to and supportive of openness and competition.

In 2005, after finding that Order 888 (and 889) had not fully foreclosed unduly preferential and discriminatory uses of transmission by its owners, FERC revisited the issue with Order 890.[18] Notwithstanding the OATT's prohibition on different forms of discrimination and the transparency provided by OASIS, transmission owners had, through opaque and uncoordinated approaches to transmission planning and cost allocation decisions, continued to engage in unduly discriminatory practices.[19] In response to this finding, the Commission issued Order 890, which contained measures designed to yield "coordinated, open, and transparent transmission planning."[20] In particular, the order directed public utility transmission providers to propose "a coordinated and regional planning process" that was consistent with nine planning principles: coordination, openness, transparency, information exchange, comparability, dispute

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[16] *Id.* at p. ix.

[17] *Id.* at p. xx; *see also New York v. FERC*, 535 U.S. 1, 8–9 (2002) (summarizing situation remedied by Order 888 as follows: "utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions").

[18] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, at P 42 (2007).

[19] *Id.* at P 26.

[20] *Id.* at P 435.

resolution, regional participation, economic planning studies, and cost allocation for new projects.[21]

In 2011, the Commission again recognized that further intervention was needed to promote competition, transparency, and uniformity to bring about an efficient and cost-effective transmission system. Finding that measures adopted to comply with Order 890 had not been sufficient, the Commission adopted a "package of reforms" focused on transmission planning and cost allocation in Order 1000.[22] With respect to planning, the Commission found that Order 890 had not led transmission-owning utilities to develop plans for the most efficient and cost-effective transmission facilities, nor to compare regional (or interregional) alternatives to the local transmission plans put forward by individual utilities.[23] With respect to cost allocation, the Commission emphasized that changing circumstances—chiefly growing demand for resources that require new transmission to interconnect—had placed growing pressure on processes encumbered by a lack of regularity and predictability.[24] The Commission also observed that concerns about the allocation of costs to parties not likely to benefit from transmission could create an ex ante disincentive to adopt regional (and interregional) transmission projects through regional planning processes.[25]

To address the deficiencies it identified with respect to planning, the Commission adopted three key measures in Order 1000, each "focused on the transmission planning *process*,

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[21] *Id.* at P 437.

[22] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 47 (2011) ("[T]hese reforms are integrally related and should be understood as a package that is designed to reform processes and procedures that, if left in place, could result in Commission-jurisdictional services being provided at rates that are unjust and unreasonable and unduly discriminatory or preferential.").

[23] *Id.* at P 78.

[24] *Id.* at PP 484–85.

[25] *Id.* at PP 485–86, 499.

and not on any substantive outcomes."[26] First, it imposed "an affirmative obligation . . . to evaluate alternatives that may meet the needs of the region more efficiently or cost-effectively."[27] This was meant to ensure that planning entailed an appropriate assessment of the potential benefits of regional transmission solutions relative to the benefits of local ones.[28] Relatedly, the Commission aimed to ensure that the list of considered transmission needs would include mitigation of costly congestion, compliance with state-level policy requirements, and the maintenance of reliability in light of existing generation and current and prospective local and regional load.[29] Second, the Commission eliminated the federal right of first refusal for incumbent transmission providers, clearing away what it determined to be an impediment to competition.[30] And third, recognizing that interregional projects often were not put on a level playing field with regional and local alternatives—if considered at all—the Commission added interregional coordination and information-sharing obligations to the list of required components of regional transmission plans.[31]

The Commission's remedy with respect to cost allocation in Order 1000 sought, fundamentally, to clarify the nature of benefits, the identity of beneficiaries, and how to account for the distribution of benefits among different beneficiaries. That remedy entailed reforms to the *planning* process as well as a tighter linkage of the planning and cost allocation processes.[32] Specifically, the Commission articulated six principles for cost allocation decisions related to

[26] *Id.* at P 12.
[27] *Id.* at P 80.
[28] *Id.* at P 81.
[29] *Id.* at P 83.
[30] *Id.* at PP 7, 229.
[31] *Id.* at PP 373, 393–96.
[32] *Id.* at P 501.

transmission developed pursuant to a regional transmission plan[33] and directed public utility transmission providers to adopt a cost allocation methodology consistent with those principles.[34] However, FERC did not require adoption of a generic approach across all transmission planning regions, nor did it require application of those principle-based methods to allocation of the costs of local transmission.

When it adopted Order 1000, the Commission rejected the argument that burgeoning transmission investments showed intervention to be unnecessary: "[R]ecent increases in constructed and planned transmission facilities supports issuance . . . to ensure that the Commission's transmission planning and cost allocation requirements are adequate to support more efficient and cost-effective investment decisions."[35] That is, the Commission was not concerned about whether investments were being made in transmission resources generally, but rather on whether investments were being made in specific types of transmission capacity. The goal of its intervention was not simply *more* transmission, but rather to spur investment in *optimal* transmission—capacity that would best serve consumers and the grid as a whole. FERC sought to do so by enhancing competition, directing transmission planners adopt a broader geographic perspective, encouraging greater analytical uniformity, and adding transparency to the process.

B. Persistent Barriers

The measures contained in Orders 890 and 1000 were meant to not only provide immediate reform to the transmission planning and cost allocation processes but also to create a

[33] *Id.* at P 586.
[34] *Id.* at PP 551–53, 558.
[35] *Id.* at P 46.

record for ongoing engagement by FERC. Following adoption of Order 890, the Commission said that it would "remain actively involved . . . beyond the compliance phase to ensure that the potential for undue discrimination in planning activities is adequately addressed."[36] And in Order 1000-A it said that processes begun pursuant to Order 1000 would "provide the Commission and interested parties with a record that we believe will be able to highlight whether public utility transmission providers are engaging in undue discrimination."[37] In short, the Commission recognized that further course correction might be necessary if, despite the Commission's actions in 1996, 2005, and 2011, the barriers preventing development of regional and interregional transmission persisted.

These barriers have persisted. Current planning and cost allocation processes, while deemed compliant with Orders 890 and 1000, have not cleared away the barriers to regional and interregional transmission development that the Commission identified when it adopted those orders. That is, the invitations and incentives provided thus far have not given life to the kind of comprehensive transmission development that FERC aimed for with its previous orders. The evidence demonstrates that present patterns of transmission development fail to tap large net benefits to consumers and society as a whole, and that the persistence of the barriers listed below is substantially to blame. Each of these conclusions is described in turn below.

[36] Order on Rehearing and Clarification, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890-A, 121 FERC ¶ 61,297, at P 180 (2007).

[37] Order on Rehearing and Clarification, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132 at P 267 (2012); *see also id.* at P 321 ("[O]ur concern is that the process allows for stakeholders to submit their views and proposals for transmission needs driven by Public Policy Requirements in a process that is open and transparent and satisfies all of the transmission planning principles set out in Order Nos. 890 and 1000, and that there is a record for the Commission and stakeholders to review to help ensure that the identification and evaluation decisions are open and fair, and not unduly discriminatory or preferential.").

Unmet Needs and Foregone Benefits. Energy system modeling and economic analyses conducted by leading experts agree that more regional and interregional transmission capacity would enable generation to meet load at lower cost.[38] There are a variety of reasons why this kind of capacity is optimal and would better meet the need for electricity transfer capacity than small, local projects. As described below, it would make good use of transmission's economies of scale, while fostering beneficial competition, generator diversity, and resilience.

First, because transmission is subject to large economies of scale, building a single high-capacity transmission line is generally more cost-effective than building multiple low-capacity lines of equivalent cumulative size.[39] Developing a small transmission project will, therefore, tend to forego this inherent potential source of efficiency and cost-effectiveness.

Second, regional and interregional transmission projects cover a larger geographic footprint, which tends to support a greater diversity of generation resources, enhancing supply competition for loads that would otherwise have fewer choices and so would be more likely to

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[38] *E.g.*, Frank A. Wolak, *Transmission Planning and Operation in the Wholesale Market Regime*, *in* TRANSMISSION NETWORK INVESTMENT IN LIBERALIZED POWER MARKETS 101, 104–105, 127–28 (M.R. Hesamzadeh et al., eds. 2020); Michiel de Nooij, *Social Cost-Benefit Analysis of Electricity Interconnector Investment: A Critical Appraisal*, 39 ENERGY ECON. 3096, 3096 (2011) (transmission between regions and markets can "increase trade between cheap and expensive production areas, fight the market dominance of incumbents and increase competition, connect more renewable energy sources to the grid and increase security of supply" (citations omitted)); Ioannis Konstantelos et al., *Coordination and Uncertainty in Strategic Network Investment: Case on the North Seas Grid*, 64 ENERGY ECON. 131 (2017) (discussing the benefits of developing transnational offshore grid in the North Sea and the need to consider interzonal coordination).

[39] *E.g.* Michel Rivier, Ignacio J. Pérez-Arriaga & Luis Olmos, *Electricity Transmission*, *in* REGULATION OF THE POWER SECTOR 260 (Ignacio J. Pérez-Arriaga ed., 2013) ("Transmission costs are highly subject to economies of scale, a characteristic feature of natural monopolies."); Konstantelos et al., *supra* note 38 (discussing capital savings provided by economies of scale by using a common transmission network for offshore wind in the North Sea); Joseph Doucet et al., *Valuing Electricity Transmission: The Case of Alberta*, 36 ENERGY ECON. 396, 397 (2013).

settle for higher-priced power.[40] This increased competition among a wider array of generation resources undermines potential applications of market power by generation owners.[41]

Third, more well-placed regional and interregional transmission capacity will give consumers better access to the energy generated at low marginal cost by variable renewable resources, both by extending the grid's reach to those resources and by better exploiting geographic diversity on the supply and demand sides of the system to intensify usage of those resources.[42] In addition to the direct benefit of more efficient and cost-effective generation, bringing more renewables online will also displace more expensive fossil-fuel generating resources, reducing system-wide emissions of global and local pollutants.[43] Thus, the indirect but material benefits of efficient and cost-effective transmission development include both the reduction of global pollutants that cause climate change, which make extreme events more frequent and severe, and thereby pose risks to electricity reliability and to society more generally; and the reduction of local pollutants in communities downwind of displaced emitting resources.[44]

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[40] *See, e.g.*, Mohamed Awad et al., *The California ISO Transmission Economic Assessment Methodology (TEAM): Principles and Applications to Path 26*, 2006 IEEE POWER ENG'G SOC'Y GENERAL MEETING, at 3 ("A new transmission project can enhance competition by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load.").

[41] Wolak, *supra* note 38, at 101–02, 115.

[42] *E.g.*, Patrick R. Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 JOULE 115 (2021); JOHANNES PFEIFENBERGER, PABLO RUIZ & KAI VAN HORN, THE VALUE OF DIVERSIFYING UNCERTAIN RENEWABLE GENERATION THROUGH THE TRANSMISSION SYSTEM 6 (2020) (estimating significant reductions in annual generation costs and renewable curtailments from the interconnection by transmission investments of submarkets with different wind profiles); Paul L. Joskow, *Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector* 2–3 (MIT Ctr. for Energy & Env't Pol'y Rsch. Working Paper 2021-009, 2021); AM. WIND ENERGY ASS'N, GRID VISION: THE ELECTRIC HIGHWAY TO A 21ST CENTURY ECONOMY 43–70 (2019); JUDY CHANG ET AL., BRATTLE GRP., WIRES GRP., THE BENEFITS OF ELECTRIC TRANSMISSION: IDENTIFYING AND ANALYZING THE VALUE OF INVESTMENTS 55 (2013).

[43] JULIA FRAYER ET AL., LONDON ECON. INT'L, INC., HOW DOES ELECTRIC TRANSMISSION BENEFIT YOU: IDENTIFYING AND MEASURING THE LIFE-CYCLE BENEFITS OF INFRASTRUCTURE INVESTMENT 34 (2018) (prepared for WIRES Grp.).

[44] *See, e.g.*, Roger Lueken et al., *The Social Costs and Benefits of Wind Energy: A Case Study of the PJM Interconnection* (Carnegie Mellon Elec. Indust. Ctr. Working Paper CEIC-14-02) (discussing social costs and

Fourth, greater intra- and interregional transmission capacity will tend to improve resilience to extreme events within and between regions.[45] Resilience is the ability to resist, absorb, and recover from high-impact, low-probability events.[46] Consumers located in areas hit repeatedly by extreme events end up paying more or experiencing more frequent outages (or both) than they would if additional increments of transmission capacity connected them to neighboring regions.[47] Winter Storm Uri's markedly different impacts on electricity reliability in regions served by SPP, MISO, and ERCOT shone a bright light on the resilience value of transmission capacity within and across those regions.[48] And New Orleans' recent experience with Hurricane Ida provided another clear example of foregone transmission capacity additions that probably would have yielded large resilience benefits.[49]

Specific barriers. The main reasons that transmission projects selected for development continue to be predominantly local rather than regional or interregional, and thus to forego various benefits, are well understood. Professor Paul Joskow has summarized several of them succinctly:

> There are organizational barriers resulting from excessively narrow transmission system planning protocols and the geographic expanses over which planning takes

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benefits of wind power displacing fossil-fuel generation); CHRISTOPHER JAMES & KEN COLBURN, OPPORTUNITY KNOCKS FOR AIR REGULATORS: FERC ORDER 1000 (2013) (discussing how air regulators can use the transmission planning system to address air pollution issues); NAT'L ASS'N OF CLEAN AIR AGENCIES, IMPLEMENTING EPA'S CLEAN POWER PLAN: A MENU OF OPTIONS 18-11 to -12 (2015).

[45] MARC CHUPKA & PEARL DONOHOO-VALLETT, BRATTLE GRP., RECOGNIZING THE ROLE OF TRANSMISSION IN ELECTRIC SYSTEM RESILIENCE 3–6 (2018).

[46] BURCIN UNEL & AVI ZEVIN, INST. FOR POL'Y INTEGRITY, TOWARD RESILIENCE: DEFINING, MEASURING, AND MONETIZING RESILIENCE IN THE ELECTRICITY SYSTEM at i (2018) [hereinafter TOWARD RESILIENCE REPORT].

[47] GOGGIN, *supra* note 5, at 4 tbl.1 (estimating monetary value of additional interregional transmission capacity increments based on various regions' experiences with extreme weather events between 2014 and 2021); SCOTT MADDEN & WIRES GRP., *supra* note 5, at 274–75.

[48] *See generally* GOGGIN, *supra* note 5.

[49] Andy Kowalczyk, *Utility Entergy Stymied Transmission Projects that Might Have Prevented Some New Orleans Blackouts*, CANARY MEDIA (Sept. 30, 2021), https://www.canarymedia.com/articles/utilities/utility-entergy-stymied-transmission-projects-that-might-have-prevented-some-new-orleans-blackouts.

> place. There are barriers created by considering too narrow a range of benefits associated with transmission capacity enhancements. There are barriers created by disputes over how the costs of these facilities will be allocated to users of the system. Finally, there are compensation (cost recovery) and financing barriers.[50]

Others have identified similar lists.[51]

Several of these barriers deserve elaboration. To begin, even though transmission development can be prerequisite to the development of cost-effective generation,[52] transmission planning processes are generally not forward-looking, instead treating generation planning decisions as fixed and predetermined.[53] This backward-looking norm is especially problematic because developing renewable resources, which are generally able to outcompete thermal resources on cost, often requires extending transmission to remote locations proactively.[54]

In addition, the administratively determined boundaries of current transmission planning regions are not aligned with the grid's physical and operational boundaries. This can lead planning to exclude regional and interregional options that would be efficient and cost-effective simply because they would span administrative boundaries and thereby encounter a more extensive and cumbersome process while introducing unwelcome competition into the region.

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[50] Joskow, *supra* note 42, at 4.

[51] *E.g.*, JOHANNES PFEIFENBERGER ET AL., BRATTLE GRP., GRID STRATEGIES, TRANSMISSION PLANNING FOR THE 21ST CENTURY: PROVEN PRACTICES THAT INCREASE VALUE AND REDUCE COSTS 19–23 (2021); BOB ZAVADIL & ALISON SILVERSTEIN, BLUEPRINT FOR A NATIONAL ELECTRIC TRANSMISSION AUTHORITY 3 (2021).

[52] *See* Joskow, *supra* note 42, at 35–36 (describing logic and success of the Texas Competitive Renewable Energy Zones (CREZ) process, which designated corridors for transmission before specific generation facilities were planned or developed).

[53] *See, e.g.*, Evangelia Spyrou et al., *What Are the Benefits of Co-Optimizing Transmission and Generation Investment? Eastern Interconnection Case Study*, 32 IEEE TRANSACTIONS ON POWER SYS. 4265, 4266 (2017) ("In the past, most planners (ISOs and other organizations such as the Western Electricity Coordinating Council (WECC)) followed procedures that evaluate transmission expansion plans by simulating system production costs given an assumed generation mix. This approach is usually called 'reactive' or 'generation-first' planning, since the transmission planner responds to a pre-defined generation fleet." (citations omitted)).

[54] Joskow, *supra* note 42, at 5–8.

This problem is compounded by the siloed approach currently taken to identifying transmission needs, which often prevents planning entities from taking a holistic view both of need for transmission and benefits of potential cross-boundary solutions.[55] That regions differ in what constitutes a need for or benefit of transmission adds yet another layer to this morass for lines that cross an administrative boundary. This causes trouble for planning by distorting what needs might be served and obscuring the options for serving them. It also creates opportunities for eventual disagreement over cost allocation within and between regions, and thereby chills efforts to develop any lines other than those whose benefits would flow unambiguously.

In short, the needs that would be met cost-effectively and the benefits that would accrue from equal consideration of regional and interregional projects alongside local reliability projects have—despite formal compliance with Orders 888, 889, 890, and 1000—mostly been ignored to date. Existing planning and cost allocation processes are substantially responsible for this failing. The structuring of those processes has allowed local reliability projects to dominate the field of transmission development for many years. The result is that sizable benefits to consumers and suppliers, and to the grid from regional and interregional transmission have gone mostly untapped.[56] This pattern demonstrates that the barriers the Commission sought to eliminate in its previous orders persist to pernicious effect. While the principles established by Orders 890 and 1000, in particular, amount to a clear and thorough call for openness, coordination, and competition, formal compliance with these orders' prescriptions has not cleared away the barriers to regional and interregional transmission. It follows that these orders are not ensuring that rates are just and reasonable, and not unduly discriminatory.

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[55] PFEIFENBERGER ET AL., *supra* note 51, at 31–33.
[56] *Id.* at 19–23.

II. Effective Reform Requires the Commission To Impose a National Perspective on Transmission Planning and Cost Allocation Decisions

The Commission should reformulate basic features of transmission planning and cost allocation in ways that recognize and address the incompatibility of balkanized and backward-looking processes with the nation's pressing need for new, well-placed, appropriately-sized transmission capacity. While the FPA does not permit the Commission to usurp entirely the roles currently played by regional and state entities with respect to transmission development,[57] it does require the Commission to steer those entities more effectively than it has done to date. In particular, as described below, the Commission can impose a greater degree of uniformity on the informational inputs, analysis, and selection criteria involved in transmission-related decisions—all in service of fostering competition to deliver the greatest net benefits and to ensure just and reasonable rates. Such changes can help ensure that the need for and potential benefits of investments in transmission capacity are not artificially obscured or distorted by administrative constructs and that a transmission line capable of capturing those benefits is not put out of reach by unnecessary procedural hurdles. Furthermore, the Commission is in a unique position to provide for analytical uniformity and ensure that the analyses that inform planning and cost allocation decisions reflect sound understanding of the relevant economics.

A. Institutional and Process Options

Leading voices on energy policy have proposed establishing a new national agency or office to help address several of the impediments described above.[58] Their proposals differ in meaningful ways, but the common features are a prescribed set of planning tools and uniform

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[57] *See* Avi Zevin et al., *Building a New Grid Without New Legislation*, 48 ECOLOGY L.Q. 169 (2021) (describing state authority over transmission siting decisions).

[58] *See, e.g.*, ZAVADIL & SILVERSTEIN, *supra* note 51; Joskow, *supra* note 42, at 28–29 ("[I]t would make sense to create an organization like ENTSO-E that covers the entire U.S., Canada, and Mexico. Let's call this organization the North American Transmission Planning Organization (NATPO).").

design specifications.[59] The Commission should adopt these features, whether it decides to implement them through a wholly new entity, an office within FERC, or mere procedural prescriptions and standards for transmission planners. Options for institutional or procedural versions include:

A National Transmission Planning Organization, modeled in part on Regional Transmission Organizations, in which transmission owners can be members. The organization would facilitate extensive consultation among its members, state-level stakeholders, and officials and staff with appropriate expertise at the Department of Energy and other agencies. Membership would entail use of the organization's prescribed planning tools and standards, as well as evaluation of portfolios of proposed projects against the substantive features described in Part III and IV of these comments. Use of prescribed tools and standards would also entitle each member to a presumption of prudence (see next subpart) regarding project proposals that satisfy the criteria of an initial application of forward-looking cost-benefit analysis.

An Office of Transmission Planning within FERC that, like the organization just described, would prescribe the use of particular planning tools and standards, and would facilitate stakeholder consultations. This office would function like a secretariat for a U.S. (or North American) version of the European Network of Transmission System Operators for Electricity (ENTSO-E), which provides a combination of prescriptions, information, and technical assistance to the dozens of transmission planners, owners, and operators located in the European Union.[60] Its functions would be informational and analytical; it would develop plans

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[59] ZAVADIL & SILVERSTEIN, supra note 51, at 5; Joskow, *supra* note 42, at 28–29.
[60] *See generally ENTSO-E Mission Statement*, ENTSO-E, https://www.entsoe.eu/ (last visited Oct. 5, 2021).

and conduct cost-benefit analyses, but would leave decisions about development and cost allocation to regional entities and the Commission.

Procedural and substantive standards can also be added to OATTs and, like the several elements of Order 1000, made a condition of doing business with RTOs for non-RTO transmission owners.[61] Such additions would effectively extend the logic of changes imposed under earlier orders but would be more specific and less flexible. Order 890, for instance, recognized that although transmission providers were posting available transfer capacity (ATC) in OASIS as Orders 888 and 889 require, the discretion to use diverse methodologies to calculate ATC gave "transmission providers the ability and opportunity to unduly discriminate in the provision of open access transmission service"[62] As a remedy, Order 890 "g[a]ve the industry specific guidance regarding the calculation of ATC and establish[ed] a firm deadline to develop certain requirements to make more consistent the ATC calculation process and the process of exchanging data between transmission providers about ATC."[63] Similarly, in Order 1000, the Commission observed that "the existing requirements of Order 890 permit regional transmission planning processes to be used as a forum merely to confirm the simultaneous feasibility of transmission facilities contained in their local transmission plans."[64] As a remedy, it prescribed the creation (but not the exclusive use) of an "open and transparent" process for regional transmission planning and interregional coordination and imposed affirmative obligations on transmission providers to participate in those processes and periodically produce a regional plan. But the Commission "decline[d] . . . to specify . . . a particular set of analyses that must be

[61] Order No. 1000, *supra* note 22, at PP 815–16.
[62] Order No. 890, supra note 18, at PP 68–69.
[63] *Id.* at P 83.
[64] Order No. 1000, *supra* note 22, at P 147.

performed by public utility transmission providers in this regional transmission planning process."[65] Thus, the Commission gave transmission providers "the information needed to determine which projects satisfy local and regional needs more efficiently and effectively"[66] but stopped short of prescribing uniformity or a set of particular parameters or methodologies for developing that information. This stopping point was not due to a determination that the Commission lacked the legal authority to take more ambitious action. For the sake of realizing the aims of Orders 890 and 1000, the Commission can and should go further.

B. The Presumption that Transmission Costs Are Prudently Incurred Should Be Qualified or Reversed

However the Commission decides to prescribe planning tools and analytical standards, it should qualify or simply reverse its presumption that local transmission plans are prudent.[67] It adopted that presumption "as a matter of procedural practice to ensure that rate cases are manageable,"[68] but it can readily determine that transmission costs should not be approved for recovery until their proponent carries the burden of persuasion as to their prudence—more specifically, by demonstrating their cost-effectiveness or net benefits relative to a regional or interregional alternative.[69]

In a recent article in the *Energy Law Journal*, Ari Peskoe argues that the Commission should maintain the presumption of prudence for capital spending on transmission that flows from "an independently administered transmission process," but reverse that presumption for

[65] *Id.* at P 149.

[66] S.C. Pub. Serv. Auth. v. FERC, 762 F.3d 41, 56 (D.C. Cir. 2014).

[67] *Potomac-Appalachian Transmission Highline, LLC v. PJM Interconnection, L.L.C.*, 158 FERC ¶ 61,050, at P 100 (2017) (citing *Iroquois Gas Transmission Sys., L.P.*, 87 FERC ¶ 61,295, 62,168 (1999)).

[68] *Iroquois Gas*, 87 FERC ¶ 61295, 62168.

[69] 16 U.S.C. § 824d(e) ("At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility . . . .").

spending that flows to local projects through processes that entail little or no scrutiny and competition.[70] Local project proponents would be obliged to seek cost recovery through a filing under FPA section 205.[71] Peskoe's proposal calls for the Commission to spell out what amounts to an "independent" planning process through a policy statement or rulemaking.[72]

The Commission should undertake what Peskoe proposes, and couple those measures with one of the institutional or process options described above. That is, a presumption of prudence should be maintained only for projects that are planned (1) "independently" and (2) using the tools prescribed by the Commission. In addition to encouraging projects that satisfy these criteria, and which are more likely to realize the objectives of Orders 890 and 1000, this would make for a more efficient allocation of Commission resources by imposing greater scrutiny on projects that are less likely to be net-beneficial.

C. Oversight

Commission-led transmission reform is needed because market incentives may not align to ensure that transmission planning entities, both in vertically integrated regions and those administered by RTOs/ISOs, approve network investments that will maximize social welfare. This is because there is a disparity in the distributional effects of new transmission that may demand additional oversight by the Commission. New regional and interregional transmission is generally good for consumers because it provides greater access to low cost supply, but bad for producers because it exposes them to greater competition.[73] This imbalance means that incumbent generators may be motivated to prevent new transmission from being built, even

[70] Ari Peskoe, *Is the Utility Transmission Syndicate Forever?*, 42 ENERGY L.J. 1, 58–59 (2021).

[71] *Id.* at 59.

[72] *Id.*

[73] Hung-po Chao & Robert Wilson, *Coordination of Electricity Transmission and Generation Investments*, 86 ENERGY ECON. 10 (2020).

though it would be welfare-enhancing on a system-wide basis.[74] Likewise, incumbent transmission owners may try to inhibit expansion where they own or are affiliated with generation firms that would face greater competition.[75] Greater transmission capacity expansion can also reduce or eliminate congestion rents that transmission providers earn.[76]

Even for RTOs/ISOs, which are formally independent, the incentives may not align properly. RTOs/ISOs are membership-driven organizations with voluntary membership requirements, such that individual members could choose to exit if they disagree with a given decision.[77] And, transmission owners are necessary members of those organizations.[78] This may create an incentive for the RTO/ISO to ensure that transmission owners remain members by selecting projects that maximize transmission owner profits, potentially to the detriment of social welfare.[79] And, rather than providing a check on transmission owners' misaligned incentives,

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[74] *Cf.* Enzo E. Sauma & Shmuel S. Oren, *Do Generation Firms in Restructured Electricity Markets Have Incentives to Support Social-Welfare-Improving Transmission Investments?* 31 ENERGY ECON. 676 (2009) (discussing effect of generator ownership of financial transmission rights on support for transmission expansion).

[75] The Commission recognized as much in its previous major orders. Order No. 1000, *supra* note 22, at 254 ("As the Commission recognized in Order Nos. 888 and 890, it is not in the economic self-interest of public utility transmission providers to expand the grid to permit access to competing sources of supply.").

[76] Doucet et al., *supra* note 39, at 397 ("First it appears that market incentives (ex-ante value of transmission as measured by price differences between regions) will not be enough to induce the socially desirable amount of investment. This comes about because incremental transmission lines, once built, reduce rice differences from the point of view of investors destroying the value that they were set out to take advantage of."); *see also* Yuri Dvorkin et al., *Co-Planning of Investments in Transmission and Merchant Energy Storage*, 33 IEEE TRANSACTIONS ON POWER SYS. 245, 245 (2018) (discussing how expanded transmission capacity can reduce congestion rents for storage).

[77] Michael H. Dworkin & Rachel Aslin Goldwasser, *Ensuring Consideration of the Public Interest in the Governance and Accountability of Regional Transmission Organizations*, 28 ENERGY L.J. 553, 579 (noting that RTOs are voluntary organizations and certain stakeholders have the ability to exit).

[78] *Id.* at 558 ("Several RTOs were established only after years of wrangling among interested parties. Of these parties, the transmission owners are the most important. Without them, RTOs could not be established because the owners need to give up a property right—management of the transmission lines—for an RTO to be able to fulfill its duties.").

[79] CHRISTINA SIMEONE, PJM GOVERNANCE: CAN REFORMS IMPROVE OUTCOMES? 2 (2017) ("[T]he RTO is not immune from self-interested behaviors and organizational biases that may serve to benefit incumbent firms."); Dworkin & Goldwasser, *supra* note 77, at 562 (discussing RTO self-interests, including interest in self-preservation and the need to maintain relationships with its stakeholders); *id.* at 557 (explaining that one way to conceive of RTOs as "agents, not of the FERC, but of the transmission owners in a region").

RTO/ISO governance structures may be designed to allow for suboptimal planning by providing incumbent transmission owners greater influence over decisionmaking.[80]

Given these misaligned incentives, it is imperative that FERC not only use this opportunity for reform to add transparency and uniformity to planning and cost allocation processes, but also to improve its oversight of those process. Existing economic incentives will often lead planners to forego (or even reject) net-beneficial, welfare-enhancing projects in favor of private-profit maximizing, but less efficient and cost-effective investment options. That is, if the Commission leaves implementation of the planning process to actors whose incentives steer them toward local reliability projects and away from regional and interregional ones, optimal planning will not occur. FERC cannot meet its statutory obligation to ensure just and reasonable rates under such circumstances.

The Commission should therefore improve oversight by creating a position for an Internal Transmission Monitor (ITM).[81] The ITM will have a similar role to the market monitors used to keep RTOs/ISOs accountable. The ITM would be a "neutral actor[] who recommend[s] actions and policy changes based on immediate observations and/or based on market research."[82] It may act to detect and address actions by market participants and provide advice to improve the

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[80] *See* SIMEONE, *supra* note 79, at 31–36 (discussing evidence of stakeholder system issues, including those that provide advantage to transmission owners); *id.* at 37–39 (discussing evidence of incumbent bias); Comments of RTOGov Researchers, *The Office of Public Participation*, Docket No. AD21-9 (May 7, 2021) (noting that transmission owners are likely to be among the most active participants, influencing decisionmaking); Christina Simeon, *Reforming FERC's RTO/ISO Stakeholder Governance*, 34 ELEC. J., 2021, at 3 (noting that transmission owners have not had their influence diluted in the same way that other sectors have where sector membership has grown over the years).

[81] This position could be integrated with or housed under the National Transmission Planning Organization described above.

[82] Dworkin & Goldwasser, *supra* note 77, at 572 (quoting Transcript of Technical Conference on Policies Regarding Market Monitoring at 12, *Review of Market Monitor Policies*, AD07-8 (Apr. 5, 2007) (remarks of Sudeen Kelly, Comm'r, FERC)).

functioning of the planning and cost allocation processes.[83] The ITM could also monitor planning entities' conduct, to ensure that the Commission's standards and prescriptions are applied.[84] The goal of establishing the ITM is to give FERC a greater degree of visibility into these processes. It is not to provide another layer of administrative review to an already burdened process.

The Commission should also consider how the Office of Public Participation (OPP) can play a role in enhancing oversight by giving the public greater visibility into planning and cost allocation processes. The Commission should direct OPP to create educational material for the public on these processes, particularly for the RTOs/ISOs, but also for the major planning entities in vertically integrated regions. FERC might also direct OPP to focus specifically on facilitating participation by the public in the RTO/ISO transmission processes. RTO/ISO stakeholder processes are complex and exceedingly technical, rendering it particularly difficult for the public to meaningfully participate.[85] This is true of transmission planning as well as wholesale energy and capacity market proceedings. OPP should assist the public in navigating the transmission planning process. Greater public involvement can provide transparency and visibility into a process that has traditionally been opaque and open only to the most

[83] *See id.* at 572 (quoting Transcript of Technical Conference on Policies Regarding Market Monitoring at 12, *Review of Market Monitor Policies*, AD07-8 (Apr. 5, 2007) (remarks of Sudeen Kelly, Comm'r, FERC)).

[84] *See id.* at 573.

[85] *See, e.g.*, Comments of the Institute for Policy Integrity at New York University School of Law at 8–9, *The Office of Public Participation*, Docket No. AD21-9 (April 23, 2021); Comments of RTOGov Researchers, *The Office of Public Participation*, Docket No. AD21-9 (May 7, 2021); *see also* Dworkin & Goldwasser, *supra* note 77, at 581–87 (discussing the "public interest problem," including how the "complicated, technical, and expensive structure of the stakeholder process results in serious challenges for public representation").

sophisticated actors. Adding this stakeholder voice can counteract biases and make planning entities more accountable for their decisions.[86]

III. The Commission Should Require Use of Future Scenarios and Modeling for Anticipated Future Generation

To examine the costs and benefits of new transmission projects fully and in a way that facilitates optimal network planning, the Commission should require planning entities use future scenarios and modeling that anticipate potential future changes in generation. Failing to properly consider the future may lead planners to select suboptimal projects that are either more expensive or less beneficial than alternatives. It may also lead planners to reject projects that would be welfare-enhancing for consumers and producers, providing the greatest benefits for the least cost.

At present, transmission planning does not consistently or adequately anticipate changes to generation. Instead, it relies on past trends in generation and transmission investment and historical weather patterns to assess the need for network expansion and identify solutions. Particularly in the present context of rapid changes in the make-up and geographic locations of the generation mix, such a planning process cannot ensure just and reasonable rates because it is unlikely to identify or select the most efficient and cost-effective transmission investments. As the Commission has previously concluded, a planning process that "fails to promote the more efficient and cost-effective development of new transmission facilities" must be corrected because it cannot ensure just and reasonable rates.[87] The current planning process fails to do so and should be reformed to employ a forward-looking and dynamic view of options for matching the future generation mix to load.

[86] *Cf.* MICHAEL SANT'AMBROGIO & GLEN STASZEWSKY, ADMIN. CONF. OF THE U.S., FINAL REPORT: PUBLIC ENGAGEMENT WITH AGENCY RULEMAKING 3–4, 12–16 (2018).

[87] Order No. 1000, *supra* note 22, at P 52.

To ensure that grid planners adopt this view, the Commission should require consideration of anticipated future generation. Further, it should consider prescribing nationally uniform assumptions for the future scenarios and modeling that provide insight into what transmission will be efficient and cost-effective. Regardless of whether the Commission insists on national uniformity, planners should be required to account for three key factors: (1) uncertainty about future system conditions; (2) strategic behavior by generators in restructured regions; and (3) climate risk and the insurance value that transmission provides by boosting resilience to disruptive extreme events. Neglecting these factors will consistently lead to the misvaluation of transmission proposals. Additionally, the Commission should consider requiring planners to also account for existing and anticipated new natural gas infrastructure. As the experience of Winter Storm Uri made terribly clear, gas and power systems are already highly interdependent and will likely remain so. Integrating planning of these systems can lead to more just and reasonable rates by protecting against stranded assets and enhancing competition.

A. The Current Planning Process Fails To Ensure Just and Reasonable Rates by Not Accounting for Anticipated Future Generation

With Order 1000, FERC sought to improve the transmission planning process so that project selection would be informed by a transparent evaluation of how efficiently and cost-effectively different proposals would satisfy identified needs.[88] The current planning process is not accomplishing this goal. Instead, it is leading to substantial investments in local transmission rather than the sort of regional and interregional network expansion that would optimize for anticipated future generation. The transmission planning process today is not sufficiently forward-looking and proactive, and is mostly blind to the changing generation mix; it does not

[88] *Id.* at PP 6, 81.

account for uncertainty, disregards market dynamics, and ignores climate risk and resilience factors. Such a planning process cannot lead to the most efficient and cost-effective outcomes and, therefore, cannot ensure just and reasonable rates for consumers.

The engineering and economics literature is replete with evidence that co-optimizing transmission and generation investment decisionmaking leads to more efficient and lower-cost solutions.[89] This is true in both vertically integrated planning regions, where co-optimization can enhance the integrated resource planning process by allowing it to best capture the value provided by transmission, and in restructured regions as part of anticipatory or proactive planning.[90] Accounting for future generation in transmission planning leads to better investment decisions because generation and transmission solutions can be substitutes in some instances, but complements in others.[91] For example, transmission expansion can substitute for building new generation because it enables the purchase of power from other areas or even regions. And the availability of transmission influences generation siting such that transmission expansion will affect future patterns and mixes of generation investment.[92] In short, transmission and generation

[89] *See, e.g.*, 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) (providing a literature review); Dvorkin et al., *supra* note 76 (finding co-planning of storage and transmission expansion achieves greater operating cost savings than solely the deployment of storage). The New York State Energy and Research Authority (NYSERDA) likewise explains that linking planning for generation and transmission will improve outcomes by ensuring that all stakeholders have more and better information what will be valuable. *See* Comments of NYSERDA on Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Case No. 20-E-0197 (N.Y. Pub. Serv. Comm'n June 22, 2021). A 2013 study by the Eastern Interconnection States' Planning Council, National Association of Regulatory Utility Commissioners, and FERC also concluded that traditional planning methods were no longer adequate, yielding sub-optimal levels of transmission investment that increased generation and transmission costs by 5-10% compared to a co-optimization approach. *See* E. INTERCONNECTION STATES' PLANNING COUNCIL ET AL., CO-OPTIMIZATION OF TRANSMISSION AND OTHER SUPPLY RESOURCES 4 (2013).

[90] Krishnan et al., *supra* note 89, at 298–99.

[91] Chao & Wilson, *supra* note 73, at 1.

[92] Krishnan et al., *supra* note 89, at 298.

investments are interdependent in complex ways and disregarding this fact makes inefficiency more likely.[93]

While the Commission may not be able to mandate full co-optimization of transmission and generation investment planning, it might still require use of a transmission planning process that accounts for anticipated future generation in the future scenarios and modeling in order to reap the benefits of their interdependencies. Doing so is just and reasonable because it will facilitate transmission planning entities' ability to select transmission solutions that most efficiently meet the needs of generators and load in a cost-effective manner. Anticipatory or proactive transmission planning has been shown to have clear benefits—one Brattle study found that taking this approach to planning nationwide could save $30-$70 billion in total generation and transmission investment costs and yield $47 billion in annual savings to customers.[94]

Mandating proper consideration of anticipated future generation is necessary to ensure the long-term efficiency of wholesale markets that currently rely on aging transmission infrastructure that will require upgrade, replacement, or decommissioning in the foreseeable future.[95] The goal for the Commission is not simply more transmission investments, but rather more efficient and cost-effective transmission investment designed and situated to serve a changing grid. Proactive transmission planning is thus central to FERC's mandate because it facilitates competition and helps to ensure just and reasonable rates.

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[93] *See* Spyrou et al., *supra* note 53, at 4265; *id.* at 4272 (finding that the proactive approach increases net benefits identified by transmission planning process by $3.5 billion compared to an iterative or reactive approach in the case study used and that the iterative approach only captures 29% of the net benefits that would be added to the system if a co-optimization is employed).

[94] PFEIFENBERGER & CHANG, *supra* note 5, at ii.

[95] Chao & Wilson, *supra* note 73, at 1.

B. The Commission Should Consider Mandating Uniform Assumptions for Future Scenarios and Modeling

The Commission can create a more transparent and systematic transmission planning process by imposing greater uniformity on the scenarios and modeling used by planners. Doing so would help to ensure optimal outcomes. In particular, for proactive transmission planning to identify efficient and cost-effective solutions, future scenarios and modeling should always account for at least four factors, described below.

1. Future Scenarios and Modeling Should Account for Uncertainty

Currently, most modeling approaches use a deterministic environment, which views future values of uncertain parameters as known in advance even though they are uncertain.[96] This assumption of certainty can lead transmission plans astray,[97] given that the value of transmission expansion hinges on a variety of risks and uncertainties, such as "future load growth, fuel costs, additions and retirements of generation capacities and the locations of those generators, exercise of market power by some generators, and availability of hydro resources."[98] Further, these future system conditions, which are uncertain, are also a major driver of the benefits of a transmission project.[99] The relevance of uncertainty may be even greater in

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[96] Álvaro García-Cerzo et al., *Robust Transmission Network Expansion Planning Considering Non-Convex Operational Constraints*, 98 ENERGY ECON., June 2021, at 2 ("[T]he lack of randomness in [future values] parameters may lead to suboptimal investment plans.").

[97] *Id.*

[98] Awad et al., *supra* note 40, at 3; *see also* Raquel García-Bertrand & Roberto Mínguez, *Dynamic Robust Transmission Expansion Planning*, 32 IEEE TRANSACTIONS ON POWER SYS. 2618, 2621 (2017) (listing pertinent uncertainties in a market setting, including demand growth, spatial distribution of demand growth, generation capacities, availability of transmission facilities, availability of generation facilities); 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, 308 (2014) ("Planning for long-lived infrastructure before it is needed involves making assumptions about the timing, size, and location of future generation investments that will depend strongly on network characteristics as well as on highly uncertainty market and regulatory conditions (e.g., technology and fuel costs, environmental regulation, renewables mandates).").

[99] Wolak, *supra* note 38, at 129; JOHANNES P. PFEIFENBERGER ET AL., BRATTLE GRP., WIRES GRP., TOWARD MORE EFFECTIVE TRANSMISSION PLANNING: ADDRESSING THE COSTS AND RISKS OF AN INSUFFICIENTLY FLEXIBLE ELECTRICITY GRID 10 (2015) ("[D]iscounting transmission-related benefits and not fully evaluating short- and long-

restructured regions where, given the independence of transmission planners and generation developers, assumptions of perfect information about future system conditions cannot hold.[100] The negative effect of uncertainty may also be exacerbated by the strategic behavior of market participants, discussed below, in a market-based system.[101]

Scenario-based planning, which considers multiple futures instead of assuming just one, often improves only somewhat on deterministic planning. It tends to define alternative futures statically and develop separate plans for each scenario rather than identifying solutions that are advantageous across some or all scenarios.[102] Thus, modeling and scenario-based planning often either inappropriately diminish or disregard the inherent uncertainty that exists in transmission network planning.

In light of the pitfalls of the deterministic approaches, the Commission should direct transmission planning entities to use future scenarios and modeling that account for uncertainty. This might be done using stochastic programming[103] or a robust optimization model to determine the optimal set of investments.[104] The former seeks to determine what investments can be made in an initial decision stage, and what corrective actions can be taken at a later stage when more information is available, in order to minimize investment costs over the planning horizon.[105]

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term uncertainties exposes customers and society to potentially high cost outcomes that may occur without the investment.").

[100] Konstantelos et al., *supra* note 38, at 132.

[101] Wolak, *supra* note 38, at 130 (providing example of fossil-fuel suppliers in a hydroelectric dominated wholesale market taking advantage of low water conditions to submit higher offer prices because they know that hydroelectric suppliers will have to conserve water rather than compete in the short-term market).

[102] *See* Munoz et al., *supra* note 98, at 308.

[103] Krishnan et al., *supra* note 89; Munoz et al., *supra* note 98.

[104] *See, e.g.*, García-Cerezo et al., *supra* note 96; Cristina Roldán et al., *Robust Transmission Network Expansion Planning Under Correlated Uncertainty*, 34 IEEE TRANSACTIONS ON POWER SYS. 2071 (2019); García-Bertrand & Mínguez, *supra* note 98.

[105] Munoz et al., *supra* note 98, at 1. Under this approach, an initial set of investment decisions is made in ignorance of which of a predefined set of scenarios may occur, but each scenario is weighted by a probability so that these first

Similarly, the latter seeks to provide expansion plans that are robust against all possible realizations by accounting for the worst-case scenario total generation cost under an uncertainty set.[106] Regardless of the tool selected, the goal is the same—to take a proactive approach to planning and to account for and deal with the uncertainty about anticipated future generation and other system conditions that necessarily result from doing so.

Using models that account for uncertainty is also important because the failure to do so can badly misvalue a transmission expansion project. Today, planners generally consider the economic benefits of a transmission project under the "average" future system condition.[107] Yet, the expected value of investments should be considered under unusual, but plausible conditions because transmission's greatest value will be realized in extreme and emergency conditions.[108] Accurately assessing the value of transmission therefore requires an accounting of the full range of potential future system conditions.[109]

A full accounting includes valuing the optionality and flexibility that transmission investments can provide. A project that leaves open more options for future resource interconnection or provides flexibility for an expansion plan to adapt to changing conditions may

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investments are selected in a manner that "minimizes the probability weighted costs over the full range of scenarios, accounting for how investments restricted or expanded the flexibility of the system to adapt later." Krishnan et al., *supra* note 89, at 322–23. A second set of investments are made part way through the planning horizon to modify the system once the planner knows which scenario occurs. *Id.* at 323.

106 *See, e.g.*, Roldán et al., *supra* note 104, at 1; García-Cerezo et al., *supra* note 96, at 2; Aakil M Caunhye & Michel-Alexandre Cardin, *Towards More Resilient Integrated Power Grid Capacity Expansion: A Robust Optimization Approach with Operational Flexibility*, 72 ENERGY ECON. 20, 21 (2018). 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. R.A. Jabr, *Robust Transmission Network Expansion Planning with Uncertain Renewable Generation and Loads*, 28 IEEE TRANSACTIONS ON POWER SYS. 4558, 4559 (2013); Caunhye & Cardin, *supra* note 106, at 21.

107 Awad et al., *supra* note 40, at 3–4. Notably, this is in direct contrast to how planners consider reliability benefits, which is performed for "critical system conditions." PFEIFENBERGER ET AL., *supra* note 99, at 11.

108 Awad et al., *supra* note 40, at 4; Wolak, *supra* note 38, at 129–31.

109 Wolak, *supra* note 38, at 129.

be preferred.[110] Stochastic modeling or robust co-optimization may show that an investment strategy, while suboptimal in any particular deterministic scenario, can provide enough additional adaptability to make it worthwhile given uncertainty.[111] The option value that flexibility provides may be a difficult to quantify, but it should not be ignored.[112] Flexibility can also balance the risk of stranded assets with the benefits that can come from investment based on economies of scale.[113] That is "an investment decisions' agility for coping with adverse scenario realizations becomes an important consideration" in selecting transmission solutions.[114]

2. Future Scenarios and Modeling Should Account for Strategic Behavior of Market Participants

The Commission should require transmission planners to use scenarios and modeling that account for the strategic behavior of market participants, particularly generators in deregulated regions. Restructuring of the energy sector introduced generator competition, which creates different incentives for generation firms regarding the location and operation of their units, as

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[110] Krishnan et al., *supra* note 89, at 323; U.S. DEP'T OF ENERGY, NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY, at xiii-ix (2015) ("Stronger and more flexible networks, in turn, create real options to use the transmission system in ways that were not originally envisioned. In the past, these unexpected uses have often proven to be highly valuable and in some cases have outweighed the original purposes the transmission enhancement was intended to serve. Past examples have included enabling grid operators to adjust smoothly and efficiently to unexpected yet ongoing changes in the relative prices of generation fuels, diverse renewable resource profiles, economic volatility, new environmental requirements, unanticipated outages of major generation and transmission facilities, and natural disasters. The options created by a strong and flexible transmission network are real. Failure to take explicit account of these options in the planning process will severely understate the value of transmission."); PFEIFENBERGER & CHANG, *supra* note 5, at 13 (2016) ("[T]he more explicit consideration of future uncertainties in the planning process yields a more cost-effective, phased-in buildout of the system that provides more flexibility to adjust plans over time.").

[111] Munoz et al., *supra* note 98, at 39.

[112] Krishnan et al., *supra* note 89, at 323; *see also* OFFICE OF MGMT. & BUDGET, EXEC. OFF. OF THE PRESIDENT, CIRCULAR A-4: REGULATORY ANALYSIS 26 (2003) (explaining that while some effects may be "too difficult to quantify or monetize," agencies must still "carry out a careful evaluation of non-quantified benefits and costs"); Exec. Order No. 13,563, 76 Fed. Reg. 3821 (Jan. 18, 2011) (reminding agencies to consider "values that are difficult or impossible to quantify, including equity, human dignity, fairness, and distributive impacts"); *cf. Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin.*, 538 F.3d 1172, 1200 (9th Cir. 2008) (noting that it is inappropriate to treat a benefit as zero—and therefore ignoring it—just because the value of the benefit might fall within a range and therefore contain some uncertainty).

[113] Konstantelos et al., *supra* note 38, at 147.

[114] *Id.* at 132.

well as how they bid into the wholesale market.[115] The existence of markets and competition has implications for optimal transmission expansion because generators will behave strategically in response to transmission investment decisions, sometimes called strategic market feedback.[116] Transmission planning in regions that have moved to a market system demands a more complex planning effort and a new approach to evaluating the economic benefits of transmission projects, one which accounts for the strategic behavior of market participants.[117] Yet, while market-based pricing and generator competition are basic features of the restructured energy sector, these aspects of the market continue to be overlooked.[118] Transmission expansion planning today continues to apply a cost-minimization approach that was appropriate under a vertically integrated planning system, but may not result in the optimal transmission network in a market-based regime.[119] In order to develop an optimal transmission network, planners must anticipate and account for responsive entry and operating decisions of generation firms.[120]

[115] *See, e.g.*, Awad et al., *supra* note 40, at 3; Wolak, *supra* note 38, at 107.

[116] Isaac-Camilo Gonzalez-Romero et al., *Transmission Expansion Planning Under Imperfect Market Competition: Social Planner Versus Merchant Investor*, at 2 (Working Paper 2020); *see also* Awad et al., *supra* note 40, at 3; Wolak, *supra* note 38, at 107.

[117] Economic and engineering literature provides a variety of solutions for modeling how transmission planning can account for market responses to generators' strategic behavior. *See* S. Saeid Taheri et al., *Transmission Expansion in an Oligopoly Considering Generation Investment Equilibrium*, 64 ENERGY ECON., 2017, at 56 (providing a literature review of research in this area).

[118] Paola Bresesti et al., *The Benefits of Transmission Expansion in the Competitive Electricity Markets*, 34 ENERGY 274, 274 (2009).

[119] *See, e.g.*, Awad et al., *supra* note 40, at 3; Wolak, *supra* note 38, at 101.

[120] *See, e.g.*, Gonzalez-Romero et al., *supra* note 116, at 28 (concluding that ignoring strategic feedback can lead to non-negligible welfare losses because sub-optimal planning leads to a significant distortion of the optimal generation mix, leading to over- or under-investment in certain resources and affecting the robustness of the system); Enzo E. Sauma & Shmuel S. Oren, *Proactive Planning and Valuation of Transmission Investments in Restructured Electricity Markets*, 30 J. REGUL. ECON. 358, 385 (2006) (a proactive network planning approach can identify more socially efficient expansion options than a reactive approach—which is currently used in many RTOs—because it considers not only the welfare gained directly by adding transmission capacity and how its investment can induce a more socially-efficient equilibrium of expected generation capacity).

Changes to the transmission system can improve performance of the competitive wholesale market and should be considered in models that seek to determine the optimal transmission expansion plan. Expanded transmission capacity creates greater competition for suppliers, potentially changing generation entry, location, and operating choices.[121] Most obviously, transmission investment decisions affect a generator's ability to boost profits through the use of local market power.[122] By introducing more and cheaper competitors to a market, transmission expansion has the ability to reduce market power.[123] This may lead to lower wholesale energy market prices by pushing generators to make energy market bids that are closer to their marginal cost.[124] It may also prevent generators from curtailing output to raise prices.[125] Failing to include the benefits of increased competition, which have been quantified and shown to be significant,[126] will misstate the value of transmission projects and make it less likely that welfare-enhancing projects will be built.[127]

However, transmission planning should also account for strategic generation investment decisions, including where and whether to expand, that will be made in response to transmission investment. Transmission planners should not assume that investment decisions of producers are

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[121] *See, e.g.*, Wolak, *supra* note 38, at 101, 103, 124; Munoz et al., *supra* note 98, at 308.

[122] Wolak, *supra* note 38, at 101–02; Awad et al., *supra* note 40, at 3.

[123] *See, e.g.*, Awad et al., *supra* note 40, at 3; Wolak, *supra* note 38, at 101, 130; Sauma & Oren, *supra* note 74, at 678.

[124] Wolak, *supra* note 38, at 101, 103.

[125] *Id.* at 101–02.

[126] *E.g.*, Awad et al., *supra* note 40, at 5–6 (calculating market impacts of new transmission by applying methodology to CAISO Path 26 upgrade); *see also* Gonzalez-Romero et al., *supra* note 116, at 28 (finding non-negligible welfare losses from using an overly-simplistic view of planning, rather than a proactive approach that considers strategic feedback); Frank A. Wolak, *Measuring the Competitiveness Benefits of Transmission Investment Policy: The Case of the Alberta Electricity Market*, 85 ENERGY POL'Y 426 (2015) (finding that reduction in ability to exercise market power due to transmission expansion provided significant economic benefits in the Alberta market).

[127] *See* Wolak, *supra* note 38, at 104–05, 117.

fixed because new transmission lines may alter these decisions in various ways.[128] Generation firms in a market-based regime seek to build units in the most profitable location, which will be either near load or on the constrained side of a congested transmission path.[129] Firms may change their siting plans as transmission expansion planning decisions are made in order to find the most profitable location.[130] Furthermore, generation firms may also alter their entry and exit decisions in response to new transmission.[131] Firms may defer generation investments in light of transmission expansion, yielding deferral benefits for consumers.[132] Thus, benefits calculations should consider not only reduced congestion, but also "capital cost savings from more efficient generation investment."[133] These strategic changes in generator behavior must be considered in models if they are to provide the optimal transmission expansion plan.

Transmission planners must "recognize the fact that generation unit owners and load serving entities will account for the current and future configuration of the transmission network in making their expected profit maximizing entry and operating decisions."[134] Therefore, transmission planners must use a forward-looking approach that accounts for such strategic decisions by generation firms. In failing to account for strategic behavior, planning models may

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[128] Teheri et al., *supra* note 117, at 56; Dvorkin et al., *supra* note 76, at 246 ("[S]iting of storage depends on sufficient profit opportunities, which are driven by the intraday and interday LMP dynamics, which in turn depend on net nodal injection and the configuration of the transmission network. Merchant storage should be expected to act strategically in electricity markets to maximize profits.").

[129] Wolak, *supra* note 38, at 107.

[130] *See* Munoz et al., *supra* note 98, at 308; Awad et al., *supra* note 40, at 4.

[131] Wolak, *supra* note 38, at 124; Teheri et al., *supra* note 117, at 58.

[132] Wolak, *supra* note 38, at 122 (citing Mohammad R. Hesamzadeh et al., *Transmission Augmentation with Mathematical Modeling of Market Power and Strategic Generation Expansion—Parts I and II*, 26 IEE TRANSACTIONS ON POWER SYS. 2040 (2011)); de Nooij, *supra* note 38, at 3103 ("Generators will respond to a lower calculated producer surplus and to additional supply arriving over a new interconnector by changing their investment pattern. This may create social benefits (fewer investments lead to a lower social cost by definition).").

[133] Krishnan et al., *supra* note 89, at 298.

[134] Wolak, *supra* note 38, at 103.

pass over expansion projects that are welfare-enhancing when competitiveness benefits and effects on generation investment are considered but fail the traditional cost-minimization approach. That is, failing to account for how restructuring has changed the incentives for generation firms will cause beneficial projects to be overlooked. When less efficient and cost-effective projects are selected and optimal projects ignored, FERC cannot ensure that rates are just and reasonable.

3. Future Scenarios and Modeling Should Account for Climate Risk and Resilience

Transmission planners also should be required to use future scenarios and modeling that account for climate risk and the need for resilience to disruptive events. Future scenarios that do not account for how climate change will affect transmission investments will overlook substantial costs that may arise from physical impacts or transition that strands fossil-fuel assets, as well as the potential resilience benefits of transmission investment. Planning processes that disregard such factors cannot yield efficient and cost-effective transmission expansion investments and in turn cannot ensure just and reasonable rates.[135]

Accounting for climate risk is particularly important in order to have an accurate picture of what future scenarios might look like. The energy sector, and specifically its long-lived, capital intensive assets, faces significant physical risk as the climate changes.[136] The physical risk to transmission assets was demonstrated in New Orleans this summer, as Hurricane Ida

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[135] *Cf.* PFEIFENBERGER ET AL., *supra* note 99, at 11 ("An important and very tangible risk associated with not pursuing certain transmission investments is that insufficient system flexibility increases the costs of (a) operating the system under stress conditions in the short-term, and (b) adapting to policy changes and changing market conditions in the longer-term.").

[136] *See generally* Romany M. Webb et al., *Climate Risk in the Electricity Sector: Legal Obligations to Advance Climate Resilience Planning by Utilities*, 51 ENV'T L. (forthcoming 2021); *see also* Madison Condon et al., *Mandating Disclosure of Climate-Related Financial Risk*, 24 N.Y.U. J. LEG. & PUB. POL'Y (forthcoming 2021) (manuscript at 5–6).

caused Entergy to lose all eight of its transmission lines that delivered power to the city, leaving over a million people without power.[137] As extreme weather becomes more intense and more frequent due to climate change, transmission assets will be put at greater risk of harm. Accounting for climate risk in identifying and selecting solutions can ensure that planners are recognizing the substantial costs that may be incurred depending on where transmission assets are located and how they are built. For example, where climate change will cause temperatures to rise above those in which assets can operate, planners may want to consider a different transmission path or the use of alternative transmission technologies. Planners may neglect to consider such alternatives if they do not take climate change into consideration.

Furthermore, the sector faces transition risk that may lead to stranded assets. Transmission expansion planned without regard for how policies and markets may change is unlikely to lead to the most efficient and cost-effective outcomes. Given the long time horizon of transmission planning and construction, planners should consider the future of climate policy and a low-carbon economy. The federal government, states, and localities are continuing to take action to combat climate change. Markets are also changing—new technologies will come online, and supply and demand will be altered by public policies, private preferences, and climate change itself.[138] Decarbonization (and the related shift to renewables) and electrification, in combination, will lead to a substantial change in the energy sector and pose significant risk for fossil-fuel fired generation.[139] Transmission assets built to serve new natural gas or other fossil-

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[137] Robert Walton, *Ida Knocks Out All Transmission Lines into New Orleans, Leaves 1M+ Without Power*, UTIL. DIVE (Aug. 30, 2021), https://www.utilitydive.com/news/ida-knocks-out-all-transmission-lines-into-new-orleans-leaves-1m-without/605754/.

[138] Condon et al., *supra* note 136 (manuscript at 6–9) (discussing climate-related transition risk).

[139] *See id.* at 6–7.

fuel plants may themselves become stranded as these generation resources become unusable or uneconomic due to public policy and market shifts.[140]

For these reasons, it is imperative that the Commission require planning entities to account for climate risk in future scenarios and modeling. In making this mandate, however, the Commission should consider providing uniform assumptions regarding climate change that can be used by planning entities. FERC might enlist assistance from other agencies, like the National Oceanic and Atmospheric Administration or the Environmental Protection Agency, to provide input on what assumptions about the future should look like.[141] The Commission might also look to organizations with expertise in resilience, like the Department of Energy's National Labs, for assistance.[142] By providing uniform assumptions or guidance on, for example, the use of downscaled climate projections, the Commission can aid planning entities in reforming their planning process to account for climate risk. Mandating or urging the use of certain climate assumptions can remove some of the confusion and difficulty that may ensue given the breadth of information that currently exists and may be unfamiliar to transmission planners.

Additionally, the Commission should mandate that future scenarios and modeling account for climate resilience. This is imperative to ensuring proper valuation of transmission projects. Much of the true value of transmission takes the form of "insurance" against extreme

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[140] *See* Comments of the Institute for Policy Integrity at New York University School of Law at 38–45, *Certification of New Interstate Natural Gas Facilities*, Docket No. PL18-1 (May 26, 2021) [hereinafter Natural Gas Policy Statement Comments].

[141] Condon et al., *supra* note 136 (manuscript at 37–38) (recommending the Securities and Exchange Commission coordinate with agencies with climate expertise in crafting any potential future scenarios).

[142] *See, e.g.*, CAITLIN MURPHY ET AL., NAT'L RENEWABLE ENERGY LAB'Y, ADAPTING EXISTING ENERGY PLANNING, SIMULATION, AND OPERATIONAL MODELS FOR RESILIENCE ANALYSIS (2020); Patrick Balducci et al., Argonne Nat'l Lab'y, *Understanding the Value of Energy Storage for Power System Reliability and Resilience Application*, 8 CURRENT SUSTAINABLE/RENEWABLE ENERGY REPS. 131 (2021); Jie Xu et al., *Mitigating Cascading Outages in Severe Weather Using Simulation-Based Optimization*, 36 IEEE TRANSACTIONS ON POWER SYS. 204 (2021).

events.[143] As noted above, use of the "average" system conditions to estimate benefits risks undercounting the critical value that transmission can provide during extreme events, like hurricanes, heatwaves, and cold snaps.[144] The insurance value of transmission is climate resilience value. Transmission projects that can allow remote generators to provide power during emergency circumstances or that are not at risk for common mode failures during extreme-weather events should be accorded additional value. Likewise, projects that provide flexibility and optionality in the future's changed climate should also be valued for their resilience. These kinds of resilience attributes not only protect against economic harm caused by sustained periods of extreme prices, but can save lives and make communities more resilient as the climate changes and weather events become more severe.

How to value this resilience adder is a difficult question. Accuracy depends on decisionmakers' level of risk aversion and willingness to incur an insurance premium to avoid the consequences of under-investment in transmission and climate resilience.[145] Overinvestment in transmission, which is unlikely,[146] can protect against rare, but costly, market outcomes and extreme weather impacts.[147] It is imperative that planning entities account for climate resilience

[143] Awad et al., *supra* note 40, at 4, 7; Wolak, *supra* note 38, at 129–31.

[144] *See generally* GOGGIN, *supra* note 5 (quantifying the value of transmission's ability to enhance the resiliency of the grid by assessing how an additional 1 GW of transmission tie would have saved consumers in several high profile extreme weather events); Frank Wolak explains that insurance value may be even greater in a market regime where suppliers may take advantage of system conditions, for example, fossil fuel producers in a hydroelectric dominated region might take advantage of drought conditions (which have become more common and more extreme due to climate change) to raise market prices when hydro resources will be unable to sell in the short-term market. Wolak, *supra* note 38, at 129–30. Additional transmission that provides increased competition from other regions can help mitigate that potential result. *Id.*

[145] Awad et al., *supra* note 40, at 7; Wolak, *supra* note 38, at 131.

[146] *See generally* Transcript of Technical Conference to Discuss Climate Change, Extreme Weather, & Electric System Reliability, Docket No. AD21-13 (June 2, 2021); Transcript of Technical Conference to Discuss Electrification of the Grid of the Future, Docket No. AD21-12 (Apr. 29, 2021).

[147] Wolak, *supra* note 38, at 131.

in selecting projects in order to select optimal investments and facilitate just and reasonable rates.

4. The Commission Should Consider Integrating Electric Transmission Planning and Natural Gas Infrastructure

Finally, the Commission should consider requiring planners to account for, and even coordinate planning with, natural gas infrastructure expansion. Transmission and pipeline investments are often inter-related. Using a co-optimizing tool that considers all options, including how transmission or pipeline expansion may be substitutes, can provide more efficient and sustainable expansion solutions, compared to a decoupled approach that looks at transmission planning and pipeline expansion separately.[148] Several models have been developed to integrate or coordinate natural gas transportation and electric transmission capacity expansion, including ones that rely on open source tools.[149] The Commission should consider requiring planning entities to use these tools when identifying and selecting transmission projects for development.

The need to integrate or coordinate natural gas infrastructure and electric transmission planning will become more important as the federal and state governments usher forward decarbonization and electrification policies and markets move toward a low-carbon future.[150] Consistent future scenarios for electrification and gas supply will be necessary as electrification

[148] Krishnan et al., *supra* note 89, at 314 & fig.3.

[149] *See* KRISTINA MOHLIN, ENV'T DEF. FUND, THE U.S. GAS PIPELINE TRANSPORTATION MARKET: AN INTRODUCTORY GUIDE WITH RESEARCH QUESTIONS FOR THE ENERGY TRANSITION 31–32 (2021) (describing various models and platforms that allow planners to "analyze the relevant interactions and interdependencies between the sectors," including National Energy Modeling System; the simultaneous steady-state natural gas and electric power optimization framework from Los Alamos National Laboratory; a market module being developed to pair with Switch 2.0; a cooperation platform that pairs the PLEXOS model for electricity with the SAInt simulation model of natural gas flows; and several others).

[150] Condon et al., *supra* note 136, at 6–7.

changes the level and shape of the demand curve.[151] Together, decarbonization and electrification will diminish demand for natural gas.[152] These trends will change supply flows and demand patterns[153] and new transmission infrastructure may better meet future transportation capacity needs. Planners on both sides of the energy system should therefore look to co-optimize new infrastructure development as the sector changes in response to policy and market trends and before making long-term, capital-intensive investments.

IV. Project Selection Should Be Guided by Nationally Uniform Cost-Benefit Analysis

Professor William Hogan has said: "A forward-looking cost-benefit analysis provides the gold standard for ensuring that transmission investments are efficient."[154] Policy Integrity urges the Commission to follow this advice and adopt a requirement that transmission project selection entail application of a nationally uniform cost-benefit analysis. Doing so would help close the gap between nominal compliance with the Commission's transmission planning principles and realization of those principles in transmission development—and so would yield rates that are more just and reasonable and not unduly discriminatory or preferential.

A. Cost-Benefit Analysis Aligns Well with the Commission's Prior Transmission Orders

Even though transmission planning frequently involves some form of cost-benefit analysis,[155] the Commission's orders governing transmission planning and cost allocation do not prescribe its use, much less a particular form or application of it. Nonetheless, making cost-

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[151] MOHLIN, *supra* note 149, at 32.

[152] *Id.* at 40–42.

[153] *See* Natural Gas Policy Statement Comments, *supra* note 140, at 32–34.

[154] WILLIAM W. HOGAN, TRANSMISSION INVESTMENT BENEFICIARIES AND COST ALLOCATION: NEW ZEALAND ELECTRICITY AUTHORITY PROPOSAL 1 (2020).

[155] JOHANNES PFEIFENBERGER, BRATTLE, TRANSMISSION PLANNING AND BENEFIT-COST ANALYSES 9 (2021) (prepared for FERC Staff) (noting similarities and differences in lists of benefits considered in analyses conducted in SPP, MISO, CAISO, and NYISO).

benefit analysis a standard and standardized feature of transmission project selection would be consistent with, and better uphold, the principles set forth in those orders.[156] Cost-benefit analysis is a well-understood embodiment of several of those principles—openness, transparency, comparability, and regional participation—and is a source of support for the others—coordination, information exchange, dispute resolution, economic planning studies (that identify significant and recurring congestion), and cost allocation for new projects.[157]

In addition, a standardized cost-benefit analysis would help to address several of the persistent barriers to regional and interregional transmission development described in Part I above. Specifically, it would: (1) facilitate the comparison of all types of projects within a region; (2) reduce the administrative encumbrances imposed on project proposals that cross multiple regions, making them more readily comparable to local and regional alternatives; (3) prevent one or more regions from ignoring relevant benefits; and (4) reduce the source of potential disputes over cost allocation. Put another way, by opting *not* to require use of a standardized cost-benefit analysis across regions for project selection, the Commission has foregone a countermeasure to the regional diversity and parochialism that seems to have undermined the key aims of its prior transmission orders. Intervening in this way would therefore aid in the realization of rates that are just and reasonable and not unduly discriminatory or preferential.

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[156] *See* Avi Zevin, *Regulating the Energy Transition: FERC and Cost-Benefit Analysis*, 45 COLUM. J. ENV'T L. 419, 449–53 (2020) (describing why FERC's decisions are amenable to incorporation of cost-benefit analysis).

[157] Order No. 890, *supra* note 18, at P 444 (directing that planning principles must inform regional transmission plans).

B. Cost-Benefit Analysis for Transmission Project Selection Should Embody At Least Six Features

Cost-benefit analysis can take a variety of forms. It is therefore important for the Commission to prescribe a standardized approach that incorporation of particular features, including the six described below.

First, the analysis should capture all costs and benefits materially related to a project. It should include those that are difficult to quantify, such as visual impacts on a landscape and the "insurance" function of transmission capacity with respect to potential uses of market power by generators.[158] And it should include those that accrue to all power sector stakeholders, such as the emission of climate-warming pollutants. At present, different regions take different approaches to the identification and valuation of similar effects, and several rely heavily on estimated production cost savings as an analytical lodestar.[159] This inconsistency and narrowness should be corrected.

Second, the analysis should consider all benefits together. This is the obverse of the point that it is a mistake to divide and measure separately different sources of need for transmission capacity, as Order 1000 invites.[160] Needs relating to reliability, economic efficiency, and compliance with state-level public policy cannot be pulled apart analytically if the goal is to gain an accurate understanding of what additional transmission capacity would do. Just as needs should not be divided up and measured separately, the benefits of a proposal for how to meet one

[158] For a discussion of this function and potential benefit, see Wolak, *supra* note 38, at 104.

[159] *See* PFEIFENBERGER, *supra* note 155, at 8 (noting prevalence of reliance on production cost savings metric and flagging its limited scope); *id.* at 9 (listing quantified and unquantified benefits considered in each of four different RTOs' analysis of proposed transmission projects).

[160] *See, e.g.*, Order No. 1000, *supra* note 22, at PP 11, 47; *see also* ROB GRAMLICH & JAY CASPARY, PLANNING FOR THE FUTURE: FERC'S OPPORTUNITY TO SPUR MORE COST-EFFECTIVE TRANSMISSION INFRASTRUCTURE 96–101 (2021) (providing overview of silos used to identify transmission needs and plan for solutions to meet them).

or more identified needs should be considered together because the benefits of a given proposal will almost certainly be multiple and diverse. Separating them out like threads from a weaving will not yield greater insight into a proposal's relative merit and could result in selection of a project with substantial reliability benefits but little or no other merits over one that scores high in multiple respects.[161]

Third, the analysis should consider all types of projects that might serve an identified need or set of needs. Even if the need is characterized as relating to "local reliability," it might still be met by a regional or interregional project. This is especially true because of transmission's large economies of scale.[162]

Fourth, the analysis should estimate net benefits (that is, benefits minus costs), not a benefit-cost ratio (BCR, or benefits divided by costs). Policy Integrity has encouraged the Commission to replace its use of a BCR with a net-benefits estimate in previous comments and does so again here.[163] This suggestion is consistent with the guidance of the Office of Management and Budget[164] and is rooted, fundamentally, in the fact that the Commission's goal should be to direct investment towards projects that provide the highest net benefits to society.

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[161] Joskow, *supra* note 42, at 50 ("Slicing up different kinds of transmission projects on the same network like a salami is not going to lead to efficient outcomes.").

[162] *See supra* note 39 and accompanying text.

[163] Comments of the Institute for Policy Integrity at New York University School of Law at 15, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket No. RM20-10 (July 1, 2020). At least one previous Commissioner was persuaded that FERC should begin using net benefits rather than BCR. In his dissent to the supplemental NOPR on transmission incentives, then-Commissioner Chatterjee recognized that economic benefits incentives should be provided "based on net benefits in an effort to ensure that the incentives flow to the most beneficial – likely regional and inter-regional – transmission projects"). Supplemental Notice of Proposed Rulemaking, 175 FERC ¶ 61,035, at P 11 n.31 (2021) (Chatterjee, Comm'r, dissenting).

[164] CIRCULAR A-4, *supra* note 112, at 10 (stating that BCR "is not a meaningful indicator of net benefits" and should not be used to determine whether one project is more efficient than another).

There are two important problems with using BCR to assess transmission projects. The first lies in the fact that a project with a higher BCR indicates that it will yield greater benefits than a project with smaller BCR *only if the projects have similar costs*.[165] Thus projects with a higher BCR are not necessarily more economically efficient. The second problem is that projects with higher costs always have lower BCRs because of a bias inherent in the use of a ratio. Given that large transmission projects will often be more cost-effective than smaller ones due to economies of scale, this bias will distort the comparison. As the Commission is already concerned about putting larger regional and interregional projects on equal analytical footing with local projects, this bias is important to recognize. The effect of this bias is evident in Figure 1, below, which depicts the 41 projects discussed in the Commission's March 2020 notice of proposed rulemaking on electric transmission incentives under FPA section 219. Each point represents a single transmission project; its position indicates its BCR (X-axis) and net benefits (Y-axis); its diameter is proportional to the project's costs; and its color indicates whether that cost is above or below $25 million.

[165] *See* RICHARD O. ZERBE, JR. & DWIGHT D. DIVELY, BENEFIT-COST ANALYSIS IN THEORY AND PRACTICE 100 (1994) (explaining that BCR should not be used to compare projects with dissimilar costs).

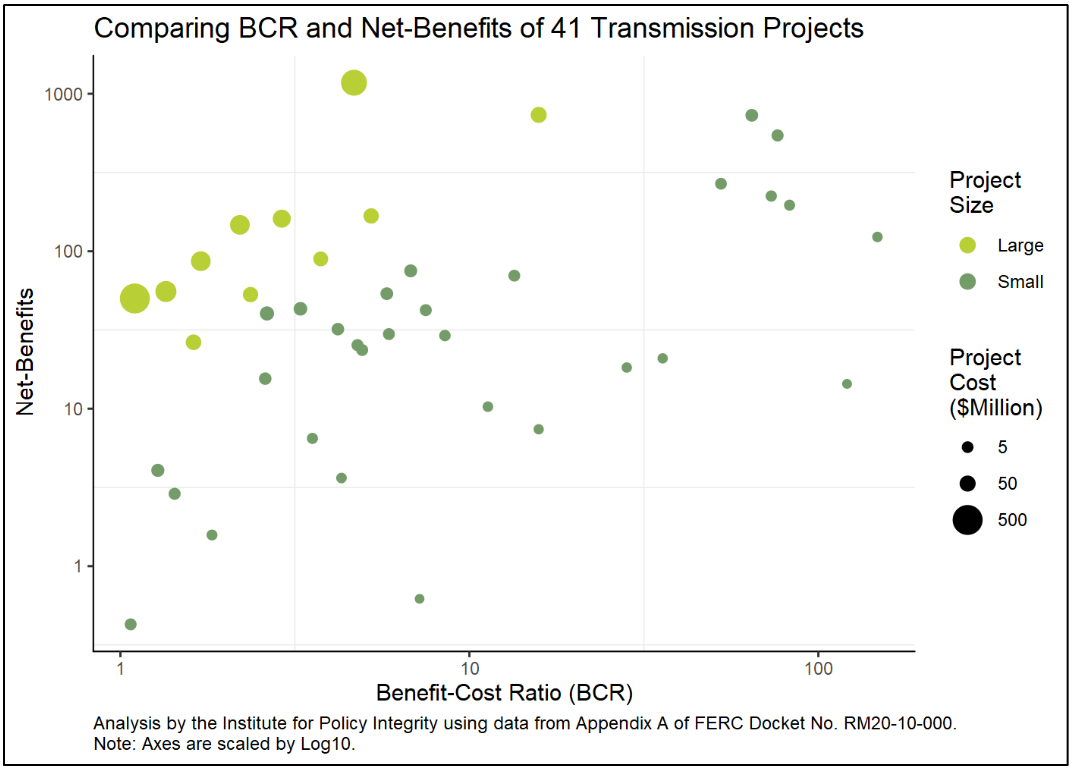

Figure 1 - Distribution of Net-Benefits and BCRs of 41 transmission projects. The diameter of each point is proportional to the projects overall cost. The color denotes whether the project is below, or above, $25 million in total cost.

As the figure shows, some projects with large net benefits have a small BCR, while some projects with a large BCR have relatively small net benefits. Further, conditional on the same net benefits, projects with larger costs have a smaller BCR, and almost all of the highest BCR projects have smaller costs. This suggests that opting for high-BCR projects will not consistently result in an economically efficient transmission network.

Fifth, the analysis should include a no-action option, non-transmission alternatives, and one or more alternatives that incorporate grid-enhancing technologies (GETs). The fundamental objective of transmission policy relates to transfer capacity, not to a particular size or type of transmission line, nor even to transmission lines as such. And so, the cost-benefit analysis framework applied to transmission project selection should allow for several possibilities. Where inaction would yield equal or greater net benefits than a conventional proposal for new wires, inaction should at least be considered. The same goes for a non-wires alternative—which might involve some combination of energy efficiency, demand response, or resources like energy storage or strategically deployed distributed solar capacity—where such an alternative would yield equal or greater net benefits than new wires. This point is especially notable because it implies that adhering to the principles of good cost-benefit analysis should lead the Commission to insist on consideration of proposals from actors that are not in the transmission business and so might be unaware of opportunities to compete for the chance to meet needs identified by a transmission-oriented analysis. In addition to no-action and non-wires alternatives, another type of alternative that an analysis of costs and benefits should consider is one that involves GETs. The Commission is well aware of the function and potential of GETs,[166] and, as recent research has made clear, they hold great potential for improving the efficiency of transmission capacity.[167] Any analysis of proposals to meet identified transmission needs should consider those that involve GETs even if they are more complex and costly because their more sophisticated capabilities could still make them the more *net*-beneficial alternative.

Sixth, the analysis should account for uncertainty, strategic behavior of market participants, and resilience to disruptive events.[168] Transmission needs and the effects of transmission capacity are complex. Good cost-benefit analysis should not shy away from that complexity, as doing so guarantees a blinkered understanding of proposals' net benefits. In

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[166] Notice of Workshop, *Electric Transmission Incentives Policy Under Section 219 of the Federal Power Act*, Docket Nos. RM20-10 & AD19-19 (Apr. 15, 2021); *see also* Managing Transmission Line Ratings, 173 FERC ¶ 61,165 (2020).

[167] *See, e.g.*, T. BRUCE TSUCHIDA, STEPHANIE ROSS & ADAM BIGELOW, BRATTLE GRP., UNLOCKING THE QUEUE WITH GRID-ENHANCING TECHNOLOGIES: CASE STUDY OF THE SOUTHWEST POWER POOL 4–12 (2021) (prepared for WATT Coalition) (describing functions and potential benefits of advanced power flow control, dynamic line ratings, and topology optimization for efficient renewables integration).

[168] For greater detail on these factors, see *supra* Part III.

practical terms, this means that good cost-benefit analysis should, at minimum, consider and, ideally, value these three categories of effect. The importance of incorporating these categories into assessments of transmission's value has been recognized for years, and several tools and techniques have been developed to help do so.[169] However, those tools only feature in the approaches currently taken by *some* entities engaged in planning for *some* categories of transmission project.[170] Resilience, which poses particular challenges,[171] is especially neglected in these approaches.[172] Given the obvious relevance of uncertainty, strategic behavior, and resilience to the need for and value of transmission solutions, the Commission should insist that standardized tools be adopted to account for each. Failing to incorporate consideration of these factors into assessments of transmission proposals leaves large blind spots, all but guaranteeing that project selection will fail to reflect projects' true net benefits.

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[169] *See, e.g.*, NAT'L ACADS. OF SCI., ENG. & MED., ENHANCING THE RESILIENCE OF THE NATION'S ELECTRICITY SYSTEM (2017) (describing transmission system vulnerabilities and options for improving resilience to disruption); PFEIFENBERGER & CHANG, *supra* note 5, at 17–20 (describing the need to deal with uncertainty in order to conduct proactive transmission planning); Mohamed Awad et al., *Economic Assessment of Transmission Upgrades: Application of the California ISO Approach* (2007) (discussing consideration in CAISO's transmission assessment rubric of strategic behavior by generators, uncertainty, and value of transmission as insurance against extreme events, among other factors).

[170] *See, e.g.*, PFEIFENBERGER, *supra* note 51, at 20–23 (noting limits of probabilistic weighting and simplistic "least regrets" planning, and proposing approach that identifies maximum losses from a give proposal across planning scenarios).

[171] MURPHY ET AL., *supra* note 142, at v ("Given the complexity of resilience analyses and mitigation strategies, there is limited value in attempting to identify a single resilience metric, as no one metric can quantify resilience or its associated value for all stakeholders. Instead, a necessary focus of the research community should lie in implementing, testing, and validating resilience metrics and analysis approaches in energy sector models, which will be invaluable for informing resilience planning and investment decisions.").

[172] *See* GOGGIN, *supra* note 5, at 5 ("[T]ransmission's value for making the grid more resilient against severe weather and other unexpected threats is not typically accounted for in transmission planning and cost allocation analyses. Grid operator transmission planning processes typically assume normal electricity supply and demand patterns, and in most cases do not account for the value of transmission for increasing resilience.").

C. Use of Cost-Benefit Analysis for Project Selection Would Facilitate Better Cost Allocation Decisions

Some of the main challenges for allocating transmission costs according to the six principles set forth in Order 1000[173] flow from the lack of routine application of a nationally uniform cost-benefit analysis at the project selection stage. While such an analysis would not itself identify beneficiaries, nor trace how benefits accrue to them, by standardizing which benefits are considered and how they are estimated, it would sweep away a long list of potential points of disparity or dispute for parties that are arguably beneficiaries to the proposed project, even if the project were to cross several administrative boundaries. Consequently, the Commission should view the prescription of a cost-benefit analysis at the project selection stage as a step toward realizing Order 1000's principles for cost allocation and facilitating compliance with the circuit court decisions that have fleshed out what exactly the Commission must do when making or authorizing a particular transmission cost allocation decision.[174]

V. The Commission Should Use Postage Stamp Allocation for Costs Associated with Societal Benefits and Public Goods like Emissions Reductions and Resilience

Because emissions reductions and enhanced resilience are economic benefits to ratepayers, utilities, and society,[175] they should—like any other economic benefit that a planning entity might consider in assessing transmission projects—be weighed in the project selection process. And, in keeping with the "beneficiary pays" principle, the costs incurred to garner these

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[173] Order No. 1000, *supra* note 22, at PP 585–87.

[174] *See* Old Dominion Elec. Coop. v. FERC, 898 F.3d 1254, 1261 (D.C. Cir. 2018) (rejecting Commission approval of a tariff amendment that confined allocation of benefits of high voltage lines to subset of regional entities); Ill. Com. Comm'n v. FERC, 756 F.3d 556 (7th Cir. 2014) (finding fault with Commission's lack of empirical justification for allocation of costs of high voltage lines); Ill. Com. Comm'n v. FERC, 721 F.3d 764, 780 (7th Cir. 2013) (rejecting Commission's refusal to authorize allocation of costs beyond MISO region for project authorized by and built within MISO); Ill. Com. Comm'n v. FERC, 576 F.3d 470 (7th Cir. 2009) (rejecting FERC's cost allocation decision as inadequately supported by evidence of benefits accruing to parties to whom costs were allocated).

[175] CHANG ET AL., *supra* note 42, at iii & tbl.ES-1.

broadly distributed benefits should be allocated as broadly as possible. This approach would be consistent with how the Commission has treated other societal benefits and public goods yielded by transmission investments, principally enhanced reliability. For reasons explained below, these benefits should be treated in the same way that the Commission has treated reliability benefits of transmission. That is, costs incurred to realize them should be socialized using a "postage stamp" cost allocation method, which assigns costs to each utility in a region based on its share of regional load.[176]

A. The Commission Has Previously Allowed Costs Associated with Societal Benefits and Public Goods to Allocated on a Postage Stamp Basis

Where the Commission can demonstrate that benefits accrue very broadly and on a roughly equal prospective basis, the postage stamp approach is consistent with the beneficiary-pays and cost-causation principles that guide the Commission under the FPA in the transmission context. This does not run afoul of courts' reading of the FPA as requiring the allocation of transmission costs to be "roughly proportionate to the anticipated benefits to a utility of being able to use the grid."[177] Rather, it applies this principle to a particular class of benefits. Thus, when courts have also affirmed FERC's approval of cost allocations that socialize some of a project's costs, they have characterized that approval as an application of the cost-causation principle to an instance where benefits are broadly distributed to all utilities and consumers on the grid. The primary example—but not the only—example of this sort of allocation has been the socialization of costs for projects that provide broad reliability benefits.

[176] Rivier et al., *supra* note 39, at 294 ("When the benefits of a transmission project are very widely distributed, it might be reasonable to 'socialize', i.e., to apply a flat charge to recover the project costs. Note that this does not mean abandoning the principle of beneficiary pays. Cost socialisation is in this case a good approximation to allocation to beneficiaries.").

[177] Ill. Com. Comm'n v. FERC ("*ICC v. FERC 2013*"), 721 F.3d 764, 771 (7th Cir. 2013).

The Commission has approved, and courts have upheld, postage stamping of costs for high-voltage transmission line projects because those projects were shown to deliver significant benefits across the entire planning regions.[178] According to the U.S. Court of Appeals for the Seventh Circuit, RTOs and the Commission may "presume . . . that new transmission lines benefit the entire region by reducing the likelihood or severity of outages," and allocate the benefits accordingly—that is, to all member utilities in proportion to their total consumption.[179] Relatedly, courts have recognized that not all benefits are easily quantifiable and may be uncertain,[180] and that the Commission may not be able to exactly match project costs to benefits with these characteristics. "If crude [cost allocation] is all that is possible, it will have to suffice."[181] If, however, the Commission decides to allocate costs across the entire region rather than calculating the particular benefits that accrue to each utility, then it must provide an "articulable and plausible reason" for doing so.[182] It must put in "some effort . . . to quantity the benefits" and justify its view that high-voltage power lines will benefit the entire grid.[183] Thus, where benefits are difficult to quantify, uncertain, or both, but the Commission offers a clear and supported rationale for finding that such benefits will accrue to some degree to all utilities and consumers in a region, a postage stamp allocation may be just and reasonable.[184]

Illinois Commerce Commission v. FERC (2013) offers an example of a court accepting FERC's rationale for postage stamping transmission costs where the benefits would accrue

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[178] *Id.* at 773–76; Old Dominion Elec. Coop. v. FERC, 898 F.3d 1254, 1261–62 (D.C. Cir. 2018).

[179] *ICC v. FERC 2013*, 721 F.3d at 775 (quoting Ill. Com. Comm'n v. FERC ("*ICC v. FERC 2009*"), 576 F.3d 470, 477 (7th Cir. 2009)); *id.* at 772 (explaining how costs apportioned).

[180] *Id.* at 774–75.

[181] *Id.* at 775.

[182] *ICC v. FERC 2009*, 576 F.3d at 477.

[183] Ill. Com. Comm'n v. FERC, 756 F.3d 556, 562 (7th Cir. 2014).

[184] *ICC v. FERC 2013*, 721 F.3d at 775.

region-wide and be difficult to specify. In that case, the Seventh Circuit affirmed FERC's approval of MISO's allocation of high-voltage transmission project's costs. MISO concluded that a postage stamp allocation was appropriate because the benefits of its Multi-Value Projects, like reliability, "will benefit all members of MISO and so the projects' costs should be shared among all members."[185] The Seventh Circuit agreed, recognizing that reliability benefits could not "be calculated in advance, especially on a subregional basis, yet are real and will benefit utilities and consumers in all of MISO's subregions,"[186] and that "[i]t's impossible to allocate these cost savings with any precision across MISO members."[187] Notably, the court also chastised the petitioners for "ignoring the limitation on calculability that the uncertainty of the future imposes."[188] In sum, FERC had appropriately approved a cost allocation method that recognized the real and significant reliability benefits of high-voltage projects and dealt with the challenge of estimating the size and incidence of their benefits by simply allocating project costs on a postage stamp or load share basis.

In its 2018 decision in *Old Dominion Electric Co. v. FERC*, the D.C. Circuit dealt with a broadly similar situation and endorsed the appropriateness of postage stamping given the diffuse, region-wide benefits of high-voltage transmission. In that case, FERC chose *not* to allow a postage stamp allocation for the high-voltage power line project at issue, and the court overturned that decision.[189] In previously approving PJM's tariff, FERC had concluded that it was appropriate to apply postage stamping to this kind of project because this allocation

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[185] *Id.* at 773.
[186] *Id.* at 775.
[187] *Id.* at 774.
[188] *Id.*
[189] Old Dominion Elec. Coop. v. FERC, 898 F.3d 1254, 1258 (D.C. Cir. 2018) (discussing PJM's tariff approved in *PJM Interconnection, LLC*, 142 FERC ¶ 61,214 (2013)).

"capture[d] the full spectrum of benefits associated with high-voltage facilities, including difficult to quantify regional benefits, such as improved reliability, reduced congestion, reduced power losses, greater carrying capacity, reduced operating reserve requirements, and improved access to generation."[190] The D.C. Circuit found this reasoning remained persuasive and rejected the Commission's subsequent decision not to allow high-voltage transmission project costs to be allocated regional-wide. It was arbitrary, the court determined, for the Commission *not* to allow this sort of cost-sharing for a high-voltage project, given the project's significant region-wide benefits.[191] Confining the allocation of costs to just a few utilities, according to the court, "produces a severe misallocation of the costs of such projects."[192]

The reliability benefits that have been postage stamped in the past are societal benefits and public goods—non-excludable, non-rivalrous benefits that accrue to all users of the grid and cannot be kept from particular users.[193] For these reasons, the Commission has seen fit to allocate at least some of the costs of these projects broadly to all utilities and their consumers, and courts have found this to be just and reasonable. The same reasoning supports similar treatment of other societal benefits of transmission projects, where those benefits are material, broadly distributed, difficult to quantify, and uncertain.

B. Reductions of Global and Local Pollution Are Societal Benefits that Warrant a Postage Stamp Allocation of Project Costs

The Commission can justify allocating some transmission project costs on a postage stamp basis where those projects will reduce the emissions that contribute to climate change, and

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[190] *Id.* at 1257 (quoting *PJM Interconnection, LLC*, 142 FERC ¶ 61,214, at P 414 (2013)).

[191] *Id.* at 1261–63.

[192] *Id.* at 1261.

[193] PAUL KRUGMAN & ROBIN WELLS, MICROECONOMICS 461 (2d ed. 2009).

where they will reduce the emissions of local pollutants that harm public health directly. This is so even though those projects will be just one link in a causal chain involving: the development and operation of low-cost renewable resources; the displacement of higher-cost emitting ones; the reduction of health-harming local pollutants; and the reduction of global pollutants responsible for the climatic changes that make extreme events more frequent and severe, and thereby pose risks to electricity reliability and to society more generally. Crucially, the sort of transmission capacity contemplated here is an *indispensable* link in that chain—one for which there are few if any cost-effective substitutes.

Postage stamp cost allocation is warranted for projects that reduce greenhouse gas emissions because at the end of the causal chain is the reduction of physical risks to the cost-effective operation of energy system assets,[194] as well as the reduction of the effects of electricity disruption to the individuals, communities, and systems that rely on those assets' reliable and cost-effective operation. Also at the end of that chain is the reduction of the risk that energy system assets will become stranded as energy transition proceeds, driven by policy, consumer preferences, and the cost-profiles of clean technologies.[195] These outcomes fit neatly within the category of benefits defined by circuit courts as being appropriate for socializing costs: material, broadly distributed, difficult to quantify,[196] and uncertain in their timing and incidence. Indeed,

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[194] *See* JUSTIN GUNDLACH & ROMANY WEBB, SABIN CTR. FOR CLIMATE CHANGE L., CARBON PRICING IN NEW YORK ISO MARKETS: FEDERAL AND STATE ISSUES 52–53 (2017) ("The near-term effects of climate change—warmer ambient temperatures, heat waves, less reliable access to water, and more frequent and intense storms—have clear import for system reliability. These effects will impair generation and transmission facility efficiency undermining reliability and creating costs . . . ."); Webb et al., *supra* note 136 (manuscript at 4).

[195] *See* Condon et al., *supra* note 136 (manuscript at 6–9).

[196] The Commission should consider using the Social Cost of Greenhouse Gases to monetize the value of any emissions benefits. As Chairman Glick has oft noted, the Social Cost of Greenhouse Gases is a "direct and accessible means of identifying and quantifying the harm caused by GHG emission." Rich Glick & Matthew Christiansen, *FERC and Climate Change*, 40 ENERGY L.J. 1, 42 (2019). It can also be used to consistently and transparently value the benefit of emissions reductions. *See generally* Comments of Env't Def. Fund et al.,

the Seventh Circuit's 2013 *Illinois Commerce Commission v. FERC* decision that upheld FERC's approval of a postage stamp cost allocation specifically noted that the ability of the projects at issue to access remote sources of wind power benefitted the entire region by, among other things, reducing greenhouse gas emissions.[197]

Similar logic supports the postage stamp allocation of some of the costs of projects that serve as a link in causal chains involving new transmission, renewables, and displaced fossil-fuel generation, and ending with reductions in local air pollution that is responsible for material adverse impacts to public health.[198] The Commission can look to recent research to satisfy the requirement that its allocation of costs related to this type of benefit be grounded in an "articulable and plausible reason"[199] and reflect "some effort . . . to quantity the benefits."[200] A recent study in CAISO concluded that an interconnection between California and Arizona would produce avoided NO_x emissions worth $2.2 million.[201] And a recent economics paper presented a methodology for determining and monetizing the local air pollution benefits of transmission projects for use in a cost-benefit analysis and cost allocation.[202] That local air pollution benefits will depend on the existing generation mix of the system does not change this basic conclusion. Where a transmission project will cause the displacement of emitting generators in a region, the

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Certification of New Interstate Natural Gas Facilities, Docket No. PL18-1 (May 26, 2021) (urging the Commission to use the social cost of greenhouse gases in assessing the impacts of a natural gas project's emissions).

[197] Ill. Com. Comm'n v. FERC, 721 F.3d 764, 772 (7th Cir. 2013) ("There is no reason to think these benefits will be denied to particular subregions of MISO.")

[198] CHANG ET AL., *supra* note 42, at 54 (2013).

[199] Ill. Com. Comm'n v. FERC, 576 F.3d 470, 477 (7th Cir. 2009).

[200] Ill. Com. Comm'n v. FERC, 756 F.3d 556, 562 (7th Cir. 2014).

[201] Deniz Sun et al., *Considering Local Air Pollution in the Benefit Assessment and Cost Allocation of Cross Border Transmission Projects*, 13 ENERGIES, 2020, at 3; *see* CHANG ET AL., *supra* note 42, at 54.

[202] *See generally* Sun et al., *supra* note 201, at 201.

resulting public health benefits can be identified and should be considered in a cost-benefit analysis and the cost allocation process.

Given that these health benefits are distributed, the Commission could reasonably opt to socialize the costs associated with producing them. It is also particularly important that projects with local air pollutant benefits move forward because reduced criteria pollutants will significantly benefit environmental justice communities, which are likely to be located near emitting generators and to have chronic health conditions that are worsened by even low levels of criteria pollutants.[203] These benefits may also be significant for regions that are not in attainment with the Clean Air Act's National Ambient Air Quality Standards (even if an individual facility is not violating its permits), where improved air quality would benefit all ratepayers. President Biden's Executive Order 14,008 calls on all agencies to seriously consider and address impacts on environmental justice communities.[204] The Commission has already begun to heed this call in initiating reforms to its natural gas infrastructure certification policy, where it sought public input on how it could better identify, assess, and address impacts to environmental justice communities.[205] The Commission should do the same here by considering how transmission expansion can benefit already overburdened communities by reducing local air pollution.

C. Enhanced Resilience Is a Societal Benefit and Public Good that Warrants Postage Stamp Allocation of Project Costs

Finally, as it does with reliability-enhancing projects, the Commission should also require planning entities to socialize at least some of the costs of regional and interregional transmission

[203] *See generally* Natural Gas Policy Statement Comments, *supra* note 140, at 54–56.

[204] Exec. Order No. 14,008 § 219 (2021).

[205] Notice of Inquiry, Certification of New Interstate Natural Gas Facilities, 174 FERC ¶ 61,125, at PP 20–22 (2021); *see also* Natural Gas Policy Statement Comments, *supra* note 140, at 45–56.

projects that can be shown to yield resilience benefits. Resilience, like reliability, is an important aspect of system health—it is the grid's ability to resist, absorb, and recover from high-impact, low-probability events.[206] Improvements to the resilience of the transmission system can enhance grid resilience overall, improving the system-wide ability to absorb and resist shocks, manage disruptions, and recover quickly.[207]

There is no single measure of resilience, which is estimated using various metrics, such as system or asset performance (e.g., cumulative hours of customer outage), or system attributes (e.g., how hardened the system components are to high winds).[208] In general, calculating the benefits of resilience from transmission involves quantifying the probability-weighted costs of disruptions, and then estimating how much the addition of a transmission asset would reduce those costs.[209] Although it will be difficult to quantify with certainty the value of resilience benefits that new transmission projects may provide, regional and interregional transmission capacity is generally a source of such benefits, and these benefits will become increasingly important as a changing climate makes extreme events more frequent and intense.[210] As the resilience benefits of regional and interregional transmission are generally significant,

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[206] TOWARD RESILIENCE REPORT, *supra* note 46, at i.

[207] *See* Comments of the Institute for Policy Integrity at New York University School of Law at 9, *Climate Change, Extreme Weather and Electric System Resilience*, Docket No. AD21-13 (Apr. 15, 2021); Comments of the Institute for Policy Integrity at New York University School of Law at 31, *Grid Resilience in Regional Transmission Organizations and Intendent System Operators*, Docket No. AD18-7 (May 9, 2018); TOWARD RESILIENCE REPORT, *supra* note 46, at 9–10 (noting that planners should evaluate the effect of resilience enhancements on the electricity system as a whole, that is, they should look at system resilience in assessing whether an action is economically justified).

[208] TOWARD RESILIENCE REPORT, *supra* note 46, at i; *see also* Comments of the Institute for Policy Integrity at New York University School of Law at 8–9, *Grid Reliability and Resilience Pricing*, Docket No. RM18-1 (Oct. 23, 2017).

[209] TOWARD RESILIENCE REPORT, *supra* note 46, at 15. For a detailed framework for how to calculate the benefits of resilience investments, see *id.* at 15–19.

[210] *See* GOGGIN, *supra* note 5; *see generally* Transcript of Technical Conference to Discuss Climate Change, Extreme Weather, & Electric System Reliability, Docket No. AD21-13 (June 2, 2021); Transcript of Technical Conference to Discuss Electrification of the Grid of the Future, Docket No. AD21-12 (Apr. 29, 2021).

widespread, but difficult to predict or specify, the Commission should consider using a postage stamp allocation method for the costs of resilience-enhancing assets.

VI. Conclusion

An efficient electric transmission network is essential for low-cost and reliable electricity provision, and the design and reach of the U.S. transmission network will be critical to realizing the benefits made available by changing technologies. The importance of the Commission's role in steering transmission system development over the coming years cannot be overstated. Because present approaches to transmission planning and cost allocation evidently do not support development of the regional and interregional transmission capacity that could unlock significant benefits for consumers and society as a whole, the Commission must act. Specifically, it must imbue these elements of transmission development with a national perspective and place regional and interregional transmission projects on equal competitive footing with local ones. Such reforms would be entirely in keeping with the aims and logic of Commission Orders 888, 889, 890, and 1000, and would help to ensure that rates are just and reasonable, and not unduly discriminatory or preferential, while also helping to ensure reliability in the bulk power system.

Respectfully submitted,

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Dated: October 12, 2021

CERTIFICATE OF SERVICE

In accordance with Rule 2010 of the Commission's Rules of Practice and Procedure, I hereby certify that I have this day served by electronic mail a copy of the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 12th day of October 2021.

Respectfully Submitted,

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