UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF NRG ENERGY, INC.

NRG Energy, Inc. submits the following comments to the Federal Energy Regulatory Commissions ("the Commission") in response to the April 21, 2022 Notice of Proposed Rulemaking ("NOPR").[1]

I. INTRODUCTION

NRG is one of the largest competitive retailers of electricity supply in the United States by customer count and by volume, participating in the wholesale markets that the Commission regulates to buy the energy, transmission services, and other products that are necessary to serve retail customers. Through its state-approved operating licenses, NRG provides retail electricity service to approximately 10% of the total volume in the service territories of restructured utilities located in PJM, NYISO, and ISO-New England, with a lesser share of markets like CAISO and MISO that are not fully open to retail competition. We serve about 6 million customers.

A significant amount of consumer demand in all these markets continues to be served by affiliates of transmission owners, who make additional profits through increased capital investment in transmission on the one hand and are able to pass through any increases in

[1] *Building for the Future Through Electric Regional Transmission Planning and cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028, Docket RM21-17-000, (issued April 21, 2022) ("NOPR").

transmission costs through cost-of-service regulation to their retail customers on the other. Many competitive-retail contracts for large customers also have pass-through clauses for transmission cost. However, NRG directly bears responsibility for transmission costs for many of its customers, especially residential and small-commercial customers, and lacks the ability to immediately adjust its retail prices to recover incremental costs imposed by regulation. As such, NRG is one of the few parties the Commission will hear from in this proceeding—other than consumers themselves—who actually bears the risk of increases in transmission costs.

II. SUMMARY

In virtually all the markets NRG serves, the rates for the distribution and transmission of energy have been rising. To give the Commission a sense of these changes over time, NRG has commissioned a comprehensive analysis, comparing these delivery charges, at rates set by regulation by the Commission and by state utility commissions, with the rates for energy-supply services. The full analysis is being separately filed with the Commission in this proceeding.[2]

Over the previous decade, through 2021, regulated rates for delivery costs in the three restructured eastern RTOs/ISOs ("ISOs") rose between 27 percent and 46 percent for residential customers. Meanwhile, the rates for energy supply fell during this period.[3]

ISO Level Analysis Results for the Residential Customer Class

Generation v Delivery Price Change for Residential Customer Class by ISO				
	Generation		Delivery	
ISO	Total % Change in the Price for Analysis Period	Compounded Annual Growth Rate ("CAGR") for Analysis Period	Total % Change in the Price for Analysis Period	Compounded Annual Growth Rate ("CAGR") for Analysis Period
NEISO	(7.05%)	(1.43%)	27.41%	4.03%
NYISO	(15.96%)	(2.22%)	31.83%	3.47%
PJM	(23.06%)	(3.13%)	46.08%	3.76%

[2] *Historical Tariff Analysis, Generation v Delivery NEISO, NYISO, & PJM* by Intelometry, Inc. (August 2022).
[3] The rates for energy-supply, or generation, are measured for this analysis by restructured utilities' benchmark rates, variously called basic, default, or standard-offer service.

ISO Level Analysis Results for the Small Commercial Customer Class

Generation v Delivery Price Change for Small Commercial Customer Class by ISO				
	Generation		Delivery	
ISO	Total % Change in the Price for Analysis Period	Compounded Annual Growth Rate ("CAGR") for Analysis Period	Total % Change in the Price for Analysis Period	Compounded Annual Growth Rate ("CAGR") for Analysis Period
NEISO	(10.66%)	(2.51%)	20.70%	3.32%
NYISO	(22.61%)	(3.23%)	36.37%	2.92%
PJM	(23.78%)	(3.53%)	46.57%	4.49%

In the face of these rising delivery costs, the Commission's posture in this proceeding is to assert the rates for delivery that it is responsible for may be unjust and unreasonable—because they have not been rising enough. This counterintuitive proposition is rooted in the Commission's belief that there are certain investments in regional transmission projects that would reduce otherwise higher costs in generation and other, more local transmission. We recommend caution when it comes to substituting the outcomes of a competitive market where power generators, demand response providers, distributed energy resources, retailers, and other market participants make investments on their own dime based on their view of their positions' usefulness in serving consumers. By contrast, what the Commission is proposing is an administrative process whereby a transmission developer has only to capture the assent of a bureaucrat or regulator in a collective planning process before availing itself of cost allocation to involuntary counterparties. These two models are in conflict with one another. The Commission's NOPR would have the effect of sweeping away the value of many private investments with a centrally planned, cost-socialized approach to the energy future—one that is no doubt founded on at least some assumptions that are wrong, as we empirically observe from prior transmission-planning efforts discussed later in these comments.

Consequently, NRG opposes the Commission's proposal to use long-term, speculative forecasts of transmission needs as a basis to justify investments that will be paid for through involuntary cost allocation. On projects where the main benefits consist of interconnecting new, economic or public-policy resources to the grid, the Commission should expect cost allocation to be voluntarily undertaken and priced into energy projects' costs through an open season process.[4] Since many such energy projects are being developed at the behest of state policy or are otherwise economical, especially in light of the extension and expansion of significant federal tax subsidies, the cost to interconnect these projects to the grid can be and should be part of the cost to develop such projects, paid for by those projects' off-takers or investors, and not through an indiscriminate allocation to consumers. It is not unreasonable to expect that these transmission costs, like all other project-development costs, can be incorporated within the bilateral commercial terms of a power purchase agreement. Meanwhile, establishing this expectation for electric transmission would contour the Commission's regulation in this space with its regulation of natural-gas transmission, where an open season and voluntary subscriptions represent a long-standing form of cost allocation for initial capital investments. To the extent resources are developed directly in relation to public policy requirements, NRG supports the Commission's attempt to involve state regulators in decisions on cost allocation, if such decisions must be made and costs imposed on involuntary consumers.

Meanwhile, NRG opposes the Commission's proposal to abolish competition in one of the few spaces in electric transmission that exists. The Commission has negligently allowed electric transmission rates to go effectively unregulated, even while the space remains largely monopolized. In its instant proposal the Commission now complains that the attractive nuisance

[4] Sometimes called "merchant" transmission lines.

it has built induces capital investment to the many unregulated-but-monopolized opportunities in the electric-transmission industry, rather than to the solitary corner of the industry reserved for competition. This sorry outcome was foreseen even as the Commission issued its last major reform in transmission planning, and the Commission's proposal here is not a remedy but a capitulation. The Commission's proposal on the federal right of first refusal should be withdrawn, and the Commission should begin to take steps to enforce competition and to actively regulate electric-transmission rates for which it has jurisdiction.

With respect to the one item the Commission proposes that resembles a traditional customer protection, NRG supports the Commission's wise proposal to prohibit Construction Work in Progress ("CWIP") from inclusion in the rates that customers pay, even before related transmission investments provide those customers any service whatsoever. The Commission's proposal here is a return to well-founded first principles of economic regulation. NRG supplements the record by providing additional rationale that allows the Commission's CWIP proposal to be adopted even if other parts of the NOPR, to which the NOPR purports to make its CWIP reasoning dependent upon, are not adopted.

Finally, NRG is generally supportive of the Commission's proposal for enhanced transparency in local transmission planning, but proposes that a rate forecast be included as an additional and useful piece of information in this exercise. The Commission makes various transmission-planning proposals in the name of just and reasonable rates, and it seems only reasonable that at the ground level the Commission require of transmission providers an actual estimation of transmission customer rate impacts in the local planning process. Meanwhile, we have no comments on the Commission's sparse proposal in relation to interregional coordination, except to note that various interregional projects are currently being pursued outside the

Commission's formal planning process, through voluntary cost allocation, in a way that is harmonic with the market for generation.

For easy reference to our positions in this matter, NRG includes the following table on each of the six categories of reform the Commission has proposed.

Commission Proposal	**NRG Position**	**Qualification of NRG Position**
Regional Transmission Planning	Oppose	A 20-year planning horizon should be allowed only for purely informational purposes and not as a basis to mandatorily allocate investment costs. Instead, a 10-year maximum planning horizon is appropriate to the extent involuntary cost allocation is necessary.
Regional Transmission Cost Allocation	Oppose	The Commission should refocus on voluntary cost allocation, which is actively being pursued by a number of major projects. NRG supports a role for states on transmission projects selected in a plan that would not exist but for state public policy and for which mandatory cost allocation is unavoidable.
Construction Work in Progress Incentive	Support	The Commission's proposal has numerous additional justifications and does not depend on the Commission's decision on an appropriate planning horizon. The Commission's proposed interpretation of an unrelated administrative regulation allowed for partial recovery of CWIP is unreasonable and should be clarified and rescinded.

Federal Right of First Refusal	Oppose	The Commission should withdraw its proposal and instead eliminate formula ratemaking and other aspects to its regulatory scheme that have caused transmission developers to avoid regional projects. If it adopts its ROFR proposal, the Commission should limit it to those filers who are free of any potential financial advantage that would be conferred by reinstating the ROFR.
Local Transmission Planning	Support	Additionally, the Commission should include a requirement for local transmission planning to forecast the rates that would result from the implementation of its plan.
Interregional Transmission Coordination and Cost Allocation	No position	Numerous interregional projects that are pursuing a business model of voluntary cost allocation outside the Commission's formal planning regulations suggest significant progress on efficient solutions in this space without Commission involvement.

III. COMMENTS

A. REGIONAL TRANSMISSION PLANNING

The NOPR proposes that transmission providers use a 20-year planning horizon, consisting of at least 4 plausible and diverse long-term scenarios, with assumptions updated at least every 3 years.[5] In addition, the scenarios must incorporate a broad range of factors in the analysis, including local laws and regulation, integrated resource plans ("IRPs"), trends in

[5] NOPR at P 91.

technology and fuel costs, and interconnection requests.[6] NRG urges caution on over reliance of any 20-year planning study for making transmission investments due to the inherent uncertainty of a study with such a long planning horizon.

The electric grid is on the brink of momentous change. The amount of electrification and resulting load requirements (and the shape of those requirements), technology costs for new resources, and the viability and repurposing of existing resources all weigh on the outcome of the energy transition. In light of the uncertainty of any of these variables, it is not clear whether a "no regrets" option genuinely exists given the range of future options. The planning the Commission proposes contemplates a central determination of particular actions that are economically justified to be taken in relation to a set of collectively determined assumptions. Even in the presence of numerous scenarios, this gives up a major advantage of competition, which is the requirement that market participants take an individual view based on available information of the future viability of any investment they might make. Giving up "that decentralized information advantage of markets is not without costs," as a recent publication by Resources for the Future on electric transmission planning has observed.[7] The Commission has not seriously contemplated that trade-off, much less quantified its costs. Notably, past long-term planning studies have done a questionable job at forecasting future needs, even in the presence of variables that were arguably not as uncertain and volatile as the ones grid planners face today.

[*continued on next page*]

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[6] I*bid.* at P 104.
[7] Timothy J. Brennan, "Is Transmission Expansion for Decarbonization Compatible with Generation Competition?", Resources for the Future, Working Paper 22-12 (August 2022) p. 3.

1. Transmission planners that use a 20-year forecast acknowledge uncertainty and do not use them to authorize investment decisions that will be charged to captive ratepayers.

On the point of the appropriate range of forecasting, some ISOs do currently perform 20-year planning studies, but have recognized the inherent limitations in their outcomes. SPP uses their 20-year study to inform, but not drive, transmission decision-making[8] and CAISO's May 2022 20-year plan is not meant to drive specific project approvals but instead "is meant to engage with stakeholders in more informal yet meaningful discussion."[9] Both of these ISOs recognize the inherent uncertainty that goes with any plan of this study length and properly limit how the study is meant to be used. However, despite this recognition of inherent uncertainty, neither CAISO nor SPP fully addresses and values changes in the range of uncertainties over that period and the need for flexibility and optionality in developing both transmission and non-transmission alternatives in achieving policy goals.

NRG is not opposed to the voluntary use of 20-year planning studies to inform shorter term transmission decision-making, but does not believe that reliance on 20-year transmission planning to drive investment decisions will lead to just and reasonable outcomes. A shorter-term assessment of 10-years would be more certain, fit within the planning horizon necessary to make transmission investment decisions, and still reflect regional policy goals. Longer-tenor expectations can and should be made by state policymakers or private actors, taking on transmission as part of energy-project development costs and priced into power purchase agreements, as we describe in the next section of these comments concerning cost allocation.

[8] *Ibid.* at P 48, fn 88.
[9] California Independent System Operator, *20-year Transmission Outlook* (May 2022), p. 5.

2. A retrospective analysis of transmission planning studies demonstrates that long-term forecasts of important variables are often wrong.

While the NOPR recognizes that a 20-year transmission study will have "inevitable uncertainty" it nonetheless states that there are a number of factors that are "known in advance and have reasonably predictable effects."[10] A closer look at some of the factors to be used in any 20-year planning study and the results of past long-term planning studies do not find this to be the case. Predictions for the future price of natural gas and thus the economics of gas generation in long-term forecasts have been notoriously inaccurate. Work done by Lawrence Berkeley National Laboratory that reviewed long-term natural gas price forecasts performed by the U.S. Department of Energy in its Annual Energy Outlook since 1985 found that they "have significantly missed their mark" with some forecasts being very high (1985-1986 forecasts had 15 year forward prices over $7/MMBTU and 2008 forecasts predicted prices remaining above $6/MMBTU for 10-years) and others being low (1996 to 2001 forecasts projected long-term prices remaining below $3/MMBTU).[11] Projecting future loads is also inherently inaccurate; the California Energy Commission's 2021 Integrated Energy Policy Report ("IEPR") forecasts 2035 managed system peak demand in the CAISO of anywhere from 45 to 58 GW, with the uncertainty growing significantly as the timeframe is extended.[12]

These "misses" predicting the future have real-world implications on customers. In the east, PJM relied on a 15-year look-ahead to propose, approve, and subsequently halt work on certain significant and high-profile backbone transmission projects. As described below, the reversal came about after several years of planning and preparation were underway. While the

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[10] NOPR at P 51.

[11] Lawrence Berkeley National Laboratory, *Comparison of AEO 2008 Natural Gas Price Forecast to NYMEX Futures Prices* (January 2008).

[12] California Energy Commission, *Final 2021 Integrated Energy Policy Report, Volume IV: California Energy Demand Forecast* (February 2022), p. 24.

region's customers were spared the full cost of these projects, it is notable that customers have been on the hook for the costs incurred by the utilities for the abandoned projects for several years. The Mid-Atlantic Power Pathway ("MAPP") was approved as part of PJM's Regional Transmission Enhancement Plan ("RTEP") in 2007. By 2011, PJM had alerted the transmission utility responsible for building the line that the project was no longer needed due to the RTO's latest analysis.[13] Similarly, the Potomac Allegheny Transmission Highline ("PATH") was approved in 2007 for development to address predicted reliability issues. PJM reaffirmed the need for the project in 2010 for an anticipated in-service date int 2015.[14] As with the MAPP project, by 2011 PJM directed the utilities responsible for the project's development to halt work and subsequently cancelled the project in 2012. In the case of both MAPP and PATH, customers may have avoided a multi-billion dollar price tag, but were still responsible for tens of millions in costs. These examples demonstrate how quickly the inputs and underpinnings relied upon to support major transmission projects can change.

Determining what technologies will be deployed to meet future loads is another area fraught with considerable uncertainty, which past studies have failed to accurately forecast. The California Public Utilities Commission initiated the Renewable Energy Transmission Initiative ("RETI") in 2008-2010[15] to forecast the locations most attractive for renewable development to meet long-term renewable energy goals. At the time, the most economic technologies were found to be wind and geothermal, with study recommendations made to prioritize development and interconnection in regions of the state with those resources. Solar technologies at the time were

[13] Potomac Electric Power Company. United States Securities and Exchange Commission Form 8-k. August 18, 2011. https://www.sec.gov/Archives/edgar/data/79732/000113597111000079/aug19pepco8-k.htm
[14] "PJM approves $1.25 B in transmission upgrades." Reuters. December 2, 2010. https://www.reuters.com/article/utilities-pjm-transmission/pjm-approves-1-25-b-in-transmission-upgrades-idUSN0220688620101202
[15] Black & Veatch Corporation, *Renewable Energy Transmission Initiative Phase 2B Final Report*, May 2010.

significantly more expensive than they are today (utility scale PV was priced at $4 to $7/W in the study, compared to <$1/W today) with debate over whether solar thermal or solar PV technologies should be prioritized. If that study was used to prioritize and develop new transmission for California in 2008, it would have placed an emphasis on geothermal and solar thermal development, while disfavoring solar PV and battery projects that the CAISO queue now reflects (the use of battery technology was not even considered at the time). In other words, if the reforms the Commission is proposing here had been in effect, the outcome indeed may have been regrettable, and might have spawned a series of transmission and generation investments that were not economic but were constructed because of a *Field of Dreams* ideation,[16] albeit undertaken by independent system operator bureaucrats with costs broadly socialized, and not Kevin Costner's character on his own dime.

Similar to the crossroads that the RETI project found California to be in back in 2010, many parts of the U.S. grid face a wide range of technology options with great uncertainty for which will be most economic or effective to meet future needs. Questions abound pertinent to what emerging technologies will become cost-effective (offshore wind, small modular nuclear, enhanced geothermal, etc.), the type and duration of storage that is needed (lithium-ion, flow batteries, pumped storage, compressed air energy storage, etc.), the breadth and impact of distributed resources which may greatly reduce the need for new transmission, and, in states with aggressive greenhouse gas reduction goals, how natural gas will play a role in the future electric grid. This leads to uncertainty that will make any 20-year transmission assessment fraught with significant inaccuracy. In a competitive market, estimates of each of these variables are important—but they need not be uniform or centrally governed. Indeed, a distinguishing feature

[16] "If you build it, [they] will come." *Field of Dreams*, Robinson, P.A. (Director), Universal Pictures, (1989).

of competition is that it "provides a means to reward entrepreneurs for finding and acting on private information to discover new markets, reduce costs, and deploy innovative technologies." What the Commission is proposing in a "collective planning" exercise and "the opposite" of competition.[17]

3. The Commission's reliance on MISO's Multi-Value Projects as a universally reliable example is inapposite.

The NOPR highlights the MISO Multi-Value Projects ("MVP") process which identifies a portfolio of "no regrets" transmission projects that can provide benefits under all the alternate future scenarios studied.[18] It is unclear to NRG, given the range of uncertainty in a 20-year transmission forecast, if a "no regrets" transmission plan exists that can be enhanced by a long-term planning assessment. For example, in the range of CAISO load forecasts developed in the 2021 CEC IEPR, a study planning for low end of peak load growth would likely recommend little to no new transmission development. Technology breakthroughs in distributed technologies and significant changes to customer demand profiles could greatly reduce new transmission needs, which may conflict with transmission builds forecasted in what may be categorized as a "no regrets" scenario. Load serving entities in California forecasted resource needs in their 2020 IRP only through 2030; concrete policy goals are well defined through 2030 (60 percent RPS) while considerable uncertainty exists for what actions will be taken beyond 2030 to meet long-term goals. It would be useful for ISOs and regional groups that have used long-term studies to inform transmission development, such as MISO and WECC, to determine if past long-term studies did in fact produce "no regrets" study results which are still practical today. This type of lookback can determine the efficacy of past transmission assessments and help inform the

[17] Brennan, RFF, p. 11.
[18] NOPR at P 31.

planning window that may be most practical moving forward. While MISO states that it adopts a no-regrets approach to planning around a set of given scenarios, these scenarios include exogenous levels of Distributed Energy Resources ("DER"), rather than including DER among the transmission alternatives. This makes it difficult to definitively conclude that MISO's MVP process was a no-regrets approach.

4. The Commission should limit the use of speculative, long-term forecasting as a means to justify investments that will be paid for through involuntary cost allocation, and the Commission should instead prioritize voluntary cost allocation and competition.

Given the significant uncertainty inherent in a 20-year transmission planning forecast, NRG recommends

- a shorter term analysis (10-years) for informing transmission planning, and
- to the extent a 20-year forecast is to be used, it solely be used for informational purposes and not be the basis for investment decisions.

As outlined in the NOPR, priority for transmission development should remain on near-term reliability and economic transmission needs.[19] Transmission investments that are justified on the basis of long-range forecasts, with their costs paid for by involuntary cost allocation, differ fundamentally from investments in technology solutions—both distributed and utility-scale—that are made by market participants staking their capital at genuine risk of their investment's value over its lifetime. Employed widely, the former approach can box out the latter. NRG suggests that it should be the Commission's objective, as much as possible, to ensure that transmission investors are standing behind the basis of their own investments—something that can be done by truncating the forecast period for which involuntary cost allocation is employed, while also ensuring voluntary cost allocation through an open season exists as the normal course

[19] NOPR at P 89.

of paying for transmission costs to interconnect new energy projects and providing for competition in transmission where possible.

B. LONG-TERM REGIONAL TRANSMISSION PLANNING COST ALLOCATION MATTERS

The Commission proposes two significant changes to the methods for cost allocation utilized by transmission providers to support Long-Term Regional Transmission Planning. First, the Commission proposes to require that public utility transmission providers in each transmission planning region seek the agreement of relevant state entities within the transmission planning region regarding the cost allocation method or methods that will apply to transmission facilities selected in the regional transmission plan.[20] Second, the Commission proposes to require public utility transmission providers in each transmission planning region to add a time period for states to negotiate an alternate cost allocation method for a transmission facility selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning.[21]

The involvement of state entities is a laudable reform that the Commission should adopt, in a more focused and productive way that NRG below recommends. However, at a higher level, NRG recommends the Commission take a step back from its apparent viewpoint that involuntary cost allocation to possibly unwilling consumers is the *sine qua non* of transmission policy. Indeed, it is not at all how transmission policy works in the other major network industry, natural gas pipelines, that the Commission regulates. Nor is it how practically any other network industry economically regulated or priced in the United States today. The Commission should

[20] NOPR at P 278.
[21] *Ibid.* at P 279.

instead focus on trying to arrive at plausible solutions for voluntary cost allocation to interconnect new energy resources to transmission, such as through open seasons.

1. Involuntary cost allocation should not be used as a substitute to participant-funded interconnection and transmission expansion.

As described by the Commission, the NOPR envisions reforms to "require public utility transmission providers to conduct long-term regional transmission planning on a sufficiently long-term, forward-looking basis to identify and plan for transmission needs *driven by changes in the resource mix* and demand."[22] To this end, the Commission proposes that "public utility transmission providers in each transmission planning region identify transmission needs driven by changes in the resource mix and demand through the development of Long-Term Scenarios,"[23] where Long-Term Scenarios "identify transmission needs driven by changes in the resource mix and demand, and enable the evaluation of transmission facilities to meet such needs."[24]

The Commission's repeated emphasis on the "resource mix" suggests that these new generators are an exogenous force that must be accommodated through a central planning exercise and an allocation of costs to consumers. It need not be so. The Commission should not lose sight of the fact that a substantial amount of transmission needed to be built is required by new energy resources that are driven either by state public policy or by favorable economics. In either case, NRG's long experience suggests that the business model to support the construction of these new resources—both in markets that are open to competition, and those that remain closed—has typically been the use of long-tenor power purchase agreements in excess of 7 years, and usually longer than 10 years, that have the practical effect of encompassing most or all

[22] NOPR at P 27 (emphasis added).
[23] *Ibid.* at P 69.
[24] *Ibid.* at P 69, fn 129.

of the up-front costs of project development and construction. There is no reason why transmission costs could not and should not be expected to be built into these up-front costs.

In such a business model, transmission developers could propose an open season for space on their proposed lines, with renewable developers and other market participants all taking positions in it in order to justify its need and finance its construction. Indeed, such an approach would resemble the natural-gas markets' open seasons, where capacity is pledged in advance of a project's certification both to demonstrate need and guarantee the overall viability of the project's finances.[25] This approach has led to a successful apportionment of rights to transmission on new gas pipelines and has opened up new sources of this energy in an open-access, competitive manner—not unlike what the Commission is seeking here with respect to remotely located renewable sources of energy. Limited examples of a merchant, open-season approach exist in electric transmission,[26] but that is understandable because they have not been given any particular space to flourish in a planning and cost allocation scheme governed by cost-of-service regulation, dominated by incumbents, and centrally planned. NRG suggests that the Commission in rulemaking focus on examples like these, and decide which parts of its regulatory practice might discourage the wider emergence of this model.

Commenters in the Advance Notice of Proposed Rulemaking ("ANOPR") in this proceeding raised the possibility of an open-season approach to transmission needs.[27] The Commission does not address those proposals in the current NOPR. It should take a step back and do so, especially in view of the fact that state policies, voluntary retailer and corporate

[25] *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *clarified*, 90 FERC ¶ 61,128, *further clarified*, 92 FERC ¶ 61,094 (2000) (1999 Policy Statement).
[26] Examples of this business model include interregional projects intended primarily for economic arbitrage like Linden VTF and the Montana-Alberta Tie Line as well as projects to access large-scale, new sources of remotely located energy such as TransWest Express and SunZia Southwest. Yet another new project that does both was only very recently proposed Pecos West Intertie, which would connect WECC and ERCOT for the first time.
[27] Comments of the Electric Power Supply Association, Docket N0. RM 21-17 (filed August 19, 2022).

purchases, and the recently passed Inflation Reduction Act all serve as catalysts to both continue the trend of power-purchase agreement structures that can support substantial fixed costs—including transmission—while driving down the costs of energy-producing technology itself, giving headroom to the facility to tolerate the direct assignment of transmission costs in more instances.

2. States should be entitled to determine cost allocation for transmission projects that would not be necessary but for state public policies.

As the Commission has observed, regional transmission cost allocation is a much-litigated issue.[28] The Commission also recognizes that the proposed Long Term Regional Transmission Planning approach may result in "increased complexity" and could make cost allocation "more contentious" and undermine "more efficient or cost-effective regional transmission facilities."[29] The Commission cites an example of this in the NOPR, pointing to a transmission cost allocation for the PJM transmission companies with origins in 2004, and coursing its way through nearly two decades of litigation, negotiations, settlements, and further litigation among the different regions and interests in the PJM footprint.[30] While this may be among the most drastic examples, it also provides insight into the degree of difficulty the Commission's efforts in certain regions are to achieve.

In the NOPR, the Commission states its belief that "providing state regulators with a formal opportunity to develop a cost allocation method for regional transmission facilities selected through Long-Term Regional Transmission Planning could help increase stakeholder—and state—support for those facilities, which, in turn, may increase the likelihood that those facilities are sited and ultimately developed with fewer costly delays and better ensure just and

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[28] NOPR at P 297.
[29] *Ibid.* at P 298.
[30] *See*, e.g., *Long Island Power Auth. v. FERC*, 27 F.4th 705, 709 (D.C. Cir. 2022).

reasonable Commission-jurisdictional rates."[31] In proposing this additional role for the states, the Commission expresses its belief that "facilitating involvement of state regulators in the cost allocation process […] would allow states to voluntarily coordinate to advance their policy goals through needed transmission development and may minimize delays and additional costs that can be associated with siting proceedings that follow the regional transmission planning and cost allocation processes at the federal level."[32]

NRG supports forums outside of the Commission's contested proceedings for the relevant state entities to consider and select cost allocation methodologies. The Commission's recent Joint Federal-State Task Force on Electric Transmission is a welcome example of a formal venue to exchange ideas that cut across the jurisdictional divide. However, a process such as the one proposed in the NOPR, where the relevant state entities are the primary negotiators of transmission cost allocation, leaves out an obvious and meaningful aspect of the cost allocation process: customers who ultimately pay the cost of the Long-Term Regional Transmission Plan.[33]

NRG suggests a more limited use of the procedure the Commission proposes. Specifically, for projects included in regional transmission plans that would not exist but for state public policy, it is reasonable for the states included with the planning footprint, and to whose jurisdictional consumers costs would be allocated under an alternative cost allocation, to fill the role that the Commission has described for them in the NOPR. This would create a clear nexus between the driver of costs—state policy—and the payment of those costs.[34]

[31] NOPR at P 299.
[32] *Ibid. at P 301.*
[33] While we typically think of this as the bill-paying end use consumer, it could also include generator and transmission interconnection customers depending on the transmission project and/or ultimate cost allocation design.
[34] This does not prevent further opportunities for states to collaborate or propose and/or agree to cost allocation concepts.

Meanwhile, the Commission appropriately recognizes that the availability of an *ex ante* cost allocation method helps to ensure the development of more efficient or cost-effective regional transmission facilities identified in the regional transmission planning process.[35] NRG agrees. However, it would be unrealistic to expect a productive negotiation among states to occur if recourse to another transmission cost allocation is the option to which any objecting state may default the negotiation. NRG, therefore, would recommend imbuing states with the authority to negotiate with respect to a limited set of projects driven by state policy considerations, and without recourse to a particular *ex ante* methodology. Meanwhile, projects that would proceed even without the additional motivating factor of state public policies could avail themselves of an *ex ante* methodology.

3. States should be afforded a reasonable 'shot clock' for cost allocation.

The Commission suggests that "providing states with a time period to propose alternate cost allocation methods could help facilitate the timely development of more efficient or cost-effective regional transmission facilities."[36] The Commission proposes a 90-day time period for state-negotiated cost allocation memorialized in writing.[37] The Commission seeks comment on the timing and duration of any time period for state-negotiated cost allocation for transmission facilities selected in the regional transmission plan for purposes of cost allocation through Long-Term Regional Transmission Planning. The Commission further seeks comment on whether there should be a requirement for a time period for state involvement in regional cost allocation for transmission facilities selected in existing near-term reliability and economic regional transmission planning processes.

[35] NOPR at P 315.
[36] *Ibid.* at P 321.
[37] *Ibid.* at P 323.

NRG reiterates that state-led cost allocation should be the default mechanism for projects included within a Long-Term Regional Transmission Plan that would not exist but for state public policies, and that the availability of an *ex ante* cost allocation paradigm likely will frustrate the effectiveness of any state-led negotiation. NRG also believes that *ex ante* cost allocation is appropriate for nearer-term reliability and economic transmission planning.

On the issue of the amount of time that states should be afforded *after* a project is selected, and where the project is subject to state-led cost allocation, NRG suggests that a set time period, sometimes known in regulatory policy as a "shot clock," is appropriate. The Federal Communications Commission's regulations permit state and local entities 60 or 90 days, for example, to consider the siting applications of relatively small 5G advanced-telecommunications installations.[38] However, that task is considerably less complex than what states would be called upon to do here, and a timeline of at least 180 days seems warranted. The Commission might consider alternative timelines that apply to situations where the decision is made by a multi-state collaboration versus where there is a single state entity responsible for the cost allocation.[39]

In the case where states do not agree, the Commission, rather than having an *ex ante* allocation, could either resolved allocation by requiring the ISO to make a filing or subject rival state filings to "jump ball" treatment. Either of these approaches would encourage comity and resolution of states' differences among each other.

C. CONSTRUCTION WORK IN PROGRESS INCENTIVE

NRG supports the Commission's proposal to remove the eligibility of Construction Work in Progress ("CWIP") to be included in the transmission rates approved by the Commission.

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[38] *See In the Matter of Accelerating Wireless Broadband Deployment by Removing Barriers to Infrastructure Investment and Accelerating Wireline Broadband Deployment by Removing Barriers to Infrastructure Investment*, WT Docket No. 17-79 and WC Docket No. 17-84, Federal Communications Commission (September 5, 2018).
[39] *See* NOPR at P 300, fn. 500.

However, NRG recommends that the Commission clarify and rule that rates for the "transmission of electric energy in interstate commerce" not include CWIP whatsoever, contrary to the Commission's suggestion that a public utility transmission provider should be entitled to rely on an inapposite administrative regulation to avail itself of partial recovery of CWIP costs.[40]

"CWIP is the award of cost recovery of construction costs during the pre-construction and construction phases to the developer."[41] Including CWIP in consumer rates axiomatically means that consumers are paying for something that is not yet—and may never become—"used," which together with "useful" are the benchmarks by which utility regulators typically judge utility rate proposals' associated costs. As the Commission notes, the federal regulator departed from this practice after the passage of the Energy Policy Act of 2005, which authorized the Commission to establish incentive-based regulation for transmission.[42]

1. The Commission's proposal on CWIP is a return to the basic principles of utility ratemaking and should be adopted.

NRG agrees with Commissioner Christie's observation that this reform "is simply in keeping with traditional good utility ratemaking principles."[43] It equitably considers the interests of transmission providers and consumers because, with respect to the former, it ensures that all used and useful capital expenditures and prudently incurred expenses are ultimately recovered by permitting the use of an Allowance for Funds Used During Construction ("AFUDC"), an accounting entry that is permitted subsequent recovery, together with an appropriate return or carrying costs, once the project enters service; meanwhile, for consumers, it ensures that they do not pay for a facility that is not rendering them service presently—and may never do so. The

[40] NOPR at P 329, fn 524, and P 333, fn 530.
[41] NOPR, Concurring Statement of Comm. Christie (hereinafter "Christie, Comm'r") at P 15.
[42] NOPR at P 328.
[43] Christie, Comm'r., at P 15.

Commission should take steps toward restoring this foundational principle of utility regulation, so that consumers only pay for equipment that is used and useful. Unfortunately, the Commission proposes that its reform here would not entirely eliminate CWIP, leaving in place the ability of a utility to seek the Commission's approval of a more limited inclusion of CWIP in its rates.[44]

2. The Commission should not otherwise interpret its regulations to apply to CWIP associated with 'the transmission of electric energy in interstate commerce'

The Commission includes *dicta* in its proposal that interprets 18 CFR 35.25(c)(3), part of its filing-requirements regulations, to apply to the rates associated with transmission service jurisdictional to the Commission.[45] In its entirety, that subsection of the Commission's administrative regulations reads: "Non-pollution control of fuel conversion (non-PC/FC) CWIP. No more than 50 percent of any CWIP allocable to *electric power sales for resale* not otherwise included in rate base under paragraphs (c)(1) and (2) of this section, may be included in the rate base of the public utility."[46] Paragraphs (c)(1) and (2), meanwhile, relate to pollution controls and fuel conversion facilities—in other words, capital investments associated with the production of electric power.[47] This NOPR does not concern rates being set for "electric power sales for resale"; it concerns rates set for the other service for which the Commission under the Federal Power Act has jurisdiction: "the transmission of electric energy in interstate commerce."[48] The administrative regulation's context clearly does not pertain to transmission service, and expressly defines its applicability to "electric power sales for resale." It is not clear to NRG whether and to

[44] NOPR at P 333, fn 530.
[45] NOPR at P 329, fn 524, and P 333, fn 530.
[46] 18 CFR 35.25(c)(3). Emphasis added.
[47] 18 CFR 35.25(c)(1)-(2).
[48] 16 USC § 824(a). (the law clearly refers to two separate things when it speaks to "the transmission of electric energy in interstate commerce and the sale of such energy at wholesale in interstate commerce").

what extent public utility transmission providers have relied on this rule to include CWIP in their rates. The Commission should clarify in its final rule the extent of that practice, if it has been permitted. In any case, the Commission should not attempt to rely on this unrelated regulation—or errantly give it further application, to the extent it has been applied—in the context of this proceeding.

3. The Commission's CWIP proposal is not by itself sufficient to remedy the risk to consumers from expanding the time horizon of the regional planning process.

The Commission justifies its proposal on CWIP to its proposed reform to require regional transmission planning to be conducted with a minimum of a 20-year time horizon. The Commission explains that this added "uncertainty" with a longer time horizon suggests "additional protection for ratepayers may be necessary to reasonably balance consumers' interest in just and reasonable rates against investors' interest in earning a return on their investment and reduce the risk to ratepayers of potentially financing over-investment in regional transmission facilities."[49]

NRG agrees that consumers are more protected under this proposal than without it. However, NRG disagrees that the Commission's CWIP proposal affords any real protection to consumers if the speculative assumptions embedded within a 20-year or longer horizon are used to justify the selection of a regional transmission facility that, ultimately, is or would have been uneconomical compared to alternatives at some point after commercial operation. That is a risk inherent in a longer time horizon, which the Commission's CWIP proposal does not and cannot obviate. The Commission's CWIP proposal merely protects consumers from bad investments that *do not* end up becoming commercially operational—not those that do become operational and entered into rate base, even if they ultimately prove to be improvident. This is the reason

[49] NOPR at P 330-31.

NRG opposes this longer time horizon to the extent it is used to justify speculative investments on the backs of ratepayers.

4. The Commission's proposal to restrain the inclusion of CWIP in transmission rates has numerous, additional justifications beyond the one the Commission has offered

NRG opposes a longer time horizon for the purpose of justifying speculative transmission projects, but supports the Commission's proposal on CWIP. Although the Commission in its NOPR connects the two, NRG submits that the "uncertainty" of a longer time horizon is not the sole nor even the best reason to adopt the Commission's CWIP proposal. NRG offers several others in the interests of a full record, on which the Commission may depend.

a. Allowing CWIP in rates forces consumers to finance facilities that are neither providing them service nor obviously lacking access to capital markets.

NRG agrees with Commissioner Christie that not permitting CWIP to be included in a utility's rate base "is simply in keeping with traditional good utility ratemaking principles."[50] That is because rate base traditionally reflects only the utility plant that is "used and useful"—and CWIP by definition is neither. To the degree CWIP ever had a justification, it should be that adequate service at just and reasonable rates required consumers to pre-pay for capital assets that had not been brought into service. Yet, nothing in the record suggests that it is a lack of access to capital at a reasonable cost that is holding up necessary transmission projects. There is no reason in view of that to treat a captive set of ratepayers as a means of financing these projects.

b. Including CWIP in rates results in unjust and unduly discriminatory intergenerational inequities.

Requiring consumers to pay for rates that include CWIP means by definition that they are paying for a service they are not yet receiving—and may never receive. It also means that the

[50] Christie, Comm'r., at P 15.

rates for the service, if it does become available, will be less for the people actually receiving it than if these costs had been booked as AFUDC and charged to customers actually receiving service. Especially for large reconfigurations of the electricity system, as the NOPR portends, such treatment of CWIP raises concerns about intergenerational inequities to such an extent that undue discrimination is more likely to result as an outcome.

c. Including CWIP in transmission rates for regional transmission facilities may result in customers paying rates to owners from which a customer literally receives no service whatsoever.

Regional transmission facilities may be developed by non-incumbents who have no connection—and thus no rate base—associated with the retail customers of a particular utility service territory. This is a good thing, to the extent it is an indication of the presence of competition. However, if such transmission facilities were permitted to charge rates to customers on the basis of CWIP, it would lead to an outcome where the developer of the transmission line charges customers for pre-construction and construction costs of that line, even while providing literally no service from that or any other facility to that customer. This would be an absurd outcome.

Meanwhile, one can plausibly imagine a situation where a utility that enters CWIP into its rate base also has other, used and useful assets included in rate base—thus allowing an argument to be made that the utility was, is, and will be providing service associated with a portfolio of rate-based assets and so it should be allowed CWIP as but one component of its larger rate structure. Allowing an incumbent to claim CWIP in such circumstances would further disadvantage the non-incumbent, even while allowing the latter to claim CWIP would be absurd. It is, again, simpler and fairer to return to the classical principles of utility regulation and pay for only that transmission service that is furnished through used and useful assets, regardless of ownership.

d. Section 219 did not intend to incentivize purposes other than reliability and economic projects, such as public policy projects.

The amendments made to the Federal Power Act that are the basis of the Commission's existing policy on CWIP provide that "the Commission, by rule, shall establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefitting consumers *by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion*."[51] Certain regional transmission facilities under the ambit of the Order 1000 regime and what the Commission is here proposing are contemplated to be undertaken for the purpose of facilitating state public policy. It would be unlawful, for these transmission facilities, to award CWIP treatment because they fall outside the enumerated purposes of Section 219 of the Federal Power Act for which transmission rate incentives are directed.

D. EXERCISE OF A FEDERAL RIGHT OF FIRST REFUSAL IN COMMISSION-JURISDICTIONAL TARIFFS AND AGREEMENTS

The Commission should not adopt its proposed reform regarding the federal Right of First Refusal ("ROFR"). Instead, it should withdraw its proposal and propose alternative reforms that eliminate the attractive nuisance that Commission regulation has inadvertently created in allowing incumbents to both monopolize transmission and evade any serious inquiry into the rate-basing of such investments. In its current proposal, the Commission has it backwards, for it is the lack of either competition or meaningful rate regulation in transmission generally—and not the presence of competition in one small part of the electric-transmission sector—that is the

[51] 16 USC § 824s(a). Emphasis added.

problem that causes "perverse investment incentives that do not adequately encourage" incumbents to compete for regional projects.[52]

Alternatively, if the Commission chooses to proceed with its ROFR proposal, it should at a minimum modify it, by allowing only those public utility transmission providers that are genuinely independent of an incumbent who would be financially advantaged by the restoration of a tariffed federal ROFR to enjoy the presumption of reasonableness that the Commission now proposes to universally attach to such tariff filings.

1. **The Commission should withdraw its ROFR proposal and make an alternative proposal that would instead subject inefficient transmission investment to meaningful scrutiny**

    a. *The Commission arbitrarily reasons that the abiding attractiveness of monopoly opportunities in most of the electric-transmission sector is a reason why competition should be dialed back in the one place it exists in the sector.*

The Commission explains that "regional transmission facilities subject to a competitive transmission development process represent only a small portion of total transmission investment in recent years across several transmission planning regions."[53] An incumbent that develops regional transmission and seeking cost allocation would potentially expose itself to competition—something that would not happen if the incumbent merely tended to local projects for which it enjoyed an effective monopoly through ROFR.[54] In addition to enjoying a monopoly on the small-ball projects, the transmission monopoly also enjoys a presumption of prudence for transmission expenses.[55] In addition to this presumption of prudence, more and more transmission utilities have been allowed to employ formula rates, where transmission expenses

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[52] NOPR at P 350.
[53] *Ibid.* at P 349.
[54] *Ibid.* at P 350.
[55] *Iroquois Gas Transmission System, L.P.*, 87 FERC ¶ 61,295 (1999) at p. 62,168 (quoting *Minnesota Power & Light Co.*, 11 FERC ¶ 61,312 (1980) at pp. 61,644-45).

are recoverable almost immediately or even subject to being forecast and recovered based on prospective estimates of investments to be made.[56] As Paul Joskow has noted, "For all intents and purposes the [Commission's transmission] regulatory process is a model of cost pass-through regulation with little scrutiny of costs."[57] It therefore should be no surprise that incumbents—given a choice between monopolization, a presumption of prudence, and an immediate return on one hand, and a competition that serves to discipline costs and increase scrutiny on the other—will choose the former and not the latter. Indeed, the NOPR cites to a prescient dissent to Order 1000 that this very outcome could occur.[58]

With this in mind, the NOPR then aims at entirely the wrong mark: the small part of the transmission space where competition exists, saying that the "perverse investment incentives" are a "result of those [Order 1000] reforms" that *encouraged* competition by removing the incumbents' ROFR.[59] That is exactly backwards. The Commission over the years has built up an attractive nuisance for regulated utilities in the form of tolerating ROFR for most transmission projects, presuming that expenditures are prudent, and that rates should formulaically adjust to immediately recoup those expenditures. By contrast, *any* regulatory regime that exposes an incumbent utility to competition, or that subjects it to slightly more scrutiny, or causes it to bear more risk for its business decisions, will look unattractive to the incumbent utility—if it is the one that has the choice.

If the *status quo* of transmission owners' monopoly opportunities were the result of some external force—like a state public policy—that the Commission merely needed to accept and

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[56] *Cost of Service Manual*, Federal Energy Regulatory Commission (June 1999); [Cost-of-Service Rates Manual (ferc.gov)](ferc.gov).
[57] Paul L. Joskow, MIT Center for Energy and Environmental Policy Research, Working Paper, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000*, (March 2019), p. 13.
[58] NOPR at P 350 (citing Moeller, Comm'r, dissenting in part).
[59] *Ibid.*

work around, that would be one thing. But the "perverse investment incentives" at issue here are created wholly or in largest part by the Commission's decisions to regulate transmission service subject to its jurisdiction in a particular way. The Commission cannot reasonably conclude that it bears no responsibility for cleaning up this attractive nuisance, and instead conclude that the monopoly fence-line should once again be built up around the one part of the electric-transmission sector the Commission has sought to clean up through Order 1000's elimination of the tariffed federal ROFR.

b. The Commission proposes no substantial consumer protection to replace competition as a tool to discipline costs.

The foundation of the Commission's legal authority in this proceeding is that transmission rates may not be just and reasonable if sufficient regional transmission is not built. This is not an immediately intuitive proposition, since additional investment typically will mean higher rates—not lower ones. However, NRG accepts the reasoning that there may well be certain regional transmission lines that would efficiently substitute for larger costs that consumers may otherwise pay—local transmission projects or generation costs, for example—such that higher rates for certain regional transmission facilities may be a net reduction in costs on a holistic basis. However, in reaching this conclusion in Order 1000, the Commission also found it appropriate to attach a consumer protection to discipline the costs of that regional transmission development, in the form of competition. In this proceeding, the Commission should be concerned with *maximizing* benefits by *reducing* costs of beneficial transmission solutions.

Order 1000 wisely recognized both of these things: the usefulness of nonincumbents to regional planning, which might spur regional development, but also the reduction in costs when competing proposals were offered. In view of the former, the Order 1000 Commission concluded, "[T]here is a disincentive for a nonincumbent transmission developer to commit its resources to a potential transmission project when it runs the risk of an incumbent transmission provider exercising its federal right of first refusal once the benefits of the transmission project are demonstrated."[60] The Commission in the instant NOPR has in mind an alternative market structure whereby an incumbent transmission developer is allowed to help itself to a potential transmission project—but must partner with at least one other ownership partner, perhaps including (or perhaps not) the nonincumbent whose good idea the project was in the first place. This cartelization is a common, although not usually successful, feature of the economic regulation of network industries in American history.[61] The approach the Commission proposes may or may not achieve genuinely regional transmission planning that the Order 1000 Commission had in mind, but it is aiming in that respect at the same goal.

However, the Commission neglects the other reason Order 1000 removed the federal ROFR, which is differing proposals' competition around costs.[62] Channeling regional transmission planning into a more and more limited set of potential projects and owners—which is the inevitable end-state of the cartelization that the Commission proposes to set in motion—will not yield a competition between differing proposals. This was a rationale of Order 1000's reform—"the presence of multiple transmission developers would lower costs to consumers"[63]—

[60] Order No. 1000, 136 FERC ¶ 61,051 (2011) (hereinafter "Order 1000") at P 257.
[61] See, for example, the history of the Civil Aeronautics Board and the ultimate liberalization of that industry by Alfred Kahn. Thomas K. McCraw, *Prophets of Regulation* (Cambridge: Harvard University Press, 1984), pp. 259-99.
[62] Order 1000 encouraged both competitive bidding—noting that existing processes relying on them "may require little or no modification to comply with the framework" of Order 1000—and also permitted an alternative approach, where the efficiency of different proposals are compared against one another in the planning process. Order 1000 at P 321. Either way, the process relied on competing proposals by multiple developers to discipline costs and maximize benefits.
[63] Order 1000 at P 268, citing *Cleco Power LLC,* 101 FERC ¶ 61,008 at P 117 (2002), *order terminating proceedings*, 112 FERC ¶ 61,069 (2005).

and it was reiterated by the Seventh Circuit in affirming Order 1000's removal of the federal ROFR.[64]

It is not at all clear how joint ownership in and of itself will serve to discipline costs. In the proposal that the Commission appears to primarily rely on, filed by the publicly owned utilities' association TAPS, it suggests that a process for joint ownership should include "bid[ding] out the cost of construction and associated capital requirements regarding regional and interregional transmission facilities selected in regional transmission plans, which would be designed to identify ownership partners… ."[65] The Commission's proposed reform, however, does not appear to contain this feature or anything that resembles competition as a necessary parameter. As such, it abandons a cost-disciplining tool that Order 1000 found necessary to adopt, without an explanation for doing so, or at least without a comparison of the foregone benefits of requiring a competition around costs versus the additional benefits the Commission believes it will obtain by greasing the skids to induce more regional transmission investment.

c. The Commission's justifications in proposing this reform are otherwise unreasoned and vague.

The Commission's conception of how its proposed reform might improve the planning process also is misplaced. The Commission states that the additional regional transmission investment will be furthered by its proposed pathway for cartelization and that such a combination could "leverage the combined transmission development strengths of the parties, potentially including the parties' knowledge of siting and permitting processes or other

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[64] "Until Order No. 1000 was promulgated, every member of MISO had a protected monopoly, created by the right of first refusal, regarding the construction of new facilities in its service area. That created a potential for higher rates to consumers of electricity than if competition to create transmission facilities in transmission companies' service areas was allowed, as FERC decreed in its order." *MISO Transmission Owners v. Fed. Energy Regulatory Comm'n*, 819 F.3d 329 (7th Cir. 2016).
[65] NOPR at P 363.

strengths."[66] This is a vague suggestion of benefits. It can be read as condoning an approach of giving everyone a piece of the pie, thereby eliminating opposition by logrolling financially interested parties. Simply put, incumbents should not be rewarded for blocking non-incumbents, and the Commission should not euphemistically endorse "knowledge of siting and permitting processes" as an ineffable business talent justifying the Commission's elimination of competition. To the degree that a cartelization of transmission is undertaken merely to remove an incumbent's political blockade of transmission by entities other than itself, that approach is likely to increase costs, not minimize them. That is contrary to the Commission's statutory mandate to ensure just and reasonable rates.

d. The Commission should withdraw its ROFR proposal, and instead re-balance transmission investment incentives by restoring consumer protections related to transmission monopolies' rates.

Rather than proposing to gut competition in regional transmission by allowing a tariffed federal ROFR to be reinstituted, the Commission should take steps to remove the profound sense of entitlement and lack of meaningful regulatory oversight that attends the rest of the transmission space. It can do this in one of two ways. Of course, it could subject all such transmission development to competition. Or, if incumbency is seen as a necessary expedient for transmission projects deemed local or for more urgent reliability purposes, the Commission could eliminate the presumption of prudence and the formula ratemaking that these projects enjoy and reinstitute its classical tradition of rate cases where multiple parties and FERC trial staff scrutinize periodic filings. Notably, this is the regulatory model that continues to exist for gas pipeline companies, and there is no indication it has dampened those companies' financial

[66] NOPR at P 372.

performance or their willingness to make investments to maintain, upgrade, or even to try to expand their systems.

As a corollary of this return to classical principles of utility regulation, the Commission should consider an approach proposed by Ari Peskoe, that in addition to reversing "its longstanding adoption of a presumption that all transmission expenses are prudent" that the Commission should "replace it with a presumption that only capital expenditures committed pursuant to an independently administered planning process are prudent."[67] To the degree that the Commission, throughout the NOPR, is concerned that underinvestment is occurring in regional transmission projects compared with other types of transmission, a way to re-balance is to adopt this reform, which would make regional transmission investment more appealing by imbuing it with a presumption of prudence, even while subjecting it to competition and independent planning. Together with the Commission's proposed consumer-protection reform on "construction work in progress" pertaining to these regional facilities, such a step would achieve true balance and actually address the perverse-incentives concerns the Commission has here raised.

2. At a minimum, if the Commission adopts its ROFR proposal, it should limit the application of its proposed reform to only those public utility transmission providers that are genuinely independent of a financial incentive resulting from the reform.

The Commission should not abrogate its responsibility to scrutinize tariff filings under an appropriate standard for incumbents who seek to use regulation to further their advantage. Contrary to this reasonably skeptical posture, the Commission proposes, "Public utility transmission providers would have the opportunity in their regular course of business to consider whether this type of a conditional federal right of first refusal would, if adopted, help improve

[67] Ari Peskoe, "Is the Utility Transmission Syndicate Forever?" *Energy Law Journal* (Volume 42:1) (2021), p. 58.

their particular regional transmission planning process or help address potentially misaligned incentives regarding regional and local transmission facility investment."[68] This is an extraordinarily naïve postulation. It should go without saying that incumbent utilities will find it "help[ful]" to entitle themselves to a right of first refusal through regulatory mandate. The Commission's proposal would subject such tariff proposals to a standard allowing them to "presumptively be found to ensure just and reasonable Commission-jurisdictional rates and limit opportunities for undue discrimination by public utility transmission providers."[69] The Commission is, if anything, making needless work for itself by requiring incumbents to pretend to consider whether to make tariff filings that advantage their incumbency, if such filings are entitled to a presumption that they are reasonable, just, and not unduly discriminatory.

Instead of taking this winking posture, the Commission at the very least should maintain a high bar for those would-be tariff filers who are themselves the incumbents who might be financially advantaged by a reinstatement of the ROFR. That is, where the public utility transmission provider that bears the responsibility of filing a tariff that sets forth whatever ROFR policies apply to transmission planning is an incumbent who could be advantaged by a ROFR, it should not be presumed that such a proposal is just and reasonable or not unduly discriminatory. In effect, this would ensure that only those RTOs/ISOs where the provision of tariffed transmission service is genuinely independently governed would be entitled to any favorable presumption around a tariff filing that seeks to reinstate a federal ROFR.

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[68] NOPR at P 355.
[69] *Ibid.*

E. ENHANCED TRANSPARENCY OF LOCAL TRANSMISSION PLANNING INPUTS IN THE REGIONAL TRANSMISSION PLANNING PROCESS AND IDENTIFYING POTENTIAL OPPORTUNITIES TO RIGHT-SIZE REPLACEMENT TRANSMISSION FACILITIES

NRG generally supports the Commission's proposals in this section of its NOPR. Local transmission planning that itself is not subjected to meaningful evaluation, but which rolls up as a given to regional plans, is the likeliest set of investments to escape meaningful scrutiny, even if such projects may be relatively pedestrian.

As in many other places in the NOPR, the Commission justifies its proposal by saying it is "needed to ensure just and reasonable Commission-jurisdictional rates."[70] In this case, the Commission asserts its proposal will be helpful "because the information provided will better facilitate the identification of regional transmission facilities that may be more efficient or cost-effective than proposed local transmission facilities through the regional transmission planning process."[71] NRG encourages the Commission to include one other important piece of information that the local transmission planning process should be required to produce, which is an estimated rate impact for each year for its local transmission plan were it to be executed. This would give in the clearest possible terms the customers possibly the most useful information—in some sense, the only information they may desire—from the local transmission planning process. Local transmission planning happens at the ground level, usually by and for a single transmission provider/owner, and such a request should not be unduly burdensome. Such added transparency would assist NRG and other transmission customers who bear the risk of transmission cost fluctuations in their own planning.

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[70] NOPR at P 402.

[71] *Ibid.*

Finally, to the extent that the Commission recommends that incremental increases to local projects—the "right-sizing" of them—be included within the regional planning and cost allocation scheme the Commission has proposed,[72] NRG's concerns expressed throughout the earlier sections of these comments would apply.

F. INTERREGIONAL TRANSMISSION COORDINATION AND COST ALLOCATION

NRG takes no position on what it understands to be a proposal to conform the NOPR's other proposals to the current forums that are convened under Commission regulations to engage in interregional coordination. NRG notes that interregional transmission development is currently underway through several major projects, none of which have availed themselves of the planning and cost allocation processes at the regional level (and thus have foregone formal interregional coordination). These projects include major endeavors to stitch together remotely located renewables with load centers and also to permit economic trading between markets, such as TransWest Express, SunZia Transmission, and the Pecos West Intertie. These projects not only suggest that a command role by the Commission in transmission planning and cost allocation may not be necessary, but also provide examples worth evaluating to determine what regulatory impediments are standing in the way of a model of voluntary cost allocation that is more conducive to competition.

[*signature page follows*]

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[72] *Ibid*. at P 413.

Respectfully submitted,

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