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 ELECTRICTY CONSUMERS RESOURCE COUNCIL

The Electricity Consumers Resource Council (ELCON) respectfully submits these comments in response to the Notice Requesting Post-Workshop Comment (Notice) issued February 28, 2023[1] in the above-captioned docket, in which the Federal Energy Regulatory Commission (FERC or Commission) considers minimum interregional transfer capability requirements for transmission planning regions to bolster grid reliability.

ELCON is the national association representing large industrial consumers of electricity. ELCON member companies create a wide range of products from virtually every segment of the industrial community. We own and operate hundreds of major facilities and are significant consumers of electricity in the footprints of all organized markets and other regions throughout the United States. Reliable electricity supply at just and reasonable rates is essential to our members' operations. Further, ELCON members rely on the transmission of electricity by FERC-jurisdictional utilities. Accordingly, any Commission actions requiring minimum interregional transfer

[1] *Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements*, Notice Requesting Post-Workshop Comment, Docket No. AD23-3-000 (Feb. 28, 2023).

capabilities will have a direct financial impact on ELCON members and other consumers, which the Commission must balance against any anticipated benefit.

SUMMARY

Extreme weather events have increased in intensity and frequency over the last decade that have significant impacts on reliable electric power for consumers. Beyond the inconvenience of interrupted power, lives and livelihoods can be destroyed by prolonged outages and exposure to life-threatening weather elements. Recent severe weather events, such as Winter Storm Uri, demonstrated that a crucial element to providing life-saving electric service is the ability to import power from other less-impacted regions.

The Commission has begun investigating whether this vital transfer capability should be mandated to provide an insurance policy against future outages. Interregional transfer capability can provide such an insurance policy while providing other benefits to local and interregional customers. However, consideration of this single "solution" ignores other beneficial regional and interregional transmission solutions. Specifically, mandating interregional transfer capability in isolation of other needs risks leaving considerable benefits on the table.

The Commission must strengthen the tenets of organized and coordinated transmission planning under Order No. 1000 to include mandatory interregional planning. In the decade since Order No. 1000, there has been no significant interregional transmission development despite evidence that interregional transmission is not only beneficial, but critical. The mismatch of interregional coordination attempts and a clear lack of consistent methodologies to determine needs and solutions has failed in identifying transmission development that saves consumers money while also providing life-saving services.

By enhancing interregional transmission planning, transmission owners are provided with the tools to determine needs and benefits on an even playing field with

shared information, methodologies, and protocols. By considering interregional transfer capability under the larger interregional planning considerations, not only does this provide examination of those benefits, but can also determine whether such transfer capability is more beneficial than costly. Mandating interregional transfer capability in isolation will not accurately demonstrate overall interregional needs and benefits. The transmission planning process should not mandate a specific outcome but provide a process for examining all needs and benefits to determine if an interregional project provides enough benefits to justify the costs to consumers, including interregional transfer capability.

ELCON recommends that the Commission (1) provide for mandatory interregional planning processes in all regions regardless of whether in an organized market or not, (2) establish minimum common metrics for determining interregional costs and benefits, (3) allow for regional flexibility to establish methodologies reflecting the needs of the region and its neighbors, and (4) apply the "beneficiary pays" tenet for interregional cost allocation with periodic review of actual beneficiaries over the life of the project.

I. MANDATING INTERREGIONAL PLANNING PROCESSES IS NECESSARY TO ESTABLISH MINIMUM INTERREGIONAL TRANSFER CAPABILITY

Order No. 1000[2] mandated the establishment of regional transmission planning regions to provide for open and transparent transmission planning with an agreed upon cost allocation methodology to spur transmission investment to meet future challenges. Arguably, these challenges have evolved since the issuance of Order No. 1000 in 2011 and has called for significant reforms.[3] However, neither Order No. 1000

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[2] *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000 -B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014) (Order No. 1000).

[3] *See Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022) (Transmission NOPR).

nor the Transmission NOPR adequately address the need for more stringent requirements regarding interregional transmission planning.

To date, there are no significant interregional transmission projects in development[4] for myriad reasons,[5] in addition to having no real incentive or mandate to actually "plan" for interregional projects. Instead, Order No. 1000 only required interregional "coordination," which has no teeth[6] and has led to a check-the-box exercise.

If the Commission enhances interregional coordination to include actual planning, minimum transfer capabilities will naturally fall into the needs and benefits categories when reviewing potential interregional transmission solutions.

A. The Commission Should Formalize Interregional Planning Requirements to Include Minimum Transfer Capability

Recent weather events such as Winter Storm Uri in 2021 and Winter Storm Elliot over the holiday season in 2022, have highlighted how the ability to borrow power from neighboring regions, if structured properly, may save costs, reduce outages, and actually save lives. Recognizing the importance of being able to transfer power to regions experiencing generation underperformance, interest in mandatory interregional transfer capabilities as an insurance policy against extreme events and stress on the grid began to receive attention, as demonstrated by the panelists at the Commission's December Staff-led Workshop (Workshop).[7]

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[4] The Brattle Group, "A Roadmap to Improved Interregional Transmission Planning," at p. 1 (Nov. 30, 2021), available at: https://www.brattle.com/wp-content/uploads/2021/11/A-Roadmap-to-Improved-Interregional-Transmission-Planning_V4.pdf.

[5] *See id.* at 8-11.

[6] Order No. 1000, 136 FERC at PP 396 (Words such as "coordinating and sharing," "possible," "could" all convey that interregional planning is a suggestion rather than a requirement).

[7] Staff-Led Workshop on Establishing Interregional Transfer Capability Transmission Planning and Cost Allocation Requirements, Docket No. AD23-3-000 (Dec. 6-5, 2022); https://www.ferc.gov/news-events/events/staff-led-workshop-establishing-interregional-transfer-capability-transmission.

A common theme from the Workshop was a call for FERC to strengthen the requirements for interregional transmission planning.[8] Interregional projects could be, if properly and economically planned, developed, and executed, the backbone of a resilient, cost-effective, and reliable future grid. For over a decade, we have failed to see one significant interregional transmission project as envisioned under Order No. 1000 despite increasing challenges related to extreme weather, resource adequacy and dispatchability, and physical and cyber-attacks on grid infrastructure. By increasing interregional transfer capabilities through mandatory interregional planning, we can mitigate these interruptions on the grid.

However, without an identified process for assessing all potential interregional project solutions, transmission planners will narrowly focus on the one benefit—the ability to provide for transfer capabilities—at the expense of interregional solutions that provide multiple benefits and with potential disregard for the very substantial costs interregional transfer buildouts could entail.[9] Therefore, rather than focusing on one specific standard, the Commission should consider broader interregional planning requirements to identify other benefits that were overlooked from inadequate interregional processes, including fostering better interregional transfer using existing infrastructure.[10]

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[8] "First, to enhance interregional operations to most effectively utilized existing transmission infrastructure. Secondly, to <u>reinforce effective interregional planning processes</u>, and third, to develop benefit metric, or metrics, associated with interregional transfer capability that could be incorporated into existing planning processes," Workshop transcript at 123:3-9 (emphasis added); "I mean one thing I think the Commission should do is issue an interregional planning NOPR," Workshop transcript at 324:13-14; "I think there was an idea of a requirement for interregional planning, just like we have proposed requirement for regional planning. I think that would be a wonderful outcome of these proceedings. I think that's something we've talked about for years," Workshop transcript at 328:2-6.

[9] *See* Workshop transcript at 160.

[10] However, we recognize that reliability and resiliency are top priorities and delaying a much-needed reliability requirement, subsumed in a larger, more complicated and time-consuming process, is not the most efficient use of resources.

Not only will mandatory planning requirements provide for the review of multi-value projects, but they also would avoid leaving an expensive interregional transmission facility dormant until an emergency is called. By mandating interregional transmission planning requirements, similar to regional transmission planning, FERC can save consumers millions through increased resiliency in the form of reduced outages and by providing additional interregional cost benefits.[11] Instead of waiting for an emergency, the additional transmission capacity can be open to the market, benefiting consumers with lower congestion costs and access to additional diverse and lower-cost resources. Without mandatory planning requirements, consumers may only receive the reliability benefit from a minimum transfer capability requirement in an emergency leaving other potential benefits and cost savings on the table.

B. The Commission Should Focus Interregional Transfer Capability Requirements on Process not Outcomes

Mandatory interregional planning will require additional metrics and protocols to consider both interregional transfer capability and other beneficial transmission solutions. Therefore, the discussion regarding the exact process for considering interregional transfer capability needs should be subsumed in the larger discussion of mandatory interregional planning. Thus, determining minimum interregional transfer capability should be one factor in the interregional transmission planning process determining need and not a universally set figure or percentage, as each planning region and its neighbors will have differing circumstances and needs.

First and foremost, as with regional transmission planning, regional transmission operators and independent system operators (RTOs/ISOs) as well as those regions not in an RTO/ISO should be required to engage in interregional transmission planning. In fact, in determining interregional transfer capabilities, it is the non-RTO/ISO regions that most need a transparent and coordinated process with their neighbors. Not only

[11] *See* Workshop transcript at 165:7-22.

will this benefit consumers in non-RTO/ISO regions with additional resources and capabilities, but also by requiring non-RTO/ISO regions to perform as part of the larger integrated grid benefitting all consumers rather than an isolated entity focusing solely on its own needs with little transparency into how needs and solutions are determined.[12]

Although interregional planning and the determinate interregional transfer capabilities are part of a process, common metrics should be applied as it implicates multiple entities and could impact the grid beyond an immediate neighbor. Having different mechanisms in each region to determine interregional transfer capability may result in a hodge-podge of inconsistent metrics and misaligned timelines, much like our current ill-defined interregional "coordination" requirement under Order No. 1000, which has resulted in a dearth of beneficial interregional solutions.

Here the Commission must provide some guidance on the means to determine need and measure potential benefits. Instead of an arbitrary set amount of required interregional transfer capability, the Commission should instead allow regions to establish a methodology that weighs costs and benefits in a way that captures reliability risks that could be mitigated with additional transmission capacity, or better interregional coordination between regions. However, to avoid similar check-the-box exercises for interregional planning, the Commission could require a certain minimal amount of capacity be interruptible and made available for delivery to any of its neighbors in case of a grid emergency.[13] From there, regions can determine a methodology for measuring how much transfer capability is sufficient for neighboring

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[12] *See* Workshop transcript at 80:19-21, "As you can imagine I think the RTO and non-RTO regions should not be treated separately because we are all one system."

[13] In establishing metrics and a process for studying interregional transmission needs, grid-enhancing technologies should be part of the equation in determining actual capacity on existing lines. This would save consumers from unnecessary costs of new capacity additions.

regions and include this in the needs assessment for interregional planning.[14] However, the established methodology must take into account extreme events and not just average blue-sky days.

The Commission would also establish a common set of metrics to measure the costs and benefits of interregional solutions that account for transfer capabilities, leaving room for regional differences. Additional metrics for transmission needs and benefits that go beyond the standard shared metrics can be determined by each region that accounts for its specific characteristics. The Commission also would set a common timeline for interregional transmission planning to ensure all regions are studying needs and determining solutions with their neighbors, and their neighbor's neighbors, instead of the current mismatch in timelines which exacerbates the problem of finding beneficial interregional solutions.

Common metrics must be applied to RTOs/ISOs and non-RTOs/ISOs as each have neighbors of the opposite structure (market vs. bilateral). In determining the need and amount of transfer capacity to increase reliability at just and reasonable rates, common metrics such as peak load; historical rates, causes, and impacts of transmission outages; historical rates, causes, and impacts of generation outages; expected weather conditions; anticipated load growth; generation diversity; electrification rates; anticipated generation retirements; and power quality are recommended. Regions are then free to establish more stringent metrics that better reflect their unique operating characteristics to be folded into the interregional transmission planning process.

Common benefit metrics will be discussed below as benefit identification and cost allocation are intertwined.

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[14] Whatever transfer capacity floor is established, transmission planners need to understand the effects and implications on reserve margins to accommodate required interregional transfer capability.

II. COST ALLOCATION MUST ADHERE TO THE BENEFICIARY PAYS DOCTRINE

A. Benefits of Interregional Transfer Capability Must Be Clearly Defined

As with determining need, the Commission should issue a common set of metrics for measuring benefits, with some regional flexibility to develop metrics beyond what is required by the Commission. These metrics must be clear and measurable as measuring the benefits of interregional transfer capability is integral in determining who benefits and by how much, as this will ultimately indicate who bears the costs of the interregional transfer facilities.

During the Workshop, the most cited metric for measuring benefits was the value of lost load (VOLL). VOLL can be thought of as the cost impacts to consumers during interruptions and outages. Though not a simple calculation, it is a defining metric in determining the benefit of increased reliability and resiliency. One complication in determining VOLL is the duration effect. The VOLL on day one of an outage is not always reflective of VOLL on the third or fourth day of an outage.[15] Therefore, this escalation should be accounted for in determining the benefit of interregional transfer capability solutions.

Other metrics, besides reliability, would also be included in a larger assessment during interregional planning. Although the primary focus has been the potential improvements in reliability and resiliency, there are economic benefits to increased capacity outside of a reliability insurance policy. As stated above, any interregional transfer solution should provide other benefits during blue-sky operations rather than sitting idle in case of system instability. Naturally, a project selected in the interregional

[15] *See* Workshop transcript at 170:1-13.

planning process would consider all benefits including reliability and economic efficiency when performing a cost/benefit analysis.[16]

Production cost savings were frequently cited as an economic benefit at the Workshop. Interregional transmission that can smooth out price volatility through resource diversity can save customers millions of dollars. When prices become too high, due to transmission congestion or a generation outage, neighboring regions can open up additional capacity to ease that volatility.[17] This price arbitrage was described by Dr. Dev Millstein:

> We find that interregional transmission offers substantial economic value from price arbitrage alone. The price arbitrage value roughly represents production cost savings that get approved from new transmission. And production cost savings are typically estimated to account for roughly half of the total transmission value within multi-value transmission studies.[18]

Similarly, shared interregional facilities can defer investment in less cost-effective regional generation and transmission solutions. Enabling access to a neighbor's generation supply can increase resource diversity with lower-cost generation resources, saving costs for consumers.

Once the common benefit metrics are set, a common methodology is necessary to properly allocate the costs of a project. Differing metrics and methodologies for cost allocation are a significant impediment to getting interregional transmission built today.[19]

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[16] Workshop transcript at 232:5-8, "There's economic values of different scenarios, all of that should be considered additional value add of the transmission design."

[17] *See* Workshop transcript at 209:1-9.

[18] Workshop transcript at 12:21-13-2.

[19] Workshop transcript at 37:7-11, "But the problem comes when you start defining the benefits, because the benefits are defined differently by different states, and so when you can't define benefits it's hard to then go to the cost allocation, things can't get done;" *see also*, Workshop transcript at 54:21-24 "and then you've got states like Mississippi, Kentucky, North Carolina, that are both RTO and non-RTO that have different benefit metrics that look over different time horizons."

B. Cost Allocation Should be Reviewed Periodically as the Grid Undergoes Significant Changes

Cost allocation continues to impede the development of cost-effective interregional solutions and therefore should be addressed under the larger discussion of mandatory interregional transmission planning. However, since interregional transfer capability is a newer concept without defined metrics, the cost allocation discussion is warranted. No single cost allocation methodology can accurately account for all beneficiaries, so the "roughly commensurate" measure provides a general rule of thumb.

Determining who benefits and who pays for interregional transmission projects, and more specifically interregional transfer capability, is as complicated and potentially contentious as regional cost allocation since benefits and beneficiaries will change over time.[20] A transmission project could be built to address a reliability contingency but over time, those transmission lines can produce economic and social benefits as well. Specific to interregional transfer capabilities, the primary driver is enhancing reliability and resiliency. Under that scenario, it should reasonably be determined who is benefiting and by how much in increased reliability and resiliency using the common set of metrics established by the Commission. However, unanticipated benefits, such as the referenced economic benefits, may materialize after energizing the facilities, changing the dynamics of the benefits and the beneficiaries. This demonstrates the need for both *ex ante* and *ex post* cost allocation.

The nation's electric grid will need significant changes to meet new challenges resulting in a constantly evolving grid that may look completely different in as little as a decade. Load patterns change, power flows change, generation retires, new technologies are introduced, each new election cycle brings regulatory upheaval, and world events cause generation supply and cost volatility. Each of these factors can

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[20] Workshop transcript at 299:16-18, "So these benefits accrue over time to various beneficiaries, so I don't think we should pretend to be able to identify who benefits from every electron."

impact the benefit evaluation of which users—if any—are ultimately benefiting. Any of these factors will have an enormous impact on the need for interregional transfer capabilities especially as the methodology assumptions and inputs to determine adequate capacity continue to change. Therefore, regular evaluation of the metrics and methodologies for transfer capability requirements and cost allocation will need to be implemented.

CONCLUSION

ELCON appreciates the Commission's efforts to explore whether interregional transfer capability provides sufficient benefit to consumers to justify its cost. Interregional transfer capability could provide an insurance policy against extreme weather threats to reliability. However, as discussed above, ELCON recommends incorporating this benefit and need assessment within the larger context of interregional planning in order to consider all potential benefits, costs, solutions, and beneficiaries between regions and its neighbors. The Commission is encouraged to establish common metrics with regional flexibility for neighbors to determine specific needs and solutions. Cost allocation must be assessed to those customers that receive tangible and quantifiable benefits with periodic review of beneficiaries over the life of the project.

Respectfully submitted,

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