UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

JOINT COMMENTS OF THE INDUSTRIAL CUSTOMER ORGANIZATIONS

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August 17, 2022

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The Industrial Energy Consumers of America ("IECA"), the American Forest & Paper Association (“AF&PA”), the PJM Industrial Customer Coalition (“PJMICC”), and the Coalition of MISO Transmission Customers (“CMTC”), collectively the Industrial Customer Organizations, welcome the opportunity to submit these Comments in response to the Federal Energy Regulatory Commission's ("FERC" or "Commission") April 21, 2022, Notice of Proposed Rulemaking (“NOPR”) on transmission planning and cost allocation.[1] While certain proposals such as reforming the CWIP Incentive and requirement for Grid-Enhancing Technologies could benefit consumers, the proposals to reinstate federal rights of first refusal (“ROFRs”) and extend the planning horizon for long-term regional transmission planning processes would increase costs to consumers.

I. DESCRIPTION OF THE INDUSTRIAL CUSTOMER ORGANIZATIONS

The Industrial Customer Organizations include associations of leading manufacturing companies, large energy-intensive users of electricity, coalitions of transmission customers, and others representing more than $1 trillion dollars in sales, thousands of manufacturing facilities, and millions of family-sustaining jobs in the United States. The Industrial Customer

[1] *Notice of Proposed Rulemaking*, 179 FERC ¶ 61,028 (2022) ("NOPR").

Organizations advocate and collaborate on matters regarding the availability, use, and cost of energy. The companies and customers that comprise the Industrial Customer Organizations include a diverse set of industries including chemicals, plastics, steel, iron ore, aluminum, paper, food processing, fertilizer, insulation, glass, industrial gases, pharmaceuticals, building products, automotive, independent oil refining, cement, and others.

II. INTRODUCTION

The Industrial Customer Organizations encourage the Commission to undertake efforts to protect manufacturers and other energy-intensive transmission customers from the relatively recent, rapid, and substantial increases in transmission rates. Through this NOPR, the Commission proposes a mixed-bag of steps to protect consumers, along with proposals that will further increase transmission rates, destroy jobs, and harm the United States economy during a time of historically high inflation. The Commission should promote competition, optimize planning processes, ensure proper transmission cost allocation, and require grid optimization to maintain reliability at just and reasonable rates. Transmission planning that introduces additional uncertainty and speculation will necessarily increase consumer costs.

In Order No. 1000, the Commission took steps to promote competition and spur transmission development in a manner that would not unjustly or unreasonably increase rates to transmission consumers. Now, more than a decade later, the Commission seeks to unwind some of the consumer protections it adopted in Order No. 1000. The Industrial Customer Organizations encourage the Commission to dive into the data on the benefits of competition, including competitively bid solutions to reliability needs in which grid-enhancing technologies, demand response, and other alternatives to new investment are considered.

III. EXECUTIVE SUMMARY

Transmission planning processes must not bypass the core function of transmission planning that rates be just and reasonable, with an assessment of costs and benefits based upon substantial evidence. "It is long-established that the 'primary aim' [of the Federal Power Act] is the protection of consumers from excessive rates and charges."[2] To protect consumers, the Commission should:

- Require competition for all transmission planning and construction, with limited and well-defined exceptions, which will address many of the issues identified in the NOPR, as argued in Comments that are being filed by the Electricity Transmission Competition Coalition;
- Give RTO/ISOs and other independent transmission planners discretion over the appropriate planning horizon for long-term regional transmission planning, rather than mandate scenario planning that extends in the future 20 years from the in-service date of new transmission facilities;
- Eliminate opportunities for transmission developers to recover constructive work in progress ("CWIP") in conjunction with further limitations on the ability to recover abandoned transmission plant costs; and
- Require Grid-Enhancing Technologies ("GETs") to be considered as an alternative to, or as a mitigating factor in, all new transmission investment.

[2] *Xcel Energy Services v. FERC*, 815 F.3d 947, 952-53 (D.C. Cir. 2016).

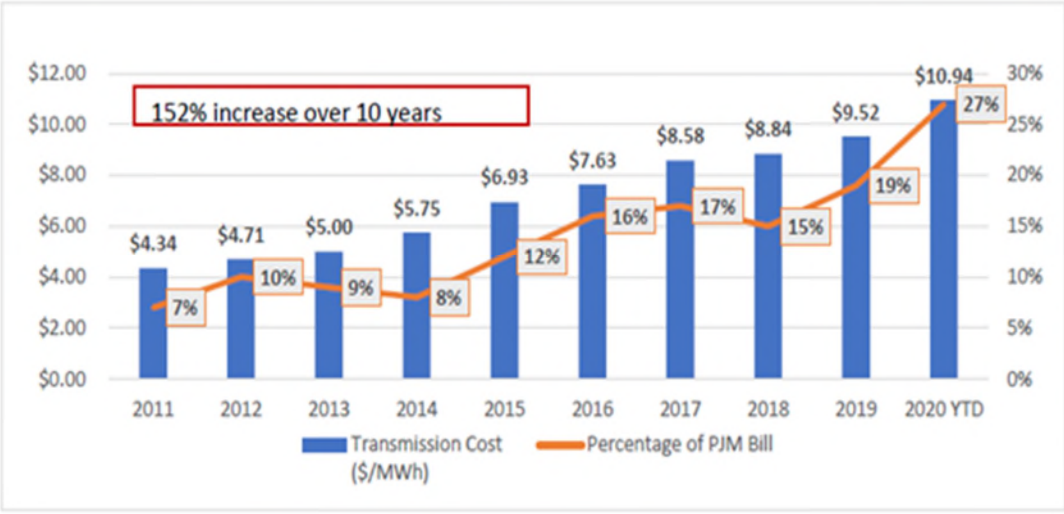
IV. COMMENTS

A. The Industrial Customer Organizations Adopt By Reference, In Their Entirety, The Comments By The Electricity Transmission Competition Coalition In Opposition To Certain Aspects Of The Proposed Rule

The Industrial Customer Organizations agree with the Electricity Transmission Competition Coalition ("Competition Coalition") that the best way to ensure just and reasonable rates is through competition in transmission planning and development. Accordingly, the Industrial Customer Organizations adopt by reference, in their entirety, the Comments by the Competition Coalition in opposition to certain aspects of the proposed rule. Specifically, the Industrial Customer Organizations oppose the Commission's proposals to implement new rights of first refusal ("ROFRs").

The proposed ROFRs for jointly owned facilities and so-called right-sizing are unlawful, unjust, unreasonable, unduly discriminatory and preferential, and would harm consumers. Regarding the ROFR for jointly-owned facilities, FPA Section 309 provides no authority, either alone or as a means to establish a presumption around FPA Section 205, for the Commission to amend Order No. 1000 to establish a new ROFR. Further, the Commission failed to find that its existing regulations that exclude federal ROFR provisions are unjust or unreasonable. The Commission also failed to demonstrate how these new ROFRs would be just and reasonable.

While competition has not developed as much as it could have after Order No. 1000, the Commission should not abandon course now. The benefits of competition identified by the Commission when it issued Order No. 1000 have been confirmed through multiple competitive solicitations. Any new ROFR would work to prohibit competition and competitive processes from further developing, ultimately driving ever-increasing transmission rates to consumers. For example, as demonstrated below, transmission costs in PJM alone increased by 152 percent in the decade preceding 2020.[3]



Transmission customers, manufacturers, and the U.S. economy cannot bear another decade of transmission cost increases that far exceed demand or improvements in reliability.

The Commission found in Order No. 1000 that "an incumbent transmission provider's ability to use a [ROFR] to act in its own economic self-interest may discourage new entrants from proposing new transmission projects in the regional transmission planning process," an outcome that can "undermine the identification and evaluation of more efficient or cost-effective solutions to regional transmission needs."[4] The lack of development of competitive processes is not the result of the Commission's elimination of ROFRs in Order No. 1000, but rather a result of incumbent transmission utilities' continued efforts to act in their own economic self-interest to discourage competition and undermine the identification and evaluation of more efficient or cost-effective solutions to regional transmission needs. The Commission should work to require

[3] Growth in PJM Transmission Rates, developed by Industrial Customer Organizations based on PJM NITS data that are available at: https://pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.

[4] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051, at P 256 (2011)("Order No. 1000").

compliance with the Commission's pro-competitive policies, rather than pursue steps to change those policies.

B. The NOPR Fails To Provide Substantial Evidence That Existing "Rates" Are Unjust, Unreasonable, or Unduly Discriminatory or Preferential.

The NOPR fails to provide substantial evidence that existing rates are unjust, unreasonable, or unduly discriminatory or preferential. Pursuant to FPA Section 206, the Commission must find, and provide substantial evidence supporting its finding, that existing rates are unjust, unreasonable, or unduly discriminatory or preferential.[5] FPA Section 206 instructs the Commission to remedy "any . . . practice" that "affect[s]" a rate for interstate electricity transmission services demanded or charged by any public utility if such practice "is unjust, unreasonable, unduly discriminatory or preferential."[6] However, any finding under FPA Section 206 that rates are unjust, unreasonable, or unduly discriminatory or preferential must be backed by substantial evidence. In the NOPR, the Commission preliminarily finds that existing regional transmission planning and cost allocation processes are resulting in unjust, unreasonable, unduly discriminatory, and preferential Commission-jurisdiction rates.[7] The Commission then fails to back up its conclusion with substantial evidence, facts, or data. Regardless, the Commission presses on with a proposal to reform regional transmission planning and cost allocation processes. In doing so, though, the Commission states that current deficiencies in transmission planning "may" be resulting in unjust and unreasonable and unduly discriminatory or preferential Commission-jurisdictional rates. FPA Section 206 requires more than a finding that rates "may" or "might be" unjust or unreasonable. The Commission must demonstrate that rates <u>are</u> unjust, unreasonable, unduly discriminatory or preferential, and also

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[5] 16 U.S.C. § 824e(a).

[6] 16 U.S.C. § 824e(a).

[7] NOPR at P 34.

that the Commission's proposed remedy is just, reasonable, and not unduly discriminatory or preferential.

1. The NOPR Does Not Fully Define, Quantify, or Provide Substantial Evidence of "Changes in Resource Mix and Demand."

The Commission declares throughout the NOPR that "the reforms proposed in the NOPR would require public utility transmission providers to conduct long-term regional transmission planning on a sufficiently forward-looking basis to meet transmission needs driven by *changes in the resource mix and demand*."[8] The NOPR then proceeds to use the term "changes in the resource mix and demand" a total of 126 times without ever fully defining or quantifying the meaning of this phrase. Apparently, the Commission intends that "changes in the resource mix and demand" means more generation from renewable resources and consumer demand for renewable energy. But transmission should not be planned based upon the fuel source of the generation fleet or demand for generation from a particular fuel source. Transmission has and should be planned to maintain reliability. Period.

Further, the NOPR fails to provide substantial evidence that these so-called changes in the resource mix and demand are even occurring to a degree that warrants substantial changes to the current approach, yet the Commission goes to great lengths to express its concerns over this ambiguous concept. The very purpose of the NOPR, as expressed by the Commission, is to address the Commission's concern that the processes in Order No. 1000 "*may not* be planning transmission on a sufficiently long-term, forward-looking basis to meet transmission needs driven by changes in the resource mix and demand."[9] The Commission makes no finding that Order No. 1000 is unjust or unreasonable but instead proposes to amend Order No. 1000 based

[8] NOPR at P 3 (emphasis added).

[9] NOPR at P 24.

upon this expressed concern that Order No. 1000 *may not* be planning transmission in a manner that meets the Commission's apparent policy preference for generation from renewable resources. This approach falls short of meeting the criteria for reasoned decision-making.

2. The NOPR acknowledges that demand is projected to grow at rates that are substantially lower than historical growth rates.

Demand growth has been and should continue to be the primary determinant of transmission capacity needs. The rate of demand growth is not expected to increase from historical levels. While demand will increase, the pace at which it increases over the next three decades is projected to decline from historical levels.[10] The NOPR itself recognizes that demand is projected to increase at rates that are substantially less than historical growth rates, citing the National Renewable Energy Laboratory's ("NREL") medium electrification case.[11] NREL projects that under a moderate scenario, electrification of the end uses that currently rely on other energy sources is expected to increase demand by 2050 to approximately 25 percent above today's level.[12] In other words, over the next 28 years, demand is expected to increase at less than 1% annually.

This finding is supported by numerous other data and industry analyses. For example, the Edison Electric Institute found that transmission spending from investor-owned electric utilities has surged 42 percent from $17.7 billion in 2013 to $25.1 billion in 2019[13] while demand during this seven-year period increased by a much lower 2.3 percent.[14] Further, annual transmission investment in Commission-regulated RTO/ISO regions is steadily increasing. In

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[10] NOPR at FN 76 ("increase electricity demand by 2050 to about 25% above today's level").

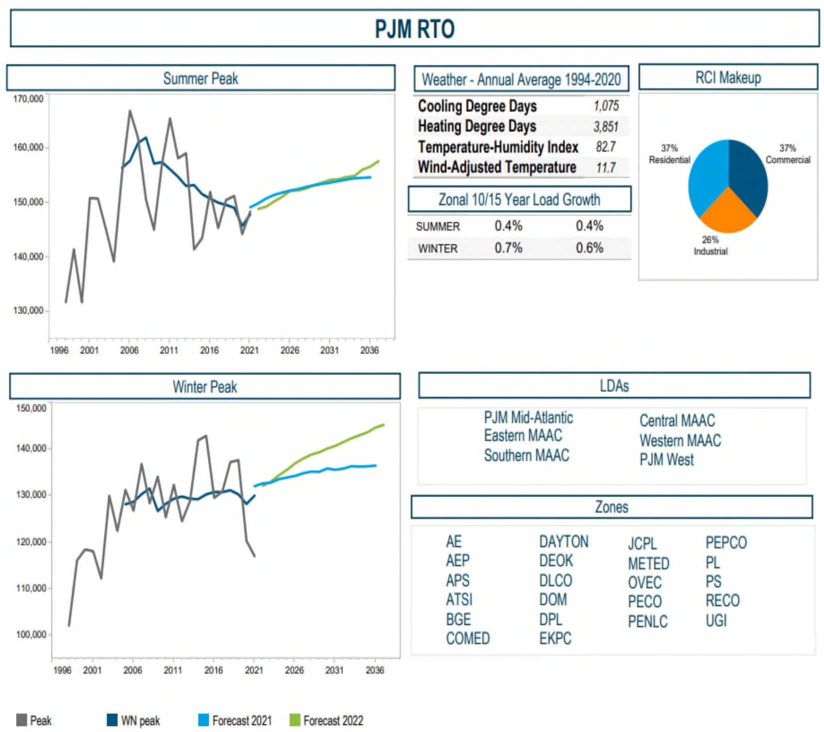
[11] *Id*.

[12] *Id.*

[13] "Financial Review 2019," Edison Electric Institute (EEI), https://www.eei.org/issuesandpolicy/Finance%20and%20Tax/Financial_Review/FinancialReview_2019.pdf.

[14] "Electric Power Annual 2019," U.S. Energy Information Administration (EIA), page 10, table 2.2, https://www.eia.gov/electricity/annual/html/epa_01_02.html.

2007, when the Commission issued Order No. 890, it noted that the United States had "witnessed a decline in transmission investment relative to load growth," and found that the resulting grid congestion could "have significant costs to consumers."[15] Today, the exact opposite scenario exists - transmission investment and associated transmission rates are increasing rapidly, while load remains generally flat.[16] As shown in the chart below, PJM estimates annual summer peak load growth of 0.4% and winter peak load growth of 0.7% over the next 10 years.[17]



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[15] *Prevent Undue Discrimination and Preference in Transmission Service*, FERC ¶ 60,421, 72 Fed. Reg. at 12,276, 12,318.

[16] U.S. Energy Information Act Annual Energy Outlook 2021 (accessed Aug. 10, 2022), https://www.eia.gov/outlooks/aeo/electricity/sub-topic-01.php (finding forecasted electric load growth of less than 1 percent annually).

[17] *Id.*

[18] "PJM Load Forecast Report", https://pjm.com/-/media/library/reports-notices/load-forecast/2022-load-report.ashx.

Meanwhile, ISO-NE's Load Forecast Committee estimates that its gross winter peak demand for the region is forecast to increase at a "compound annual growth rate of 1.8% from 2021 through 2030.[19] This increase would result in peak winter demand increasing from 22,363 MW for winter 2022/2023 to 25,041MW for 2030/2031.[20] ISO-NE's summer peak is "forecast to increase at a compound annual growth rate of 0.7% from 2021 through 2030."[21] These estimates of peak demand growth are generally less than historical annual peak demand growth rates and certainly do not depart sufficiently from historical levels to constitute a "change in . . . demand" that necessitates a wholesale change in the approach to transmission planning.

3. There is nothing novel about "changes in resource mix" – such changes have been occurring for decades.

There is nothing novel about "changes in the resource mix" that necessitate a wholesale change in the approach to transmission planning. Changes in the resource mix have been occurring for over a century. A cursory glance at the shifts in policies impacting generation, technological innovation, and public attitudes toward specific generation types clearly indicate that the resource mix in the United States will continue to shift in ways that no one can predict. Technological advancement is necessarily unpredictable and is a primary driver in electric generation types. Transmission planners should not be required to consider speculative and uncertain factors when modeling future transmission needs. Practically, transmission planners should not have to assume that certain technology outcomes or generation types will dominate for the next 25 years. The risks to consumers of a wrong guess are simply too high. There is currently no reason to believe, and the NOPR provides no concrete evidence, that transmission

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[19] "Final 2022 Energy and Seasonal Peak Forecasts", "https://www.iso-ne.com/static-assets/documents/2022/05/lf2022_energy_seaspeak.pdf.

[20] *Id*. at slide 28.

[21] *Id*. at slide 18.

planners are in a better position today than they were more than ten years ago. Transmission planners are not now better situated to predict future supply-side technologies, electricity storage, and demand-side measures (such as demand response and distributed generation) with sufficient accuracy to justify the expenditure of billions of dollars in new transmission investment. The resource mix may be changing, but it has always been changing, and transmission is planned based upon known and measurable factors. Speculating about future "changes in the resource mix and demand" will place the risk of stranded costs and over-building the transmission system squarely on the backs of consumers.

Assuming that "changes in the resource mix and demand" means more generation from renewable energy resources, there is nothing new or novel about this change that warrants overruling Order No. 1000. In fact, if anything, the rapid increase in generation from renewable resources over the past 15 years is indicative that current procedures and processes in transmission planning and cost allocation are already facilitating a change in the resource mix. PJM, as of May 10, 2022, has more than 250 GW in its Interconnection Queue over its service territory.[22] PJM reports that "Generation Interconnection" was, by far, the number one "new service requests by application type" in 2022.[23] Renewable energy generation resources predominate PJM's Interconnection Queue.[24] And this is not unique to PJM. However, instead of adopting consumer protection and competitive processes to allow this transition to continue occurring at the lowest possible cost to consumers, the Commission sets out to drive transmission investment based upon the generation resource mix, instead of peak demand and reliability.

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[22] "Tariff Revisions for Interconnection Process Reform, Request for Commission Action by October 3, 2022, and Request for 30-Day Comment Period" ER22-2110-000, June 14, 2022, at 17.

[23] *Id*. at 4.

[24] *Id*. at 19.

4. Having substantial transmission investment occur through interconnection network upgrade costs has not been shown to be unjust, unreasonable, or unduly discriminatory.

The Commission has not asserted or provided substantial evidence that transmission investment through interconnection network upgrades is unjust, unreasonable, or unduly discriminatory or preferential. With participant funding and proper cost allocation, the transmission system and system planning should be indifferent to the fuel source of any given generator. Imposing the costs of network upgrades that are driven by interconnecting generators' location choices on those interconnecting generators sends the right price signals for generation location and transmission build-out.

The transmission system is designed to maintain reliability during hours of peak demand. For this reason, transmission planners conduct load forecasts and generation models to ensure the transmission system can handle the load during these hours of peak demand. When planning the transmission system, what matters most is the size and geographic location of the load, not the type of the interconnecting generators. Commission policies should recognize that it is economically efficient and appropriate for generators to locate close to load or close to existing transmission capacity that exists to serve load.

a. Disciplining the selection of the locations of new generation promotes consumer interests.

The Industrial Customer Organizations oppose any efforts to eliminate efficient locational price signaling to new generation. The Industrial Customer Organizations encourage the Commission not to base any rulemaking decisions on the view that generation is shifting from resources located close to population centers to resources, including renewables, located far from load centers.[25] Likewise, the Commission should not base any rulemaking decisions on arguments that interconnection costs for renewable energy resources are too high and should be socialized across all transmission customers. While some large-scale renewable resources may locate far from load centers (just as large-scale fossil-fueled generators often located closer to fuel sources that were distant from load centers), some generators are now capable of locating closer to load than ever before. With opportunities for on-site generation, energy storage, demand response, and interruptible capabilities, the opportunity for supply-demand imbalances to be addressed at or close to load is higher than ever, and opportunities for load itself to be better managed to support reliability continue to increase.

b. All network upgrade costs incurred by new generation are recoverable if the new generation is competitive in the market.

Network upgrade costs should be recovered by new generators through competitive market revenues. Competitive markets, driven by price signals and the principles of supply and demand, should drive the identification, size, and location of new generation. This includes consideration of the proximity of that new generation to transmission access, and recovery of generator network upgrade costs through generation market revenues (energy, capacity, ancillary services, etc.).

The Commission can streamline the interconnection process, while continuing to ensure that interconnection costs are not unjustly and unreasonably shifted to transmission customers. Reforms to the generator interconnection process should be directed at streamlining the process and accelerating the timing for generators to complete interconnection, as well as prohibiting generators from holding multiple speculative queue positions, and spreading the interconnection

[25] ANOPR at p. 4 ("The electricity sector is transforming as the generation fleet shifts from resources located close to population centers toward resources, including renewables, that may often be located far from load centers.").

costs borne by first-in-line projects to other subsequent generation projects that benefit from the network upgrades. With any reform, the Commission must ensure that generator interconnection costs remain in the first instance with the interconnecting generators and that those interconnecting generators have reasonable opportunities to recover those costs through market revenue to the extent they are competitive.

In Order No. 2003, the Commission found that "relatively unencumbered entry into the market is necessary for competitive markets."[26] Further, the Commission held that the objectives of Order No. 2003 were to "limit opportunities for Transmission Providers to favor their own generation" and to "facilitate market entry for generation competitors by reducing interconnection costs and time."[27] These are noble objectives that should remain true for the Commission, but any goal of facilitating market entry by lowering the cost and time of interconnection must be focused on lowering the costs to all customers and avoiding a shift in costs from interconnection customers to transmission customers

While transmission expansion planning for generator interconnections based on generator-by-generator assessments may not be optimal, it does result in generator costs being properly allocated to generators. Some areas have moved to studying clusters of generators simultaneously. The Commission should further consider and pursue considering generator interconnection requests in clusters or groups so as to lower costs to generators for interconnection while keeping costs from being shifted to transmission customers. The cluster or group studies allows similarly situated generator interconnection customers to pay a prorated share of the costs of required network upgrades, resulting in generation interconnection costs properly remaining with the generators.

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[26] Order No. 2003, 104 FERC ¶ 61,102 at P 11.

[27] *Id*. at P 12.

5. The NOPR Does Not Demonstrate That Existing Long-Term Transmission Planning Processes and Criteria Are Unjust, Unreasonable, or Unduly Discriminatory

Pursuant to FPA Section 206, the Commission must find, and provide substantial evidence supporting its finding, that existing rates are unjust, unreasonable, or unduly discriminatory or preferential.[28] FPA Section 206 instructs the Commission to remedy "any . . . practice" that "affect[s]" a rate for interstate electricity transmission services demanded or charged by any public utility if such practice "is unjust, unreasonable, unduly discriminatory or preferential."[29] However, the Commission has not demonstrated that any rate is unjust, unreasonable, unduly discriminatory or preferential and warrants a remedy.

Transmission planning is currently based upon known and measurable outcomes, and the Commission has not made any finding that this approach is unjust and unreasonable. Planning for so-called changes in the resource mix and demand, without establishing with certainty the change in resources or demand, will likely result in overbuilding the transmission system for generation that may ultimately not get built. This would be unjust and unreasonable. When transmission facilities are built for generation that does not get built, transmission customers pay the tab with little to no benefit. For this reason, transmission investment is properly driven by modeled future scenarios to ensure that there are sufficient long-term and comprehensive forecasts of future transmission needs.

C. A 20-Year Planning Horizon For New Transmission Has Not Been Shown To Be Just and Reasonable.

The Industrial Customer Organizations oppose the Commission's proposal for a 20-year planning horizon for new transmission that begins with the in-service date of new transmission

[28] 16 U.S.C. § 824e(a).

[29] 16 U.S.C. § 824e(a).

facilities. Simply stated, the 20-year planning horizon[30] for new transmission has not been shown to be just and reasonable because there is no demonstration that the benefits of such long-term planning will outweigh the uncertainty, speculation, and associated costs of such a lengthy planning horizon. Transmission planners should not be required to adopt a hardline 20-year planning horizon that may not be appropriate for their region, and that could be considered overly ambitious. As the D.C. Circuit noted in *Old Dominion Electric Cooperative v. FERC*, "We are sensitive to the concern . . . that individual utilities should not have free rein to impose unjustified costs on an entire region *by unilaterally adopting overly ambitious planning criteria*."[31] That is exactly what the Commission's proposed 20-year planning horizon would produce – overly ambitious planning criteria that will impose unjustified costs on consumers.

Transmission investment is and should always be driven by reliability and economic metrics that signal the need for new or upgraded transmission facilities. Requiring transmission planners to utilize 20-year planning horizons will result in substantially more uncertainty in transmission planning, ultimately driving up costs to consumers. The Commission itself recognizes the additional uncertainty and additional cost a 20-year planning horizon will impose on ratepayers - "there is likely to be more uncertainty in Long-Term Regional Transmission Planning, e.g., requiring public utility transmission providers to conduct Long-Term Transmission Planning over a minimum of 20 years (compared to the current practice of 6-15 years), than in the existing regional transmission planning processes."[32]

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[30] The Commission's proposed 20-year planning horizon is actually proposed as 20 years from the in-service date of a transmission project. Given the lead times for engineering, permitting, siting, and construction, the Commission's actual proposal is more like a 27-30 year planning horizon. For ease of reference, however, these Comments refer to a 20-year planning horizon.

[31] *Old Dominion Electric Cooperative v. FERC*, 898 F.3d 1254, 1263 (D.C. Cir. 2018).

[32] NOPR at P 330.

The Commission states its belief that "to be just and reasonable, the transmission planning horizon used in Long-Term Regional Transmission Planning should extend far enough into the future that public utility transmission providers can identify transmission needs that could be met with more efficient or cost-effective regional transmission facilities, i.e., the transmission planning horizon should capture the longer-term benefits of addressing transmission needs driven by changes in the resource mix and demand."[33] However, the NOPR presents no evidence that a significant expansion of the transmission planning horizon, beyond current industry accepted standards, will deliver net benefits to consumers.

1. Current Regional and Individual Transmission Owner Planning Horizons Typically Do Not Exceed 15 Years, and Many Are Less Than 15 Years.

As the Commission itself notes, current practices in regional transmission planning processes generally include planning horizons between 6 years and 15 years, with the vast majority utilizing a 10-year planning transmission planning horizon.[34] Here are examples of the current planning horizons in certain regions:

- CAISO – 10 years, with a recent effort to conduct informational high-level technical studies utilizing a 20-year horizon.
- NYISO – 10 years or shorter for reliability and economic needs.
- SPP – 10 years, with an informational 20-year assessment using scenarios every five years.
- MISO – 20 years.
- PJM – 15 years.
- Southeastern RTP – 10 years.
- WestConnect – 10 years.

[33] NOPR at P 92.

[34] NOPR at P 330.

- NorthernGrid – 10 years.

The reason for a 10-year planning horizon is because the vast majority of transmission projects have lead times less than 10 years. Additionally, NERC recognizes a typical, industry-standard planning horizon around 10 years. For example, NERC's definition of the Long-Term Transmission Planning Horizon is the "[t]ransmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete."[35] The Commission's view that Long-Term Regional Transmission Planning must extend 20+ years into the future to remain just and reasonable is not backed by substantial evidence. The vast majority of transmission planners utilize a much shorter planning horizon to more accurately forecast supply and demand, while still recognizing the lead times that are required for various voltages of transmission projects. The Commission has made no finding or provided substantial evidence that the current practice of utilizing planning horizons between 6 and 15 years is unjust or unreasonable. Indeed, the Commission even recognizes that the time needed to plan, obtain siting and permitting approval for, and construct regional transmission facilities take an average of 10 years.[36] The evidence supports continuation of the 10-year planning horizon currently utilized by the majority of transmission planning regions.

Requiring all transmission owners to use a 20-year planning horizon will interject substantial additional uncertainty into transmission planning, ultimately resulting in increased speculation and higher transmission rates. While there may be scenarios where a 20-year planning horizon can be utilized, shorter planning horizons should be utilized for any reliability

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[35] See NERC, *Glossary of Terms Used in NERC Reliability Standards* (June 28, 2021), https://www.nerc.com/files/glossary_of_terms.pdf.

[36] NOPR at P 98.

and economic needs. For example, NYISO utilizes a 20-year horizon to evaluate scenarios involving Public Policy Requirements and its Outlook. However, for its regional transmission planning process for reliability and economic needs, NYISO uses a 10-year or shorter transmission planning horizon.[37] And in its Comments to the ANOPR, NYISO did not recommend requiring a 20-year planning horizon, but rather proposed that the Commission grant discretion *up to* 20 years.[38]

The Eastern Interconnection Planning Collaborative ("EIPC") has recognized that member regions within the Eastern Interconnection typically utilize a 10-year-forward forecast. The EIPC Transmission Analysis Working Group produces Eastern Interconnection roll-up integration cases, which it conducted for 2028 summer and 2028 winter. The roll-up integration cases represent the "base cases" for the Eastern Interconnection that are suitable as starting points for additional transfer analysis and analysis of scenarios developed by industry stakeholders. In conducting these analyses, the EIPC utilized a 10-year-forward forecast "because that is the typical horizon utility by EIPC member regions for their regional planning."[39] By requiring a 20-year planning horizon, the Commission will insert substantial uncertainty into long-term regional transmission planning, ultimately driving up costs to consumers for no commensurate reliability benefit.

2. Exceeding Reasonable Forecast Periods Increases Speculation and Uncertainty, Which Increases Consumer Costs.

Currently, transmission investment is driven by modeled future scenarios to ensure that there are sufficient long-term and comprehensive forecasts of future transmission needs,

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[37] NOPR at P 94.

[38] NYISO ANOPR Comments at 34-37.

[39] *EIPC State of the Grid Report*, December 2021, (Accessed August 2, 2022), https://static1.squarespace.com/static/5b1032e545776e01e7058845/t/61b8f9ae4172c60bdd3a72ad/1639512495712/2021+EIPC+State+of+the+Grid+12-7-21.pdf

including consideration of generation that is known and measurable. Generally, transmission planners include in baseline reliability models only those generators that have completed a facilities study and are thus far enough along in the interconnection queue so as to have a sufficiently high commercial probability and be modeled as an expected future generator. By considering generators at certain advanced stages of an interconnection queue, transmission planners can properly plan for future generation deployment that is known and measurable without the need to consider highly speculative or uncertain future factors. By proposing to increase the planning horizon beyond a reasonable forecast period, the Commission adds "more uncertainty in Long-Term Regional Transmission Planning . . . than in the existing regional transmission planning processes."[40] The Commission has not shown that any uncertainty or speculation in long-term supply and demand forecasts will not be consistently construed in favor of decisions to build rather than decisions not to build. A few examples may illustrate the point. If a transmission owner models demand 20+ years into the future, and load forecasts vary between 20% load growth over that period to 30% load growth over that period, why would the transmission provider (or, ideally, the independent transmission planner) not commence a build-out based on the 30% load growth projection "just to be sure"? Likewise, if a transmission owner modelled a possible range of 10,000 MWs to 20,000 MWs of new wind generation in a wind-rich area, why would the transmission provider not commence a transmission build-out based on the possibility of 20,000 MWs of new wind generation "just to be sure"? Tightening these ranges by continuing nearer-term scenario analyses reduces the monetary impacts of the "just to be sure" approach and would produce better rate outcomes for transmission customers.

[40] NOPR at P 330.

In short, the Industrial Customer Organizations have serious concerns that requiring 20+ year scenario modelling will result in substantially increased uncertainty and speculation in transmission planning that will be addressed by "just to be sure" projects that will turn out to be unnecessary and very costly to consumers. The NOPR does not any evidence to the contrary that would ameliorate, much less fully address, these concerns. The Commission should not move forward with a mandatory 20+ year transmission planning horizon.

D. Transmission Cost Allocation Must Continue to Abide By the "Roughly Commensurate Benefits" Standard.

The Commission has described its "long standing policy" on utility cost allocation in this manner: "Properly designed rates should produce revenues from each class of customers which match, as closely as practicable, the cost to serve each class or individual customer."[41]

1. The Roughly Commensurate Benefits Standard is Well-Established.

Cost-causation principles have "traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[42] This applies as much in general ratemaking as it does to transmission cost allocation.[43] In applying principles of cost-causation, the Seventh Circuit in *Illinois Commerce Commission v. FERC* reversed a FERC decision approving PJM's proposed pricing mechanism for new transmission facilities with a capacity of 500 kV or higher, in part because the Commission had not adequately followed the principle of cost causation.[44] The Seventh Circuit noted:

> We do not suggest that the Commission has to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars . . . If it cannot quantify the benefits to the

[41] *New Dominion Energy Cooperative*, 122 FERC ¶ 61,174, P 41 (2008), *citing Alabama Electric Cooperative, inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982).

[42] *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1991).

[43] *See Pac. Gas & Elec. Co. v. FERC*, 373 F.3d 1315 (D.C. Cir. 2004).

[44] *Illinois Commerce Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009).

> Midwestern utility from new 500 kV lines in the East . . ., but it has *an articulable and plausible reason to believe that the benefits are at least roughly commensurate* with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis.[45]

While the principle of cost-causation and standard of "roughly commensurate benefit" did not necessarily start with the Seventh Circuit's opinion, the Seventh Circuit did establish that for benefits that cannot be quantified there must be an "articulable and plausible" reason to believe that such benefits are roughly commensurate to the costs.

More recently, in *Old Dominion Electric Cooperative v. FERC*, the D.C. Circuit held in 2018 that the Commission acted arbitrarily and capriciously in prohibiting high-voltage transmission lines in PJM from being regionally cost allocated.[46] In that case, the Court held that the Commission failed to justify its prohibition of regional cost sharing for projects which were conceded to have regional benefits. The Court found that "the cost-causation principle, by allocating project costs consistent with project benefits, creates the best incentives for … utilities themselves to agree on when to invest their scarce resources in transmission improvements."[47] Long-established legal precedent on cost causation and ratemaking principles require that rates remain just and reasonable, that customers pay for transmission upgrades based upon their roughly commensurate benefits, and that new generators pay the costs for the return of and return on network upgrades if such upgrades would not be needed *but for* the new generator(s).[48]

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[45] *Id.* at 477 (emphasis added).

[46] *Old Dominion Electric Cooperative v. FERC*, 898 F.3d 1254 (D.C. Cir. 2018).

[47] *Id*.

[48] *See KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *Ill. Com. Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009); *ISO New England, Inc., New England Power Pool*, 115 FERC ¶ 61,145 at P 13 (2006), *aff'd*, *Transcanada Power Mktg. Ltd. v. FERC*, 811 F.3d 1 (D.C. Cir. 2015); *El Paso Elec. Co. v. FERC*, 832 F.3d 495, 499-500, n.10 (5th Cir. 2016); *Midcontinent Indep. Sys. Operator, Inc*., 159 FERC ¶ 63,016 at P 138 (2017), adopted without modification by, *Midcontinent Indep. Sys. Operator, Inc.*, 164 FERC ¶ 61,194, (2018). *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 at P 622 (2011) ("Order No. 1000"), *order on reh'g*, Order No. 1000-A, 139 FERC ¶

2. Any State Agreement Approach Must Remain Subject To The Roughly Commensurate Benefits Standard.

For Long-Term Regional Transmission Cost Allocation, the Commission proposes to require that public utility transmission providers in each transmission planning regions revise their OATTS to "include either (1) a Long-Term Regional Transmission Cost Allocation Method to allocate the costs of Long-Term Regional Transmission Facilities, or (2) a State Agreement Process by which one or more relevant state entities may voluntarily agree to a cost allocation method, or (3) a combination thereof."[49] Regarding the State Agreement Process, the Commission requires that it "comply with the existing six Order No. 1000 regional cost allocation principles."[50] The first of the six Order No. 1000 regional cost allocation principles is that "The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits."[51] Similarly, Order No. 1000 prohibits costs from being allocated to entities with little to no benefits.[52] Even where there is a State Agreement Process, or a combination State/LTRT cost allocation methodology, the cost allocation methodology must remain within the Commission's jurisdiction and responsibility to ensure that rates are roughly commensurate with estimated benefits to abide by principles of cost-causation. While the Commission is providing deference to states on cost allocation methods, any method that may be adopted pursuant to a State Agreement Process or combined State/LTRT Process must fall

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61,132 (2012) ("Order No. 1000-A"), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012) ("Order No. 1000-B"), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[49] NOPR at P 302.

[50] NOPR at P 302.

[51] Order No. 1000 at P 558; see also, *Old Dominion Electric Cooperative v. FERC*, 898 F.3d 1254 (D.C. Cir. 2018).

[52] *Id.*

within the scope of the Commission's jurisdiction to ensure that rates are roughly commensurate with estimated benefits.

Finally, the Commission should specifically find that any State Agreement Process or combined State/LTRT Process is required to comply with the roughly commensurate benefits standard. While cost-causation is one of the six Order No. 1000 regional cost allocation principles, it could be argued that "compliance with Order No. 1000 does not necessarily ensure compliance with the cost-causation principle [which is a] pre-existing, more general rule that, in order to ensure just and reasonable rates, FERC must make some reasonable effort to match costs to benefits."[53] To this end, the Commission should find that any State Agreement Process or combined State/LTRT Process meets the six Order No. 1000 regional cost allocation principles <u>and</u> establishes rates based upon the roughly commensurate benefits.

E. The Proposed Elimination Of The Construction Work In Progress Incentive Is, Potentially, A Step In The Right Direction, But Only If Coupled With Greater Discipline On Abandoned Plant Recovery.

The Industrial Customer Organizations are supportive of any "additional protection for ratepayers [that] 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."[54] Accordingly, the premise for eliminating the CWIP Incentive and requiring utilities to book pre-construction and construction costs using only the AFUDC approach is sound. However, if the AFUDC approach is required as the exclusive means for booking the costs of Long-Term Regional Transmission Facilities, the Commission should adopt additional consumer protections to prevent consumers from paying for facilities that do not become used and useful. With greater

[53] *Id.*, *citing BNP Paribas Energy trading GP v. FERC*, 743 F.3d 264, 268 (D.C. Cir. 2014).

[54] NOPR at P 331.

attention to consumers and additional consumer protections, the Industrial Customer Organizations would ultimately support the outcome of the Commission's proposal to allow costs to be booked using the AFUDC approach.

1. All Else Being Equal, The Time Value Of Money Is The Only Cost Difference To Customers Between The CWIP And AFUDC Approach To Booking Costs Incurred During Pre-Construction and Construction.

Whether costs are booked using the CWIP or AFUDC approach, the utility would ultimately be expected to recover its return on those construction costs. Under the CWIP Incentive adopted by the Commission in Order No. 679, transmission developers were authorized to include construction costs in rate base prior to commercial operation, which provides the utility with additional cash flow in the form of an immediate earned return rather than delaying cost recovery until the plant is placed in service. Under the CWIP Incentive, the utility recovers its return on a current basis during construction, while under the AFUDC approach, the utility recovers its return when the projects is eventually placed in service. Accordingly, absent the potential non-recovery of abandoned plant costs, the only difference between the approaches should be whether customers pay the utility's return on pre-construction and construction costs now or later.

However, all else does not have to be equal. The Commission notes its concern that, under the CWIP Incentive, "should the regional transmission facilities not be placed in service, then ratepayers will have financed the construction of such facilities that were not used and useful, while ultimately receiving no benefits from such facilities."[55] Even under the AFUDC approach, the same risk remains – customers may finance construction of transmission facilities that are not ultimately used and useful without receiving any benefit for such facilities. The

[55] NOPR at P 332.

Commission should do more than eliminate the pay me now approach in favor of a pay me later approach because that change, standing alone, may do little or nothing to minimize consumer costs.

2. AFUDC Could Be a Superior Approach For Consumers, But Only If A Final Rule Adopts Certain Protections To Ensure That Customers Do Not Pay For Abandoned Plant Costs.

Current Commission regulations could require customers to pay the return to a transmission owner even when the financed facilities are not ultimately used and useful, even under the AFUDC approach.[56] The Commission notes that under its proposed reform of the CWIP Incentive to allow the return on pre-construction and construction costs under the AFUDC approach, "should the regional transmission facilities not be placed in service, then ratepayers will have financed the construction of such facilities that were not used and useful, while ultimately receiving no benefits from such facilities."[57] Allowing transmission owners to book the return on pre-construction and construction costs itself will not protect customers from paying for the return on transmission facilities that do not become use and useful.

a. Abandoned plant costs should not be presumed prudent or recoverable.

Abandoned plants costs should not be presumed prudent or recoverable. The transmission owner must demonstrate that costs incurred for any abandoned plant were what a reasonable utility would have undertaken under like circumstances known at the time. Under either the CWIP Incentive or the AFUDC approach, the transmission owner must maintain the burden to demonstrate the prudency of all costs incurred. Regarding prudence of abandoned

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[56] Order No. 679, 116 FERC ¶ 61,057 at P163 (2006); *MidAmerican Central California Transco, LLC*, 168 FERC ¶ 61,197 at P 3 (2019); *GridLiance West Transco LLC*, 164 FERC ¶ 61,049, at P 19-20 (2018); *Xcel Energy Services, Inc*., 121 FERC ¶ 61,284 at P 62 (2007).

[57] NOPR at P 331.

plant costs, the Commission noted in *Potomac-Appalachian Transmission Highline, LLC* ("PATH"), citing *New England Power* that:

> [M]anagers of a utility have broad discretion in conducting their business affairs and in incurring costs necessary to provide services to their customers. In performing our duty to determine the prudence of specific costs, the appropriate test to be used is whether they are costs which a reasonable utility management [] would have made, in good faith, under the same circumstances, and at the relevant point in time.[58]

However, while the regulated utility has the burden of proof to establish prudence, the Commission "presumes that all expenditures are prudent, so the utility need not justify in its case-in-chief the prudence of all of its costs."[59] The Commission has alleged that this is to "ensure that rate cases are manageable."[60] However, this puts consumers in the difficult position of rebutting a presumption of prudence for abandoned plants costs, with the Commission then applying a simple preponderance of the evidence standard to determine whether such costs are recoverable. If the Commission moves forward with the AFUDC approach for abandoned plant costs, it must also eliminate the presumption of prudence for such abandoned plant costs. The Commission should be clear that recovery of abandoned plant costs may not occur automatically through transmission formula rates and, instead, require that all requests for such recovery occur in a stand-alone proceeding. And when seeking to recover abandoned plant costs in rates, the Commission should require transmission utilities to demonstrate the prudence of such costs in their case-in-chief.

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[58] *Potomac-Appalachian Transmission Highline, LLC*, 158 FERC P 61,050 at 61,313; citing, *New England Power Co*., 31 FERC P 61,047, 61,084 (1985).

[59] *Id*. at 61,315.

[60] *Id.*

3. Abandoned plant costs should be recovered with a lower return than what applies to plant that is used and useful.

The Commission should establish that prudently incurred plant costs will be recovered with a return based upon a lower cost of capital than the cost of capital that applies to plant that is used and useful in service to the public. If abandoned plant recovery is permitted at all, customers will typically be required to pay a return on prudently incurred plant costs even though they receive no benefit for it. However, the Commission has historically found that the utility's ROE would not be just and reasonable if applied to abandoned plant costs because the risk of recovery of such costs is not comparable to the risks of an operating utility. Accordingly, the Commission should ensure that the return is calculated using the lowest cost method for determining the cost of capital. Because recovery of all costs is virtually guaranteed (*i.e.* risk-free), the Commission could use yields on U.S. Treasury bonds that are commonly used as the risk-free rate in the Discounted Cash Flow analysis for establishing a just and reasonable cost of capital for abandoned plant costs. The Commission could also set the cost of capital based on an ROE for abandoned plant costs at the low end of the zone of reasonableness and recognize that the Commission has also used the "median of the lower half of the zone of reasonableness."[61] Whichever method the Commission uses, the return on abandoned plant costs should be less than the return that is allowed for plant that is used and useful, and the Commission should establish the appropriate means for setting the return on abandoned plant costs.

In *PATH*, the Commission found that the utility's 10.4 percent ROE was not just and reasonable for abandoned plants costs that the utility sought to recover.[62] The Commission found that "in the abandonment phase of the project, PATH's risk profile has decreased

[61] *Id*. at 61,345.

[62] *Id.*

significantly as compared to the proxy companies that face ongoing business risks."[63] The Commission found that investors will have certainty of recovery of 100 percent of the prudently incurred costs for projects that are abandoned due to factors outside the control of the developer, plus an ROE on those costs commensurate with the developer's risk. The Commission's decision in *PATH* followed the decision of the D.C. Circuit in *Town of Norwood v. FERC*, in which the Court held that following the early retirement of a nuclear power plant, the utility had no ongoing need to attract capital and was guaranteed recovery of virtually all costs, so the plant's reduced risk profile required the Commission to reduce its ROE to the lower end of the zone of reasonableness.[64]

When plant is abandoned, there is no need to attract capital, so equity should not factor into the ROE determination. With 100% assurance of recovery of costs, equity holders have no more business risk than the bondholders. For this reason, the Commission should set the ROE equal or close to the cost of debt.[65] Pursuant to the Commission's finding in *PATH* and the D.C. Circuit in *Town of Norwood*, any determination that return on abandoned plant costs should be at or above the median ROE within the zone of reasonableness would be unjust and unreasonable.

F. Industrial Customers Appreciate The Proposed Requirement For Transmission Providers To Consider Certain Grid-Enhancing Technologies, But the Proposal Stops Short Of Optimizing Consumer Protections or Transmission Cost Savings.

The Industrial Customer Organizations support the Commission's proposal to incorporate dynamic line ratings ("DLRs") and advanced power flow control devices ("APFC Devices")

[63] *Id.* at 61,333.

[64] *Town of Norwood v. FERC*, 80 F.3d 526, 317 U.S. App. D.C. 50 (D.C. Cir. 1996).

[65] *See Yankee Atomic Elec. Co.*, 65 FERC at 65,015 (ALJ Decision) (the Commission's Trial Staff recommended fixing Yankee's rate of return at its cost of servicing debt).

directly into transmission planning.[66] Additionally, the Industrial Customer Organizations urge the Commission to require consideration of more Grid-Enhancing Technologies ("GETs") than just DLRs and APFC Devices, and support requiring non-RTO/ISO transmission planning regions to update their energy management systems if GETs are identified as more efficient or cost-effective. Finally, Industrial Customer Organizations urge the Commission to require consideration of GETs in all transmission planning, including local/supplemental transmission planning, not just in regional transmission planning.

In the NOPR, the Commission proposes "to require that public utility transmission providers in each transmission planning region more fully consider in regional transmission planning and cost allocation processes two specific technologies: the incorporation into transmission facilities of dynamic line ratings and advanced power flow control devices."[67] The Commission then seeks comment on (1) the requirement to incorporate DLRs and APFC Devices, (2) whether there are other transmission technologies serving a transmission function that should be considered in regional transmission planning and cost allocation processes, and (3) whether non-RTO/ISO transmission planning regions should be required to update their energy management systems or make other similar changes if DLRs are identified as a more efficient or cost-effective transmission facility in the regional transmission plan for purposes of cost allocation.[68] While the Industrial Customer Organizations appreciate the proposed requirement for DLRs and APFC Devices, the proposal does not go far enough to optimize consumer protections or transmission cost savings.

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[66] NOPR at P 256-277.

[67] NOPR at P 272.

[68] NOPR at P 272.

The Commission should require consideration and usage of more GETs than just DLRs and APFC Devices. For instance, in the ANOPR, the Commission noted that power flow control and switching equipment, storage technologies, and advanced line rating management technologies all work to increase the capacity, efficiency, and reliability of transmission facilities.[69] However, in the NOPR, the Commission abandons many of the other GETs that could provide meaningful capacity, efficiency, and reliability benefits to consumers and the transmission system.

The benefits of DLRs are well established. For example, in January 2020, PPL Electric Utilities ("PPL") presented at a number of PJM stakeholder meetings about placing DLRs in service on two 230 kV transmission lines: the Susquehanna-Harwood and Juniata-Cumberland lines.[70] The Susquehanna-Harwood and Juniata-Cumberland lines were in the 2020 Top 10 Congested Facilities in PJM (#8 and #10, respectively) and together were responsible for approximately $30 million in congestion costs.[71] As a result of implementing DLRs on the lines, PPL expects an average increase of almost 30% in the capacity of the lines.[72] The savings to consumers from DLRs are real, but the savings should not stop with consideration of DLRs and APFC Devices alone.

Additionally, the Commission should require GETs for all Commission-jurisdictional public utilities and in more situations. Requiring GETs would be a positive step toward enabling grid operators to measure and make transparent the optimal physical capacity of electric

[69] FERC, *Grid Enhancing Technologies*, Notice of Workshop, Docket No. AD19-9-000 (Sept. 9, 2009).

[70] See "Dynamic Line Ratings – Impacts to PJM", PJM, Slide 4, available at 20201113-item-03c-dlr-impacts.ashx (pjm.com) (last accessed Sept. 22, 2021).

[71] See "Dynamic Line Ratings Strategy," PPL Electric Utilities, available at 20210113-item-12-ppl-dynamic-line-ratings.ashx (pjm.com) (last accessed Sept. 22, 2021).

[72] 2020 Top 10 Congested Facilities – PJM Presentation: Markets Report, Slide 52, PJM Members Committee Webinar, January 2021, available at 20210125-item-07a-markets-report.ashx (pjm.com) (last accessed Sept. 22, 2021). The $30 million is an approximate amount based on the chart on Slide 52.

transmission circuits so that grid operators, market participants, and other stakeholders may make informed decisions about planning and system operations.

1. **Consideration of GETs Should Be Required For <u>All</u> Transmission Investment by all Commission-Jurisdictional Utilities.**

The Commission should adopt rules requiring the implementation of GETs for *<u>all</u>* transmission investment, unless transmission owners can establish that the cost of implementing GETs would exceed the GET-related benefits to consumers (via lower transmission rates and energy, capacity, and ancillary services prices). In nearly every case, the cost of installing GETs will be nominal in comparison to the benefits of reduced congestion, lower energy and capacity costs, and reduced need for investment in new transmission system capability. Further, GETs can reduce the cost of interconnection-related network upgrades. To this end, the Commission should require transmission providers to consider GETs for all transmission investment.

2. **The Commission should require consideration of GETs by all Commission-jurisdictional transmission utilities.**

The Commission specifically requests "comment on whether non-RTO/ISO transmission planning regions should be required to update their energy management systems or make other similar changes if [DLRs] are identified as a more efficient or cost-effective transmission facility selected in the regional transmission plan for purposes of cost allocation."[73] The answer is unequivocally *yes*. The Commission's requirement for DLRs and APFC Devices should apply to all Commission-jurisdictional transmission utilities. Non-RTO/ISO transmission planning regions should be required to update their energy management systems and make other changes to incorporate the benefits of GETs into their regional transmission plans for purposes of cost allocation.

[73] NOPR at P 277.

The Commission should promote optimization of existing transmission infrastructure before transmission expansion. To do this, the Commission should require that GETs be used by all incumbent Commission-jurisdictional transmission owners when they benefit consumers. Before new projects are developed, transmission utilities and developers should be required to demonstrate full utilization of GETs and other grid optimizations when they are cost-effective. Generally, there is very little opposition to GETs, and in comments to the Commission's ANOPR, parties widely support further use of GETs. All Commission-jurisdictional utilities should be required to consider GETs as an alternative to all new transmission investment, which will reduce congestion and eliminate the costs of unnecessary new transmission buildout. Requiring GETs where cost-effective will enable grid operators in all regions, not just RTO/ISOs, to measure and make transparent the optimal physical capacity of electric transmission circuits so that grid operators, market participants, and other stakeholders may make informed decisions about planning and system operations.

3. The Commission should require consideration of GETs for all new transmission investment, not just facilities in regional transmission plans.

The Commission proposes to incorporate DLRs and APFC Devices into regional transmission planning processes for selection in the regional transmission plan for purposes of cost allocation. However, transmission utilities are making substantial investment in local transmission facilities, typically without consideration of whether GETs would provide a more efficient or cost-effective solution. Accordingly, the Commission should require consideration of GETs for all transmission investment.

The Commission should adopt rules requiring consideration of GETs for all transmission investment. Regarding DLRs specifically, the Commission should require transmission utilities to establish that the cost of implementing DLRs would exceed DLR-related benefits to consumers (via lower transmission rates and energy, capacity, and ancillary services prices) before proceeding with transmission investment. In nearly every case, regardless of the size or location of the transmission facility, the cost of installing DLRs will be nominal in comparison to the benefits of reduced congestion, lower energy and capacity costs, and reduced need for investment in new transmission system capability.

4. Consideration of Alternatives to New Transmission Investment Should Not Be Limited to GETs.

The Industrial Customer Organizations support competition in transmission planning and design, which includes competing proposals for resolving identified reliability needs. To protect consumers, the Commission should adopt an all-of-the-above approach to transmission planning requiring consideration of demand response and GETs on equal footing with new transmission investment.

5. Demand response, facilitated by remedial action schemes or other load-limiting devices, can provide meaningful alternative to new transmission investment.

The Industrial Customer Organizations represent large, energy-intensive transmission customers, many of which have made extensive investments in interruptible, demand response, and other load-limiting devices. These customers are capable of providing substantial benefits to the transmission system by lowering their Network Service Peak Load, which can provide meaningful alternatives to new transmission investment. Demand response, when properly managed and accounted for, can provide alternatives to new transmission investment.

Cost allocation and rate design must reflect the peak loads that drive new transmission investment. Transmission investment is made to meet peak load, with such peak demand determined based upon an analysis of the coincident peaks ("CPs") in the relevant transmission planning area. While different regions may utilize different CP approaches (*e.g.* 1 CP, 4 CP, etc.), transmission planning for reliability is to ensure that the transmission system is sufficient to meet demand during those peak hours. Demand response can provide a meaningful alternative to new transmission investment because it can respond in real-time during these peak demand hours. Demand response, interruptible load, and other load-limiting devices reduce demand during peak demand hours, resulting in transmission cost savings to consumers. The Commission should take the necessary steps to ensure that cost allocation and rate design are fully aligned with the peak demand determinants that drive transmission planning.

6. The Commission should universally apply transmission cost allocation on a net basis to facilitate consumer adoption of distributed energy resources.

The Commission should universally apply cost allocation on a net basis to facilitate greater consumer adoption of distributed energy resources. The Industrial Customer Organizations represent large, energy-intensive transmission customers, many of which have or have the capability to deploy on-site distributed energy resources ("DERs"). As noted previously, opportunities for on-site generation, energy storage, demand response, and interruptible capabilities continue to increase, allowing for supply-demand imbalances to be addressed at or close to load, and for load itself to be better managed to support reliability. These distributed energy resources, located behind the customer's meter, can result in less load during peak demand hours. For example, for summer peaking regions, distributed solar resources located behind the meter of a large manufacturer can reduce peak demand during those summer peak load hours. This can result in cost savings to all transmission customers in the form of lower peak demand and less investment in transmission facilities. The Commission should require transmission planning in all regions to apply transmission cost allocation on a net basis, considering not just customer load but also behind-the-meter generation and demand response that reduces load during peak demand hours.

V. CONCLUSION

WHEREFORE, the Industrial Customer Organizations respectfully request that the Commission afford due consideration to these Comments.

Respectfully submitted,

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Dated: August 17, 2022

CERTIFICATE OF SERVICE

I hereby certify that I have this day served, via first-class mail, electronic transmission, or hand-delivery the foregoing upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, DC this 17th day of August, 2022.

/ s / Robert A. Weishaar, Jr.

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