UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements	)))))	Docket No. AD23–3–000

COMMENTS OF PUBLIC INTEREST ORGANIZATIONS

Natural Resources Defense Council, Sustainable FERC Project, Western Resource Advocates, RMI, Southern Environmental Law Center, Environmental Defense Fund, Sierra Club, and NW Energy Coalition (together "Public Interest Organizations" or "PIOs") submit these comments in response to the March 6, 2023 notice inviting comments to the December 5-6, 2022 technical conference ("Technical Conference") convened by the Federal Energy Regulatory Commission ("Commission" or "FERC") regarding whether and how the Commission could establish a minimum requirement for Interregional Transfer Capability for public utility transmission providers in transmission planning and cost allocation processes.[1] Below, PIOs address the questions included in the Notice.

I. Introduction

PIOs appreciate the opportunity to provide the Commission with further information to inform the development of a minimum requirement for Interregional Transfer Capability. Since the December 2022 workshop, the need for Commission action on establishing a minimum requirement has only grown more compelling. Several weeks after the workshop, Winter Storm Elliott caused multiple grid operators in the Southeast to implement rolling blackouts and brought

[1] Staff-Led Workshop Concerning Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*,* Docket No. AD23–3–000 (Dec. 5-6, 2022).

several large Regional Transmission Organizations to the brink of shedding load.[2] Along with Winter Storm Uri,[3] this marked the second significant loss of load event in less than two years, and adds to a growing tally of other rolling blackouts and near-misses due to severe weather: the 2011 cold snap that caused rolling outages in ERCOT and the Southwest, the 2014 Polar Vortex, the 2018 Bomb Cyclone, the 2018 South Central cold snap event, the 2019 Polar Vortex, Hurricane Ida in 2021,[4] and Western heat waves in 2020 and 2022.[5] Expanded interregional transmission could have greatly reduced if not eliminated the reliability risks during these events, providing a lifeline to those for whom reliable power is a matter of life and death.

Winter Storm Uri showed the value of interregional transmission for electric reliability and resilience. Grid operating regions with strong interconnections to neighbors, like MISO, were able to weather the storm with minimal loss of load, while those with weak transmission ties, like ERCOT, fared far worse. During Uri, MISO was able to import 15 times as much power as ERCOT.[6] Severe weather is increasingly harming electric reliability, and threats from physical and

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[2] *See*, *e.g*., https://www.pjm.com/markets-and-operations/winter-storm-elliott. *See also* https://rmi.org/wasted-wind-and-tenable-transmission-during-winter-storm-elliott/.

[3] *See, e.g*., Peter Aldhous et al., *The Texas Winter Storm And Power Outages Killed Hundreds More People Than The State Says*, BuzzFeed News (May 26, 2021), https://www.buzzfeednews.com/article/peteraldhous/texas-winter-stormpower-outage-death-toll. In addition to the lives lost in Uri, power outages due to extreme weather events also led to the deaths of over 1,000 people in Puerto Rico from Hurricane Maria. *See* Eliza Barclay*, 1,427 deaths: Puerto Rico is coming clean about Hurricane Maria's true toll*, Vox (Aug. 9, 2018), at https://www.vox.com/2018/8/9/17670762/puerto-rico-hurricane-maria-death-toll-congress.

[4] Eleven people are estimated to have died as a result of power outages in New Orleans during Hurricane Ida linked to the failure of all 8 transmission lines serving the city as well as the natural gas plant Entergy claimed would serve as a blackstart resource. *See* Max Blau et al., *Entergy Resisted Upgrading New Orleans' Power Grid. Residents Paid The Price*, NPR (Sept. 22, 2021), https://www.npr.org/2021/09/22/1039110522/entergy-resisted-upgrading-new-orleans-power-grid-residents-paid-the-price.

[5] *See, e.g.,* A root cause analysis of the event determined that while there was energy availability in the north that could have alleviated the crisis, "transmission constraints ultimately limited the amount of physical transfer capability into the CAISO footprint." *See* The Brattle Group and Grid Strategies, *Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Cost*, at 10 (Oct. 2021) (citing California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC), *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*, Final, January 13, 2021, p 48, at http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[6] *See* FERC-NERC, Presentation on February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations, at Slide 7 (Sept. 23, 2021) ("Overall, MISO's and SPP's ability to transfer power through their

cyber-attacks and other unexpected events have also increased in recent years. Because all of these threats tend to have a limited duration and geographic scope, transmission ties that increase the ability to import power from neighboring regions are an essential part of the solution.

Transmission has several attributes that make it uniquely well-suited for addressing such risks. Transmission can deliver electricity in both directions, so both connected regions benefit. For example, transmission flows flipped from westward to eastward as Winter Storm Elliott moved eastward across the country, as has happened during past severe weather events. Similarly, power flows into the Southeast during Elliott were in the opposite direction of those during Uri, when the Southeast was largely unaffected by the extreme cold and was exporting power to the west. Second, transmission is a far less costly and superior solution to the alternative of building additional capacity resources. Especially during extreme weather events or potential infrastructure disruptions, even fossil-based resources offer a reduced capacity contribution because their reliance on fuel deliveries makes them subject to the same correlated outage risk as existing fossil generators. Consequently, new or existing fossil generators offer little marginal reliability value in addressing these kinds of reliability threats because they are fueled from the same gas fields and pipelines that are subject to disruptions and capacity constraints. The capacity of transmission lines also increases during cold and windy conditions, in contrast to generators that are often derated during extreme weather.

These comments build on the consensus at the December workshop that:

(a) a minimum Interregional Transfer Capability requirement is valuable and consistent with FERC's duty to ensure reliability and just and reasonable rates;

(b) such a requirement should be based on how transmission accesses geographic diversity in the timing of peak demand, renewable output, and correlated generator outages, all

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many transmission ties with adjacent Balancing Authorities in the Eastern Interconnection helped to alleviate their generation shortfalls, preventing more severe firm load shed.").

of which significantly improve reliability and/or reduce the need for generating capacity;

(c) a straightforward requirement is superior to one based on complex analysis and extensive modeling, due to intractable uncertainty around analytical factors including future weather and climate patterns, the generation mix and location, load patterns, and the geography of gas supply and demand and pipeline networks; and

(d) due to that uncertainty and the broadly spread and bidirectional benefits of transmission, the cost of transmission to meet an interregional requirement should be broadly allocated.

Just like generation reserve margins built around the one-day-in-ten-year Loss of Load Expectation ("LOLE") reliability standard provide an insurance value from which all users benefit and thus all pay for, an interregional transfer capacity standard provides the same type of systemic reliability benefits to all users.

These comments are designed to provide the Commission with a roadmap for how to implement a minimum interregional transfer requirement. PIOs offer specific answers to the questions the Commission posed in its notice requesting post-workshop comments, building on comments and themes from the December workshop. Our comments also reference the May 2023 Grid Strategies report entitled "Quantifying a Minimum Interregional Transfer Capability Requirement," that Americans for a Clean Energy Grid (ACEG) has filed in its post-workshop comments in this docket ("Grid Strategies Report"). The Grid Strategies Report uses electricity supply and demand data over the last 10 years, during normal operations and in case studies of four severe weather events,[7] to quantify how an Interregional Transfer Capability requirement should be calculated based on transmission's value for accessing geographic diversity in the timing of peak demand, renewable output, and correlated generator outages.

[7] These include Winter Storm Elliott in December 2022, Winter Storm Uri in February 2021, the South Central event in January 2018, and the Polar Vortex event in January 2014.

The Grid Strategies Report shows all regions have a similar need for interregional transmission, supporting the case for FERC to adopt a single straightforward Interregional Transfer Capability requirement of 20-25% for all regions. Setting a uniform reliability standard is particularly beneficial in this context. While the need for and benefits of Interregional Transfer Capability can be precisely quantified for past events, future events will never exactly replicate past events. There is significant intractable uncertainty regarding how weather and climate patterns, the generation mix, load profiles, the natural gas system, and other factors that affect the need for interregional transmission will evolve in the future, making a modeling-based effort to set an exact amount of interregional transfer capacity for each region excessively difficult. However, it is absolutely certain that ensuring reliability for *all regions* has required and will increasingly require the ability to transfer power not just from immediately adjacent neighbors but across entire interconnects. As a result, ratepayers are better served by the Commission setting a baseline standard that gets close to the right answer for all regions instead of spending years of lawyers' and technical consultants' time debating the intractable uncertainties inherent to setting a specific requirement for each region. PIOs recommend the Commission adopt a minimum interregional transfer capacity requirement of 20-25% of peak load in each region, which conservatively approximates the need for and reliability benefit of interregional transmission for all regions and ensures enough capacity to serve multiple regions during large-scale events. Such a minimum requirement shares the same rationale as minimum generation reserve margin determination and the underlying one-day-in-ten-years LOLE standard, which are widely employed by utilities and grid operators.

Moreover, this methodology has already been adopted elsewhere. Europe uses a similar default minimum with a target for each country's interregional transfer capacity to cover 15% of its installed generating capacity by 2030.[8] In the U.S. installed generating capacity is about 67% greater than peak load,[9] so Europe's 15% minimum transfer requirement based on installed generating capacity would equate to a 25% requirement based on peak load in the U.S.

To account for true regional differences in transmission and generation makeup that would significantly alter its transmission need (in either direction), the Commission could allow regions to conduct their own analysis to demonstrate that their interregional transfer requirement should be different than the default *pro forma* standard, using the same "Consistent With or Superior To" approach used by the Commission in Order No. 888 and other instances. As it does for other reliability-based requirements, the Commission should set a high bar for such exceptions to prevent actors from abusing inherent uncertainty to pursue self-interested outcomes. The Grid Strategies Report provides an example of the methodology that the Commission could require regions to use for such an analysis, based on quantifying how three geographic diversity factors (diversity in the timing of peak demand, renewable output, and correlated generator outages) combine to determine the reliability benefit of interregional transmission. That method calculates the megawatts of geographic diversity benefit among any grouping of regions, reflecting the reduction in capacity needs for the grouping relative to the sum of the stand-alone capacity needs for the component regions. That megawatt amount of reduced capacity need should set the Interregional Transfer Capability requirement. This reflects that a certain quantity of megawatts

[8] *See* European Commission, "Electricity interconnection targets," *available at* https://energy.ec.europa.eu/topics/infrastructure/electricity-interconnection-targets_en.
[9] The U.S. has 1,241,578 MW of installed capacity to meet 742,000 MW of peak demand. Thus, installed capacity is 1.6733 times greater than peak demand, per https://www.eia.gov/electricity/data/eia860m/ and https://www.eia.gov/electricity/gridmonitor/expanded-view/custom/pending/ElectricityOverview-2/edit.

of interregional transmission allows the region to achieve the same level of reliability with that many fewer megawatts of generating capacity.[10]

In our answers below, PIOs outline requirements the Commission should establish for the methods and assumptions regions could use to propose an Interregional Transfer Capability requirement that differs from the default value. At a minimum, the methodology should quantify how three geographic diversity factors (diversity in the timing of peak demand, renewable output, and correlated generator outages) combine to determine the reliability benefit of interregional transmission. While the analysis in the Grid Strategies Report is based on historical events, the Report also explores straightforward methods that could be used to extrapolate the analysis into the future to estimate how expected changes in electricity demand and the generation mix affect the geographic diversity benefit of interregional transmission. Regions seeking an individualized Interregional Transfer Capacity requirement should be required to file their analysis justifying a different requirement in a contested proceeding at the Commission, where intervenors and FERC staff would be allowed to review their models, input assumptions, and implications for reliability across the interconnect.

The Commission should broadly allocate the cost of transmission built to meet an Interregional Transfer Capability requirement to all beneficiaries. Interregional transmission serves as a reliability insurance policy against unexpected events, as it is impossible to precisely predict when, where, or for what that insurance policy will be needed, but over the long term all regions will be affected by such an event and will thus benefit from an increase in interregional transfer capacity. The inherent uncertainty in the precise benefits and beneficiaries of interregional

[10] Here and elsewhere in these comments, "MW of generating capacity" refers to MW of "unforced" generating capacity, generating capacity that has been derated to account for outages and derates during peak periods (including correlated outages and derates), and thus equates to theoretical capacity that is perfectly dependable.

transmission, and the fact that transmission is bidirectional so both interconnected regions benefit from the underlying insurance value interregional transmission provides, argues for broadly allocating transmission costs to match this broad distribution of benefits.[11]

II. Answers to Specific Commission Questions in Notice Requesting Post-Workshop Comments

The Commission's questions are copied below in italics, with PIOs' answer following each question.

1. *To what extent can Interregional Transfer Capability mitigate risks that may occur across a wide geographic area (e.g., the shedding of load, correlated generation outages, or transmission outages due to the same extreme weather event, fuel disruptions, cyber-attacks, or physical security events)?*

As noted above, Interregional Transfer Capability is uniquely well-positioned to address a range of threats that cause localized losses of electricity supply or increases in electricity demand. Because severe weather and other reliability threats tend to have a limited duration and geographic scope, transmission ties that increase the ability to import power from unaffected regions nearby are an essential part of the solution. As noted above, interregional transmission is uniquely bidirectional, so both connected regions benefit as a reliability concern affects different regions over time or across events. Second, transmission is a far less costly and superior solution to the alternative of building additional capacity resources. Especially during extreme weather events or potential infrastructure disruptions, even fossil-based resources offer a reduced capacity contribution because their reliance on fuel deliveries makes them subject to the same correlated outage risk as existing fossil generators. Consequently, new or existing fossil generators offer little

[11] *See, e.g.,* Lawrence Berkley National Laboratories, Dev Millstein et al., *Empirical Estimates of Transmission Value Using Locational Marginal Prices*, Aug. 22, 2022, pp. 33-34, *available at* https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf; Johannes Pfeifenberger (Prepared for the Department of Energy Building a Better Grid Initiative), *The Benefits of Interregional Transmission: Grid Planning for the 21st Century*, Mar. 15, 2022, p. 6, *available at* https://www.brattle.com/wp-content/uploads/2022/03/The-Benefits-of-Interregional-Transmission-Grid-Planning-for-the-21st-Century.pdf.

marginal reliability value because they are fueled from the same gas fields and pipelines that are subject to disruptions and capacity constraints. Moreover, the capacity of transmission lines actually increases during cold and windy conditions, in contrast to generators that are often derated during extreme weather.

> a. *Could evaluating how Interregional Transfer Capability can mitigate such risks serve as a useful framework for determining whether, and at what minimum amount, Interregional Transfer Capability is necessary to ensure reliability and just and reasonable rates? If so, how could this framework help to inform an analysis of the appropriate amount of Interregional Transfer Capability?*

Yes. The Grid Strategies Report provides just such a framework based on an analysis of severe weather events over the last decade. The Report quantifies how transmission addresses reliability concerns by accessing geographic diversity in the timing of peak demand, renewable output, and correlated generator outages. As explained in more detail below, the Grid Strategies analysis shows that all regions have a similar need for interregional transmission and provides a strong justification for the adoption by FERC of a single straightforward Interregional Transfer Capability requirement for all regions. This question also correctly posits that an Interregional Transfer Capability requirement is necessary to both ensure reliability and just and reasonable rates.

> b. *Would such a framework be useful in determining the benefits of a Transfer Transmission Facility as well?*

The default Interregional Transfer Capability requirement for all regions would provide sufficient expected benefits to each paired region for use in cost allocation, consistent with FERC's beneficiary pays principle and court interpretations of the FPA under the "roughly commensurate" standard.[12] Such a method is not arbitrary and is based on actual physical factors that drive the

[12] *See, e.g., Illinois Com. Comm'n v. FERC,* 576 F.3d 470, 476 (7th Cir., August 6, 2009, citations omitted)*; Illinois Com. Comm'n v. FERC*, 721 F.3d 764, 770-6 (7th Cir. 2013).

benefits. As noted above, precisely quantifying those benefits for future events is impossible because of intractable uncertainty regarding how weather and climate patterns, the generation mix, load profiles, the natural gas system, and other factors that affect the need for interregional transmission will evolve in the future. These are reasonably quantifiable "known unknowns" as the term is used in risk management.[13] If a regional planning entity believes a different level is more appropriate, applying a methodology similar to the one the Grid Strategies Report used for historical events to future events could be used to estimate the Interregional Transfer Capability requirement for that region.[14]

2. *During the workshop, participants identified several metrics that could be used to evaluate the need for and benefit of a minimum amount of Interregional Transfer Capability. Participants mentioned metrics including loss of load expectation, expected unserved energy, planning reserve margin, value of lost load, grid stress, First Contingency Incremental Transfer Capability, and avoided transmission costs, among others.*

    a. *What metrics should be used to evaluate the* ***need*** *for a minimum amount of Interregional Transfer Capability, and why?*

The Interregional Transfer Capability requirement should be expressed as a percentage of a region's peak load that is expected in a future year, with both existing and required interregional transfer capability measured in the MW of First Contingency Incremental Transfer Capability (FCITC). FCITC is the best metric as it represents the actual transmission capacity that can be used for interregional transfers, after accounting for transmission capacity that must remain unloaded to ensure power system reliability in the event of a contingency, like the loss of the regional power system's single largest element.

As explained in the Grid Strategies Report, the need for and benefit of a minimum Interregional Transfer Capability requirement can be justified based on geographic diversity in the

[13] *See* Hugh Courtney, Jane Kirkland, and Patrick Viguerie, *Strategy Under Uncertainty*, HARVARD BUSINESS REVIEW 66–79 (Nov.-Dec. 1997), https://hbr.org/1997/11/strategy-under-uncertainty.
[14] *See* Grid Strategies Report at 5-6.

timing of peak demand, renewable output, and correlated generator outages.[15] That method calculates the megawatts of geographic diversity benefit among any grouping of regions, reflecting the reduction in capacity needs for the grouping relative to the sum of the stand-alone capacity needs for the component regions.[16] That quantity of reduced capacity need should set the Interregional Transfer Capability requirement. This reflects that a certain quantity of megawatts of interregional transmission allows the region to achieve the same level of reliability with many fewer megawatts of generating capacity.[17] While the analysis contained in the Grid Strategies Report is based on historical events,[18] the report also explores straightforward methods that can be used to extrapolate those results into the future to estimate how expected changes in electricity demand and the generation mix affect the geographic diversity benefit of interregional transmission.[19]

> b. *What metrics should be used to evaluate the* ***benefit*** *of a minimum amount of Interregional Transfer Capability, and why?*

The methodology outlined in the previous answer calculates the benefit from the reduction in a region's need for capacity, which sufficiently reflects the benefits to each region for cost allocation purposes. If a region provides a more precise measure with better data that the Commission finds to be more accurate, that would also be just and reasonable. As discussed in more detail below, increasing Interregional Transfer Capability would also provide other benefits, like reduced production costs, access to lower cost generating resources, improved market efficiency, and other economic benefits. However, those additional economic benefits would be best considered in a more comprehensive Commission rulemaking related to interregional

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[15] *Id*. at 1.
[16] *Id.*
[17] *Id.*
[18] *See id*. at 3-4.
[19] *See id*. at 4-5.

transmission planning and cost allocation, which ideally would create a framework for planning and paying for transmission that provides multiple benefits.

> c. *Should a common set of these metrics be used consistently across transmission planning regions to evaluate the need for and benefits of a minimum amount of Interregional Transfer Capability? Why or why not? If so, which metrics should be included in that common set? Should the Commission be prescriptive in how public utility transmission providers in transmission planning regions define these metrics?*

As noted above, PIOs recommend that the Commission establish a minimum Interregional Transfer Capability requirement of 20-25% of peak load in all regions and both existing and required transfer capacity should be measured in FCITC. For regions that would seek a requirement different from the default Interregional Transfer Capability requirement, a common set of metrics that aligns with the establishment of the default requirement should be used to support such a request. A primary benefit of the methodology presented above for calculating the default requirement is that it can be applied in any region, as all regions have access to the data necessary to conduct the analysis.

3. *Several participants in the workshop indicated that existing regional transmission planning and interregional transmission coordination processes have not led to the development of a sufficient amount of Interregional Transfer Capability in many regions across the United States. For instance, some participants explained that existing processes consider only normal system conditions in their transmission modeling and benefit calculations and do not adequately consider infrequent, extreme events.*

> a. *Please describe whether there are gaps in existing regional transmission planning and interregional transmission coordination processes that could result in potentially beneficial Transfer Transmission Facilities not being considered, which could lead to a lack of sufficient Interregional Transfer Capability in some transmission planning regions and the possibility of unjust and unreasonable rates.*

Yes, there are major gaps in existing processes that cause a failure to build beneficial transmission. The question correctly notes that most if not all existing transmission planning processes consider only normal system conditions by assuming typical weather year conditions, and do not adequately consider infrequent, extreme events. This is despite the fact that analysis by Lawrence Berkeley National Laboratory indicates that extreme events account for about half of the total value of transmission.[20] With a few notable exceptions, most regions currently fail to conduct proactive multi-value transmission planning, and do not broadly allocate the cost of regionally beneficial transmission to all beneficiaries. Interregional transmission planning processes are plagued by the above problems, as well as even thornier issues due to inconsistent planning assumptions between regions and disputes over cost allocation. As one example, in March 2023 MISO and PJM decided that a "long-term Interregional Market Efficiency Project (IMEP) study will not be conducted in 2023 because no interregional constraints were identified after RTOs coordinated modeling updates,"[21] despite abundant real-world evidence of transmission constraints between those two RTOs. MISO and PJM's interregional planning processes decision is reflective of what is referred to as the triple hurdle problem, in which planned transmission must separately pass each of the two connected regions' particular (and often very different) benefit-cost analyses, as well as for the benefit-cost analysis for the combined footprint of both regions. Many of these planning processes fail to consider all of the benefits that are realized from such transmission projects, which results in the rejection of net beneficial transmission projects. For more information on these issues, please see PIOs' comments in the Commission's transmission planning and cost allocation docket.[22]

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[20] *See* LBNL, "The Latest Market Data Show that the Potential Savings of New Electric Transmission Was Higher Last Year that at Any Point in the Last Decade" (Feb. 7, 2023), https://emp.lbl.gov/news/latest-market-data-show-potential-savings-new ("LBNL 2023").
[21] March 24, 2023 email to stakeholders from MISO and PJM (available upon request).
[22] *See* Federal Energy Regulatory Commission, *Building the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Reply Comments of Public Interest Organizations at 22-25, Docket No. RM21-17-000 (Nov. 30, 2021), *available at* https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20211130-5284&optimized=false.

b. *If there is insufficient Interregional Transfer Capability between certain transmission planning regions, what additional actions should be taken by the Commission to increase Interregional Transfer Capability? What actions have already been taken by public utility transmission providers in transmission planning regions to increase Interregional Transfer Capability?*

As discussed above, there is widespread evidence both that there is currently insufficient Interregional Transfer Capability between most if not all transmission regions due primarily to a failure to properly recognize the reliability need for Interregional Transfer Capability along with the triple hurdle problem and cost allocation disputes that plague all interregional planning efforts. Because Interregional Transfer Capability is an essential tool for ensuring reliability in the face of increasingly extreme weather and other low frequency, high risk events, the Commission's primary responsibility is to set standards to ensure that sufficient Interregional Transfer Capability is built. Additionally, in order to ensure that interregional transmission projects are also affordable and efficient, the Commission should also put forward an interregional planning and cost allocation rule that addresses other concerns limiting the development of interregional transmission, including the failure to do proactive multi-value planning, the lack of broad cost allocation, and the triple hurdle in transmission planning analysis. An interregional transmission planning and cost allocation rule is needed in addition a minimum Interregional Transfer Capability requirement because the transfer capability requirement is only based on the reliability benefits of transmission, and does not account for other extant benefits, including the economic benefits of transmission, such as reduced production costs, reduced generator investment costs from accessing more productive resources, or improved market efficiency.

4. *What are the advantages and disadvantages of the following approaches to establishing a minimum amount of Interregional Transfer Capability, and determining who should identify that minimum amount? Could these different approaches be combined? If so, how? Do your responses change based on whether or not non-public utility transmission providers are considered in the development of an Interregional Transfer Capability requirement?*

a. *A set of principles developed by the Commission. These principles would inform the processes that public utility transmission providers would need to implement to determine what minimum amount of Interregional Transfer Capability is needed.*

The Commission's experience with Order No. 1000 has demonstrated that the mere establishment of planning principles without setting clear baseline requirements that all regions must follow, including common methodological standards and assumptions, is insufficient to ensure that cost effective and needed transmission will be built. This is especially true of interregional transmission planning efforts that have essentially become nothing more than a check-the-box exercise. Unless the principles provide a clear default standard or require the universal application of a methodology that closely tracks the one outlined above, the Commission simply putting forward a set of general principles would result in regions using inconsistent methodologies and assumptions that may hamper the interregional coordination necessary for any effort to succeed. As noted above, there is significant intractable uncertainty about future weather and climate patterns, the generation mix and profile, load patterns, the geography of natural gas supply and demand and pipeline network topology, and the location and nature of severe events. Some actors may use that uncertainty to significantly understate the need for Interregional Transfer Capacity. Insurance policies, and the electricity policy equivalent of standards like planning reserve margins and one-day-in-ten-year LOLE thresholds, are necessarily straightforward and inexact. Yet they are critical for a well-functioning regulatory regime that supports reliability.

b. *An economic analysis that compares the incremental benefits and costs of increasing Interregional Transfer Capability between transmission planning regions and determines the minimum amount of Interregional Transfer Capability based on the comparison of benefits and costs. This analysis could be conducted by public utility transmission providers in neighboring transmission planning regions, in two or more transmission planning regions within an interconnection, or in each interconnection.*

Current experience with interregional planning has demonstrated that economic-only analyses have generally been unsuccessful in driving interregional transmission, due in part to a lack of mandatory standards around data requirements, methodologies, and assumptions, as well as the failure to assess the multi-value benefits. Moreover, Interregional Transfer Capability is central to reliability and should not therefore depend solely on an incremental economic benefit analysis. As outlined above, our proposal is that the Commission establish a single default Interregional Transfer Capacity requirement, with a region allowed to use a methodology prescribed by the Commission to present an alternative analysis if it believes a different requirement is consistent with or superior to the default requirement. Without clear mandates from the Commission, the analytic process is likely to get bogged down in an unproductive and self-interested debate over the factors discussed above that introduce intractable uncertainty about future transmission needs.

c. *A standardized minimum amount of Interregional Transfer Capability based on a single characteristic of the transmission planning region(s), like a percentage of peak load or the single largest contingency. Do your responses change based on whether or not non-public utility transmission providers are considered?*

This is our preferred solution for the reasons outlined above. The default Interregional Transfer Capability requirement should be set as a percent of aggregate peak load across a region, and both existing and required transfer capacity should be measured in FCITC. A region would be allowed to use a methodology prescribed by the Commission to present a region-specific analysis if it believes a different requirement is justified. Our answer does not change based on whether non-public utility transmission providers are considered. A minimum percentage is also less arbitrary, results in consistent treatment across the regions, maximizes efficiency both in compliance and enforcement, and is based in sound, reasonably quantifiable physical factors in each region.

d. *A standardized formula to determine a minimum Interregional Transfer Capability requirement based on identified characteristics of the transmission planning region(s), such as peak load, ramping needs, generation outages, and variability of generation and load. Do your responses change based on whether or not non-public utility transmission providers are considered?*

This option is a distant second best relative to option c above, as it is similar to the process by which a region would be allowed to use a methodology prescribed by the Commission to present a region-specific Interregional Transfer Capability requirement analysis if it believes a requirement different from the default is justified, but makes this the rule instead of the exception. Consequently, such an approach is more burdensome for all parties, is likely to perpetuate inconsistencies across the regions, and is less likely to be as successful in ensuring reliability as having a minimum standard. As explained above and below, should it choose this option, the Commission should specify the precise methodology for this analysis based on straightforward and objective inputs like historical net load diversity and correlated outage rate, as well as methods to ensure that there is sufficient transfer capability across the interconnect. Regions should be required to file their analysis justifying a different requirement in a contested proceeding at FERC, where intervenors and FERC staff would be allowed to review their models and input assumptions.

e. *A transmission planning study that assesses unconstrained power flows between transmission planning regions to optimize the economic and reliability benefits of Interregional Transfer Capability. This approach would determine the minimum amount of Interregional Transfer Capability based on the level of interregional power flows during normal and emergency conditions.*

The analysis called for in this approach would be subject to the concerns discussed above about regional inconsistency and an inability to resolve intractable uncertainty. This type of analysis would be more appropriate for a separate Commission rulemaking on interregional transmission planning and cost allocation, as it calls for multi-value planning to account for the economic and other benefits of transmission in addition to reliability.

5. *Some participants in the workshop recommended a transmission planning study to determine a minimum amount of Interregional Transfer Capability. What is the appropriate geographic scope of a transmission planning study for Interregional Transfer Capability?*

   a. *What are the benefits and drawbacks of a transmission planning study between neighboring transmission planning regions to determine the minimum amount of Interregional Transfer Capability between those regions?*

An analysis only focused on geographic diversity with immediate neighbors can serve as a straightforward measure of generation that can be delivered during a time of need. However, these results will be conservative because the analysis does not capture benefits from neighbor-of-neighbor interactions, which have been significant during many recent severe weather events. For example, during Winter Storm Uri, SPP was importing power from MISO which, in turn, was importing power from PJM, while during Winter Storm Elliott the Southeast was importing power from MISO which, in turn, was importing power from Canada and other regions.[23] The power system is a network of interdependent regions, so looking at a small number of regions in isolation does not fully capture the benefits of aggregation across a larger area.

   b. *What are the benefits and drawbacks of an interconnection-wide study to determine the minimum amount of Interregional Transfer Capability for a transmission planning region with its neighboring transmission planning regions?*

An interconnection-wide study would account for the significant interactions with neighbors-of-neighbors discussed above. However, in a hypothetical example where region A touches region B, which in turn touches region C, region A may express concerns that neighboring grid operator B may not be able to fully deliver the power that it is obtaining from region C to region A, due to transmission congestion within region B that limits the flow of power across its footprint. The analysis in the Grid Strategies Report quantifies the difference in the calculated transmission need if diversity with only immediate neighbors is considered versus accounting for

[23] *See* Grid Strategies Report at 5.

diversity across a larger footprint. Which methodology is more appropriate can be assessed on a case-by-case basis, accounting for factors like the typical amount of transmission congestion within a neighboring region during a region's peak need periods.

> c. *To what extent could existing interregional organizations (e.g., Eastern Interconnection Planning Collaborative and Western Electricity Coordinating Council) support an interconnection-wide transmission planning study for Interregional Transfer Capability?*

These groups could play an important role in aggregating information, including about existing transfer capacity, and could potentially play a role in conducting such a study if given proper direction.

> d. *What type of analysis should an Interregional Transfer Capability planning study include? For example, would a study consider the "single largest contingency" or "common mode failures"?*

The methodology for such an analysis was outlined above and is presented in more detail in the Grid Strategies Report. Geographic diversity in common mode failures or correlated outages of generators are an important input in setting the Interregional Transfer Capability requirement, as explained above. The single largest contingency is already reflected in NERC reliability requirements that govern reliable transmission operations, which is why measurement of transfer capacity should be based on FCITC.

> e. *Should a transmission planning study for Interregional Transfer Capability require that neighboring transmission planning regions consider Transfer Transmission Facilities that would cross between the interconnections?*

Yes, as these facilities are likely to have significant value for many regions.

6. *Ahead of developing a transmission planning study, as suggested in question 5, some workshop participants raised the idea of the Commission, or public utility transmission providers in each transmission planning region, establishing an easily quantifiable minimum Interregional Transfer Capability requirement (e.g., a region-specific default amount, based on criteria such as a percentage of peak load or the single largest contingency) that could later be revised up or down to reflect the region-specific*

transmission needs or the additional benefits of Interregional Transfer Capability after a more detailed interconnection-wide Interregional Transfer Capability study is completed.

a. *How would the Commission, or public utility transmission providers within a transmission planning region, define region-specific default minimum Interregional Transfer Capability requirements, which could be revised after an interconnection-wide Interregional Transfer Capability study is completed?*

Our suggested methodology is outlined in our comments above and presented in the Grid Strategies Report.

b. *What are important considerations for defining a metric, like those in question 2 above, used to evaluate the need for and benefits of region-specific default Interregional Transfer Capability requirements?*

It is important for the methodology for determining a default Interregional Transfer Capability requirement is straightforward and based on objective inputs and assumptions. Our suggested methodology meets those criteria.

c. *What are important considerations for an interconnection-wide Interregional Transfer Capability study for revising region-specific default Interregional Transfer Capability requirements?*

Our suggested methodology is outlined in our comments above and presented in the Grid Strategies Report, and meets criteria for simplicity and objectivity while rigorously reflecting the need.

i. *How would you measure and use the benefits of mitigating risk through Interregional Transfer Capability to revise up or down region-specific default Interregional Transfer Capability requirements?*

Our suggested methodology does not account for risk beyond the historical severe weather events that were included in our analysis. Accounting for other risks could justify setting an even higher default requirement than one based on severe weather alone.

ii. *How would you use benefits in addition to reliability and resilience risk-mitigating benefits to revise up or down region-specific default Interregional Transfer Capability requirements?*

As explained above, the Commission should consider a separate rulemaking on interregional transmission planning and cost allocation that requires transmission planners to conduct scenario-based planning that accounts for all benefits of regional and interregional transmission in addition to reliability and resilience. The results from such a holistic planning effort could serve as a basis for revising a default minimum Interregional Transfer Capability requirement.

> iii. *What region-specific transmission needs could be used to revise up or down region-specific default Interregional Transfer Capability requirements?*

The methodology for a region to propose deviating from the default requirement was discussed at the beginning of our comments.

7. *Should the need for Interregional Transfer Capability be considered within existing regional transmission planning and interregional transmission coordination processes or in a new, separate transmission planning process? Are there other ways to consider Interregional Transfer Capability given the existing processes already underway?*

As explained above, existing processes fail to effectively plan or pay for transmission to address interregional needs, and because of its critical role in ensuring reliability of the grid in the face of increasingly extreme weather and other major threats, a new process based on a minimum Interregional Transfer Capability requirement is needed. As also explained above, the Commission should initiate a separate proceeding to fix interregional planning and cost allocation, as that could include multi-value planning that accounts for the economic and other benefits of transmission in addition to the reliability and resilience benefits addressed by the minimum Interregional Transfer Capability requirement.

> a. *Could a metric be defined and used to capture the benefits of Interregional Transfer Capability in maintaining reliability during extreme events in existing regional transmission planning and interregional transmission coordination processes? Would the use of such a metric in existing regional transmission planning and interregional transmission coordination processes sufficiently consider the benefits of Interregional Transfer Capability?*

The Commission could explore this in another proceeding on interregional planning and cost allocation.

b. Should potential common mode failures and correlated outages be incorporated into studies for identifying Transfer Transmission Facilities in an Interregional Transfer Capability transmission planning process? If so, how?

Yes, correlated outages are a key input into our recommended calculation method.

8. To what extent, if any, should the following be considered when establishing a minimum Interregional Transfer Capability requirement; if so, how and why?

a. Historical or projected extreme events (e.g., extreme weather, loss of fuel supply, etc.).

Yes, the proposed methodology outlined above is based on historical events. While the analysis in the Grid Strategies Report is based on historical events, the Report also explores straightforward methods that can be used to extrapolate those results into the future to estimate how expected changes in electricity demand and the generation mix affect the geographic diversity benefit of interregional transmission. The proposed methodology for a region to deviate from the default requirement includes extrapolating historical events forward based on expected changes in the generation mix and load patterns, including the impact of climate change.

b. Load and resource diversity across a wide geographic area.

Yes, geographic diversity in load, renewable output patterns, and correlated generator outages are the foundation of the methodology outlined above.

c. Anticipated changes in the resource mix and demand.

Yes, the proposed methodology for a region to deviate from the default requirement includes accounting for these anticipated changes.

d. Improved reliability.

Yes, the proposed methodology is based on either improving reliability or meeting the same level of reliability with less generating capacity.

e. Avoided production costs.

Economic benefits of transmission, while large, are likely best addressed in a separate rulemaking proceeding focused on multi-value transmission planning and cost allocation.

f. Geographic zones with the potential for large amounts of new generation.

Economic benefits of transmission, including access to lower cost generating resources, are likely best addressed in a separate rulemaking proceeding focused on multi-value transmission planning and cost allocation.

g. The option value of Transfer Transmission Facilities, as determined by the increased access to supplemental capacity during emergency operating conditions.

Yes, this is captured by the methodology proposed above.

h. Increased operator flexibility.

Yes, increasing access to capacity resources is captured by the methodology proposed above.

i. Impact of correlated generator outages and common mode failures.

Yes, this is captured by the methodology proposed above.

j. Power system stability.

While this is a significant benefit of transmission expansion, it is highly subject to assumptions and the specific transmission build, and computationally complex. This is probably best addressed in a separate proceeding on multi-value interregional transmission planning and cost allocation.

k. Other factors?

The multiple other benefits of transmission are likely best addressed in a separate proceeding on multi-value interregional transmission planning and cost allocation.

9. *In the context of establishing an Interregional Transfer Capability requirement, what challenges exist to modeling the impact of extreme weather events on generation, load, and transmission system performance in forward-looking transmission planning studies? What data, tools, and information sharing can help to mitigate these challenges?*

As noted above, there is significant intractable uncertainty regarding these factors. It will never be possible to predict when or where future events will occur. Using a straightforward default requirement for transfer capacity avoids protracted and unproductive debates about those inherently uncertain factors and is consistent with FERC authority over transmission cost allocation and reliability. Regions proposing to deviate from the default requirement should be required to extrapolate future needs based on the impact of climate change and other expected changes in electricity supply and demand, using models designed to project how climate change will affect future weather patterns.[24] As noted above, the Grid Strategies Report explores straightforward methods that can be used to extrapolate those results into the future to estimate how expected changes in electricity demand and the generation mix affect the geographic diversity benefit of interregional transmission.

10. *To what extent do transmission planners rely on normalized weather data in transmission planning models? Are there drawbacks to using normalized weather data in determining the need for and benefits of Interregional Transfer Capability?*

As discussed above, most if not all existing transmission planning processes consider only normal system conditions by assuming typical weather year conditions, and do not adequately consider infrequent, extreme events. This is despite the fact that analysis by Lawrence Berkeley National Laboratory indicates that extreme events account for about half of the total value of

[24] For example, see https://www.osti.gov/biblio/1885888.

transmission.[25] Severe weather events should be included in calculating a minimum Interregional Transfer Capability requirement

11. *In determining an Interregional Transfer Capability requirement, should public utility transmission providers use data on generation, load, and transmission system performance during past extreme weather events and other hours of reported transmission system stress (i.e., during normal conditions) in forward-looking transmission planning studies? Is such data sufficient to capture the possible impacts of future extreme weather events? Why or why not?*

As discussed above, historical events should be included in the analysis. Regions proposing to deviate from the default requirement should be required to extrapolate future needs based on the impact of climate change and other expected changes in electricity supply and demand using models designed to project how climate change will affect future weather patterns.[26]

12. *Should the Commission require an ex-ante cost allocation method, an ex-post cost allocation method, or some combination for Transfer Transmission Facilities? What are the advantages or disadvantages of each approach? If an ex-ante cost allocation method, are there factors that would make changing the ex-ante cost allocation method appropriate? If so, what are those factors?*

FERC should broadly allocate the cost of transmission built to meet an Interregional Transfer Capability requirement. Interregional transmission serves much like an insurance policy against unexpected events in that it is impossible to precisely predict when, where, or for what that insurance policy will be needed, but over the long term all regions will be affected by such an event and will thus benefit from an increase in interregional transfer capacity. The inherent uncertainty in the precise benefits and beneficiaries of interregional transmission, and the fact that transmission is bidirectional so both interconnected regions benefit from transmission and the insurance value it provides, argues for broadly allocating transmission costs to match the broad distribution of benefits.

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[25] LBNL 2023.
[26] For example, *see* Sandia National Lab, *The Multi-scenario Extreme Weather Simulator: Energy Resilience for Mission Assurance*, *available at* https://www.osti.gov/biblio/1885888.

13. *How would one design an ex-ante cost allocation method for Transfer Transmission Facilities that relies on identified benefits? Which benefits should be considered when determining how to allocate the costs of Transfer Transmission Facilities in a manner that is at least roughly commensurate with the benefits and why?*

An advantage of broad cost allocation is that it avoids unproductive fights over cost allocation that are unresolvable due to intractable uncertainty.

14. *Should the Commission establish a defined set of benefits for Transfer Transmission Facilities or require the public utility transmission providers in a pair (or more) of neighboring transmission planning regions to determine the set of benefits considered for purposes of cost allocation? What are the advantages and disadvantages of each approach?*

An advantage of broad cost allocation is that it avoids unproductive fights over cost allocation that are unresolvable due to intractable uncertainty.

15. *How should a single cost allocation method be determined for Transfer Transmission Facilities? Should the relevant public utility transmission providers be tasked with jointly proposing a cost allocation method for Transfer Transmission Facilities in the first instance? Should there be a process in place for the Commission to establish a cost allocation method for Transfer Transmission Facilities if the public utility transmission providers cannot agree on one?*

Per the above answer, the Commission should require broad cost allocation.

16. *What role, if any, could merchant transmission facilities play in meeting a minimum Interregional Transfer Capability requirement?*

Merchant transmission facilities should be allowed to compete to build transmission to meet the identified need.

17. *Are existing market-to-market operational protocols and congestion management tools sufficient to manage flows across Transfer Transmission Facilities effectively during extreme events? Are there modifications to the Transmission Loading Relief process that would more effectively manage congestion across seams between regions than the current Transmission Loading Relief process?*

There is significant room to improve existing market-to-market operating practices. Transmission Loading Relief is a blunt and inefficient instrument that can harm reliability and at best sub-optimally redispatch generation. PJM's market monitor has advocated for moving to optimized dispatch that includes resources in neighboring grid operating areas.[27]

Short of that, the PJM and MISO market monitors have advocated reforms to schedule interchange based on real-time conditions and removing hurdle rates. Specifically, the PJM market monitor "recommends that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market,"[28] and that "the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner."[29]

MISO's market monitor has recommended other incremental solutions to seams problems. Most notably, the MISO IMM recommends "that MISO eliminate all transmission and other charges applied to CTS [Coordinated Transaction Scheduling] transactions, while encouraging PJM to do the same…"[30] This change would produce more liquidity for CTS transactions and more efficient price formation. The MISO IMM also notes that inefficiencies in the calculation of interface prices incorrectly double congestion at MISO-SPP seam.[31] MISO's IMM also notes the

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[27] *See* 2021 State of the Market Report for PJM at 99, *available at* https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec2.pdf ("The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an LMP market.").
[28] *Id.*
[29] *Id.*
[30] 2021 State of the Market Report for the MISO Electricity Market at 121, *available at* https://cdn.misoenergy.org/20220622%20Markets%20Committee%20of%20the%20BOD%20Item%2004%20IMM%20State%20of%20the%20Market%20Report625261.pdf.
[31] MISO IMM, "OMS-RSC: Seams Study: Market-To-Market Coordination" (May 2020) at 91, *available at* https://www.potomaceconomics.com/wp-content/uploads/2020/06/Seams-Study_MISO-IMM_M2M-Evaluation_Final.pdf.

use of a 30-minute ahead forecast for scheduling seams transactions costs tens of millions of dollars relative to more efficiently using prices from the latest 5-minute market interval.[32] The MISO IMM further notes that a redispatch agreement with TVA and Ontario could greatly reduce congestion relative to the current practice of issuing transmission loading relief requests.[33]

Finally, the MISO IMM recommends that MISO "[r]emove external congestion from interface prices. When MISO includes congestion associated with external constraints in its interface prices, this congestion pricing is inefficient because it is generally not accurate and duplicates the congestion pricing by the external system operator. In addition, external operators provide MISO no credit for making these payments, neither through the TLR process nor through the M2M process. Hence, they are both inefficient and costly to MISO's customers. To fully address these concerns, we continue to recommend that MISO eliminate the portions of the congestion components of each of MISO's interface prices associated with the external constraints."[34]

III. Conclusion

PIOs appreciate the opportunity to provide these comments in response to the Commission's notice inviting comments to the Technical Conference convened by the Commission regarding whether and how the Commission could establish a minimum requirement for Interregional Transfer Capability for public utility transmission providers in transmission planning and cost allocation processes and ask that the Commission consider the recommendations made herein in any future rulemaking.

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[32] *Id*. at 89.
[33] *Id.* at 113.
[34] *Id*. at 114.

Respectfully submitted,

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