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

POST-WORKSHOP COMMENTS OF THE TRANSMISSION ACCESS POLICY STUDY GROUP

The Transmission Access Policy Study Group ("TAPS") appreciates the opportunity to submit comments following up on the December 5-6, 2022 Workshop on whether and how the Commission could establish a minimum requirement for Interregional Transfer Capability ("ITC") for public utility transmission providers in transmission planning and cost allocation processes.[1] As discussed below, TAPS recognizes the need to assess and address the sufficiency of transfer capability between regions. However, as transmission dependent utilities ("TDUs") that have faced steep transmission rate increases in recent years,[2] TAPS members believe it is crucial that this be done in a manner that is cost-effective and tailored to regional needs. Thus, we recommend advancing this objective through enhancements to the regional planning processes, and building on the successes of existing interregional processes. We also urge against use of Federal Power Act ("FPA") Section 215 to address this issue.

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[1]. Notice Requesting Post-Workshop Comments, (Feb. 28, 2023), eLibrary No. 20230228-3004.

[2] *See* Comments of Transmission Access Policy Study Group at 6-7 & nn.6-7, *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, Docket No. RM21-17 (Oct. 12, 2021), eLibrary No. 20211012-5388 ("TAPS ANOPR Comments") (examples of transmission rate hikes borne by TAPS members and the consumers that rely on them for affordable electricity).

INTEREST OF TAPS

TAPS is an association of TDUs in thirty-five states promoting open and non-discriminatory transmission access.[3] As entities entirely or predominantly dependent on transmission facilities owned and controlled by others, TAPS members recognize the importance of a robust transmission grid, and have long been outspoken on the need for improved transmission and ways to get needed transmission built.[4] TAPS recognizes the critical roles played by an open, inclusive, and transparent planning process, and fair cost allocation, in achieving needed transmission expansion.

As municipal, cooperative, and investor-owned load-serving entities, TAPS members are responsible for providing reliable and affordable service to the consumers and businesses that rely on them and their members. Our paramount concern is reliable service at reasonable cost to consumers, consistent with FPA Section 217(b)(4)'s[5] directive that the Commission facilitate the planning and expansion of the grid to meet the reasonable needs of LSEs to satisfy their service obligations. This statutory mandate, along with the Commission's statutory obligation to ensure just and reasonable rates, should guide the Commission as it considers whether and how to assess and address interregional transfer capability.

In addition to actively participating in all previous Commission transmission planning rulemaking proceedings, TAPS filed extensive comments in the *Building for the*

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[3] *See* TAPS, https://www.tapsgroup.org (last visited Mar. 9, 2023). Jane Cirrincione, Northern California Power Agency, is the TAPS Chair; Dave Osburn, Oklahoma Municipal Power Authority, is the Vice Chair. Terry Huval is TAPS's Executive Director.

[4] *See* TAPS, *Effective Solutions for Getting Needed Transmission Built at Reasonable Cost* (June 2004), https://www.tapsgroup.org/wp-content/uploads/2013/01/effectivesolutions.pdf ("TAPS 2004 White Paper").

[5] 16 U.S.C. § 824q(b)(4).

Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection proceeding, Docket No. RM21-17, responding to both the Advance Notice of Proposed Rulemaking,[6] and the Notice of Proposed Rulemaking.[7]

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COMMENTS

I. GUIDELINES FOR ASSESSING AND ADDRESSING INTERREGIONAL TRANSFER CAPABILITY

At the Workshop and in the Notice, many questions were raised about different ways to determine and address the sufficiency of interregional transfer capability. Workshop panelists suggested a wide variety of approaches, ranging from simple formulas to the creation of new interregional or even interconnection-wide processes and institutions. TAPS questions many of those suggestions as unlikely to achieve the intended goals cost-effectively and efficiently, in a manner that minimizes costs to

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[6] *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, 176 FERC ¶ 61,024 (2021) ("ANOPR"). *See* TAPS ANOPR Comments.

[7] *See* Initial Comments of Transmission Access Policy Study Group, *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, Docket No. RM21-17 (Aug. 17, 2022), eLibrary No. 20220817-5183 ("TAPS Initial NOPR Comments"); Reply Comments of Transmission Access Policy Study Group, *Bldg. for the Future Through Elec. Reg'l Transmission Plan. & Cost Allocation & Generator Interconnection*, Docket No. RM21-17 (Sept. 19, 2022), eLibrary No. 20220919-5104 ("TAPS Reply NOPR Comments") (collectively, "TAPS NOPR Comments").

consumers consistent with the Commission's statutory obligations under FPA sections 205, 206, and 217(b)(4). Instead, we offer a set of guidelines that should shape the Commission's efforts in this area.

A. To the extent possible, the Commission should encourage regions to leverage and build on existing transmission planning processes, rather than require creation of new interregional planning entities and/or processes[8]

TAPS suggests that the best way to assess and address interregional transfer capability challenges is by building on existing regional planning institutions and interregional efforts that are showing promise. Requiring Transmission Providers ("TPs") to create new processes and institutions to undertake interregional planning at each interface, on top of intensive regional planning processes, would be a time-consuming and heavy lift. Doing so would be disruptive of well-functioning regional processes in RTO regions, thereby creating new obstacles to all existing planning efforts, as well as those under consideration in the *Building for the Future* NOPR.[9] And prospects for success would be questionable. Superimposing new interregional planning requirements on TPs is unlikely to produce robust plans, particularly in non-RTO regions given their post-Order 1000[10] regional planning track record.[11] Interconnection-wide approaches are even less likely to achieve the intended goals.[12]

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[8] *See* Notice question 7.

[9] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, 179 FERC ¶ 61,028 (2022) ("Building for the Future NOPR").

[10] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 136 FERC ¶ 61,051 (2011) ("Order 1000"), *reh'g denied*, Order No. 1000-A, 139 FERC ¶ 61,132, *on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *review denied sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014) (per curiam).

[11] As recognized in the *Building for the Future* NOPR P 39, no regional project has emerged from *any* non-RTO region since Order 1000. See also Post-Technical Conference Comments of Transmission Access Policy Study Group at 17, *Transmission Planning and Cost Management*, Docket No. AD22-8, (Mar. 23,

1. Interregional Transfer Capability should be a new need to be considered in Order 1000 regional planning processes.

The Commission can better advance its objectives by modifying existing *regional* planning processes, so that they can effectively address the need for *interregional* transfer capability.[13] One way to do so would be to make ITC a new regional need that must be considered in an updated Order 1000 regional process.

Today, Order 1000 requires regional planning only for identified regional Economic, Reliability, and Public Policy Requirement needs. None of those expressly encompasses or focuses on the sufficiency of interregional transfer capability. And the current regimen for interregional coordination only seeks to identify more cost-effective and efficient solutions to each region's individual Economic, Reliability, and Public Policy Requirement needs. Interregional transfer capability is not a consideration in that process.

Modifying Order 1000 to require that each region identify its ITC needs, and plan for them, could pave the way for significant increases in transfer capability. Such regional processes may be able to identify regional projects that will significantly

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2023), eLibrary No. 20230323-5152; TAPS ANOPR Comments at 15-19; TAPS Initial NOPR Comments at 69-70; Summary Statement of Dan O'Hagan on behalf of the Florida Municipal Power Agency and the Transmission Access Policy Study Group for the October 6, 2022 Technical Conference (Sept. 22, 2022), eLibrary No. 20220922-5032; Transcript of the Transmission Planning and Cost Management Technical Conference held on October 6, 2022 at 29:20-31:20 (Nov. 1, 2022), eLibrary No. 20221101-4000.

[12] Interconnection-wide planning studies (see Notice question 5(a)) would ignore significant regional differences and make it difficult or impossible for states and stakeholders to effectively participate. The absence of such meaningful participation and engagement could lead to projects that are less efficient and cost-effective and lack the necessary buy-in needed to facilitate state siting and to resolve cost allocation issues.

[13] To be effective in non-RTO regions, the existing Order 1000 processes of those regions must also be reformed, as discussed in TAPS's Comments in the *Building for the Future* and *Transmission Planning and Cost Management* proceedings, referenced in footnote 11 above.

increase ITC, even without the addition of new facilities by a neighboring region.[14] And regional plans that meaningfully address interregional transfer capability could invigorate existing interregional coordination processes by triggering the identification of interregional projects that could displace regionally planned projects and more cost-effectively and efficiently address ITC needs.

Inclusion of ITC among the needs to be planned for fits well within the existing regional planning structure. And it respects Order 1000's interregional coordination requirements and processes, including: (1) joint evaluation of interregional projects;[15] (2) that an interregional transmission project sponsored by one region should not be

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[14] For example, in a situation in which the loss of a large interregional line would cause an overload on a lower-voltage local or regional transmission facility, upgrading that facility could increase ITC. And a region's ability to facilitate large power transfers to a neighbor in an emergency—either from resources located within the region, or resources imported from other neighbors and wheeled across the region—may well be limited by constraints in the region's footprint located far from its interregional seams.

Whether a particular project located entirely within a single region can substantially increase ITC will be a fact-specific question. However, most of the MISO-PJM Targeted Market Efficiency Projects ("TMEPs")—which are designed to address congestion across the MISO-PJM seam—are located within a single region (i.e., either completely in MISO or completely in PJM). PJM Interconnection, L.L.C., *2017 PJM Regional Transmission Expansion Plan* at 97 (Feb. 28, 2018), https://www.pjm.com/-/media/library/reports-notices/2017-rtep/2017-rtep-book-3.ashx (PDF p. 105); PJM Interconnection, L.L.C., *Regional Transmission Expansion Plan, 2018*, at 77 (Feb. 28, 2019), https://www.pjm.com/-/media/library/reports-notices/2018-rtep/2018-rtep-book-1.ashx (PDF p. 89); PJM Interconnection, L.L.C., *RTEP 2022: Regional Transmission Expansion Plan* at 73 (Mar. 14, 2023), https://www.pjm.com/-/media/library/reports-notices/2022-rtep/2022-rtep-report.ashx (PDF p. 79).

In addition, six of the seven projects identified by the MISO-SPP Joint Targeted Interconnection Queue ("JTIQ") process in July 2022, were located within a single region. And although the purpose of the JTIQ process is not to increase interregional transfer capability or decrease congestion, MISO stated that the portfolio would "[i]ncrease interregional transfer capability." Midcontinent Independent System Operator, Inc., *MISO-SPP Joint Targeted Interconnection Queue Study (JTIQ) Update* at 4 (July 2022), https://cdn.misoenergy.org/20220726%20RECBWG%20Item%2002%20MISO-SPP%20Joint%20Targeted%20Interconnection%20Queue%20(JTIQ)%20Update625716.pdf.

[15] Order 1000, PP 435, 439.

involuntarily imposed on another region;[16] and (3) "having an interregional transmission facility in a regional transmission plan does not mean that it will be constructed."[17]

2. Build on existing successful interregional efforts

The Commission should also encourage regions to build on existing interregional efforts that are working well or are in their early stages but show considerable promise. For example, the ***MISO-PJM Targeted Market Efficiency Project ("TMEP")*** process—also known as the "Quick Hits" process—was created to provide relatively inexpensive and readily implementable solutions to address congestion along the MISO-PJM seam.[18] It identifies near-term, high-value interregional projects to alleviate historical congestion, using a simplified approach based on actual historical day-ahead and real-time congestion, in contrast to the forward-looking production cost models used in each region's regional transmission planning process for economic projects.[19]

In the short period it has been in effect, this process has yielded significant successes. As described in the filing to implement the TMEP process, the five initially selected Quick Hits projects were collectively estimated to have a total installed cost of

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[16] *Id.* P 442.

[17] *Id.* P 443.

[18] *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,005, P 1 (2017). TAPS has previously urged expansion of the "quick hits" process as a means to facilitate effective incorporations of grid-enhancing technologies (GETs"). *See, e.g.*, TAPS ANOPR Comments at 21-22 (a quick fix process could provide a good vehicle for open and transparent regional consideration of GETs along with quickly implementable conventional projects, producing more efficient and cost-effective approaches to provide timely congestion relief for consumers).

[19] A "quick hits" project must: (a) be demonstrated by joint or coordinated study to have an expectation for substantial relief of historical congestion; (b) have an estimated in-service date by third summer from the year approved; (c) have an estimated installed cost of less than $20 million; (d) have a four-year payback in terms of expected congestion relief; and (e) be recommended by PJM and MISO and approved by both boards. Cost allocation between regions is based on each RTO's share of expected benefits—i.e., each RTO's share of the total avoided congestion. *See PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,005 PP 5, 58 (2017).

$17.25 million and to avoid approximately $100 million in congestion costs over their first four years in service.[20] The three additional TMEPs approved since then were estimated to cost less than $5 million, while avoiding approximately $40 million in congestion costs during their first four years.[21] Except for a TMEP approved in March 2023, all of the projects have been completed.[22]

In addition, MISO and SPP are working together to facilitate the planning and cost-sharing of generator interconnection-enabling transmission investments along their seam through another promising interregional effort. ***MISO and SPP initiated the Joint Targeted Interconnection Queue Study ("JTIQ Study")*** in 2020 after cluster study observations demonstrated that the transmission system along the MISO/SPP seam is at capacity, and network upgrades triggered by interconnections in that area were cost-prohibitive for individual or small groups of generator interconnection customers.[23] Other barriers identified by the RTOs included the absence of a tariff mechanism to share infrastructure costs between the two regions and a lack of alignment between the two RTOs' processes, criteria, and schedules.[24]

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[20] *Id.* P 8.

[21] Source of data: PJM Interconnection, L.L.C., *Regional Transmission Expansion Plan, 2018*, at 77 (Feb. 28, 2019), https://www.pjm.com/-/media/library/reports-notices/2018-rtep/2018-rtep-book-1.ashx (PDF p. 89); PJM Interconnection, L.L.C., *RTEP 2022: Regional Transmission Expansion Plan* at 73 (Mar. 14, 2023), https://www.pjm.com/-/media/library/reports-notices/2022-rtep/2022-rtep-report.ashx (PDF p. 79) ("2022 RTEP Report"). The Powerton-Towerline project identified in the 2022 RTEP Report was approved by PJM in February 2023 (2022 RTEP Report at 72) and MISO in March 2023.

[22] Midcontinent Independent System Operator, Inc., *MISO Transmission Expansion Plan (MTEP) In Service Project List 01/27/2023* (Jan. 27, 2023), https://cdn.misoenergy.org/MTEP In Service Projects106330.xlsx.

[23] Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc., *JTIQ Study Executive Summary* at 1 (Mar. 2022), https://www.spp.org/documents/66725/jtiq%20report.pdf (March 2022 JTIQ Report).

[24] *Id.*

The JTIQ Study targets the identification of: (1) more comprehensive, cost-effective, and efficient network upgrades than the current interconnection and Affected System coordination processes; (2) solutions to address interconnection needs and provide benefits to load in MISO/SPP; and (3) opportunities to improve coordination between the two RTOs.[25] Although still at a relatively early stage, the JTIQ Study identified a portfolio of 345 kV facilities that would support the interconnection of significant amounts of new generation along the seam.[26] The resulting JTIQ portfolio of projects is expected to cost approximately $1 billion. The projects are expected to enable 30,000 MW of generator interconnections,[27] and to provide $56 million and $133 million in Adjusted Production Cost ("APC") benefit to customers in the MISO and SPP footprints, respectively, over a ten-year period.[28]

Recognizing that JTIQ Study projects are generator interconnection-driven, future generator interconnection customers that are determined to impact the SPP-MISO seam will pay 90% of project costs, while the remaining 10% would be allocated to load in both RTOs.[29] Each RTO's share of the 10% of JTIQ costs allocable to load would be determined by that RTO's calculated APC benefits, divided by the sum of both RTOs'

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[25] *Id.*

[26] Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc., *SPP-MISO Joint Targeted Interconnection Queue Cost Allocation and Affected System Study Process Changes White Paper* at 9 (Dec. 2022), https://www.spp.org/documents/68518/spp-miso%20jtiq%20study%20updated%20white%20paper%2020221220.pdf (December 2022 JTIQ Whitepaper).

[27] *Id.* at 9.

[28] *Id.* at 7.

[29] *Id.* More specifically, Generator interconnection customers would fund 90% of engineering and construction ("E&C") costs, 90 % of transmission owner carrying costs, and 100% of the JTIQ study costs. *Id.* Load in MISO and SPP would fund the remaining 10% of E&C costs, 100% of O&M costs, and 10% of the transmission owner carrying cost of JTIQ projects. *Id.* at 7.

calculated APC benefits.[30] Current calculations show that SPP load will be responsible for 7% of JTIQ portfolio costs, while load in MISO will bear the other 3%.[31] MISO has recently previewed more details on cost allocation, and indicated that it intends to file tariff changes in Summer 2023 to implement the proposed JTIQ cost allocation.[32]

While these two promising interregional processes are different from each other, there is much that the Commission can learn from them. By focusing on narrowly defined existing and historical conditions, both the TMEP and JTIQ processes avoid the challenging task of reaching interregional agreement on long-term future scenarios as inputs to binding planning and cost allocation analyses. They have nevertheless identified projects that provide substantial benefits and, in the case of the JTIQ process, comprise over $1 billion in new facilities. In addition, the cost allocation methodology of each process reflects the objective of, and benefits sought to be achieved by, that focused planning effort.

Even with their more limited scope, developing and implementing these types of interregional processes takes hard work. To succeed, neighboring regions must coordinate and reach agreement on significant issues including cost allocation methodology and project criteria that will result in the selection and construction of the right facilities. While the TMEP and JTIQ processes demonstrate that this is possible, any

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[30] *Id.*

[31] Midcontinent Independent System Operator, Inc., *Joint Targeted Interconnection Queue Project Tariff Additions and Revisions Overview* at 7 (Apr. 26, 2023), https://cdn.misoenergy.org/20230426%20PAC%20Item%2006c%20JTIQ%20Update%20and%20Draft%20Tariff%20Presentation628664.pdf

[32] *Id.* at 12.

new ITC requirements should be flexible, accommodate regional differences, and foster such agreements rather than impose one-size-fits-all mandates.

B. One size does not fit all, and the Commission should avoid adopting an over-simplified minimum ITC requirement.

At the Workshop, various panelists urged the Commission to set an ITC standard as a fixed percentage of peak load.[33] That approach is not appropriate. The Commission has long-avoided "one-size-fits-all" planning requirements in favor of regional flexibility,[34] and should continue to do so here.

The level of interregional transfer capability that will best serve a region should be the product of detailed study and analysis, not an arbitrary metric unmoored from regional needs. While Dr. Adria Brooks (DOE Grid Deployment Office) used 15% of peak demand in her presentation on how a possible transfer capability requirement might be implemented, she explained that there was no clear basis to support setting ITC at that percentage. Instead, 15% was chosen: [35]

> because that's been thrown around, that's been discussed in the industry. It was by no means linked to congestion value.

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[33] *See, e.g.,* Final Transcript of the December 5, 2022 Staff-Led Workshop on Establishing Interregional Transfer Capability (Feb. 3, 2023), eLibrary No. 20230203-4000 (for transcript pages 1-194); Final Transcript of the December 6, 2022 Staff-Led Workshop on Establishing Interregional Transfer Capability (Feb. 3, 2023), eLibrary No. 20230203-4001 (for transcript pages 195-389) (collectively, "Tr."). Tr. at 28:7-9 (Liza Reed, PhD, Research Manager, Electricity Transmission, Niskanen Center) ("15 percent is a pretty standard resource adequacy planning margin, and should be considered a starting level for interregional transfer"); *id.* at 143:16-18 (Sharon Segner, Senior Vice President of Transmission Policy, LS Power Development, LLC) ("we believe that the minimum transfer capability should be established as a percentage of peak load"); *id* at 213:15-21 (Michael Goggin, Vice President, Grid Strategies, LLC, speaking on behalf of the American Clean Power Association) (suggesting a default minimum requirement of 20% of a balancing area's peak load).

[34] *See, e.g., Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000-A, 139 FERC ¶ 61,132, P 266 (2012) (recognizing that "various regions of the country differ significantly in resources, industry organization, market design, and other ways so that a one-size-fits-all approach to regional transmission planning would not be appropriate.") (subsequent history omitted).

[35] Tr. 181:25 – 182:8.

> It was not linked to historical prices, it was also not linked to scenario planning, right. So that shows the gaps that we could see if we were to just choose a number, and try to apply that uniformly to all transfers versus trying to base that in some type of transmission value, or trying to base that in scenario based planning.

Panelist David Souder, Executive Director of System Planning for PJM and Technical Committee Vice Chair of the Eastern Interconnection Planning Collaborative, cautioned that "keeping it simple" should not come at the expense of doing the work required to justify any standard.[36]

A simplistic approach to establishing ITC would be inappropriate. Interregional transfer capability needs vary significantly from region-to-region, and change depending on what area of a regional seam is being studied.[37] As panelist Digaunto Chatterjee, Vice President of System Planning at Eversource Energy, explained, a fixed-percentage ITC requirement might undermine, rather than support, development of transfer capability that addresses a region's specific needs. In fact, a 20-25% standard in New England would result in relatively modest additions to the transmission system, without solving the region's biggest concern: [38]

> Our transfer capability ties in New England hover between 2,500 and 5,000 megawatts, right? So that's about 10 to 20 percent depending on hours in a year, 10 to 20 percent.

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[36] Tr. 232:24 – 233:4 ("One concern I do have about . . . keeping it simple . . . yesterday we heard that . . . an interregional transfer criteria of 15 percent, today we're hearing 20 or 25 percent. I do believe that has to be some kind of analytics behind it to justify what that percentage is.").

[37] *See* U.S. Department of Energy, *National Transmission Needs Study*, Draft for Public Comment at iv – xv (Feb. 2023), https://www.energy.gov/sites/default/files/2023-02/022423-DRAFTNeedsStudyforPublicComment.pdf ("Draft National Transmission Needs Study") (highlighting a range of drivers for increasing interregional transfer capability among the thirteen interfaces studied).

[38] Tr. 272:16 – 273:2.

> Anyone who looks at our resource adequacy issues in New England would easily deduce that a minimum 20 percent or 25 percent transfer capability in core capability is not good enough right? At 26 percent it seems like 6,500 [of] our peak demand today. So that's one 345 kV line from potentially outside from New York to New England. That's one 345 kV line.
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> That's not – we all know intuitively that doesn't solve the problem[.]

Rather than a one-size-fits-all standard, the Commission should preserve regional flexibility and seek to drive the development of new interregional transmission where, taking into account all the relevant factors, data and analysis demonstrate a region's need for and benefits from additional ITC. One way to do so would be by: (a) establishing interregional transfer capability study guidelines; and (b) directing each region to identify the ITC needs the region will plan for as part of its regional transmission planning process, consistent with those guidelines, based on the specific circumstances at each of its regional interfaces, and after coordination with the neighboring region.[39]

C. Any required process to identify the need for ITC, and plan for it, must include transparent criteria for assessing its costs and benefits.

Any process for identifying and planning for interregional transfer capability must be transparent as to *all* the various costs and benefits of increased ITC, and ensure that other market rules and resource adequacy requirements appropriately take ITC changes into account. Regional planners, for example, must have the ability to compare the delivered cost of remote versus local generation resources—including interregional

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[39] *See* Part I.A.1 above.

versus regional resources—and to determine whether reliance on regional alternatives would be more cost-effective than increasing interregional transfer capability.[40]

Resource adequacy implications should also be considered. The ability to take advantage of imports from neighbors during shortages has long been recognized to be directly related to the amount of reserves that must be carried to reliably serve firm load.[41] And the Commission has allowed Transmission Reliability Margin set-asides that reduce the Available Transfer Capability to facilitate reserve sharing and other such uses.[42] Thus, the process of considering the need for, and costs and benefits of, increasing ITC should include determination of whether and by how much the proposed additional interregional transfer capability would operate to reduce regional reserve requirements. The Commission should then ensure that consumers actually receive the expected resource adequacy requirement reductions.

It is also important to recognize that increased ITC, by itself, is not necessarily sufficient to ensure appropriate access to and use of that transfer capability in times of shortage. Even those with firm transmission reservations that cross regional boundaries were unable to count on those reservations in recent emergencies. For example, Missouri Electric Commission ("MEC"), which has loads and resources in both SPP and MISO,

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[40] *See* TAPS Initial NOPR Comments at 10-12.

[41] *See, e.g. Gainesville Utils. Dep't v. Fla. Power Corp.*, 402 U.S. 515, 518-520; 528-29 (1971) (reinstating Federal Power Commission's decision to require interconnection of then-isolated Gainesville (which would otherwise need to carry reserves covering loss of its largest unit) to Florida Power Corp. without charging Gainesville a standby fee (on top of the costs of the interconnection and the obligation to maintain 15% reserves).

[42] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 118 FERC ¶ 61,119, PP 264, 273, *order on reh'g and clarification*, Order No. 890-A, 121 FERC ¶ 61,297 (2007) (describing the uses of TRM and its availability for reserve sharing), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

had its *firm* tags from MISO to SPP curtailed by MISO during Winter Storm Uri because MISO was in a Maximum Generation event.[43] During that storm, SPP also curtailed MEC's firm tags because of TLR events at times when MEC's MISO generation was on-line.[44] Disruption of firm cross-seam transmission service is a particular problem for transmission dependent utilities that all too often find themselves split across RTO seams determined by the decisions made by transmission owners on which they have load and/or resources. Steps should be taken to address that problem. But MEC's experience also highlights a general issue: in emergency conditions, a region may block some or all interregional transfers. Such curtailments may well be a reasonable response in some circumstances; and as system operators gain experience with emergencies, they may find ways to limit them. But particularly if the economic benefits of increased ITC are concentrated in periods of extreme conditions,[45] any evaluation of the benefits of increased ITC must take this possibility into account.

D. Any Commission action on ITC planning should provide for periodic reassessment.

While ITC planning is more likely to succeed if built on existing planning processes, it will be a challenging task, regardless. Thus, whatever action the Commission takes to enhance planning to address ITC needs should incorporate a

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[43] *See* Midcontinent Independent System Operator, Inc., The February Arctic Event at 6-7 (Feb. 14 - 18, 2021), https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf (describing maximum generation events).

[44] *See generally*, Southwest Power Pool, Inc., A Comprehensive Review of Southwest Power Pool's Response to the February 2021 Winter Storm: Analysis and Recommendations at 67 (July 19, 2021), https://www.spp.org/documents/65037/comprehensive%20review%20of%20spp's%20response%20to%20the%20feb.%202021%20winter%20storm%202021%2007%2019.pdf (showing the volume of scheduled curtailments and corresponding shedding of load within SPP).

[45] *See*, *e.g.*, Draft National Transmission Needs Study at 40 ("Extreme conditions and high-value periods play an outsized role in the value of transmission, with 50% of transmission congestion value coming from only 5% of hours.").

reporting requirement to facilitate evaluation of the effect of those actions and what further actions, if any, are required.

For example, the Commission could require each planning region to report to the Commission after each planning cycle. Those reports, which should be subject to public comment, could include an overview of the needs studied, the determinations reached through those analyses, and the results of those efforts. Requiring these submissions would enable the Commission to evaluate periodically the effectiveness of ITC planning efforts and, if necessary and appropriate, consider taking steps, including further planning process changes, if a region's efforts to implement ITC planning fall short of expectations.

II. FPA SECTION 215 DOES NOT PROVIDE STATUTORY AUTHORITY FOR EFFORTS TO EXPAND INTERREGIONAL TRANSFER CAPABILITY

A number of Workshop panelists pointed to FPA Section 215 as providing authority for the Commission to impose interregional transfer capability requirements.[46] TAPS disagrees. Section 215(a)(3) expressly prohibits mandatory reliability standards that require enlargement of bulk power system facilities or construction of new transmission capacity or generation capacity:[47]

> The term "reliability standard" means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-

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[46] *See, e.g.,* Tr. 132:1-3 (Sharon Segner, LS Power) ("legal framework for establishing the minimum transfer capability . . . is found under Section 215 of the Federal Power Act"); Tr. 137:20-21); Deral Danis, Pattern Energy) ("I do tend to think that NERC is the right entity to sort of set the standards"); Tr. 28:12-15 (Liza Reed, Niskanen Center) ("[I]ncreasing interregional transfer is a reliability action because it extends how far the reliability of a system could go before it hits the wall of required resilience measures.").

[47] 16 U.S.C. §824o(a)(3) (emphasis added).

> power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, *but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity* or generation capacity.

Section 215(i)(2) also provides that Section 215 "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services."[48]

The Commission's recent order approving the North American Electric Reliability Corporation's ("NERC") cold weather standard—which included requirements that generator owners add new, or modify existing, freeze-protection measures—expressly acknowledged FPA Section 215(a)(3)'s limitation on the Commission's jurisdiction. In *North American Electric Reliability Corp.*,[49] the Commission responded to objections that it had exceeded its FPA Section 215(a)(3) authority by noting that the freeze-protection requirements "are intended to reduce capacity that is forced off-line due to freezing conditions and to help ensure that such capacity is not forced off-line in newer units";[50] the requirements thus fit clearly within Section 215(a)(3)'s inclusion of requirements regarding "the design of planned additions or modifications to [bulk-power system] facilities to the extent necessary to provide for reliable operation of the bulk-power system."[51] According to the Commission:[52]

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[48] 16 U.S.C. §824o(i)(2).

[49] 182 FERC ¶ 61,094 (2023) ("Cold Weather Standard Order").

[50] *Id*. P 49.

[51] Reply Comments of the North American Electric Reliability Corporation at 5 (Dec. 16, 2022), Docket No. RD23-1, eLibrary No. 20221216-5162. *See also Id.* at 7 ("The proposed requirements may call for

> [N]either of these requirements [to add new, or to modify existing, freeze protection measures] mandate the construction of new generation capacity or an expansion of the unit's generating capacity, which are the only relevant exclusions identified in the statutory definition of a "Reliability Standard."

In contrast, it is hard to conceive of a reliability standard that requires transmission owners or other registered entities to establish and meet minimum interregional transfer capability standards, but that would not entail a "*requirement to enlarge such facilities or to construct new transmission capacity*," which Section 215 expressly defines as beyond the scope of reliability standards.[53]

Further, ITC needs are not necessarily driven solely by "provid[ing] for reliable operation of the bulk-power system," which further limits the scope of permissible reliability standards under FPA Section 215(a)(3).[54] Many factors listed in Notice question 8 for possible consideration in determining a minimum transfer capability go far beyond reliable operation of the bulk power system. Similarly, the DOE *National Transmission Needs Study* and the studies it relies upon,[55] derive ITC needs by optimizing generation, storage, and transmission investment decisions for the lowest capital and operations costs, based on assumptions about electrification, renewable requirements, market conditions, and consumer demand behavior. Although "some

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operational or design measures, depending on the approach chosen by the individual Generator Owner to implementing freeze protection measures or implementing corrective actions as required by the standard. The proposed Reliability Standard provides significant flexibility on the freeze protection or corrective action approaches that may be considered. Under no reasonable reading, however, could proposed Requirements R1 or R2 be interpreted as requiring the 'enlargement' of existing facilities, as that term is commonly understood, or as calling for the construction of new generation capacity").

[52] Cold Weather Standard Order P 47 (quoting Section 215(a)(3)).

[53] *Id.* P 41.

[54] 16 U.S.C. § 824(o)(a)(3).

[55] *See* Draft National Transmission Needs Study.

essential grid reliability services, such as resource adequacy" are considered, reliability is not the focus.[56] The statutory definition of Reliability Standard, which includes modifications to facilities only "*to the extent* they are necessary to provide for reliable operation of the Bulk-Power System," [57] is ill-suited to support minimum interregional transfer requirements (even assuming—incorrectly—that they could be viewed as something other than an enlargement of or construction of new transmission facilities).

Thus, as the Commission considers potential further actions to address interregional transfer capability, it should not rely on FPA Section 215 as a source of authority to establish and enforce minimum interregional transfer capability requirements.

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[56] *See also* Draft National Transmission Needs Study at 80-81 (noting that studies of certain factors critical to the transmission planning process to ensure reliable operation of the grid are "out of scope for the analysis presented here").

[57] Cold Weather Standard Order P 47 (emphasis added) (citing FPA Section 215(a)(3)).

CONCLUSION

The Commission should take these comments into account as it considers next steps in assessing and addressing interregional transfer capability.

Respectfully submitted,

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May 15, 2023