UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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| **Transmission System Planning** | ) | |
| **Performance Requirements** | ) | **Docket No. RM22-10** |
| **For Extreme Weather** | ) | |
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# COMMENTS OF THE AMERICAN CLEAN POWER ASSOCIATION ON NOTICE OF PROPOSED RULEMAKING

The American Clean Power Association ("ACP")[1] appreciates the opportunity to provide comment on the Federal Energy Regulatory Commission's ("FERC" or "Commission") Notice of Proposed Rulemaking on Transmission System Planning Performance Requirements for Extreme Weather ("NOPR").[2] As extreme weather events continue to increase in frequency and severity due to climate change, a robust and resilient transmission system is essential to assuring affordable, reliable electric service that ensures access to a diverse range of resources. As detailed below, ACP strongly supports aspects of the NOPR that would help to ensure reliability in the face of extreme weather events, and offers clarifications and improvements on other areas of the NOPR. Additionally, these comments highlight the need for – and evidence supporting – further actions from the Commission on transmission scheduling and interregional transmission that would further meet these goals.

[1] ACP is a national trade association representing a broad range of entities with a common interest in encouraging the expansion and facilitation of wind, solar, energy storage, and electric transmission in the United States. The views and opinions expressed in this filing do not necessarily reflect the official position of each individual member of ACP.
[2] *Transmission System Planning Performance Requirements for Extreme Weather*, 179 FERC ¶ 61,195 (2022)("NOPR").

## I. COMMENTS

### A. Comments on actions proposed in the NOPR

#### 1. FERC's proposed actions are helpful, but a final rule should include more specific requirements for the revisions to NERC Standard TPL-001

ACP strongly supports FERC's proposal in concept. As an overarching comment, FERC's final Order should also address the inputs and assumptions that should be used for the reliability analysis, as well as provide guidance on what would constitute an acceptable level of performance. This will ensure the NERC Standard meets the identified reliability need and is effective in all regions. Consistent with Order No. 693, the Commission should "provide sufficient guidance so that [NERC] has an understanding of the Commission's concerns and an appropriate, but not necessarily exclusive, outcome to address those concerns."[3] Consistent with the Commission's statutory mandate, it should also ensure that it evaluates any eventual standard with "due weight to the technical expertise of the Electric Reliability Organization with respect to the content of a proposed standard or modification to a reliability standard."[4]

Further direction on the inputs, assumptions, and level of performance – and a requirement that adjacent planning regions coordinate their assessments and corrective action plans - will also assure consistent results between neighboring regions, which is essential for evaluating solutions that affect both regions (such as changes in inter-regional transfer capacity). As FERC explained in the NOPR, "it is important that transmission planners and planning coordinators likely to be impacted by the same types of extreme weather events use consistent benchmark events"[5] in conducting their

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[3] *Mandatory Reliability Standards for the Bulk-Power System* at P185, 120 FERC ¶ 61053 (2007).
[4] 16 U.S.C. § 824o(d)(2).
[5] NOPR at P52.

analyses. FERC should go further and establish clear benchmarks for consistent inputs and assumptions. As Commissioner Clements notes in her concurrence, "Consistency in the inputs and assumptions feeding these cases and scenarios will allow for neighboring transmission planners and planning coordinators to work together towards cost-effective corrective actions, like increasing transfer capability, that could otherwise be missed for lack of apples-to-apples comparisons."[6]

For example, FERC should specify that any modification to the TPL-001 Standard direct each Regional Entity to develop the benchmark severe weather events that will be evaluated by all Transmission Planners and Planning Coordinators in a given region. This would allow for regional variation, while also ensuring that entities likely to be impacted by the same types of extreme weather events use consistent benchmark events. The Regional Entities cover large footprints, but are often subject to the same type of extreme weather events (such as hurricanes, wildfires, or extreme cold) that can cause widespread transmission outages, so they are well positioned to determine the benchmark for their regions.

ACP also notes that some weather events cross multiple Regional Entities – such as Winter Storm Uri, which traversed the seams between Texas Reliability Entity (TRE), MRO, and SERC. To account for this, the Regional Entities should be required to coordinate regarding assumptions when multiple regions share the same most extreme historical weather events (after accounting for loss of imports from the other Regional Entities), as was likely the case for MRO and TRE in Winter Storm Uri. For those extreme weather events that occur wholly within a sub-region of a Regional Entity, the revised Reliability Standard could allow a Regional Entity to specify different events for parts of their footprint based upon a demonstration that events typically affect (or are likely to affect) subregions differently, including accounting for existing sub-regional

[6] NOPR, Comm'r Clements, Concurring, at P10.

electrical connections. For example, SERC might need a benchmark hurricane scenario focused upon coastal areas, but less applicable to the rest of its footprint, or MRO might identify separate events for MISO North and South. Additionally, scenarios should account for preemptive actions that transmission providers might take that affect transmission availability; for example, in extremely dry and windy conditions, Western transmission providers have proactively taken transmission lines out of service to mitigate the risk of faults on those lines causing wildfires.[7] Another option would be to allow NERC to approve the benchmarks proposed by each Regional Entity for those events that affect either only part of the Regional Entity or cross multiple Regional Entities.

The Commission and NERC should also require that benchmark events account for how climate change is increasing the frequency and magnitude of extreme heat, cold, and drought events. As discussed in the NOPR,[8] if historical events are used as the basis for a benchmark event, adjustments should be used to account for how climate change is affecting the frequency and magnitude of those events. The probabilistic modeling methods discussed later in these comments are well-suited for statistically incorporating the impact of climate change, as well as ensuring that planners are not excessively focused on modeling a single historical event when future events will have at least somewhat different geography, impact, and other characteristics. As discussed, utilities and grid operators already use probabilistic modeling based on historical meteorological records; correlations between extreme temperatures, electricity demand, generator outages, and the observed and anticipated impacts of climate change can and should be incorporated into those tools.

[7] *See e.g.* Pacific Gas & Electric, *Public Service Power Shutoff Overview*, https://www.pge.com/en_US/large-business/outages/public-safety-power-shuttoff/learn-about-psps.page.
[8] NOPR at P 47 and n. 83.

There is precedent for the Commission directing NERC to develop standards that, while incorporating technical expertise and acknowledging regional differences, meet certain requirements. For example, Order 779 on Reliability Standards for Geomagnetic Disturbances directed NERC to develop a standard that identified benchmark geomagnetic events to be studied, and specifies the type of solutions that must be considered in plans to address concerns identified in those reliability assessments.[9]

**2. FERC should require planners to account for correlated generator outages and derates in their planning analyses and development of Corrective Action Plans**

The Commission proposes requiring that correlated outages of generation and transmission equipment be accounted for in transmission planning,[10] which is appropriate in light of abundant evidence that correlated outages occur, and pose a significant risk to reliability.[11] However, correlated conventional generator outages and derates should also be accounted for in other aspects of jurisdictional reliability standards. This includes generation planning, which can be a component of Corrective Action Plans under TPL-001. The Commission should ensure that Corrective Action Plans account for the

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[9] *See Reliability Standards for Geomagnetic Disturbances* at P2, 143 FERC ¶ 61,147 (2022)("In the first stage, NERC must submit, within six months of the effective date of this Final Rule, one or more Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the Bulk-Power System. In the second stage, NERC must submit, within 18 months of the effective date of this Final Rule, one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole. The Second Stage GMD Reliability Standards must identify "benchmark GMD events" that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System.").

[10] *See* NOPR at PP68-72.

[11] *See e.g.* Sinnott Murphy, *Correlated generator failures and power system reliability* (2019), https://www.cmu.edu/ceic/assets/docs/publications/phd-dissertations/2019/sinnott-murphy-phd-thesis-2019.pdf; Murphy et al, *Resource adequacy risks to the bulk power system in North America*, Applied Energy Vol. 212 (15 February 2018), Pages 1360-1376, https://www.sciencedirect.com/science/article/pii/S0306261917318202.

reliability risks of building more generation that could be subject to the same correlated outage risks as existing generation. For example, building more gas generators supplied by a gas field or interstate pipeline that already supplies existing gas generators might not be an effective tool for mitigating risk *after* accounting for the risk of correlated outages. The NOPR correctly notes this concern, stating that:

> Contingency reserves would only contribute to a corrective action plan to the extent that they are expected to perform during the applicable modeled extreme weather event(s) and thereby contribute to meeting the applicable performance criteria. Accordingly, if for instance, extreme cold is anticipated to cause fuel unavailability for the applicable area, a corrective action plan would need to account for such limitations.[12]

The Commission should further clarify that generation additions that are subject to the same correlated outages as existing generation should be similarly discounted in Corrective Action Plans, to ensure that steps taken to ensure reliability do not exacerbate the risk of correlated outages.

As Commissioner Clements highlights in her concurrence, current generation planning methods do not account for the risk of correlated outages and derates of conventional generators.[13] It is important that the risk of correlated outages be accounted for in both resource adequacy analysis and capacity value accreditation. Failure to include them in the former masks reliability risks, while failure to include them in the latter can bias the resource selection to include a suboptimal mix of resources. In many regions Effective Load Carrying Capability analyses account for correlated output profiles of wind, solar, and storage, but correlated outages of conventional generators are not accounted for. This results in both reliability risk that is not accounted for, and undue preference by overstating the probable reliability contributions of conventional generators.

[12] P36, n. 72.
[13] Concurrence at PP26-27.

Grid operators and other experts have established methods for accounting for these correlated outage risks. MISO has filed a proposal with FERC that at least attempts to account for correlated outages of thermal generators as part of its resource adequacy analysis and capacity value accreditation processes, though there are concerns with its approach.[14] As another example, PJM[15] and ISO New England[16] have both used scenario-based approaches to evaluate the performance of different generation portfolios under historical severe weather conditions, and found that generation mixes with larger amounts of renewable generation were more resilient to outage and fuel supply interruption risks. Finally, utility consultant Astrape found that the capacity value contribution of conventional resources in part of PJM is 24% lower in winter and 15% lower in summer relative to their nameplate capacity after accounting for correlated outages and derates, while traditional planning techniques that assume generator outages are random, uncorrelated events find only a 5% reduction in their capacity value.[17]

In fact, correlated conventional generator outages have been the primary factor in recent severe weather events that resulted in electric reliability problems or risks.[18] The

[14] *See* Midcontinent Independent System Operator, *Filing to Include a Minimum Capacity Obligation in the MISO Resource Adequacy Construct,* Docket No. ER22-496 (Nov. 30, 2021), https://cdn.misoenergy.org/2021-11-30_Minimum%20Capacity%20Obligation%20Filing608323.pdf; Midcontinent Independent System Operator, *Resource Adequacy Reforms Conceptual Draft* (Aug. 16, 2021), https://cdn.misoenergy.org/20210901%20RASC%20Item%2003%20Seasonal%20RA%20Conceptual%20Design585538.pdf.

[15] ACP, *PJM study quantifies wind's value for building a reliable, resilient power system* (Aug. 2017), https://cleanpower.org/blog/pjm-study-quantifies-winds-value-building-reliable-resilient-power-system/.

[16] ISO-New England, *Operational Fuel-Security Analysis* at 33 (Jan. 17. 2019), https://www.iso-ne.com/static-assets/documents/2018/01/20180117_operational_fuel-security_analysis.pdf.

[17] Advanced Energy Economy, *Accrediting Resource Adequacy Value to Thermal Generation* at 6 (Mar. 30, 2022), https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf.

[18] Goggin et al, Grid Strategies, *Fleetwide Failures: How Interregional Transmission Tends to Keep the Lights on When There Is a Loss of Generation* (Nov. 2021) https://gridprogress.files.wordpress.com/2021/11/fleetwide-failures-how-interregional-transmission-tends-to-keep-the-lights-on-when-there-is-a-loss-of-generation.pdf.

FERC-NERC report on Winter Storm Uri documented that fossil and nuclear generators accounted for 75% of capacity experiencing unplanned outages and derates in that extreme weather event.[19] During several recent winter peak demand periods in regions across the country, gas generators have been forced offline by fuel supply limitations or interruptions.[20] Other examples of widespread correlated failures of conventional generators include:

- During a cold snap in February 2011, ERCOT experienced rolling blackouts due to equipment failures at fossil generators and gas supply interruptions.
- In the 2014 Polar Vortex, PJM was forced to resort to voltage reductions to maintain reliability after extreme cold caused widespread conventional generator failures due to gas supply interruptions and equipment failures. Two other cold snaps that year, and a similar event in early 2015, also posed challenges for electric reliability in various regions of the country.[21]
- In the January 2018 Bomb Cyclone event, New England faced reliability risks as gas supplies were interrupted and fuel oil supplies dwindled during a two-week cold spell.

[19] *FERC - NERC - Regional Entity Staff Report:The February 2021 Cold Weather Outages in Texas and the South Central United States* at 16 (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

[20] *See, e.g.*, PJM, *Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events* (May 2014), https://www.pjm.com/~/media/library/reports-notices/weather-related/20140509-analysis-of-operational-events-and-market-impacts-during-the-jan-2014-cold-weather-events.ashx; FERC, *2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018* (July 2019), https://www.ferc.gov/legal/staff-reports/2019/07-18-19-ferc-nerc-report.pdf ("FERC January 2018 Report").

[21] Michael Goggin, *For the Third Time in a Month, Wind Energy Protects Consumers in a Cold Snap*, Into the Wind (Feb. 10, 2014), https://cleanpower.org/blog/for-the-third-time-in-a-month-wind-energy-protects-consumers-during-cold-snap/

- In January 2018, many conventional generators in the South Central U.S. experienced correlated outages due to equipment failures and gas supply interruptions.[22]

During these cold snap events, weather-related equipment failures have also forced multiple types of generators offline at the same time, including multiple gas generators. Events in which many generators experience outages during the same time period due to a common cause, like extreme cold weather, are referred to as correlated outages, concurrent outages, or "common mode" failures. Following these events, grid operators and NERC are increasingly focused on the risks associated with fuel supplies, with multiple NERC reports noting how correlated outages are a major risk, particularly for gas generators.[23]

In addition to the extreme winter weather and fuel supply interrupts discussed above, severe weather heat and drought events can cause correlated outages. Water-cooled fossil and nuclear steam generators can be de-rated or even taken offline if drought or extreme heat affects common cooling water supplies.[24] As a recent paper co-authored by experts from NERC and Carnegie Mellon University documented the widespread occurrence of conventional generator correlated outages:

> Our findings highlight an important limitation of current resource adequacy modeling (RAM) practice: distilling the availability history of a generating unit to

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[22] FERC January 2018 Report.

[23] NERC, *Fuel Assurance and Fuel-Related Reliability Risk Analysis for the Bulk Power System* (March 2020), https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Fuel_Assurance_and_Fuel-Related_Reliability_Risk_Analysis_for_the_Bulk_Power_System.pdf; NERC, *Winter Reliability Assessment* at 6 (Nov. 2019), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdf.

[24] Melissa R. Allen-Dumas *et al.*, *Extreme Weather and Climate Vulnerabilities of the Electric Grid: A Summary of Environmental Sensitivity Quantification Methods,* Oak Ridge National Laboratory, at 9–11 (Aug. 9, 2019), https://www.energy.gov/sites/prod/files/2019/09/f67/Oak%20Ridge%20National%20Laboratory%20EIS%20Response.pdf.

> a single value (e.g. EFORd, the equivalent forced outage rate during times of high demand) discards important information about when units in a power system fail in relation to one another. Only by incorporating the full availability history of each unit into RAM can we account for correlations among generator failures when determining the capacity needs of a power system. We strongly recommend that system planners incorporate correlated failure analysis into their RAM practice.[25]

NERC data used in the Carnegie Mellon analysis demonstrates that conventional generators experience correlated outages many times more frequently than is predicted under the assumption that individual plant outages are uncorrelated independent events. Charts included in the analysis show that actual winter generation outages are much more common than would be expected under the status quo assumption that generator outages are uncorrelated independent events.[26]

Based on the primary role of correlated conventional generator outages in causing these recent reliability events, and the fact that ELCC methods are already widely used by utilities and other grid operators to account for how correlations in wind or solar output affect their capacity value, ACP urges the Commission to clarify that correlated generator outages for *all types of generators* (not only renewable resource output) should be a primary focus of reliability analyses and revisions to TPL-001 required under any final rule. ACP notes that at points in the NOPR, the Commission's discussions appear to place undue focus on renewable resources relative to conventional resources in discussing risks due to severe weather.[27] The risk of correlated outages is not unique to any one type of generator, and any modifications to TPL-001 or associated Corrective Action Plans should reflect this.

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[25] Sinnott Murphy *et al.*, *Resource Adequacy Risks to the Bulk Power System in North America* at 29 (Feb. 15, 2018), https://www.andrew.cmu.edu/user/fs0v/papers/CEIC_17_02R1%20Resource%20adequacy%20risks%20to%20the%20bulk%20power%20system%20in%20North%20America.pdf.
[26] *Id.* at S–22.
[27] *See e.g.* NOPR at PP 70-73 (focusing upon unavailability of wind and solar resources in extreme heat and cold conditions).

### 3. FERC should require planners to evaluate a range of potential solutions as part of their Corrective Action Plans

NERC TPL-001-5 requires the development of a Corrective Action Plan once a planning entity has found a deficiency in its ability to meet reliability criteria. FERC should require that planners developing Corrective Action Plans evaluate a range of potential solution options, including portfolios of solutions, and pick the solutions that offer the greatest net benefits for economics and reliability. FERC should specifically require planners to evaluate transmission upgrades, improvements to transmission scheduling practices or seams coordination that increase transfer capacity, grid-enhancing technologies, battery storage, and energy efficiency and demand response as part of the development of Corrective Action Plans.[28]

As noted in the preceding section, adding new generation or contingency reserves that are subject to the same correlated outage risks as existing generation is unlikely to be an effective solution to severe weather risk. However, increases in transfer capacity achieved through transmission upgrades, improvements to transmission scheduling practices or seams coordination that increase transfer capacity, or grid-enhancing technologies, as well as solutions like battery storage, energy efficiency, and demand

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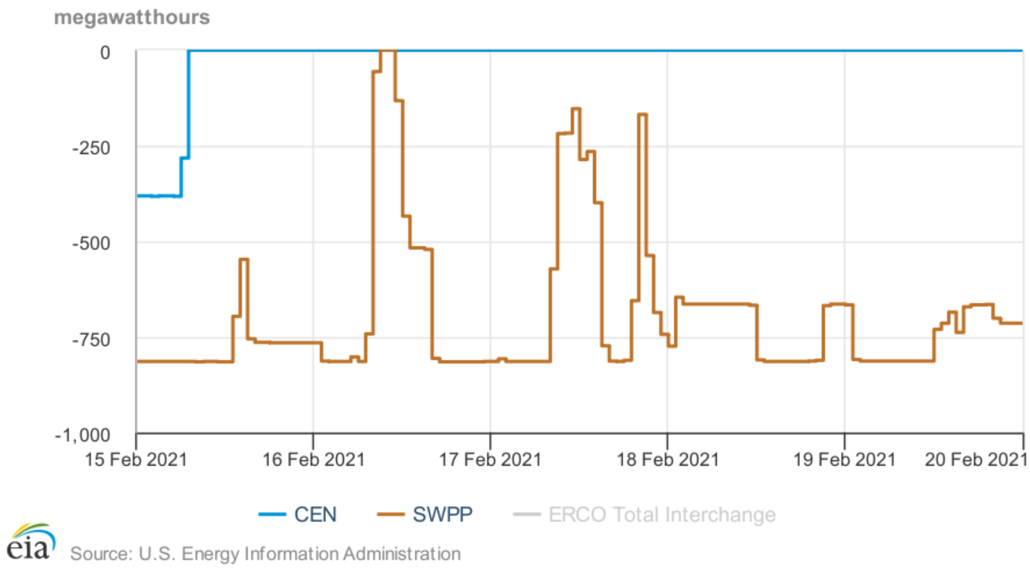
[28] TPL-001-5, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-5.pdf, provides the following list of examples of actions that can be used to achieve required system performance after a deficiency has been identified:
"Examples of such actions include:
-Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
-Installation, modification, or removal of Protection Systems or Remedial Action Schemes.
-Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
-Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
-Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
-Use of rate applications, DSM, new technologies, or other initiatives."

response, are not exposed to those correlated risks. As a result, there is a compelling reliability justification for the Commission at least requiring that such solutions be considered as part of the development of Corrective Action Plans, in addition to requiring planners to account for the reduced effectiveness of generation or contingency reserve additions that are subject to correlated outages in their development of Corrective Action Plans.

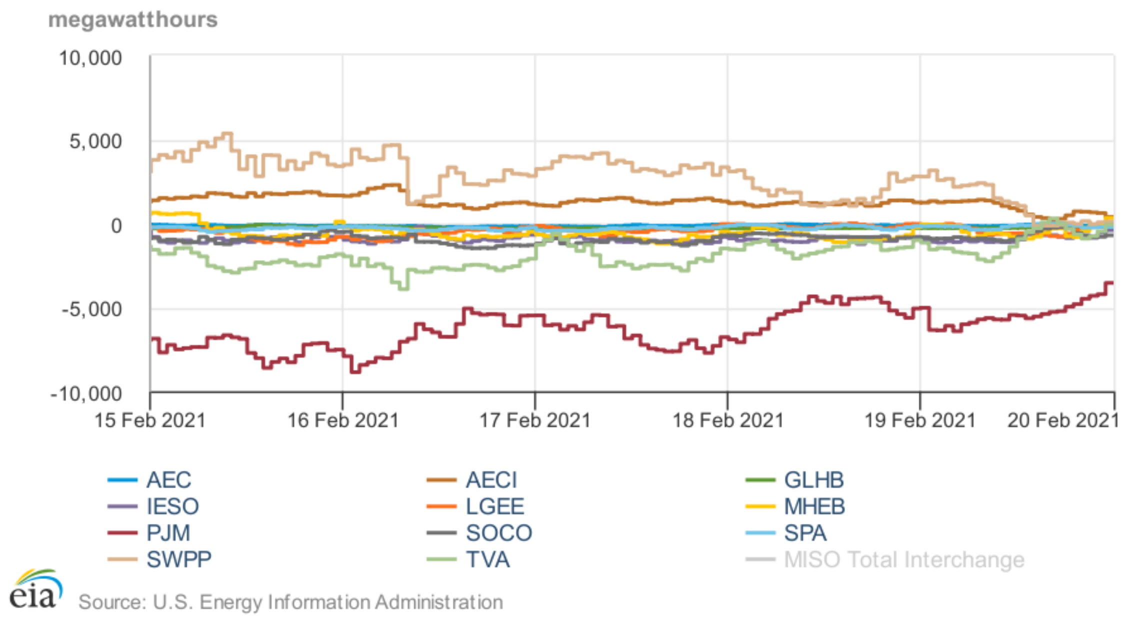
As the Commission notes, and as documented in other recent studies, transmission plays an essential role in mitigating reliability risks from a range of severe weather events because it provides access to geographically diverse loads and generating resources that are not subject to the same extreme weather. The importance of transmission was powerfully illustrated by the different outcomes experienced by ERCOT and MISO during Winter Storm Uri. Due to a lack of interregional ties, ERCOT was only able to import approximately 800 MW of power during most of the event, as shown below.[29]

[29] Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, at 8, July 2021 (citing Energy Information Administration).




While MISO and SPP experienced similar cold weather conditions, those RTOs were able to import electricity from other regions experiencing milder temperatures. For example, at maximum, MISO was able to import approximately 9,000 MW from PJM, a few thousand MW from the Tennessee Valley Authority (TVA), and a combined 3,000 MW from Southern Company, Louisville Gas and Electric and Kentucky Utilities Company, and Canada, as shown below. As a result of its interregional capacity, MISO was able to import a total of 13,000 MW during the peak of the event - about 15 times as much power as ERCOT was able to import. MISO was also able to export 5,000 MW and 2,500 MW to SPP and Associated Electric Cooperative Incorporated, respectively, over the course of the cold snap.[30]

[30] *Id.* at 8.




As another example, recent analysis found that transmission between ERCOT and the Southeast is highly cost-effective for providing resource adequacy and increasing resilience in both regions.[31] Based on these events and findings, the Commission has a compelling justification for requiring planners to at least evaluate transmission-based solutions, including grid-enhancing technologies, in their development of Corrective Action Plans.

Many grid-enhancing technologies are particularly well-suited to help address severe weather reliability risks. Dynamic line rating technology offers particularly large benefits when transmission lines are being cooled by low temperatures and high winds, as is the case during many winter peak demand periods, but they can also help operate lines closer to their true operating limits during summer peak demand periods. Topology

[31] Energy Systems Integration Group, *Multi-Value Transmission Planning for a Clean Energy Future* (2022), https://www.esig.energy/wp-content/uploads/2022/06/ESIG-Multi-Value-Transmission-Planning-report-2022.pdf.

optimization and power flow control devices also provide large net benefits under a range of severe weather events, and can be particularly helpful for preserving the reliable and efficient flow of power if severe weather has altered usual flows on the transmission system. Because they can be deployed quickly and re-deployed to other locations once they are no longer needed, grid-enhancing technologies can be used in Corrective Action Plans to complement longer-term solutions, like transmission upgrades – although the eventual selection of corrective actions would be up to each region.[32]

Because any given severe weather event does not occur in most years, planners should use a probabilistic approach to determine the best portfolio of solutions to maximize economic and reliability net benefits under a Corrective Action Plan. This should ensure that long-lead time investments that are likely to make up part of the long-term optimal solution to a reliability risk, like transmission investment to increase transfer capacity, are fairly evaluated in the analysis and not excluded because other solutions can be implemented more quickly. Current deterministic planning approaches, in which a region is assessed as either meeting or falling short of reliability criteria in a specific year, often do not provide sufficient flexibility for incorporating longer-lead time solutions. Long-term solutions should reduce or eliminate the need for more costly and inefficient short-term solutions, such as out-of-market payments or increases in reserves.

ACP supports the Commission's proposed use of probabilistic planning in conducting analysis of severe weather impacts, even though there is inherent uncertainty in attempting to quantify the impact of events that occur infrequently and whose likelihood and magnitude are being actively affected by climate change. Many transmission planners currently ignore or discount the impact of extreme events when

[32] ACP notes that requiring *evaluation* of generation and transmission-based solutions, where appropriate, in Corrective Action Plans would not amount to "order[ing] the construction of additional generation or transmission capacity," which is proscribed under § 216(i)(2) of the Federal Power Act. *See* 16 U.S.C. § 824o(i)(2).

conducting transmission benefit-cost analysis. Accounting for such events, even with uncertain estimates for their frequency and magnitude, will yield a more accurate analysis than ignoring those events. Recent analysis by Lawrence Berkeley National Laboratory (LBNL) found that roughly half of the marginal value of transmission in providing congestion relief occurs during extreme grid conditions and high-value periods that account for only five percent of hours but are challenging to model and so are often not fully considered in transmission planning.[33]

There is precedent for using probabilistic tools in assessing electric reliability. NERC has a Probabilistic Assessment Working Group, which regularly uses probabilistic tools to assess the risk various factors pose to electric reliability.[34] Probabilistic tools are now widely used by utilities and RTOs to assess resource adequacy and loss of load risk, based on the recognition that deterministic methods are no longer adequate.[35] Methods have also been developed to use probabilistic tools for transmission planning. Researchers used those methods in four case studies, and found them superior to the deterministic approaches in use today in large part because they better capture the impact of severe weather and allow the identification of an optimal solution:[36]

> System reliability analysis is at present performed using deterministic approaches in order to comply with the NERC TPL standards. Deterministic analysis of system reliability is evaluated by first identifying the expected and most limiting

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[33] Millstein et al, Empirical Estimates of Transmission Value Using Locational Marginal Prices, Berkeley Lab at 3 (Aug. 2022), https://eta-publications.lbl.gov/sites/default/files/lbnl-empirical_transmission_value_study-august_2022.pdf ("LBNL Transmission Value Study").

[34] *See e.g.* NERC, 2020 Probabilistic Assessment -Regional Risk Scenario Sensitivity Case (June 2021), https://www.nerc.com/comm/RSTC/PAWG/2020%20ProbA%20Regional%20Risk%20Scenarios%20Report_final_approved.pdf.

[35] *See e.g.* Energy Systems Integration Group, *Redefining Resource Adequacy for Modern Power Systems* (2021), https://www.esig.energy/wp-content/uploads/2021/08/ESIG-Redefining-Resource-Adequacy-2021.pdf.

[36] *See* Eastern Interconnection States' Planning Council, *A Study on Probabilistic Risk Assessment for Transmission and Other Resource Planning* (2015), https://www.astrape.com/?ddownload=2655.

load/generation dispatch and associated system power flows for which the system must operate based on the production cost simulations. Once a given generation dispatch is determined, the reliability of the system is evaluated by simulating the ability of the system to operate within specific thermal and voltage limits for the normal system state, all N-1 contingencies of generators and transmission components, and other credible higher order contingencies. This deterministic N-1 criterion does not inherently consider the probability of a given contingency or the severity of the contingency, nor is the impact considered of potential variability of other system components such as load that can affect reliability. Another problem with the deterministic method is that it does not provide a measure of reliability or relative trade-off between equally effective reinforcements. If several similar system expansion plans can alleviate contingency system problems, it is not immediately evident as to which alternative assures greatest reliability or benefit. The use of probabilistic measures in transmission system planning is a step towards providing answers to such questions. Utilizing component outage statistics, a set of reliability measures such as frequency, probability, duration and expected values (averages) of load loss or system violations can be defined and computed.

Ideally, the goal of any electric system analysis should be to identify the plan that provides adequate reliability at the lowest cost for the probabilistically weighted expected case. Historically, the small number of discrete scenarios considered in deterministic analyses were assumed to serve as a reasonable proxy for the expected case. But the impact of risk and uncertainty is generally asymmetric. Extreme weather hurts average reliability and market prices worse than mild weather helps them. The same effect can be seen with higher than usual generator outages. To meaningfully capture the effect of this asymmetry, probabilistic analysis is required. Probabilistic reliability analysis incorporates not only the higher risk scenarios of generator outages and extreme weather, but also their likelihood by means of a probability distribution function. Probabilistic economic analysis captures the same risk scenarios as the reliability analysis and also potentially fuel price, regulatory, environmental and other uncertainties.

Academic research shows that relative to standard deterministic methods (which do not account for uncertainty), probabilistic transmission planning methods that account for uncertainty by simultaneously evaluating a large number of possible scenarios result in more optimal solutions, potentially saving consumers tens or even hundreds of billions of dollars.[37] Analysis by WECC similarly found that the consumer savings from use of such probabilistic tools in the Western U.S.:

> "can be as much as or even exceed the cost of the recommended transmission facilities themselves. Furthermore, we provide evidence that the transmission recommendations of stochastic programming models are more robust to scenarios that haven't been considered than recommendations by deterministic models. That is, stochastic plans appear to make the network more adaptable in the face of all uncertainties, not just those that were included as specific scenarios."[38]

Based on these benefits, FERC should require the revisions to TPL-001 to move to probabilistic analysis, at least for the analysis of severe weather.

ACP also agrees with Commissioner Clements on the importance of coordinating with states in the development of Corrective Action Plans, given that states have primary authority over the generation mix and transmission permitting.

**4. Drought events should be included in the analysis of severe weather risks**

ACP agrees with Commissioner Clements that drought should be included in the analysis of weather risks, given the potential impact on hydroelectric and thermal resources documented in the NOPR.[39] As discussed above, during severe weather events across nearly every region of the country in recent decades, the U.S. has seen thermal resources forced offline or to operate at reduced output due to cooling water being in

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[37] *See* Francisco David Munoz Espinoza, *Engineering-Economic Methods for Power Transmission Planning under Uncertainty and Renewable Resource Policies* at 102 (2014), http://hobbsgroup.johnshopkins.edu/docs/FD_Munoz_Dissertation.pdf.
[38] Western Electricity Coordinating Council, *Planning Transmission for Uncertainty: Applications and Lessons for the Western Interconnection* at 1 (2016), https://www.ethree.com/wp-content/uploads/2017/02/Planning-for-Uncertainty-Final-Report.pdf.
[39] Concurrence at P 91.

short supply or exceeding high temperature limits. As climate change worsens the frequency and severity of drought and extreme heat, these events are likely to become a greater risk to reliability. Because drought events are already widespread across all regions, and climate change will make them even more frequent and widespread, it would be prudent for the Commission and NERC to require all regions to include drought in their analysis of severe weather benchmark events under TPL-001.

### B. FERC should take additional actions beyond those proposed in the NOPR

#### 1. FERC should require a minimum amount of interregional transfer capacity

ACP agrees with Commissioner Clements' concurrence regarding the importance of:

> "(1) establishing a process for setting explicit minimum interregional transfer capability requirements or otherwise identifying least regrets interregional solutions, (2) improved scheduling and coordination in non-RTO regions, and (3) ensuring that planning and market mechanisms appropriately reflect resource availability during extreme weather events, accounting for the possibility of common mode failures or other correlated outages."[40]

To the first point, ACP submits that either in this proceeding or another proceeding, FERC should create a minimum interregional transfer capacity requirement to ensure reliability during extreme weather events and ensure that customers benefit from lower-cost energy that presently cannot be transferred between regions.[41] ACP also notes that

[40] Concurrence at P6.
[41] *See also* ACP Reply Comments in Docket No. RM21-17 at pp12-14 (Nov. 30, 2022)(supporting development of an interregional transfer minimum).

Commissioner Phillips's concurrence expresses strong support for developing a minimum transfer capability requirement.[42]

Inadequate interregional transmission capacity results in both reliability risks under Section 215, and rates that are not just and reasonable under Sections 205 and 206 of the FPA. Consistent with FERC's authority under § 215(o)(i)(2),[43] consideration of a transfer minimum as a reliability measure could be structured as an element to be evaluated in a Corrective Action Plan and potentially adopted at a regional level, rather than as a formal reliability requirement.  Such a directive could be included in the NERC TPL-001 standard that FERC is proposing to revise in this proceeding. If FERC seeks to use NERC standards to evaluate the role of interregional transfer capability, it would make sense for a NERC drafting team to ensure that interregional transfer minimums are considered along with the other revisions to TPL-001 FERC is proposing in this proceeding.

Additionally, sections 205 and 206 of the Federal Power Act provide a distinct justification for an interregional transfer minimum as a means of ensuring just and reasonable rates.  As noted above, a recent report from Lawrence Berkeley National Laboratory found that extreme weather events account for around half of the value of transmission, yet those events are often not fully accounted for in the cost-benefit analyses used for transmission planning.[44] Inadequate transmission capacity results in rates that are demonstrably higher than they should be; transmission provides economic and other benefits in addition to reliability benefits, and transmission planning is more efficient when all of those benefits are accounted for in a cost-benefit analysis.

Any minimum interregional transmission capacity requirement should take into account the geographic diversity in load, conventional generator outages, and renewable

[42] Phillips Concurrence, at PP6-7
[43] 16 U.S.C. § 824o(i)(2).
[44] LBNL Transmission Value Study at 3.

output between one Balancing Authority (BA) and neighboring BAs. Ideally, transmission should optimize the net benefits from the reduction in peak capacity needs due to geographic diversity, as well as other benefits including production cost savings, against the cost of the transmission. FERC should require each region to either (a) analyze those diversity benefits and calculate the amount of interregional transmission capacity required to optimally realize those net benefits or (b) adopt a FERC-established default minimum requirement for the total transfer capacity (in MW) of a Balancing Authority's (BA's) ties to neighboring Balancing Authorities relative to the BA's peak load (such as, for example, 15% of the BA's peak load).

Analysis using publicly available Energy Information Administration (EIA) data demonstrates that load and renewable output diversity benefits among BAs are quite large. By comparing stand-alone versus regionally aggregated EIA hourly load and generation data for BAs in different regions,[45] ACP found a large reduction in peak capacity needs from aggregating diverse loads and renewable resources across regions.

The Northwest saw the largest percentage benefit, with a 15% reduction in the capacity needed to meet peak net load from aggregating electricity demand and renewable output across the region, as opposed to each BA needing enough capacity to meet its own peak needs. Peak net load was reduced by 12,750 MW, which translates into savings of over $10 billion for the Northwest if the benefit were realized through a reduced need for new gas combustion turbine capacity.[46] The Southwest saw the next largest percentage benefit, with a reduction of over 8% or 8,500 MW, which translates to

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[45] Data available from U.S. Energy Information Administration, https://www.eia.gov/electricity/gridmonitor/sixMonthFiles/EIA930_BALANCE_2021_Jan_Jun.csv, https://www.eia.gov/electricity/gridmonitor/sixMonthFiles/EIA930_BALANCE_20211_Jul_Dec.csv.

[46] Conservatively using an assumed $785/kW cost of a frame combustion turbine from U.S. Energy. Info. Admin., *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2022* (Mar. 2021), *available at* https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf, and the conservative assumption that a new combustion turbine offers 95% of its nameplate capacity as dependable capacity value.

$7 billion in savings. Finally, the Southeast could achieve a 5% or 8,250 MW reduction in peak net load by aggregating demand and renewable output as opposed to each BA meeting its needs on its own, saving around $7 billion.

ACP also examined hypothetical scenarios in which net load in the Eastern and Western Interconnections could be aggregated, as well as a scenario with nationwide aggregation across those Interconnections as well as ERCOT. Aggregating across the Western Interconnect reduced peak net load by 14% or 19,400 MW, which could displace $16 billion in costs for generating capacity. Aggregating across the Eastern Interconnect would reduce peak net load by over 5% or 28,300 MW, saving over $23 billion. Finally, aggregating net load across the three Interconnections reduced peak net load by almost 10% or 71,500 MW, yielding savings worth $59 billion. These cost savings only account for the reduction in capacity needed to meet peak net load, and do not account for other benefits of transmission such as reducing production costs and operating reserve needs, enabling generation to be built in more productive and lower cost areas, and other savings.

Notably, this analysis does not account for weather and climate diversity that reduces correlations in conventional generator outages and derates across large areas, as the hourly generator outage and derate data needed to quantify that benefit is not publicly available for most regions. Correlated outages and derates have been a major economic and reliability threat in a range of severe weather events, as explained above.[47] In events like Winter Storm Uri, up to 40% of the generating fleet in a region experienced concurrent outages. Accounting for the ability to access surplus generation from other

[47] *See e.g.* American Council on Renewable Energy/Grid Strategies, *Transmission Makes the Power System Resilient to Extreme Weather* (2021), https://acore.org/wp-content/uploads/2021/07/GS_Resilient-Transmission_proof.pdf; *FERC - NERC - Regional Entity Staff Report:The February 2021 Cold Weather Outages in Texas and the South Central United States* at 16 (Nov. 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and.

regions that are not experiencing the same level of extreme weather and outages would further increase the value of transmission and the optimal amount of transfer capacity above the amounts found in our analysis. Moreover, the benefits of transmission for accessing geographic diversity will likely increase as the generation mix continues to shift to variable renewable and fuel-constrained resources like natural gas. ACP's analysis also only examined diversity among U.S. power systems; increased transfer capacity to Canada and to a lesser extent Mexico would yield further benefits.[48]

On the other hand, other factors may cause this analysis to overstate the benefits of transmission for reducing peak capacity needs. ACP's analysis calculates benefits against an assumed status quo case in which BAs assign no capacity credit to non-firm market imports in their loss of load or reserve margin analyses. As discussed below, most BAs' planning practices currently do assign some capacity credit to non-firm imports, though this credit is usually extremely conservative - in part because planners are aware import transmission capacity is limited and may be congested during times of peak need. This analysis also assumes regional resource adequacy accounting and generation planning practices evolve so that BAs can take advantage of the geographic diversity provided by transmission. An effort to develop a regional resource adequacy program is ongoing across parts of the Western U.S.[49]

Even in 2020's worst case scenario of a heat wave across much of the West, there were still significant geographic diversity benefits across the region. As shown in the load and net load duration curves below, the U.S. portion of the Northwest Power Pool could have realized a 5 GW reduction in peak load and 7 GW reduction in peak net load (from 2 GW of renewable diversity benefit) in 2020 if it aggregated diverse loads and

[48] *See* National Renewable Energy Laboratory, *North American Renewable Integration Study* (2021), https://www.nrel.gov/analysis/naris.html.
[49] *See* Western Power Pool, *Western Resource Adequacy Program* (2022), https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

renewable resources by evaluating resource adequacy on a regional basis. The 7 GW reduction in peak net load reduces the need for capacity by 11%, and translates into regional savings of nearly $6 billion if the benefit were realized through a reduced need for new gas combustion turbine capacity.

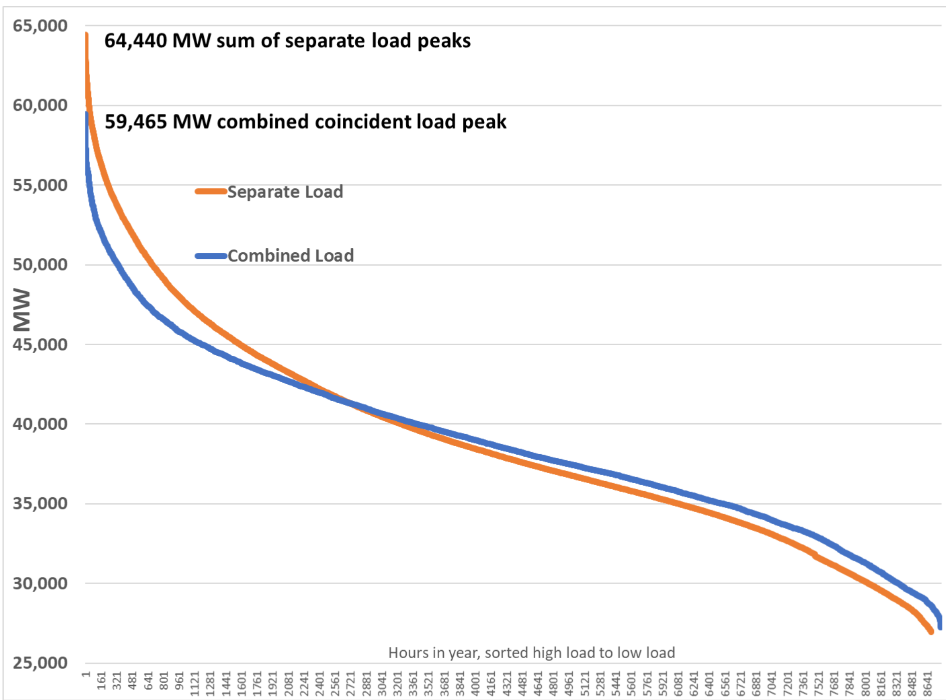


**Figure 1: Peak load reduction by aggregating across Northwest**

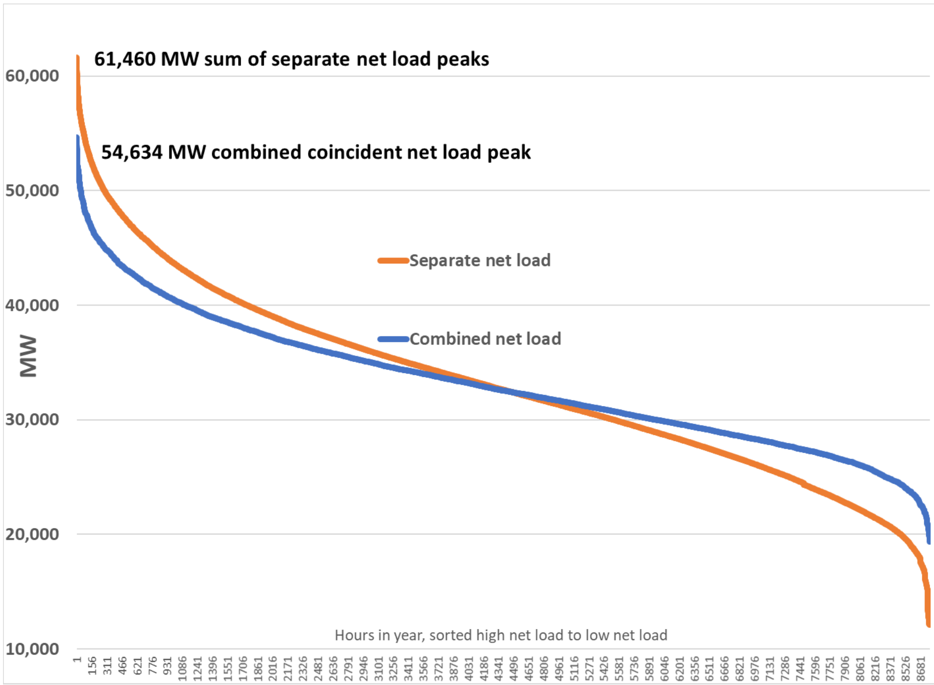


**Figure 2: Peak net load reduction by aggregating across Northwest**

The August 2020 heatwave was an extreme anomaly for its geographic breadth, so these results should be viewed as an extremely conservative estimate of the benefits of interregional transmission for both reliability and cost benefits. For California, the August 2020 heat wave was quantified as a 1-in-30 year event,[50] but the breadth of the heat across much of the West makes it even rarer. For example, the June 2021 Pacific Northwest heat wave was quantified as a 1-in-1000 year event in today's climate,[51] yet the heat wave most severely affected California and the Pacific Northwest at different times, allowing each region to meet load using imports from the other region. As noted

[50] CAISO, *Root Cause Analysis: Mid-August 2020 Extreme Heat Wave* (2021), http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.
[51] *See* Rebecca Lindsey, Climate.gov, *Preliminary analysis concludes Pacific Northwest heat wave was a 1,000-year event…hopefully* (2021), https://www.climate.gov/news-features/event-tracker/preliminary-analysis-concludes-pacific-northwest-heat-wave-was-1000.

above, ACP's analysis confirms that aggregating electricity demand and renewable supply across the Northwest in 2021 could yield a 15% reduction in the capacity needed to meet peak net load, larger than the 11% benefit found in 2020.

To ensure reliability and just and reasonable rates, it is important that the minimum interregional transfer capacity requirement apply broadly, and not only RTOs. The BAs in non-RTO regions tend to have less internal diversity in their loads and supply resources due to their smaller size, making transfer capacity with neighboring BAs even more valuable for reliability and economic benefits. For example, non-RTO regions in the Western U.S. have a mix of winter-peaking and summer-peaking BAs, making load diversity benefit among those BAs even larger. FERC could conduct further analysis to determine an appropriate default minimum transfer capacity requirement for all BAs, including accounting for correlated conventional generator outages that could not be evaluated in this analysis due to a lack of public data, and could appropriately hold a technical conference to further develop the record for this concept.

#### i. Action under the NOPR and on interregional transfer requirements should be coordinated with FERC action on transmission planning and cost allocation

ACP agrees with Commissioners Clements and Phillips that action taken to increase transmission capacity should be coordinated with the Commission's parallel efforts to reform transmission planning and cost allocation in Docket No. RM21-17, and potential future FERC action to address interregional transmission planning and cost allocation. Increases in transfer capacity between BAs inherently affect both BAs, and the Commission needs to develop a workable solution for allocating the cost of increasing transfer capacity. As noted above, the optimal increase in transfer capacity should be determined based on all of the net benefits provided by that investment. This requires a multi-value approach to transmission planning, which the Commission should require for inter-regional transmission. Commissioner Clements correctly notes in her concurrence that:[52]

> Since efficiencies are gained when considering multiple drivers for new transmission investment and it is likely that some amount of the corrective action that may emerge from the new reliability standard involves regional or interregional transmission development, it is important to derive stakeholders' perspectives on how potential performance standards and corrective actions under a revised reliability standard interact with both shorter-term reliability and proposed longer term planning, both in terms of consistency in planning inputs and the selection of cost-effective solutions. For instance, processes may be established to prioritize finding solutions via long-term planning in the first instance wherever possible, or to incorporate multiple drivers and probabilistic benefit cost assessments into the reliability planning process, so as to leverage the benefits of multi-value planning.

The Commission also appropriately states that "there may be potential benefits in better incorporating interregional transfer capability into corrective action plans, where warranted and encourage NERC to consider establishing requirements that appropriately recognize the value of interregional transfer capability."[53] The failure of transmission planning and cost allocation to fully account for the large net benefits of interregional transfer capability is a major reason why there has been so little investment in interregional transmission lines. Through this docket or another proceeding, the Commission should remedy that failure and its negative effects on both electric reliability and just and reasonable rates.

As Invenergy Transmission LLC noted in its July 19, 2022, request for a technical conference on interregional HVDC merchant transmission, there is not currently a workable framework for valuing and compensating many of the reliability and resilience benefits provided by interregional transmission lines (including merchant HVDC lines).[54]

[52] Concurrence, at P11

[53] NOPR at P88.

[54] Invenergy Transmission LLC, *Request for Technical Conference concerning Interregional HVDC Merchant Transmission*, Docket No. AD22-13 (July 19, 2022).

The Commission's October 2020 technical conference on offshore wind transmission raised similar concerns about the failure of current transmission planning and cost allocation and generator interconnection procedures to fully value the economic and reliability benefits of offshore transmission networks.[55]

### ii. The Commission Should Ensure that Planning Assumptions are Updated

Part of the problem is that many grid operators' planning reserve margin and loss of load expectation analyses use conservative fixed estimates for the availability of imports during peak periods, without accounting for how transmission upgrades and other power system changes have increased the availability of imports. As a result, these studies would not account for the reduction in capacity needs from increasing interregional transfer capacity, resulting in the over-procurement of capacity to the detriment of ratepayers as well as ignoring the reliability value provided by interregional transmission.

For example, MISO's loss of load expectation study assumes on-peak imports of 2,331 MW,[56] which is much lower than the more than 13,000 MW that the Commission's NOPR notes MISO *actually* imported during Winter Storm Uri.[57] Similarly, PJM's reserve margin analysis assumes that only 3,500 MW of import transmission capacity is available during peak periods, and that that capacity in turn provides only 2,127 MW of

[55] For example, see the comments of Michael Goggin at the October 2020 technical conference in docket AD20-18-000, pages 231-232 at https://elibrary.ferc.gov/eLibrary/filelist?document_id=14912324&optimized=false

[56]MISO Loss of Load Expectation Working Group, *Planning Year 2022-2023 Loss of Load Expectation Study Report* at 22 (2021) ("Historically, MISO modeled the external system, including non-firm imports, in the LOLE study which resulted in year-over-year volatility in the PRM. In order to provide a more stable result and remove the false sense of precision, the external non-firm support was set at an ICAP of 2,987 MW and a UCAP of 2,331 MW in the 2015 LOLE study and has since remained constant."), https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

[57] NOPR at P86.

reduced installed capacity need.[58] PJM's assumed capacity benefit margin from transmission ties with neighboring Balancing Authorities has been fixed at 3,500 MW[59] since 2010 per the terms of the Reliability Assurance Agreement among PJM Load-Serving Entities. No effort has been made to evaluate or update that assumption despite significant changes in the generation mix, load patterns, and transmission capacity and flows with neighbors since 2010, even though the 2010 agreement assigned PJM responsibility for "periodic reviews of the capacity benefit margin."[60] PJM's calculation of the 2,127 MW reduction in installed capacity needs due to the assumed 3,500 MW of transmission ties also only accounts for demand diversity with neighbors,[61] which misses the benefits for both conventional and renewable resource output from geographic diversity across the larger footprint of neighboring BAs. While a conservative approach is warranted for maintaining reliability, actual performance in past extreme weather conditions should be accounted for – which would enable regions to better rely on proven transmission capacity when it is most needed.

Mechanisms are also needed to compensate the builders of interregional transmission lines (including merchant lines) for the reliability and resilience value they provide (as well as customer savings). Without such compensation, many of these lines will continue to go unbuilt. Accordingly, the Commission should consider requiring evaluation of interregional transmission, including the speed at which different interregional transmission options might realistically be implemented. As discussed

[58]PJM, *2021 PJM Reserve Requirement Study* at 34 (2021), https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20211005/20211005-item-05b-2021-pjm-reserve-requirement-study.ashx/
[59]PJM, *2022 PJM Reserve Requirement Study – Determination of the PJM Installed Reserve Margin and Forecast Pool Requirement for Future Delivery Years* at 17 (2022), https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220510/item-08c---rrs-assumptions-letter-2022---redline---20220411.ashx.
[60]PJM Reliability Assurance Agreement Tariff Filing, Docket No. ER10-2710-006 at 89, 126 (Nov. 29, 2010) https://www.pjm.com/directory/etariff/FercDockets/63/20101129-er10-2710-006.pdf, at 89, 126
[61] PJM, *2021 PJM Reserve Requirement Study* at 19-20 (2021), https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20211005/20211005-item-05b-2021-pjm-reserve-requirement-study.ashx.

above, a major benefit of interregional transfer capacity is realizing geographic diversity that reduces the reliability risk posed by high load, low renewable output, and correlated generator outages. Interregional transmission lines increase the ability of both interconnected regions to meet peak needs using non-firm market imports from the other region, as they are unlikely to experience peak needs (as measured by load net of renewable output and conventional generator outages) at the same time. The resulting reduction in both regions' capacity needs can be accounted for using statistical methods, and that benefit could be credited to the owner of the interregional transmission capacity in the form of a credit towards meeting resource adequacy needs. The transmission developer or a customer that has contracted for capacity on the transmission line could then sell that capacity value credit to a load-serving entity that can in turn use it to meet its resource adequacy obligation.

### 2. FERC should take action to improve available transmission capacity calculations and transmission scheduling

ACP also agrees with Commissioner Clements' concurrence that "Transmission scheduling and coordination can potentially be improved both via mandating a transition to flowgate methodology for determining transmission capacity in areas that continue to use path-based methodologies, and via facilitation of economic redispatch and narrowing the circumstances under which transmission curtailment procedures are permissible."[62] Transmission scheduling capacity is larger and transaction scheduling is more reliable under the flowgate methodology. Schedules are less likely to be curtailed in real-time, because they are confirmed under day-ahead conditions. In contrast, transmission schedules using contract paths do not reflect actual power flows over individual

[62] Concurrence at P18.

transmission facilities. In many cases there may be unused transfer capacity even though the contract path is fully scheduled.

In addition to the evidence cited by Commissioner Clements, the benefits of transitioning to a flow-based methodology for determining transmission capacity can be seen in the efficiency improvements observed when the Western Area Power Administration (WAPA) Upper Great Plains Region transitioned from path-based to flow-based transmission capacity when it joined the Southwest Power Pool in 2015.[63] This successful transition also shows that a transition from contract path to flow-based methods can be achieved while respecting legacy transmission rights, including for federal preference customers.

Commissioner Clements also outlines a number of potential improvements to transmission scheduling that would reduce inefficiencies at seams between grid operators. These include greater use of economic redispatch instead of Transmission Loading Relief (TLR) and Qualified Path Unscheduled Flow Relief (USF) procedures in non-RTO areas, as well as other suggestions put forward by MISO to improve seams issues.[64] ACP agrees with Commissioner Clements that these solutions merit serious consideration.

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[63] *See Southwest Power Pool Inc.,* 149 FERC ¶ 61,113 at PP49-50 (2014) (accepting tariff revisions for the Integrated System, including WAPA, to join SPP, including a federal service exemption); https://www.wapa.gov/newsroom/NewsFeatures/2016/Pages/one-year-spp.aspx (explains the reduction in transmission loading relief WAPA experienced after joining SPP).
[64] Concurrence, at PP21-25.

## II. CONCLUSION

The Commission's proposal, if properly implemented, could help to assure reliable, affordable, and clean electricity by accounting for risks and benefits that current standards fail to address. ACP urges adoption of a final rule consistent with the recommendations contained in these comments, as well as further record development to support a minimum interregional transfer threshold and improvements to scheduling and transfer capability determination.

Respectfully submitted,

*/s/ Gabe Tabak*

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