EXHIBIT 141

Department of Energy
Washington, DC 20585

Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-26

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the SERC Reliability Corporation (SERC)–Florida Peninsula assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Stanton Energy Center (Stanton) is an electric generating facility in Orlando, Florida. Stanton Unit 1 (464.5 MW)[3] is a coal-fired generator owned[4] and operated by the Orlando Utilities Commission (OUC). Unit 1 began operations in July 1987.[5] The OUC Board of Commissioners had approved the retirement of Unit 1 by 2025,[6] and OUC anticipates placing Stanton Unit 1 in an "extended cold shutdown."[7] OUC expects to

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Form EIA-860M, Inventory of Operating Generators* (March 2026), (hereinafter EIA, *Form EIA-860M*) https://www.eia.gov/electricity/data/eia860m/. Stanton also includes a second coal-fired generation unit, Unit 2 (464.5 MW) and two natural gas-fired combined cycle generation units, Unit B (129.8 MW) and Unit B1 (203.2 MW).

[4] nFront Consulting LLC, *Orlando Utils. Comm'n 2025 Ten-Year Site Plan*, at 2-3, https://www.floridapsc.com/pscfiles/website-files/pdf/Utilities/Electricgas/TenYearSitePlans/2026/Orlando%20Utilities%20Commission.pdf [hereinafter nFront, *OUC 2025 Ten-Year Site Plan*].

[5] EIA, *Form EIA-860M*, *supra* note 3.

[6] *See, e.g.*, Michelle Lynch, *Fla. Mun. Elec. Ass'n, OUC's Bd. of Comm'rs moves to retire Unit 1 coal plant by no later than 2025* (Dec. 15, 2021), https://www.flpublicpower.com/news/oucs-board-of-commissioners-moves-to-retireunit-1-coal-plant-by-no-later-than-2025.

[7] nFront, *OUC 2025 Ten Year Site Plan*, at 6-2. It likely would be difficult for the coal-fired unit to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if OUC were to begin disassembling the unit or other related facilities, the associated challenges would be

make a determination as to Stanton Unit 2 by year end based on an Integrated Resource Plan currently underway.

EMERGENCY CONDITIONS

In its 2025 Long-Term Reliability Assessment (LTRA), released in January 2026, the North American Electric Reliability Corporation (NERC) notes that the SERC–Florida Peninsula assessment area is currently at a "Normal Risk" for long-term energy adequacy.[8] Nevertheless, the 2025 LTRA highlights that within the SERC–Florida Peninsula assessment area projections for resource and transmission growth lag behind what is needed to support new data centers and other large loads that drive escalating demand forecasts.[9] Additionally, the 2025 LTRA maintains that new data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.[10] As of April 2026, eight data centers are planned for construction in Florida.[11] Total peak demand is expected to increase from 48,628 MW in 2025/2026 to 54,931 MW in 2034/2035.[12]

The 2025 LTRA also notes that, with "the heavy dependence on natural gas in the SERC–Florida Peninsula subregion, fuel diversity could become an area of future concern."[13] Further, the 2025 LTRA states that:

> [t]he growing penetration of renewable energy means that SERC and the SERC–Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation

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greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Business Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[8] N. Am. Elec. Reliability Corp., *2025 Long-Term Reliability Assessment*, at 23 (Jan. 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf [hereinafter NERC, *2025 LTRA*].

[9] *Id.* at 6.

[10] *Id.* at 9.

[11] *See* Skyler Seets & Kaitlyn Radde, *Most new data centers in the U.S. are coming to rural areas*, PEW RESEARCH CENTER (Apr. 13, 2026), https://www.pewresearch.org/?p=299017.

[12] *See* Fla. Reliability Coordinating Council, Inc., *2025 Reg'l Load & Res. Plan FRCC-MS-PL-642 Version: 1*, at 6 (2025), https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2025/FRCC_RLRP.pdf.

[13] *See* NERC, *LTRA*, *supra* note 9, at 116.

continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.[14]

OUC resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when OUC requested two section 202(c) emergency orders to preserve the reliability of the bulk electric power system due to anticipated unusually high load forecasts from unusual cold weather conditions throughout the entire state of Florida: (i) one application[15] for 2.7 GW of specified resources (generating units) [16] and (ii) another[17] for 55 MW of back-up generators.[18] As a result, DOE issued two 202(c) emergency orders to OUC from January 31 through February 6: (i) Order No. 202-26-11 for specified resources,[19] and (ii) Order No. 202-26-15 for back-up generators.[20] OUC leveraged the 202(c) orders to meet demand during extreme cold weather conditions. Stanton Unit 1 produced 66,230 MWh between January 31, 2026 and February 6, 2026.[21] The back-up generating units reported over 400 hours of run-time under the respective Order.

According to OUC, customer demand was projected to exceed record-breaking thresholds for OUC on Sunday, February 1, 2026, and again on Monday, February 2, 2026, and maybe throughout the following week.[22] OUC had projected that it may not have sufficient generation available to meet the unusually high demand and may be forced to curtail load in order to maintain the security and reliability of the grid.[23] In January 2026, Stanton Units 1 and 2 produced a total of 249,473 MWh from coal-fired generation.[24]

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[14] *Id.*

[15] OUC 202(c) Application (Jan. 31, 2026).

[16] OUC Specified Resources (Exhibit A to 202(c) Application) (Jan. 31, 2026).

[17] OUC 202(c) Application – Backup Generators (Jan. 31, 2026).

[18] OUC 202(c) Application Exhibit A – Backup Generators (Jan. 31, 2026).

[19] *Orlando Utils. Comm'n,* Order No. 202-26-11 (Jan. 31, 2026).

[20] *Orlando Utils. Comm'n,* Order No. 202-26-15 (Jan. 31, 2026).

[21] *See* U.S. Env't Prot. Agency, CAMPD (Clean Air Markets Program Data), https://campd.epa.gov/data/custom-data-download (choose "Emissions" from "Data Type" dropdown; then choose "Daily Emissions" from "Data Subtype" dropdown; then choose "Unit (No Aggregation)" from the "Aggregation" dropdown; then click "Apply"; then click "Time Period" button and enter "January 31, 2026" as "Start Date" and February 6, 2026 as "End Date"; then click "Facility" and select "Curtis H. Stanton Energy Center"; then click "Apply Filter"; then click "Preview Data".).

[22] Letter from Clint Bullock, Gen. Manager & CEO, Orlando Utils. Comm'n, to The Honorable Chris Wright, Sec'y, Dept. of Energy (Jan. 31, 2026) (requesting emergency order under FPA section 202(c)), https://www.energy.gov/documents/ouc-202c-application-backup-generators.

[23] *Id.*

[24] EIA, *Form EIA-923, Schedule 4: Generator Data* (Apr. 2026), https://www.eia.gov/electricity/data/eia923/.

According to NERC's 2026 Summer Reliability Assessment, the SERC–Florida Peninsula is a summer-peaking assessment area.[25] It further notes that "[t]emperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South . . . ."[26] For the SERC–Florida Peninsula, the anticipated reserve margin is projected to be 25.8%; however, the anticipated reserve margin drops to 13.6% in the event of "higher demand, outages, [or] derates in extreme conditions."[27]

Executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[28] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets." In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[29]

Further, the Department of Energy detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," which was issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that, "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[30]

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[25] North American Electric Reliability Corporation, 2026 Summer Reliability Assessment, at 28 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[26] *Id.* at 4.

[27] *Id* at 10.

[28] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[29] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[30] DOE, RES. ADEQUACY REP.: EVALUATING THE RELIABILITY & SEC. OF THE U.S. ELEC. GRID (Jul. 7, 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[31] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Stanton Unit 1, when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the conditions resulting from the combination of increasing demand and shortage will continue on in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or power outages, presenting a risk to public health, and safety.

I have determined that, under the conditions specified below, continued availability of Stanton Unit 1 is necessary to best meet the emergency arising from increased demand for electric energy, shortage of facilities for the generation of electric energy, and other causes, thus serving the public interest pursuant to FPA section 202(c).

To ensure that Stanton Unit 1 will be available if needed to address emergency conditions, it shall remain in operation through September 1, 2026.

[31] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

Based on my determination of an emergency set forth above, I hereby order:

A. From June 4, 2026, OUC shall take all measures necessary to ensure that Stanton Unit 1 is not placed in extended cold shutdown and is available to operate.[32] Following the conclusion of this Order, sufficient time for orderly ramp down will be permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Stanton Unit 1 to the times and within the parameters as determined by OUC pursuant to paragraph A. OUC shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Stanton Unit 1 has operated in compliance with the allowances contained in this Order.

C. All operations of Stanton Unit 1 must comply with applicable environmental requirements, including, but not limited to, monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency conditions or to use other geographic or temporal flexibilities available to generators.

D. By June 18, 2026, OUC is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Stanton Unit 1, consistent with this Order. OUC shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

E. OUC is directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Stanton Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Stanton Unit 1 shall not be considered a capacity resource.

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[32] According to OUC, neither Florida Municipal Power Pool (FMPP) in its role as the Balancing Authority nor Florida Reliability Coordinating Council (FRCC) in its role as the Reliability Coordinator directs OUC to operate Stanton 1 in a manner similar to organized markets.

H. This Order shall be effective from June 4, 2026, through September 1, 2026, with the exception of applicable compliance obligations in paragraph D.

I. OUC is directed to provide the Department at least fifteen days' prior advance notice in writing before any change in operational status or otherwise of Stanton Unit 2 occurs.

Issued in Washington, D.C. on this 4th day of June 2026.

Chris Wright

Chris Wright
Secretary of Energy

cc: **FERC Commissioners**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Florida Public Service Commissioners
Chairman Gabriella Passidomo Smith
Commissioner Gary F. Clark
Commissioner Mike La Rosa
Commissioner Bobby Payne
Commissioner Ana Ortega

EXHIBIT 142

Department of Energy
Washington, DC 20585

Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-42

Pursuant to the authority vested in the Secretary of Energy (Secretary) by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the SERC Reliability Corporation (SERC)–Florida Peninsula assessment area due to a sudden increase in demand for electric energy, or a shortage of electric energy or facilities for the generation or transmission of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The Stanton Energy Center (Stanton) is an electric generating facility in Orlando, Florida. Stanton Unit 1 (464.5 MW)[3] is a coal-fired generator owned[4] and operated by the Orlando Utilities Commission (OUC). Unit 1 began operations in July 1987.[5] The OUC Board of Commissioners had approved the retirement of Unit 1 by 2025,[6] and OUC anticipated placing Stanton Unit 1 in an "extended cold shutdown" in June 2026.[7] OUC expects to make a determination as to Stanton Unit 2 by year's end based on an Integrated Resource Plan currently underway.

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Preliminary Monthly Elec. Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860)*, https://www.eia.gov/electricity/data/eia860m/ (choose "June 2026") [hereinafter EIA, *Form EIA-860M*]. Stanton also includes a second coal-fired generation unit, Unit 2 (464.5 MW), as well as two natural gas-fired combined cycle generation units, Unit B (129.8 MW) and Unit B1 (203.2 MW).

[4] nFront Consulting LLC, *Orlando Utils. Comm'n: 2026 Ten-Year Site Plan*, at 2–3, https://www.floridapsc.com/pscfiles/website-files/pdf/Utilities/Electricgas/TenYearSitePlans/2026/Orlando%20Utilities%20Commission.pdf [hereinafter nFront, *OUC 2026 Ten-Year Site Plan*].

[5] EIA, *Form EIA-860M*, *supra* note 3.

[6] *See, e.g.*, Michelle Lynch, *Fla. Mun. Elec. Ass'n, OUC's Bd. of Comm'rs moves to retire Unit 1 coal plant by no later than 2025* (Dec. 15, 2021), https://www.flpublicpower.com/news/oucs-board-of-commissioners-moves-to-retireunit-1-coal-plant-by-no-later-than-2025.

[7] *See* nFront, *OUC 2026 Ten-Year Site Plan*, *supra* note 4, at 6–2. It likely would be difficult for the coal-fired unit to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the

Order No. 202-26-26, which was issued pursuant to FPA section 202(c) on June 4, 2026, required that Stanton Unit 1 continue to be available to operate for 90 days, through September 1, 2026. That order was based on my determination that emergency conditions existed within the SERC Reliability Corporation (SERC)–Florida Peninsula assessment area.

Specifically, I determined that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.[8] I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.[9] I determined that continued operation of the Stanton Unit 1 was necessary to best meet the emergency and serve the public interest.[10]

In its 2025 Long-Term Reliability Assessment (2025 LTRA), released in January 2026, the North American Electric Reliability Corporation (NERC) notes that the SERC–Florida Peninsula assessment area is currently at a "Normal Risk" for long-term energy adequacy.[11] Nevertheless, the 2025 LTRA highlights that within the SERC–Florida Peninsula assessment area projections for resource and transmission growth lag behind what is needed to support new data centers and other large loads that drive escalating demand forecasts.[12] Additionally, the 2025 LTRA maintains that new data centers for artificial intelligence and the digital economy account for most of the projected increase in North American electricity demand over the next 10 years.[13] As of April 2026, eight data centers are planned for construction in Florida.[14] Total peak demand in Florida is expected to increase from 48,628 MW in 2025/2026 to 54,931 MW in 2034/2035.[15]

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timeline for resumption of operations during the period they are needed. Moreover, if OUC were to begin disassembling the unit or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9–12 (Aug. 2021), https://www.osti.gov/servlets/purl/1821476.

[8] *See, e.g.*, *PJM Interconnection, L.L.C.*, Order No. 202-26-24, at 10 (May 21, 2026).

[9] *Id*.

[10] *Id.*

[11] N. Am. Elec. Reliability Corp., *2025 Long-Term Reliability Assessment*, at 23 (Jan. 2026), https://prod.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[12] *Id.* at 6.

[13] *Id.* at 9.

[14] *See* Skyler Seets & Kaitlyn Radde, *Most new data centers in the U.S. are coming to rural areas*, PEW RESEARCH CENTER (Apr. 13, 2026), https://www.pewresearch.org/?p=299017.

[15] *See* Fla. Reliability Coordinating Council, Inc., *2025 Reg'l Load & Res. Plan FRCC-MS-PL-642 Version: 1*, at 6 (2025), https://www.floridapsc.com/pscfiles/website-files/PDF/Utilities/Electricgas/TenYearSitePlans//2025/FRCC_RLRP.pdf.

The 2025 LTRA also notes that, with "the heavy dependence on natural gas in the SERC–Florida Peninsula subregion, fuel diversity could become an area of future concern."[16] Further, the 2025 LTRA states that:

> [t]he growing penetration of renewable energy means that SERC and the SERC–Florida Peninsula entities will need to continue to monitor the resource adequacy studies and the impact that renewable resources will have. As solar generation continues to grow, the need to ensure the availability of quick start generating units to meet the ramp in demand will increase.[17]

OUC resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when OUC requested two section 202(c) emergency orders to preserve the reliability of the bulk electric power system due to anticipated unusually high load forecasts from unusual cold weather conditions throughout the entire state of Florida: (i) one application for 2.7 GW of specified resources (generating units)[18] and (ii) a second application for 55 MW of back-up generators.[19] As a result, DOE issued two 202(c) emergency orders to OUC from January 31 through February 6, 2026: (i) Order No. 202-26-11 for specified resources[20] and (ii) Order No. 202-26-15 for back-up generators.[21] OUC leveraged the 202(c) orders to meet demand during the extreme cold weather conditions. Stanton Unit 1 produced 66,230 MWh between January 31 and February 6, 2026.[22] The back-up generating units reported over 400 hours of run-time under the respective Order.

According to OUC, customer demand was projected to exceed record-breaking thresholds for OUC on Sunday, February 1, 2026, and again on Monday, February 2, 2026, and maybe throughout the following week.[23] OUC had projected that it may not have

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[16] *See* NERC, *LTRA*, *supra* note 9, at 116.

[17] *Id.*

[18] Application, ex. A (Specified Resources) (Jan. 31, 2026).

[19] Application, ex. A (Backup Generators) (Jan. 31, 2026).

[20] *Orlando Utils. Comm'n*, Order No. 202-26-11 (Jan. 31, 2026).

[21] *Orlando Utils. Comm'n*, Order No. 202-26-15 (Jan. 31, 2026).

[22] *See* U.S. Env't Prot. Agency, *CAMPD (Clean Air Markets Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from "Data Type" dropdown; then choose "Daily Emissions" from "Data Subtype" dropdown; then choose "Unit (No Aggregation)" from the "Aggregation" dropdown; then click "Apply"; then click "Time Period" button and enter "January 31, 2026" as "Start Date" and February 6, 2026 as "End Date"; then click "Facility" and select "Curtis H. Stanton Energy Center"; then click "Apply Filter"; then click "Preview Data").

[23] Letter from Clint Bullock, Gen. Manager & CEO, Orlando Utils. Comm'n, to The Honorable Chris Wright, Sec'y, Dept. of Energy (Jan. 31, 2026) (requesting emergency order under FPA section 202(c)), https://www.energy.gov/documents/ouc-202c-application-backup-generators.

sufficient generation available to meet the unusually high demand and may be forced to curtail load in order to maintain the security and reliability of the grid.[24] In January 2026, Stanton Units 1 and 2 produced a total of 249,473 MWh from coal-fired generation.[25]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order No. 202-26-26 continue, both in the near and long term. The production of electricity from Stanton Unit 1 continues to be critical to maintain reliability in the SERC–Florida Peninsula assessment area.

According to NERC's 2026 Summer Reliability Assessment, the SERC–Florida Peninsula is a summer-peaking assessment area.[26] In its 2026 Summer Reliability Assessment, NERC further notes that "[t]emperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South . . . ."[27] For the SERC–Florida Peninsula, the anticipated reserve margin is projected to be 25.8%; however, the anticipated reserve margin drops to 13.6% in the event of "higher demand, outages, [or] derates in extreme conditions."[28]

NERC released its 2026 State of Reliability (SOR) on June 24, 2026. In the SOR, NERC identifies worsening reliability concerns tied to large-load integration and localized operating stress. In its technical discussion of major system events, NERC states "shoulder seasons have become increasingly challenging for [bulk power system] operators to manage, resulting in several recent instances of pre-contingent load shedding."[29] The SOR also finds large load growth is increasing reliability risk and states that "data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics."[30]

DOE Order No. 202-26-26 was preceded by executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, which underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156,

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[24] *Id.*

[25] EIA, *Form EIA-923 detailed data with previous form data (EIA-906/920)*, *Page 4: Generator Data* (May 2026), https://www.eia.gov/electricity/data/eia923/.

[26] N. Am. Elec. Reliability Corp., *2026 Summer Reliability Assessment*, at 28 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[27] *Id.* at 4.

[28] *Id* at 10.

[29] N. Am. Elec. Reliability Corp., *2026 State of Reliability: Tech. Assessment of 2025 Bulk Power Sys. Performance*, at 5 (June 24, 2026), https://nerc.com/globalassets/programs/rapa/pa/nerc_sor_2026_technical_assessment.pdf.

[30] *Id.* at vii.

"Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[31] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets." In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[32]

Further, the Department of Energy detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," which was issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that, "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[33]

Pursuant to section 202(c)(4)(B) of the FPA, the Department has consulted with the primary Federal agency with expertise in the environmental interest protected by the laws or regulations that may conflict with this Order. The agency did not submit additional conditions for inclusion in this Order.

ORDER

FPA section 202(c)(1) provides that whenever the Secretary determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[34] This statutory language constitutes

[31] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[32] Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

[33] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid* (July 7, 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[34] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of the Department of Energy. *See* 42 U.S.C. § 7151(b).

a specific grant of authority to the Secretary to require the operation of Stanton Unit 1, when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the conditions resulting from the increasing demand and shortage of electric energy from the premature retirement of Stanton Unit 1 will continue on in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas affected by curtailments or power outages, presenting a risk to public health and safety.

I have determined that, to best meet the emergency arising from increased demand, determined shortage, and other causes, and to serve the public interest under FPA section 202(c), Stanton Unit 1 shall be made available for operation through November 30, 2026.

Based on my determination of an emergency set forth above, I hereby order:

A. From September 2, 2026, OUC shall take all measures necessary to ensure that Stanton Unit 1 is available to operate.[35] Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Stanton Unit 1 to the times and within the parameters as determined by OUC pursuant to paragraph A. OUC shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Stanton Unit 1 has operated in compliance with this Order.

C. All operations of Stanton Unit 1 must comply with applicable environmental requirements, including, but not limited, to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.

D. By September 16, 2026, OUC is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Stanton Unit 1 consistent with this Order. OUC shall also provide such additional information regarding the

[35] According to OUC, neither Florida Municipal Power Pool (FMPP) in its role as the Balancing Authority nor Florida Reliability Coordinating Council (FRCC) in its role as the Reliability Coordinator directs OUC to operate Stanton 1 in a manner similar to organized markets.

environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

E. OUC is directed to file with the Federal Energy Regulatory Commission any tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

F. This Order shall not preclude the need for Stanton Unit 1 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Stanton Unit 1 shall not be considered a capacity resource.

H. This Order shall be effective from September 2, 2026, through November 30, 2026, with the exception of applicable compliance obligations in paragraph D.

I. OUC is directed to provide the Department at least fifteen days' prior notice in writing before any anticipated change in operational status, or as soon as practicable if an unexpected change in status of Stanton Unit 2 occurs.

Issued in Washington, D.C. on this 1st day of September 2026.

Chris Wright
Secretary of Energy

cc: **Federal Energy Regulatory Commission**
Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Florida Public Service Commission
Chairman Gabriella Passidomo Smith
Commissioner Gary F. Clark
Commissioner Mike La Rosa
Commissioner Bobby Payne
Commissioner Ana Ortega

EXHIBIT 143

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-26-44

FOURTH DECLARATION OF CALLAHAN MORIYASU IN SUPPORT OF MOTION TO INTERVENE, REQUEST FOR REHEARING, AND MOTION TO STAY BY STATE OF WASHINGTON

I, Callahan Moriyasu, declare under penalty of perjury under the laws of the state of Washington that the following is true and correct:

Background and Qualifications

1. I am currently employed as a Supervising Regulatory Analyst with the Public Counsel Unit of the Washington State Office of the Attorney General. In this role, I serve as an in-house expert on utility regulation. I have submitted testimony and written formal comments in several cases related to energy and electricity. I have a Master of Public Policy degree from the University of Southern California, as well as a Bachelor of Arts in Economics and History from Northwestern University. In addition to my formal education, I have completed several utility ratemaking courses, including New Mexico State University's Electricity Regulatory Training Course, Michigan State University's Power Grid School, and the National Association of Regulatory Utility Commissioners' (NARUC) Rate School and Fundamentals of Electricity Course.

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2. I previously submitted declarations on behalf of the Washington State Office of the Attorney General in support of the Rehearing Requests for Order No. 202-25-11 (Exhibit 41), Order No. 202-26-18 (Exhibit 104), and Order No. 202-26-28 (Exhibit 131).

Purpose of This Declaration

3. This declaration provides context for the North American Electric Reliability Corporation (NERC) 2026 State of Reliability (SOR) Report cited in the Order, as well as the continued lack of dispatch of TransAlta Centralia since the previous order. A more fulsome reading of NERC's 2026 SOR and the fact that Centralia has not been dispatched show that Centralia is not needed to maintain resource adequacy during the period of this order.

The Order Takes NERC's 2026 State of Reliability Report Out of Context and Ignores the SOR's Main Findings

4. In its description of the "Emergency Situation," the Order cites NERC's 2026 SOR. Specifically, the Order highlights that the NERC SOR "identified worsening reliability concerns tied to large-load integration and localized operating stress," as well as that "shoulder seasons have become increasingly challenging." The Order also states that the SOR "finds that large load growth is increasing reliability risk." (Order at 6)

5. It is important to recognize the purpose and data that the NERC SOR is based on to put the SOR's findings in context. First, the SOR "focuses on BPS [Bulk Power System] performance during the prior calendar year." (SOR Technical at v). Using this backward-looking data, the SOR "analyzes performance trends and emerging reliability risks." (SOR Technical, at v.). Unlike NERC's Long-Term Reliability Assessment, Summer Assessment, and Winter Assessment, the SOR does not use forward-looking models to predict future

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reliability. The Report is therefore not a useful indicator of resource adequacy and reliability in the future.

6. Additionally, the specific quotes from the NERC SOR cited in the Order are not relevant to the Northwest. For example, the NERC SOR's reference to pre-contingent load shedding in shoulder seasons references NERC's Incident Review of four incidents from three entities.[1] NERC's report does not explicitly name Entity A, but the description of Entity A aligns with outages reported by SPP in New Mexico.[2] Entity B is explicitly cited as Southwestern Electric Power Company, which operates in SPP in Louisiana.[3] NERC's description of Entity C and the particulars referenced align with the May 2025 outage affecting CLECO, Entergy Louisiana, and Entergy New Orleans, in MISO.[4] All three of these entities are located a considerable distance from TransAlta Centralia and its Balancing Authority Area, with two located in a completely separate Interconnection.

7. Additionally, NERC describes the shoulder-season load shedding issues as specific to small load pockets in Balancing Authority Areas. (SOR Technical, at 5). NERC's Incident Review indicates that these load pockets have unique reserve margin issues with a combination of planned and unplanned outages, exacerbated by extreme weather conditions.[5] NERC's SOR and Incident Reviews do not mention any similarly problematic load pocket in

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[1] Incident Review: Load-Pocket Shoulder Season Challenges

[2] https://www.spp.org/documents/73732/2025-05-05%20joint%20stakeholder%20briefing%20materials%20v3.pdf , at 16

[3] spp's summary of the april 26, 2025, shreveport-area load shed event.pdf

[4] https://cdn.misoenergy.org/May%2025%20Load%20Shed%20Event%20Report%20-%20August%202025711584.pdf?_t_id=gUsifJ_prODNO6cO7qBgSg%3d%3d&_t_uuid=8qgSkToASzqg3qoSYaqQ5w&_t_q=Load+Shed&_t_tags=language%3aen%2csiteid%3a11c11b3a-39b8-4096-a233-c7daca09d9bf%2candquerymatch&_t_hit.id=Optics_Models_Find_RemoteHostedContentItem/711584&_t_hit.pos=1

[5] Incident Review: Load-Pocket Shoulder Season Challenges

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the same Balancing Authority as TransAlta Centralia, or even one that could be readily served by Centralia. The Order inappropriately extrapolates NERC's description of localized problems in certain load pockets in other regions to Washington and the Pacific Northwest. Without these localized problems, the shoulder seasons (spring and fall) remain as seasons with "reserve margins…sufficient for the shoulder seasons to accommodate" any planned outages. (Incident Review, at 1)

8. The Order also references NERC's takeaway that "data center and computational loads continued emerging as a major reliability consideration." (SOR Overview, at vii). A full read of the report shows that this finding emerged from customer-initiated load reductions in 2025. There were five data center customer-initiated load reduction events in the Eastern Interconnection and 12 in Texas in 2025. (SOR Overview, at 5–6). None of the customer-initiated load reduction events in 2025 occurred in the Western Interconnection, let alone in the Pacific Northwest and TransAlta Centralia's Balancing Authority Area. Again, the Order conflates a region-specific finding in another part of the country as an indication of a problem in the Northwest when one does not exist. Operation of TransAlta Centralia is not the answer to location-specific problems in other regions across the country.

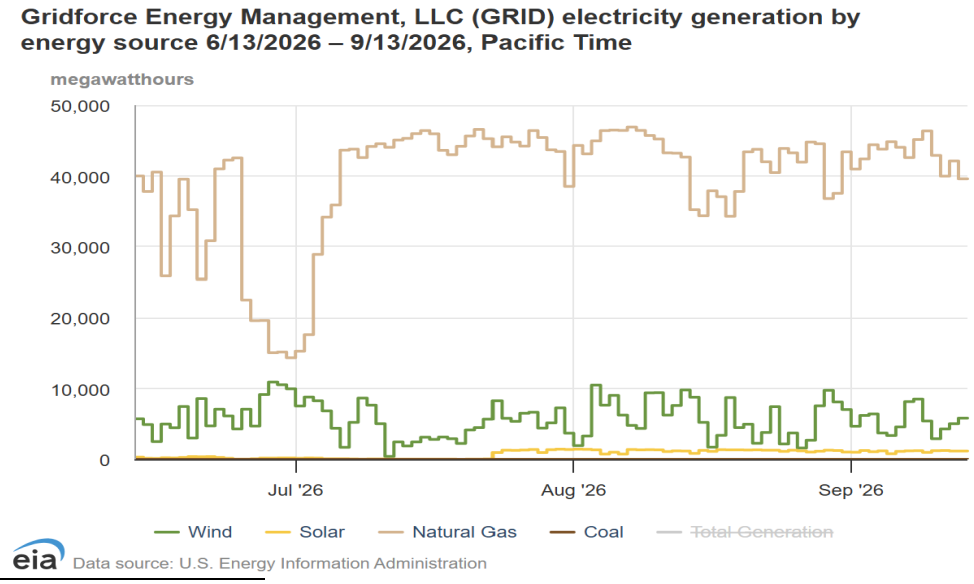
9. A more comprehensive review of the report indicates strong reliability for the Western Interconnection in 2025. For example, the SOR states that the "Texas and Western Interconnections both maintained stable trends with no IROL [Interconnection Reliability Operating Limit] exceedances reported in 2025" (SOR Technical, at 54) and that the Severity Risk Index for the Western Interconnection "was the lowest among the five years analyzed" (SOR Technical, at 72).

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10. There were only two major events discussed in the report affecting the Western Interconnection in 2025: the "Wyoming System Event" (SOR Technical, at 4–5) and the atmospheric river transmission outages (SOR Technical, at 17–18). The Wyoming System Event happened in an area not served by TransAlta Centralia and was caused by an error in usage of real-time systems during a planned transmission outage rather than any generation shortage.[6] The atmospheric river outages were similarly caused by transmission issues, which could not be solved by increased generation (SOR Technical, at 17–18).

Centralia Was Not Called Upon to Operate During the 90-Day Period of the Third Emergency Order

11. During the 90-day period of the third emergency order, Centralia was never called on to operate, demonstrating that it was not needed to serve load.[7] The figure below shows U.S. Energy Information Administration generation data for Gridforce Energy Management, LLC, the Balancing Authority where TransAlta Centralia is located. There were 0 MWh of coal generation in this Balancing Authority Area for the duration of the third emergency order.



[6] November 13 Wyoming Disturbance_Report_Final.pdf

[7] https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/balancing_authority/GRID

DATED this 6 day of October 2026, in Seattle, Washington.

Callahan Moriyasu

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EXHIBIT 144

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

TransAlta Centralia Generation LLC Docket No. ER26-2422

MOTION TO INTERVENE AND PROTEST BY THE STATE OF WASHINGTON AND THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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MOTION TO INTERVENE

The State of Washington and the Washington Utilities and Transportation Commission move to intervene in this proceeding on behalf of themselves and their electricity consumers. *See* 18 C.F.R. §§ 385.214; 385.1306. This motion is timely, as it is filed before the Commission's May 21, 2026 comment deadline. Washington has an interest in this proceeding because TransAlta seeks to recover costs for operating Centralia that may ultimately fall on Washington electricity users, including the State itself. *See Maryland People's Counsel v. FERC*, 760 F.2d 318, 320 (D.C. Cir. 1985). Washington also has a sovereign interest in this proceeding, as Washington's Clean Energy Transformation Act prevents the recovery of costs for coal-fired electricity in Washington consumer rates after December 2025. *See* Wash. Rev. Code § 19.405.030(1)(a). Finally, Centralia's retirement as a coal-fired power plant was part of an agreement between TransAlta and the State of Washington. *See* Ex. A, Mot. To Intervene, Request for Rehearing, and Mot. to Stay by the State of Washington, Order No. 202-25-11 (Dep't Energy, filed Jan. 13, 2026) at 10-11. Requiring Centralia to remain available to operate as a coal plant and recovering its costs for doing so deprives Washington of the benefit of its bargain under that agreement, including by reducing or eliminating the customer cost savings that Centralia's timely retirement would have achieved.

COMMUNICATIONS

All communications and documents related to this proceeding should be served on the following persons:

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PROTEST

The Commission may set rates allowing for recovery of costs related to section 202(c) orders, subject to the constraints of the Federal Power Act. Here, those constraints require the Commission to deny TransAlta's application for cost recovery. This case is unlike other cost recovery proceedings under section 202(c) that the Commission has recently addressed.[1] TransAlta's Centralia plant is not part of an organized electricity market. It is a merchant generator operating with a market-based-rate tariff. *See* Ex. B, TransAlta Centralia Generation Tariff Filing, *TransAlta Centralia Generation LLC*, Dkt. No. ER15-2536-000 (FERC). During the emergency orders, no entity has purchased TransAlta's electricity. In this context, the Commission lacks jurisdiction to order cost recovery for TransAlta for three reasons.

[1] *See PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,159 (Aug. 2025), *modified on rehearing*, 193 FERC ¶ 61,229 (Dec. 2025); *Consumers Energy v. MISO*, 192 FERC ¶ 61,158 (Aug. 2025), *modified on rehearing*, 193 FERC ¶ 61,228 (Dec. 2025).

First, TransAlta has not provided any service, such as the wholesale sale or transmission of energy, for which the Commission can set rates under the Federal Power Act. Second, section 202(c) allows the Commission to set the terms for an arrangement between "parties" affected by an emergency order. It does not allow the Commission to force an unwilling buyer to purchase TransAlta's power or to treat a non-party *as if* they had purchased TransAlta's power. TransAlta has no arrangements for the sale of electricity, and the Commission cannot supply one. Third, the lack of demand for TransAlta's energy reveals the fundamental problem with this proceeding: there is no valid emergency justifying the Department of Energy's order under section 202(c). The Commission cannot require ratepayers to pay for an unlawful "emergency" order.

Accordingly, the Commission should deny the application for lack of jurisdiction until TransAlta Centralia provides a jurisdictional service to a willing customer and the legal validity of the TransAlta emergency orders is settled. In the alternative, should the Commission order cost recovery in this proceeding, TransAlta's proposed allocation of costs does not match costs with benefits, to the extent any benefits exist.

I. Background

A. Facts

The TransAlta Centralia Generating Facility is a fifty-five-year-old coal power plant in Washington State. *See* Ex. A at 16. Until this year, TransAlta Centralia has been a major polluter in Washington, causing significant health and environmental harms to Washingtonians. *See id*. 16-18. Fifteen years ago, the State of Washington, TransAlta, and other stakeholders formalized an agreement to transition the Centralia plant off coal by

December 2025. The State Legislature codified this agreement. *See* Rev. Code Wash. 80.80.040(1), (3)(c).

Utilities and regulators have had fifteen years to plan for Centralia's retirement and replace its capacity, which they have done. *See* Ex. A at 18-20, 20-23. Those plans included private investment to convert Centralia from coal to natural gas by 2028. *See id*. 19-20. This transition would better support grid reliability than continued coal operations. Centralia is an aging plant that has not been maintained for continued coal operations after 2025. It is incapable of reliable operations in an emergency: in the past two years, Centralia has shut down twenty-nine times. *See id*. 37. Converting to natural gas will increase Centralia's total capacity from 680 to 700 MW, enhancing the grid's ability to respond to potential increases in demand. With natural gas, Centralia can quickly adjust power generation in response to changing supply and demand, an impossibility with coal generation. *See id*. 38. Finally, using natural gas in lieu of coal will be a more affordable source of power, reduce air pollution that harms human health, and comply with state law limiting the sale of coal-powered electricity after 2025. *See id*. 37-41; Wash. Rev. Code § 19.405.030(1)(a).

In December 2025, the Department of Energy disrupted those plans when it issued an emergency order preventing Centralia's planned retirement as a coal facility. *See* U.S. Dep't of Energy, Order No. 202-25-11 (Dec. 16, 2025)[2] (*Centralia I*). The Department found an "emergency exists within the Western Electricity Coordinating Council [] Northwest assessment area due to a shortage of electric energy, a shortage of facilities for

[2] Available at https://www.energy.gov/documents/order-number-202-25-11.

the generation of electric energy, and other causes." *See id*. at 1. The Department ordered Centralia to remain open as a coal plant until March 16, 2026. *See id*. at 4.

Washington requested rehearing with the Department of Energy. *See* Ex. A. Washington argued that *Centralia I* violated the Federal Power Act and the Department's regulations, impermissibly intruded into matters reserved to state jurisdiction, and violated the Administrative Procedure Act's requirement for notice-and-comment rulemaking. Additionally, Washington argued that *Centralia I* was unreasoned and lacked substantial evidence to support it. The sources the Department relied on did not describe an emergency, and the Department did not address other alternatives to meet any potential energy shortfall. Finally, Washington argued that *Centralia I* arbitrarily and erroneously named Bonneville Power Administration as the balancing authority and the California Independent System Operator (CAISO) as the Reliability Coordinator when those entities have no authority to order TransAlta to run. *See id*. 6-9, 70-71. The Department denied Washington's rehearing request by operation of law and has not, to date, issued a substantive response.

The day after the Department issued *Centralia I*, Bonneville Power Administration contacted the Department of Energy to alert the Department of its mistake in naming Bonneville as the Balancing Authority. *See* Ex. C, Letter & First Partial Response to Freedom of Information Act Request, Bonneville Power Administration (Mar. 12, 2026) at 2, 4. The Department met with Bonneville three weeks later, on or about January 9, 2026, to clarify the error and confirmed that "BPA's role related to the [emergency order] is business as usual as BPA provides transmission services to TransAlta. BPA does not provide power

services for Centralia as Centralia is not within BPA's [Balancing Authority Area]." *See* Ex. C at 5.

Inexplicably, the Department waited an additional nine weeks, until March 13, 2026 to amend its "emergency" order to correctly name the entities that could even plausibly call on Centralia to operate: Gridforce as the Balancing Authority and the Southwest Power Pool as the Reliability Coordinator. *See* U.S. Dep't of Energy, Order No. 202-25-11B (March 13, 2026)[3] (*Amended Centralia I*). The next business day, on March 16, 2026, the Department issued a new emergency order extending the emergency for ninety days, the maximum period allowed under the Federal Power Act. *See* U.S. Dep't of Energy, Order No. 202-26-18 (March 16, 2026)[4] (*Centralia II*). Washington requested rehearing of *Centralia II*. *See* Ex. D, Mot. Intervene, Request for Rehearing, and Motion to Stay by State of Washington, Order No. 202-26-18 (Dep't Energy, filed Apr. 14, 2026). Washington has also sought review of *Centralia I* in the Ninth Circuit Court of Appeals. *See* Pet. for Review, *Wash. v. U.S. Dep't of Energy*, No. 26-1252 (9th Cir., filed Mar. 3, 2026). That petition remains pending.

B. The Commission Has Independent Authority and Discretion to Set Just and Reasonable Rates for Emergency Orders

Under the Federal Power Act and the Department of Energy Organization Act, the Commission has authority over the "establishment, review, and enforcement of rates and

[3] Available at https://www.energy.gov/documents/centralia-amendment-order-no-202-25-11b.

[4] Available at https://www.energy.gov/documents/centralia-order-no-202-26-18.

charges" for the wholesale use, sale, or transmission of electric energy. *See* 42 U.S.C. § 7172(a)(1)(B); 16 U.S.C. § 824. Generally, the Commission cannot establish or change rates retroactively, "no matter how compelling the equities." *See Oklahoma Gas & Elec. Co. v. FERC*, 11 F.4th 821, 830 (D.C. Cir. 2021). Section 202(c) provides a limited exception, allowing the Commission to set just and reasonable terms to an arrangement between parties affected by an emergency order after the order has been entered. *See* 16 U.S.C. § 824a(c)(1).

Under section 202(c), the Department of Energy has a narrow power to order temporary interconnections and "generation, delivery, interchange, or transmission of electric energy" in emergencies. *See id*. The Commission retains authority to set just and reasonable rates allowing generators to recover section 202(c) costs from affected parties. *See* 42 U.S.C. § 7172(a)(1)(B); 16 U.S.C. § 824a(c)(1). In other words, the Department's authority to respond to emergencies does not divest the Commission of its authority – or obligation – under the Federal Power Act to ensure any rates or charges for those connections are just and reasonable.

The Commission's independent authority here is consistent with the Department of Energy's regulations. The Department's regulation requires it to refer rate issues to the Commission "for determination by that agency in accordance with its standards and procedures." 10 C.F.R. § 205.376. When promulgating this regulation, the Department explained that "specific allocation of costs was not included in the regulations since this responsibility is vested in the [Commission] and must be addressed by its regulations." U.S. Dep't of Energy, *Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39984, 39985 (1981).

Under the Federal Power Act, ordering customers to pay for emergency connections, generation, or delivery of electricity is not automatic. Rather, the Commission "may" prescribe terms, including compensation or reimbursement. 16 U.S.C. § 824a(c)(1). Because use of the term "may" connotes discretion, the Commission need not decide compensation simultaneously or immediately following an emergency service: it may issue such an order "either before or after such [emergency service] order takes effect." § 824a(c)(1). The Commission must also hold a hearing before issuing an order. *Id*. If the Commission does allow compensation, the terms must be "just and reasonable." *Id*.; *see also* § 824d(a) ("all rates and charges . . . subject to the jurisdiction of the Commission . . . shall be just and reasonable"). The Commission cannot order rates or charges that "subject any person to any undue prejudice or disadvantage." § 824d(b).

Collectively, use of the word "may," the hearing requirement, the flexibility on timing, and the requirement that any terms be just and reasonable all indicate that the Commission's action here is far from ministerial. Consistent with its role as a neutral, adjudicatory body, the Commission must carefully review the available evidence, adhere to its standard legal principles, hold a hearing, and only set rates that are just, reasonable, and not unduly prejudicial. Finally, because TransAlta asks the Commission to establish rates retroactively, the Commission may only act following a lawful exercise of section 202(c) authority.

II. Argument

A. TransAlta Cannot Recover Costs Because It Has Not Sold Energy Or Capacity

Section 202(c) authorizes the "temporary connection[] . . . generation, delivery, interchange, or transmission" of electricity in emergencies. Those enumerated powers do not include actions that do not involve the wholesale use, sale, or transmission of energy. As a result, section 202(c) does not authorize the Commission to set rates for such actions. *See* 16 U.S.C. §§ 824, 824a(c)(1); *see also Pub. Utilities Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 90 (1927). Here, no temporary connections have been made, and no electricity has been generated, delivered, interchanged, or transmitted. Accordingly, there is nothing the Commission may set rates for.

TransAlta appears to presume that, since it took measures necessary to ensure it was available to operate, it provided a service for which it is entitled to recover its costs. But being available to operate is not a jurisdictional service.

To be sure, the Commission has asserted jurisdiction over capacity transacted in organized wholesale markets under its authority to order just and reasonable rates, terms and conditions pursuant to sections 205 and 206 of the Federal Power Act. *See New England Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283, 290 (D.C. Cir. 2014). That authority is inapplicable here, as the Commission is not setting rates for an organized wholesale market and is instead acting under its more limited section 202(c) authority.

There also is no basis on which to award costs for any "capacity" resource here. The emergency orders plainly state: Centralia "shall not be considered a capacity resource." *See*

Centralia I; *Centralia II*. TransAlta cannot recover costs under the theory that it provided a capacity service the Department specifically barred it from providing.

TransAlta also has not provided capacity services. "Capacity" is a collection of promises about the availability and deliverability of the resource, backed by consequences for non-performance. *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009). TransAlta has made no such promises and has done nothing that would enable any utility to reduce its purchases of capacity from other sources. Load-serving entities have already secured necessary capacity; requiring them to pay for capacity from Centralia would effectively require them to pay for the same service twice. *See, e.g., N.Y. Indep. Sys. Operator, Inc*., 155 FERC ¶ 61,076 at ¶¶ 82–83 (2016) (finding tariff provisions that force consumers to pay twice for capacity to be unjust and unreasonable).

At best, TransAlta has remained available to operate primarily at the direction of entities who lacked the authority to order it to run, which cannot be understood as a capacity service. For the first 87 days of *Centralia I*, the Department of Energy erroneously named the Bonneville Power Administration as the balancing authority and CAISO as the reliability coordinator. Neither entity has authority over the region in which Centralia is located. The Department inexplicably failed to correct its mistake until March 13, 2026. *See* Ex. C at 5; *Amended Centralia I*; *see also* Ex. E, Benjamin Storrow, *DOE lists wrong grid operator in emergency order to open Washington coal plant*, E&E News (May 15, 2026). There can be no "articulable or plausible reason" to support a finding of benefits from *Centralia I* to Bonneville Power Administration or CAISO when these entities were erroneously named in the order and could not direct Centralia to operate. *See PJM Interconnection*, 192 FERC ¶

61,159 at ¶ 33. Without an entity in a position to direct dispatch of Centralia, the generator was not available for use as a capacity resource for at least 87 days of *Centralia I*. For the same reason, costs incurred when TransAlta could not be effectively dispatched were neither prudently incurred nor used and useful to any customer.

Unless and until TransAlta provides a jurisdictional service to a customer, the Commission cannot order recovery of TransAlta's costs from anyone.

B. The Commission Cannot Force a Business Relationship Between TransAlta, a Merchant Generator, and Unwilling Purchasers

TransAlta Centralia has a market-based rate tariff. *See generally Montana Consumer Couns. v. FERC*, 659 F.3d 910, 914-15 (9th Cir. 2011) (describing FERC's development of market-based rates); *see also* Ex. B at 11. As a merchant generator, TransAlta takes all market risk, including the risk of adverse regulatory measures. That TransAlta has not found a willing buyer for its electricity is a cost it must bear. The Federal Power Act simply does not authorize the Commission to order rate recovery for energy or capacity provided to unwilling purchasers or to create business relationships that did not previously exist.

By its plain terms, section 202(c) confers on the Department of Energy only the power to order facilities engaged in the generation or transmission of electricity to generate, deliver, interchange, or transmit electric energy during an emergency. *See* 16 U.S.C. § 824a(c). It nowhere suggests that the Department of Energy could order an entity to purchase energy when they did not benefit from its use. Compelling the purchase of energy is an extraordinary power and, as a result, requires explicit authorization from Congress, such as Congress's explicit command that utilities purchase energy from qualifying facilities under the Public Utility Regulatory Policies Act. *Compare* 16 U.S.C. § 824a-3(a)(2). And,

consistent with its statutory authority, the Department of Energy has not attempted to compel power or capacity purchases in this case.

Interpreting section 202(c) to allow the Department of Energy to compel purchases from unwilling buyers would raise serious questions under the Commerce Clause of the U.S. Constitution. The Federal Power Act is an exercise of Congress's power to regulate interstate commerce. *See Pub. Utilities Comm'n of R.I.*, 273 U.S. at 90. The Commerce Clause allows Congress to regulate existing commercial relationships; Congress cannot direct someone to "purchase particular products" in the market for "energy" or any other market. *Nat'l Fed'n of Indep. Business v. Sebelius*, 567 U.S. 519, 557 (2012). Put simply, "the Framers gave Congress the power to *regulate* commerce, not to *compel* it." *Id.* at 555.

Just as the Department of Energy lacks authority under section 202(c) to compel purchases, the Commission also lacks such authority. Section 202(c) permits the Commission to "prescribe . . . terms" that are just and reasonable for "parties affected" by an emergency order who "fail to agree upon the terms of any arrangement between them." 16 U.S.C. § 824a(c)(1). This presupposes the existence of an "arrangement" between the parties, where all that remains is for the Commission to prescribe the terms. It does not allow the Commission to create a contractual relationship between parties where none existed before. And it certainly does not give the Commission the ability to prescribe terms for otherwise unrelated entities in their assumed role of "balancing authority" or "reliability coordinator." *See* Ex. C at 2 (explaining that Bonneville Power Administration is not the balancing authority for Centralia and the Department of Energy named Bonneville

erroneously); Ex. E (same); *Amended Centralia I* (amending order to name correct Balancing Authority and Reliability Coordinator).

As the Commission has acknowledged in other cases, "the Federal Power Act does not confer jurisdiction upon this Commission to dictate to a potential wholesale purchaser of power the particular supplier who it must purchase from." *See Monongahela Power Co., et al. Pub. Serv. Comm'n of the Dist. of Columbia*, 39 FERC ¶ 61,350, 62,098 (1987). Section 202(c) is no exception, so the Commission must deny TransAlta's application for lack of jurisdiction.

C. TransAlta May Not Recover Costs from Ratepayers Pursuant to Section 202(c) Because There Has Been No Lawful Exercise of Section 202(c) Authority

TransAlta appears to concede that, as a market-based-rate seller, it may recover costs only under section 202(c). *See* Application for Cost Recovery (filed Apr. 30, 2026) at 1. Compensation under section 202(c) is "supplemental" to an order addressing emergency conditions. 16 U.S.C. § 824a(c). Here, there is no valid emergency order, so TransAlta cannot recover costs under that provision.

As described in Washington's requests for rehearing of *Centralia I* and *II* (incorporated by reference here), the emergency orders are unlawful and *ultra vires*. *See* Ex. A at 6-9; Ex. D at 2-3. Section 202(c) requires a sudden, unforeseen, and imminent emergency situation, but the *Centralia* orders fail to identify such a situation. Instead, the orders rest on a speculative series of future events, ranging years into the future, and impermissibly rely on long-term resource adequacy concerns. *See* Ex. A at 44-55, 57-69.

The Department of Energy's novel application of section 202(c) is also inconsistent with the Department's own regulations governing that authority. *See id*. at 55-56.

The administrative record before the Department of Energy provided conclusive evidence that preventing Centralia's retirement as a coal plant was unnecessary, and even harmful, for the region's reliability. The emergency orders threaten to curtail cheaper, abundant hydroelectric energy sources and disrupt the planned expansion of Centralia into a natural gas facility. *See* Ex. A at 88-94. Unsurprisingly, Centralia was not needed for the duration of the emergency orders, even during a six-day outage of the largest non-hydroelectric generating facility in the state of Washington. *See* Ex. D at 36; Ex. E at (quoting TransAlta CEO that Centralia "hasn't run thus far and our expectation is that it likely will not run"). Rather than improve regional reliability or affordability, the Centralia orders are actively harming it.

The Department of Energy's sluggish response to correct crucial errors in *Centralia I* is proof of the non-emergency here. If the Department truly believed Centralia was needed, it would have taken prompt action to ensure Centralia could be dispatched appropriately. Instead, the Department waited three weeks to meet with Bonneville to understand its mistake, then another nine weeks to correct it. *See* Ex. C at 4-5.

Washington is seeking judicial review of *Centralia I* before the Ninth Circuit. *See Wash. v. U.S. Dep't of Energy*, No. 26-1252 (9th Cir., filed Mar. 3, 2026). The Commission should therefore deny the application without prejudice, allowing TransAlta to re-file after the legal validity of the Centralia orders is settled.

Alternatively, the Commission should exercise its discretion to stay adjudication of TransAlta's application until that time. Section 202(c) plainly states that ordering compensation is at the Commission's discretion and sets no time limit on when the Commission must act. *See* 16 U.S.C. § 824a(c)(1) (stating the Commission "after hearing held either before *or after* such order takes effect, *may* prescribe" compensation in a supplemental order) (emphasis added); *MISO Transmission Owners v. FERC*, 45 F.4th 248, 262 (D.C. Cir. 2022) (stating the Commission has "broad discretion to manage its docket").

Awaiting the legal validity of the underlying order has several benefits. First, the Commission and parties to this proceeding will not have to expend resources litigating the amount and allocation of costs for an order that may later be overturned in court. Second, entities will not need to pay costs pursuant to an unlawful section 202(c) order, which they may not be able to recover later. *See, e.g.*, Brief of Respondent-Intervenor Consumers Energy Company, *Mich. v. Dep't of Energy*, No. 25-1159 (D.C. Cir. filed Mar. 17, 2026) at 16-27 (arguing that coal plant subject to emergency order is entitled to compensation even if the emergency order is vacated on review).[5] Entities inappropriately allocated costs also will not need to expend resources to update their own tariffs and rates to pass on those costs to

[5] While Washington does not agree with the arguments made therein, Consumers Energy's brief highlights potential legal disputes over ratepayers' entitlement to refunds if a court sets aside an emergency order. Owners seeking compensation from unlawful section 202(c) orders should instead direct their claims at the federal government, not ratepayers who did not benefit. *See, e.g.*, Request for Rehearing by Tri-State Generation, Department of Energy Order No. 202-25-14, (Jan. 29, 2026), available at: https://www.energy.gov/documents/request-clarification-and-rehearing-tri-state-generation-and-transmission-association-and (challenging the Department of Energy's emergency order as an unconstitutional taking in violation of the Fifth Amendment).

electricity consumers. It is unclear how the entities to which TransAlta now proposes to allocate costs would pass on those costs. Those entities, as well as their customers and the Commission, likely must expend resources on tariff changes and related proceedings. It would be unnecessarily burdensome to trigger those actions before the validity of the underlying order is settled. Third, TransAlta and other market participants will benefit from the clarity that any cost recovery is contingent on the validity of the underlying emergency order, especially since TransAlta has indicated plans to invest tens of millions of dollars in capital upgrades in anticipation of future emergency orders. *See* Application for Cost Recovery at 12.

On the other hand, TransAlta argues that it should receive expedited adjudication because the orders are temporary and it is incurring costs now to comply with them. *See* Application 3. However, TransAlta has not shown a particular urgency to recover these costs, including by waiting over four months to file the instant application. The interests of administrative and judicial efficiency weigh against a complicated shifting of costs at this point in the proceeding.

D. In the Alternative, TransAlta's Proposal Does Not Match Costs With Benefits (to the Extent Any Benefits Exist)

For the reasons described above, the Commission should deny TransAlta's application for lack of jurisdiction. In the event the Commission does allow TransAlta to recover costs in this proceeding, it should not accept TransAlta's proposed method for cost allocation because it does not match costs with benefits. As the Commission has acknowledged, the "relevant legal standard" for allocating costs from section 202(c) orders is the cost causation principle that "all approved rates reflect to some degree the costs

actually caused by the customer who must pay them." *See Consumers Energy v. MISO*, 192 FERC ¶ 61,158, ¶ 38. The Commission explained that "a cost allocation method can satisfy the cost causation principle if the Commission 'has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with' the allocation of the costs." *Id*. (quoting *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009)).

TransAlta fails to explain how any of the named entities benefit from the emergency orders. Nor could it. As explained in Washington's requests for rehearing of *Centralia I* and *II* (and incorporated by reference here), there is no "emergency" in the Northwest necessitating the order. *See* Ex. A at 56-69; Ex. D at 38-49. Having Centralia remain available to operate does not benefit regional electricity consumers, it harms them. *See supra* pp. 4, 14 (explaining adverse impacts on regional reliability and affordability from the order). Requiring entities to pay costs for orders that actively harm them is inconsistent with the cost causation principle.

TransAlta unreasonably proposes to allocate 96 percent of costs to Bonneville and CAISO merely because the Department erroneously named them for 87 days of the 90-day order. The suggestion that Bonneville and CAISO derived 96 percent of the "benefit" on this ground is not plausible. Due to the Department's error, TransAlta kept Centralia online for 87 days to run only at the direction of a balancing authority or reliability coordinator that could not call on the plant. Charging Bonneville or CAISO millions of dollars for the Department's mistake is unjust and unreasonable.

The Commission should also reject TransAlta's proposal to allocate 96 percent of the "one-time fixed costs" for complying with the Department's emergency orders to Bonneville

and CAISO. *See* Duncan Aff. ¶¶ 21-26. TransAlta explains it incurred $19.8 million in fixed costs, $11 million of which are one-time fixed costs associated with storing and disposing of coal onsite. *See id*. ¶¶ 15-17. TransAlta allocates those one-time fixed costs on a *per diem* basis between BPA/CAISO and Gridforce/SPP for the duration of *Centralia I*. But the Department has already issued *Centralia II* and is likely to continue issuing such orders going forward. TransAlta does not suggest the one-time fixed costs are only necessary to comply with *Centralia I* and not *Centralia II*. The one-time fixed costs, to the extent they are recoverable at all, should be spread across relevant entities for the duration of all Centralia emergency orders. *See Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255 (D.C. Cir. 2018) (stating the Commission "generally may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse").

Finally, TransAlta also has not established that the emergency orders caused its one-time fixed costs. Given that TransAlta already owned the stockpiled coal onsite, the cost to remediate or dispose of it was TransAlta's liability before the emergency orders were issued. Accordingly, this cost should be disallowed entirely as the emergency order did not cause those costs. *See Ill. Com. Comm'n*, 576 F.3d at 477 (shifting the sunk costs of transmission lines to new users of the system was inconsistent with cost causation).

The Commission should reject TransAlta's proposed allocation of costs as unjust and unreasonable because it is inconsistent with the cost causation principle.

CONCLUSION

For the foregoing reasons, the Commission should deny TransAlta's application for cost recovery.

Respectfully submitted this 21st day of May, 2026.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic mail.

Dated this 21st day of May, 2026, in Seattle, Washington,

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EXHIBIT 145

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

TransAlta Centralia Generation LLC Docket No. ER26-3437

MOTION TO INTERVENE AND PROTEST BY THE STATE OF WASHINGTON AND THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

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MOTION TO INTERVENE

The State of Washington and the Washington Utilities and Transportation Commission move to intervene in this proceeding on behalf of themselves and their electricity consumers. *See* 18 C.F.R. §§ 385.214; 385.1306. This motion is timely, as it is filed before the Commission's August 26, 2026, comment deadline. Washington has an interest in this proceeding because TransAlta seeks to recover the costs for operating the coal-powered Centralia Power Plant, which may ultimately fall on Washington electricity users, including the State itself. *See Maryland People's Counsel v. FERC*, 760 F.2d 318, 320 (D.C. Cir. 1985). Washington also has a sovereign interest in this proceeding, as Washington's Clean Energy Transformation Act prevents the recovery of costs for coal-fired electricity in Washington consumer rates after December 2025. *See* Wash. Rev. Code § 19.405.030(1)(a). Finally, Centralia's retirement as a coal-fired power plant was part of an agreement between TransAlta and the State of Washington. *See* Ex. A, Mot. To Intervene, Request for Rehearing, and Mot. to Stay by the State of Washington, 202-25-11 (Dep't Energy, filed Jan. 13, 2026) at 10-11. Requiring Centralia to remain available to operate as a coal plant and recovering its costs for doing so deprives Washington of the benefit of its bargain under that agreement, including by reducing or eliminating the customer cost savings that Centralia's timely retirement would have achieved. The State of Washington and the Washington Utilities and Transportation Commission previously moved to intervene and protest in the related Docket No. ER26-2422. The reasons set forth in the prior motion pertain to the present matter and are repeated below.

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PROTEST

The Commission may set rates allowing for recovery of costs related to section 202(c) orders, subject to the constraints of the Federal Power Act. Here, those constraints require the Commission to deny TransAlta's application for cost recovery. This case is unlike other cost recovery proceedings under section 202(c) that the Commission has

recently addressed.[1] TransAlta's Centralia plant is not part of an organized electricity market. It is a merchant generator operating with a market-based-rate tariff. *See* Ex. B, TransAlta Centralia Generation Tariff Filing, *TransAlta Centralia Generation LLC*, Dkt. No. ER15-2536-000 (FERC). During the emergency orders, no entity has purchased TransAlta's electricity. In this context, the Commission lacks jurisdiction to order cost recovery for TransAlta for three reasons.

First, TransAlta has not provided any service, such as the wholesale sale or transmission of energy, for which the Commission can set rates under the Federal Power Act. Second, section 202(c) allows the Commission to set the terms for an arrangement between "parties" affected by an emergency order. It does not allow the Commission to force an unwilling buyer to purchase TransAlta's power or to treat a non-party *as if* they had purchased TransAlta's power. TransAlta has no arrangements for the sale of electricity, and the Commission cannot supply one. Third, the lack of demand for TransAlta's energy reveals the fundamental problem with this proceeding: there is no valid emergency justifying the Department of Energy's order under section 202(c). The Commission cannot require ratepayers to pay for an unlawful "emergency" order.

Accordingly, the Commission should deny the application for lack of jurisdiction until TransAlta Centralia provides a jurisdictional service to a willing customer and the legal validity of the TransAlta emergency orders is settled. In the alternative, should the

[1] *See PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,159 (Aug. 2025), *modified on rehearing*, 193 FERC ¶ 61,229 (Dec. 2025); *Consumers Energy v. MISO*, 192 FERC ¶ 61,158 (Aug. 2025), *modified on rehearing*, 193 FERC ¶ 61,228 (Dec. 2025).

Commission order cost recovery in this proceeding, TransAlta's proposed allocation of costs does not match costs with benefits, to the extent any benefits exist.

I. Background

A. Facts

The TransAlta Centralia Generating Facility is a fifty-five-year-old coal power plant in Washington State. *See* Ex. A at 16. Until this year, TransAlta Centralia has been a major polluter in Washington, causing significant health and environmental harms to Washingtonians. *See id*. 16-18. Fifteen years ago, the State of Washington, TransAlta, and other stakeholders formalized an agreement to transition the Centralia plant off coal by December 2025. The State Legislature codified this agreement. *See* Rev. Code Wash. 80.80.040(1), (3)(c).

Utilities and regulators have had fifteen years to plan for Centralia's retirement and replace its capacity, which they have done. *See* Ex. A at 18-20, 20-23. Those plans included private investment to convert Centralia from coal to natural gas by 2028. *See id*. 19-20. This transition would better support grid reliability than continued coal operations. Centralia is an aging plant that has not been maintained for continued coal operations after 2025. It is incapable of reliable operations in an emergency: in the past two years, Centralia has shut down twenty-nine times. *See id*. 37. Converting to natural gas will increase Centralia's total capacity from 680 to 700 MW, enhancing the grid's ability to respond to potential increases in demand. With natural gas, Centralia can quickly adjust power generation in response to changing supply and demand, an impossibility with coal generation. *See id*. 38. Finally, using natural gas in lieu of coal will be a more affordable source of power, reduce air

pollution that harms human health, and comply with state law limiting the sale of coal-powered electricity after 2025. *See id*. 37-41; Wash. Rev. Code § 19.405.030(1)(a).

In December 2025, the Department of Energy disrupted those plans when it issued an emergency order preventing Centralia's planned retirement as a coal facility. *See* U.S. Dep't of Energy, Order No. 202-25-11 (Dec. 16, 2025)[2] (*Centralia I*). The Department found an "emergency exists within the Western Electricity Coordinating Council [] Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes." *See id*. at 1. The Department ordered Centralia to remain open as a coal plant until March 16, 2026. *See id*. at 4.

Washington requested rehearing with the Department of Energy. *See* Ex. A. Washington argued that *Centralia I* violated the Federal Power Act and the Department's regulations, impermissibly intruded into matters reserved to state jurisdiction, and violated the Administrative Procedure Act's requirement for notice-and-comment rulemaking. Additionally, Washington argued that *Centralia I* was unreasoned and lacked substantial evidence to support it. The sources the Department relied on did not describe an emergency, and the Department did not address other alternatives to meet any potential energy shortfall. Finally, Washington argued that *Centralia I* arbitrarily and erroneously named Bonneville Power Administration as the balancing authority and the California Independent System Operator (CAISO) as the Reliability Coordinator when those entities have no authority to

[2] Available at https://www.energy.gov/documents/order-number-202-25-11.

order TransAlta to run. *See id*. 6-9, 70-71. The Department denied Washington's rehearing request by operation of law and has not, to date, issued a substantive response.

The day after the Department issued *Centralia I*, Bonneville Power Administration contacted the Department of Energy to alert the Department of its mistake in naming Bonneville as the Balancing Authority. *See* Ex. C, Letter & First Partial Response to Freedom of Information Act Request, Bonneville Power Administration (Mar. 12, 2026) at 2, 4. The Department met with Bonneville three weeks later, on or about January 9, 2026, to clarify the error and confirmed that "BPA's role related to the [emergency order] is business as usual as BPA provides transmission services to TransAlta. BPA does not provide power services for Centralia as Centralia is not within BPA's [Balancing Authority Area]." *See* Ex. C at 5.

Inexplicably, the Department waited an additional nine weeks, until March 13, 2026 to amend its "emergency" order to correctly name the entities that could even plausibly call on Centralia to operate: Gridforce as the Balancing Authority and the Southwest Power Pool as the Reliability Coordinator. *See* U.S. Dep't of Energy, Order No. 202-25-11B (March 13, 2026)[3] (*Amended Centralia I*). The next business day, on March 16, 2026, the Department issued a new emergency order extending the emergency for ninety days, the maximum period allowed under the Federal Power Act. *See* U.S. Dep't of Energy, Order No. 202-26-18 (March 16, 2026)[4] (*Centralia II*). Washington requested rehearing of *Centralia II*. *See*

[3] Available at https://www.energy.gov/documents/centralia-amendment-order-no-202-25-11b.

[4] Available at https://www.energy.gov/documents/centralia-order-no-202-26-18.

Ex. D, Mot. Intervene, Request for Rehearing, and Motion to Stay by State of Washington, Order No. 202-26-18 (Dep't Energy, filed Apr. 14, 2026). Washington has also sought review of *Centralia I* in the Ninth Circuit Court of Appeals. *See* Pet. for Review, *Wash. v. U.S. Dep't of Energy*, No. 26-1252 (9th Cir., filed Mar. 3, 2026). That petition remains pending.

B. The Commission Has Independent Authority and Discretion to Set Just and Reasonable Rates for Emergency Orders

Under the Federal Power Act and the Department of Energy Organization Act, the Commission has authority over the "establishment, review, and enforcement of rates and charges" for the wholesale use, sale, or transmission of electric energy. *See* 42 U.S.C. § 7172(a)(1)(B); 16 U.S.C. § 824. Generally, the Commission cannot establish or change rates retroactively, "no matter how compelling the equities." *See Oklahoma Gas & Elec. Co. v. FERC*, 11 F.4th 821, 830 (D.C. Cir. 2021). Section 202(c) provides a limited exception, allowing the Commission to set just and reasonable terms to an arrangement between parties affected by an emergency order after the order has been entered. *See* 16 U.S.C. § 824a(c)(1).

Under section 202(c), the Department of Energy has a narrow power to order temporary interconnections and "generation, delivery, interchange, or transmission of electric energy" in emergencies. *See id*. The Commission retains authority to set just and reasonable rates allowing generators to recover section 202(c) costs from affected parties. *See* 42 U.S.C. § 7172(a)(1)(B); 16 U.S.C. § 824a(c)(1). In other words, the Department's authority to respond to emergencies does not divest the Commission of its authority – or obligation – under the Federal Power Act to ensure any rates or charges for those connections are just and reasonable.

The Commission's independent authority here is consistent with the Department of Energy's regulations. The Department's regulation requires it to refer rate issues to the Commission "for determination by that agency in accordance with its standards and procedures." 10 C.F.R. § 205.376. When promulgating this regulation, the Department explained that "specific allocation of costs was not included in the regulations since this responsibility is vested in the [Commission] and must be addressed by its regulations." U.S. Dep't of Energy, *Emergency Interconnection of Electric Facilities*, 46 Fed. Reg. 39984, 39985 (1981).

Under the Federal Power Act, ordering customers to pay for emergency connections, generation, or delivery of electricity is not automatic. Rather, the Commission "may" prescribe terms, including compensation or reimbursement. 16 U.S.C. § 824a(c)(1). Because use of the term "may" connotes discretion, the Commission need not decide compensation simultaneously or immediately following an emergency service: it may issue such an order "either before or after such [emergency service] order takes effect." § 824a(c)(1). The Commission must also hold a hearing before issuing an order. *Id*. If the Commission does allow compensation, the terms must be "just and reasonable." *Id*.; *see also* § 824d(a) ("all rates and charges . . . subject to the jurisdiction of the Commission . . . shall be just and reasonable"). The Commission cannot order rates or charges that "subject any person to any undue prejudice or disadvantage." § 824d(b).

Collectively, use of the word "may," the hearing requirement, the flexibility on timing, and the requirement that any terms be just and reasonable all indicate that the Commission's action here is far from ministerial. Consistent with its role as a neutral,

adjudicatory body, the Commission must carefully review the available evidence, adhere to its standard legal principles, hold a hearing, and only set rates that are just, reasonable, and not unduly prejudicial. Finally, because TransAlta asks the Commission to establish rates retroactively, the Commission may only act following a lawful exercise of section 202(c) authority.

II. Argument

A. TransAlta Cannot Recover Costs Because It Has Not Sold Energy Or Capacity

Section 202(c) authorizes the "temporary connection[] . . . generation, delivery, interchange, or transmission" of electricity in emergencies. Those enumerated powers do not include actions that do not involve the wholesale use, sale, or transmission of energy. As a result, section 202(c) does not authorize the Commission to set rates for such actions. *See* 16 U.S.C. §§ 824, 824a(c)(1); *see also Pub. Utilities Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 90 (1927). Here, no temporary connections have been made, and no electricity has been generated, delivered, interchanged, or transmitted. Accordingly, there is nothing the Commission may set rates for.

TransAlta appears to presume that, since it took measures necessary to ensure it was available to operate, it provided a service for which it is entitled to recover its costs. But being available to operate is not a jurisdictional service.

To be sure, the Commission has asserted jurisdiction over capacity transacted in organized wholesale markets under its authority to order just and reasonable rates, terms and conditions pursuant to sections 205 and 206 of the Federal Power Act. *See New England Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283, 290 (D.C. Cir. 2014). That authority

is inapplicable here, as the Commission is not setting rates for an organized wholesale market and is instead acting under its more limited section 202(c) authority.

There also is no basis on which to award costs for any "capacity" resource here. The emergency orders plainly state: Centralia "shall not be considered a capacity resource." *See Centralia I*; *Centralia II*. TransAlta cannot recover costs under the theory that it provided a capacity service the Department specifically barred it from providing.

TransAlta also has not provided capacity services. "Capacity" is a collection of promises about the availability and deliverability of the resource, backed by consequences for non-performance. *See Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009). TransAlta has made no such promises and has done nothing that would enable any utility to reduce its purchases of capacity from other sources. Load-serving entities have already secured necessary capacity; requiring them to pay for capacity from Centralia would effectively require them to pay for the same service twice. *See, e.g., N.Y. Indep. Sys. Operator, Inc*., 155 FERC ¶ 61,076 at ¶¶ 82–83 (2016) (finding tariff provisions that force consumers to pay twice for capacity to be unjust and unreasonable).

At best, TransAlta has remained available to operate primarily at the direction of entities who lacked the authority to order it to run, which cannot be understood as a capacity service. For the first 87 days of *Centralia I*, the Department of Energy erroneously named the Bonneville Power Administration as the balancing authority and CAISO as the reliability coordinator. Neither entity has authority over the region in which Centralia is located. The Department inexplicably failed to correct its mistake until March 13, 2026. *See* Ex. C at 5; *Amended Centralia I*; *see also* Ex. E, Benjamin Storrow, *DOE lists wrong grid operator in*

emergency order to open Washington coal plant, E&E News (May 15, 2026). There can be no "articulable or plausible reason" to support a finding of benefits from *Centralia I* to Bonneville Power Administration or CAISO when these entities were erroneously named in the order and could not direct Centralia to operate. *See PJM Interconnection*, 192 FERC ¶ 61,159 at ¶ 33. Without an entity in a position to direct dispatch of Centralia, the generator was not available for use as a capacity resource for at least 87 days of *Centralia I*. For the same reason, costs incurred when TransAlta could not be effectively dispatched were neither prudently incurred nor used and useful to any customer.

Unless and until TransAlta provides a jurisdictional service to a customer, the Commission cannot order recovery of TransAlta's costs from anyone.

B. The Commission Cannot Force a Business Relationship Between TransAlta, a Merchant Generator, and Unwilling Purchasers

TransAlta Centralia has a market-based rate tariff. *See generally Montana Consumer Couns. v. FERC*, 659 F.3d 910, 914-15 (9th Cir. 2011) (describing FERC's development of market-based rates); *see also* Ex. B at 11. As a merchant generator, TransAlta takes all market risk, including the risk of adverse regulatory measures. That TransAlta has not found a willing buyer for its electricity is a cost it must bear. The Federal Power Act simply does not authorize the Commission to order rate recovery for energy or capacity provided to unwilling purchasers or to create business relationships that did not previously exist.

By its plain terms, section 202(c) confers on the Department of Energy only the power to order facilities engaged in the generation or transmission of electricity to generate, deliver, interchange, or transmit electric energy during an emergency. *See* 16 U.S.C. § 824a(c). It nowhere suggests that the Department of Energy could order an entity to

purchase energy when they did not benefit from its use. Compelling the purchase of energy is an extraordinary power and, as a result, requires explicit authorization from Congress, such as Congress's explicit command that utilities purchase energy from qualifying facilities under the Public Utility Regulatory Policies Act. *Compare* 16 U.S.C. § 824a-3(a)(2). And, consistent with its statutory authority, the Department of Energy has not attempted to compel power or capacity purchases in this case.

Interpreting section 202(c) to allow the Department of Energy to compel purchases from unwilling buyers would raise serious questions under the Commerce Clause of the U.S. Constitution. The Federal Power Act is an exercise of Congress's power to regulate interstate commerce. *See Pub. Utilities Comm'n of R.I.*, 273 U.S. at 90. The Commerce Clause allows Congress to regulate existing commercial relationships; Congress cannot direct someone to "purchase particular products" in the market for "energy" or any other market. *Nat'l Fed'n of Indep. Business v. Sebelius*, 567 U.S. 519, 557 (2012). Put simply, "the Framers gave Congress the power to *regulate* commerce, not to *compel* it." *Id.* at 555.

Just as the Department of Energy lacks authority under section 202(c) to compel purchases, the Commission also lacks such authority. Section 202(c) permits the Commission to "prescribe . . . terms" that are just and reasonable for "parties affected" by an emergency order who "fail to agree upon the terms of any arrangement between them." 16 U.S.C. § 824a(c)(1). This presupposes the existence of an "arrangement" between the parties, where all that remains is for the Commission to prescribe the terms. It does not allow the Commission to create a contractual relationship between parties where none existed before. And it certainly does not give the Commission the ability to prescribe terms

for otherwise unrelated entities in their assumed role of "balancing authority" or "reliability coordinator." *See* Ex. C at 2 (explaining that Bonneville Power Administration is not the balancing authority for Centralia and the Department of Energy named Bonneville erroneously); Ex. E (same); *Amended Centralia I* (amending order to name correct Balancing Authority and Reliability Coordinator).

As the Commission has acknowledged in other cases, "the Federal Power Act does not confer jurisdiction upon this Commission to dictate to a potential wholesale purchaser of power the particular supplier who it must purchase from." *See Monongahela Power Co., et al. Pub. Serv. Comm'n of the Dist. of Columbia*, 39 FERC ¶ 61,350, 62,098 (1987). Section 202(c) is no exception, so the Commission must deny TransAlta's application for lack of jurisdiction.

C. TransAlta May Not Recover Costs from Ratepayers Pursuant to Section 202(c) Because There Has Been No Lawful Exercise of Section 202(c) Authority

TransAlta appears to concede that, as a market-based-rate seller, it may recover costs only under section 202(c). *See* Application for Cost Recovery (filed Apr. 30, 2026) at 1. Compensation under section 202(c) is "supplemental" to an order addressing emergency conditions. 16 U.S.C. § 824a(c). Here, there is no valid emergency order, so TransAlta cannot recover costs under that provision.

As described in Washington's requests for rehearing of *Centralia I* and *II* (incorporated by reference here), the emergency orders are unlawful and *ultra vires*. *See* Ex. A at 6-9; Ex. D at 2-3. Section 202(c) requires a sudden, unforeseen, and imminent emergency situation, but the *Centralia* orders fail to identify such a situation. Instead, the

orders rest on a speculative series of future events, ranging years into the future, and impermissibly rely on long-term resource adequacy concerns. *See* Ex. A at 44-55, 57-69. The Department of Energy's novel application of section 202(c) is also inconsistent with the Department's own regulations governing that authority. *See id*. at 55-56.

The administrative record before the Department of Energy provided conclusive evidence that preventing Centralia's retirement as a coal plant was unnecessary, and even harmful, for the region's reliability. The emergency orders threaten to curtail cheaper, abundant hydroelectric energy sources and disrupt the planned expansion of Centralia into a natural gas facility. *See* Ex. A at 88-94. Unsurprisingly, Centralia was not needed for the duration of the emergency orders, even during a six-day outage of the largest non-hydroelectric generating facility in the state of Washington. *See* Ex. D at 36; Ex. E at (quoting TransAlta CEO that Centralia "hasn't run thus far and our expectation is that it likely will not run"). Rather than improve regional reliability or affordability, the Centralia orders are actively harming it.

The Department of Energy's sluggish response to correct crucial errors in *Centralia I* is proof of the non-emergency here. If the Department truly believed Centralia was needed, it would have taken prompt action to ensure Centralia could be dispatched appropriately. Instead, the Department waited three weeks to meet with Bonneville to understand its mistake, then another nine weeks to correct it. *See* Ex. C at 4-5.

Washington is seeking judicial review of *Centralia I* before the Ninth Circuit. *See Wash. v. U.S. Dep't of Energy*, No. 26-1252 (9th Cir., filed Mar. 3, 2026). The Commission

should therefore deny the application without prejudice, allowing TransAlta to re-file after the legal validity of the Centralia orders is settled.

Alternatively, the Commission should exercise its discretion to stay adjudication of TransAlta's application until that time. Section 202(c) plainly states that ordering compensation is at the Commission's discretion and sets no time limit on when the Commission must act. *See* 16 U.S.C. § 824a(c)(1) (stating the Commission "after hearing held either before *or after* such order takes effect, *may* prescribe" compensation in a supplemental order) (emphasis added); *MISO Transmission Owners v. FERC*, 45 F.4th 248, 262 (D.C. Cir. 2022) (stating the Commission has "broad discretion to manage its docket").

Awaiting the legal validity of the underlying order has several benefits. First, the Commission and parties to this proceeding will not have to expend resources litigating the amount and allocation of costs for an order that may later be overturned in court. Second, entities will not need to pay costs pursuant to an unlawful section 202(c) order, which they may not be able to recover later. *See, e.g.*, Brief of Respondent-Intervenor Consumers Energy Company, *Mich. v. Dep't of Energy*, No. 25-1159 (D.C. Cir. filed Mar. 17, 2026) at 16-27 (arguing that coal plant subject to emergency order is entitled to compensation even if the emergency order is vacated on review).[5] Entities inappropriately allocated costs also will

[5] While Washington does not agree with the arguments made therein, Consumers Energy's brief highlights potential legal disputes over ratepayers' entitlement to refunds if a court sets aside an emergency order. Owners seeking compensation from unlawful section 202(c) orders should instead direct their claims at the federal government, not ratepayers who did not benefit. *See, e.g.*, Request for Rehearing by Tri-State Generation, Department of Energy Order No. 202-25-14, (Jan. 29, 2026), available at: https://www.energy.gov/documents/request-clarification-and-rehearing-tri-state-generation-

not need to expend resources to update their own tariffs and rates to pass on those costs to electricity consumers. It is unclear how the entities to which TransAlta now proposes to allocate costs would pass on those costs. Those entities, as well as their customers and the Commission, likely must expend resources on tariff changes and related proceedings. It would be unnecessarily burdensome to trigger those actions before the validity of the underlying order is settled. Third, TransAlta and other market participants will benefit from the clarity that any cost recovery is contingent on the validity of the underlying emergency order, especially since TransAlta has indicated plans to invest tens of millions of dollars in capital upgrades in anticipation of future emergency orders. *See* Application for Cost Recovery at 12.

On the other hand, TransAlta argues that it should receive expedited adjudication because the orders are temporary and it is incurring costs now to comply with them. *See* Application 3. However, TransAlta has not shown a particular urgency to recover these costs, including by waiting over four months to file the instant application. The interests of administrative and judicial efficiency weigh against a complicated shifting of costs at this point in the proceeding.

D. In the Alternative, TransAlta's Proposal Does Not Match Costs With Benefits (to the Extent Any Benefits Exist)

For the reasons described above, the Commission should deny TransAlta's application for lack of jurisdiction. In the event the Commission does allow TransAlta to

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and-transmission-association-and (challenging the Department of Energy's emergency order as an unconstitutional taking in violation of the Fifth Amendment).

recover costs in this proceeding, it should not accept TransAlta's proposed method for cost allocation because it does not match costs with benefits. As the Commission has acknowledged, the "relevant legal standard" for allocating costs from section 202(c) orders is the cost causation principle that "all approved rates reflect to some degree the costs actually caused by the customer who must pay them." *See Consumers Energy v. MISO*, 192 FERC ¶ 61,158, ¶ 38. The Commission explained that "a cost allocation method can satisfy the cost causation principle if the Commission 'has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with' the allocation of the costs." *Id*. (quoting *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009)).

TransAlta fails to explain how any of the named entities benefit from the emergency orders. Nor could it. As explained in Washington's requests for rehearing of *Centralia I* and *II* (and incorporated by reference here), there is no "emergency" in the Northwest necessitating the order. *See* Ex. A at 56-69; Ex. D at 38-49. Having Centralia remain available to operate does not benefit regional electricity consumers, it harms them. *See supra* pp. 4, 14 (explaining adverse impacts on regional reliability and affordability from the order). Requiring entities to pay costs for orders that actively harm them is inconsistent with the cost causation principle.

TransAlta unreasonably proposes to allocate 96 percent of costs to Bonneville and CAISO merely because the Department erroneously named them for 87 days of the 90-day order. The suggestion that Bonneville and CAISO derived 96 percent of the "benefit" on this ground is not plausible. Due to the Department's error, TransAlta kept Centralia online for 87 days to run only at the direction of a balancing authority or reliability coordinator that

could not call on the plant. Charging Bonneville or CAISO millions of dollars for the Department's mistake is unjust and unreasonable.

The Commission should also reject TransAlta's proposal to allocate 96 percent of the "one-time fixed costs" for complying with the Department's emergency orders to Bonneville and CAISO. *See* Duncan Aff. ¶¶ 21-26. TransAlta explains it incurred $19.8 million in fixed costs, $11 million of which are one-time fixed costs associated with storing and disposing of coal onsite. *See id*. ¶¶ 15-17. TransAlta allocates those one-time fixed costs on a *per diem* basis between BPA/CAISO and Gridforce/SPP for the duration of *Centralia I*. But the Department has already issued *Centralia II* and is likely to continue issuing such orders going forward. TransAlta does not suggest the one-time fixed costs are only necessary to comply with *Centralia I* and not *Centralia II*. The one-time fixed costs, to the extent they are recoverable at all, should be spread across relevant entities for the duration of all Centralia emergency orders. *See Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, 1255 (D.C. Cir. 2018) (stating the Commission "generally may not single out a party for the full cost of a project, or even most of it, when the benefits of the project are diffuse").

Finally, TransAlta also has not established that the emergency orders caused its one-time fixed costs. Given that TransAlta already owned the stockpiled coal onsite, the cost to remediate or dispose of it was TransAlta's liability before the emergency orders were issued. Accordingly, this cost should be disallowed entirely as the emergency order did not cause those costs. *See Ill. Com. Comm'n*, 576 F.3d at 477 (shifting the sunk costs of transmission lines to new users of the system was inconsistent with cost causation).

The Commission should reject TransAlta's proposed allocation of costs as unjust and unreasonable because it is inconsistent with the cost causation principle.

CONCLUSION

For the foregoing reasons, the Commission should deny TransAlta's application for cost recovery.

Respectfully submitted this 25th day of August, 2026.

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CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding by electronic mail.

Dated this 25th day of August, 2026, in Seattle, Washington,

/s/ Alexandra Kory
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EXHIBIT 146

197 FERC ¶ 61,005
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Laura V. Swett, Chairman;
David Rosner, Lindsay S. See,
Judy W. Chang, and David LaCerte.

TransAlta Centralia Generation LLC Docket No. ER26-2422-000

ORDER REJECTING TARIFF REVISIONS

(Issued October 1, 2026)

1. On April 30, 2026, TransAlta Centralia Generation LLC (TransAlta) filed an application for cost recovery under section 202(c) of the Federal Power Act (FPA).[1] TransAlta proposes to recover its costs associated with complying with the Department of Energy's (DOE) emergency orders, Order No. 202-25-11 (Initial Emergency Order)[2] and Order No. 202-25-11B (Amended Emergency Order),[3] which directed TransAlta to make Unit 2 at its Centralia Generation Facility (Centralia) available to operate in order to address an energy emergency in the Western Electricity Coordinating Council's (WECC) Northwest assessment area. As discussed below, we reject TransAlta's filing without prejudice.

I. Background

2. TransAlta is a Washington limited liability company and owns Centralia. TransAlta is an indirect wholly owned subsidiary of TransAlta Corporation, which owns and operates generation in Canada, the United States, and Western Australia. Centralia is a coal-fired generation unit with a nameplate capacity of 729.9 MW, located in Centralia, Washington. Pursuant to a Memorandum of Agreement signed in 2012, as well as Washington State Law SB5769 enacted in 2011, TransAlta was scheduled to retire

[1] 16 U.S.C. § 824a(c).

[2] U.S. Dept. of Energy, *Order No. 202-25-11* (Dec. 16, 2025), https://www.energy.gov/documents/order-number-202-25-11.

[3] U.S. Dept. of Energy, *Order No. 202-25-11B* (Mar. 13, 2026), https://www.energy.gov/documents/centralia-amendment-order-no-202-25-11b.

Centralia from coal-fired operation on December 31, 2025, with a plan to convert the unit to natural gas-fired operations.[4]

3. On December 16, 2025, under section 301 of the DOE Organization Act,[5] DOE issued the Initial Emergency Order pursuant to FPA section 202(c), determining that an emergency exists in the WECC Northwest assessment area, "which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho."[6] The Initial Emergency Order stated that the finding of the emergency situation is based on North American Electric Reliability Corporation's (NERC) 2025-26 Winter Reliability Assessment and an Energy + Environmental Economics report evaluating resource adequacy in the Pacific Northwest. The Initial Emergency Order directed TransAlta to "take all measures necessary" to ensure that Centralia is available to operate at the direction of either Bonneville Power Administration (Bonneville), in its role as balancing authority (BA), or California Independent System Operator Corporation (CAISO) Reliability Coordinator West (RC West), in its role as reliability coordinator (RC), from December 16, 2025, through March 16, 2026.[7] The Initial Emergency Order stated that rate recovery is available under FPA section 202(c) and directed TransAlta to file tariff revisions or waivers with the Commission to effectuate the Initial Emergency Order, as needed.[8] The Initial Emergency Order also directed Bonneville to facilitate transmission service as needed, while clarifying that Centralia shall not be considered a capacity resource.[9]

4. On March 13, 2026, DOE issued the Amended Emergency Order, which maintained the same 90-day effective window, from December 16, 2025, through March 16, 2026, but replaced Bonneville with Gridforce Energy Management, LLC (Gridforce) as the BA and CAISO with Southwest Power Pool, Inc. (SPP) as the RC.[10] On June 10,

[4] Transmittal at 3-4.

[5] 42 U.S.C. § 7151(b).

[6] Initial Emergency Order at 1.

[7] *Id*. ordering para. A.

[8] *Id*. ordering para. E.

[9] *Id.* ordering para. H.

[10] Amended Emergency Order at ordering para. A.

2026, DOE issued a rehearing Order No. 202-25-11C (DOE Rehearing Order)[11] addressing requests for rehearing of the Initial Emergency Order.

II. TransAlta Filing

5. TransAlta asks the Commission for the following relief: (a) a declaration that TransAlta is entitled to recover the costs that were necessary to ensure that Centralia was available to operate at the direction of Bonneville or CAISO during the 87-day period from December 16, 2025, to March 13, 2026; (b) a declaration that TransAlta is entitled to recover the costs that were necessary to ensure that Centralia was available to operate at the direction of Gridforce or SPP during the three-day period from March 14, 2026, to March 16, 2026; (c) approval of the allocation of the fixed costs incurred by TransAlta at Centralia during the 87-day period from December 16, 2025, to March 13, 2026, to be divided equally between Bonneville and CAISO; (d) approval of the allocation of the fixed costs incurred by TransAlta at Centralia during the 3-day period from March 14, 2026. to March 16, 2026, to be divided equally between Gridforce and SPP; (e) a declaration that TransAlta would be entitled to recover any variable costs incurred by TransAlta at Centralia during the effectiveness of the Emergency Orders if directed to operate, with such costs to be allocated to the entity directing operation; and (f) acceptance of the TransAlta Centralia Generation LLC Unit 2 Cost-Based Tariff, effective December 16, 2025, and a waiver of the prior notice requirement pursuant to 18 C.F.R. § 35.11 (2025), to the extent necessary.[12]

6. TransAlta asserts that the instant filing is concerned only with the assignment and recovery of costs associated with making Centralia available, and only for the period specified in the Emergency Orders. TransAlta states that the filing does not seek the assignment or recovery of costs associated with the subsequent emergency order issued on March 16, 2026.[13]

7. TransAlta argues that to the extent the relevant parties "fail to agree upon the terms of any arrangement between them in carrying out" an FPA section 202(c) order, the Commission is authorized to "prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid

[11] U.S. Dept. of Energy, *Order No. 202-25-11C* (June 10, 2026), order-addressing-arguments-raised-rehearing-order-no-202-25-11c. Initial Emergency Order, Amended Emergency Order, and DOE Rehearing Order will collectively be referred to as "Emergency Orders."

[12] Transmittal at 2-3.

[13] *Id*. at 3 (citing U.S. Dep't of Energy, Order No. 202-26-18 (Mar. 16, 2026)).

to or by any such party."[14] TransAlta asserts that it has not been able to come to an agreement with Bonneville, CAISO, Gridforce, or SPP (collectively, Allocated Parties).[15]

8. TransAlta proposes to allocate the costs incurred in compliance with the Orders during the 90-day period as follows: (a) for the 87-day period from December 16, 2025, to March 13, 2026, for which the Initial Emergency Order was in effect, to Bonneville and CAISO in equal amounts; and (b) for the 3-day period from March 14, 2026, to March 16, 2026, to Gridforce and SPP in equal amounts. TransAlta explains that, in the Initial Emergency Order, DOE directed TransAlta to make Centralia available to operate at the direction of either Bonneville or CAISO and that in the Amended Emergency Order, DOE directed TransAlta to make Centralia available to operate at the direction of either Gridforce or SPP. TransAlta avers that the Emergency Orders do not direct TransAlta to provide any priority or preference to one entity over the other in directing the operation of Centralia and that, absent any specified method of allocating costs or any ability to forecast when or how each entity may require Centralia to operate through the duration of the Emergency Orders, a just and reasonable method is to allocate the fixed costs of making Centralia available equally between (a) Bonneville and CAISO, and (b) Gridforce and SPP, as applicable, for each day that Centralia was made available to these entities to operate in accordance with the Emergency Orders.[16]

9. TransAlta states that in support of its proposal it is guided by the Commission's recent orders in Docket Nos. ER25-2653 and AD25-15, which concerned cost recovery for Constellation Energy Generation, LLC's Eddystone Units 3 and 4, which were similarly subject to an emergency order from DOE.[17] TransAlta states that in that proceeding, the Commission stated that "a cost allocation method can satisfy the cost causation principle if the Commission has 'an articulable and plausible reason to believe that the benefits are at least roughly commensurate with' the allocation of the costs."[18] TransAlta explains that the Commission further stated that an emergency order itself may form the basis for the allocation, finding that "it is just and reasonable for the cost allocation method to allocate costs in accordance with the scope of the emergency as

[14] *Id*. at 5 (citing 16 U.S.C. § 824a(c)(1)).

[15] *Id*.

[16] *Id*. at 6.

[17] *Id*. (citing *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,159, *order on reh'g*, 193 FERC ¶ 61,229 (2025)).

[18] *Id*. at 6-7 (citing *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,159 at P 33).

described by the Emergency Order."[19] TransAlta argues that the Emergency Orders directed TransAlta to make Centralia available to operate at the direction of the identified BA or RC, and forbade all other operation, and, as such, the proposed equal allocation method satisfies the cost causation principle and allocates the costs of making Centralia available to operate in a manner that is roughly commensurate with the benefits to the parties.[20]

10. TransAlta states that affected parties may argue for alternative approaches to cost allocation and that TransAlta is aware of recent precedent with respect to cost allocation related to FPA section 202(c) orders applicable to plants located within a regional transmission organization (RTO), in which the plant owner and RTO agreed on the need for an RTO tariff mechanism to collect such costs, and then the Commission addressed disputes about how costs would be allocated within the RTO.[21] TransAlta states that with respect to cost allocation, TransAlta's interest is in having the Commission ensure that there is a workable mechanism for TransAlta to fully recover its costs of complying with the Emergency Orders, consistent with the terms of FPA section 202(c), not in the particular details of any alternative cost allocation approach the Commission may choose to adopt.[22]

11. TransAlta requests acceptance of the TransAlta Centralia Generation LLC Unit 2 Cost-Based Tariff, which provides for recovery of costs of compliance with the Emergency Orders in two separate charges. TransAlta states that the first charge is a fixed charge, representing the unavoidable fixed costs TransAlta has incurred to ensure that Centralia is available to operate at the direction of the Allocated Parties for the period starting on December 16, 2025, and ending March 16, 2026. TransAlta asserts that these costs include general operating, maintenance, and administrative costs that do not vary with the operating level of Centralia. TransAlta states that the sum of these costs is $19,862,266.65. TransAlta states that the second is a variable charge, representing the incremental costs of operating Centralia in response to a dispatch or direction in accordance with the Emergency Orders.[23]

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[19] *Id*. at 7 (citing *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,159 at P 35).

[20] *Id.*

[21] *Id*. (citing *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,159 at PP 33-35; *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,192 at PP 30-34).

[22] *Id*. at 7-8.

[23] *Id*. at 8-9.

12. TransAlta states that it proposes to collect the fixed charge independently of actual operations, as TransAlta has been directed by the Emergency Orders to take measures to make Centralia available to operate, the costs of which are not dependent on MWh usage. TransAlta explains that, as Centralia was not directed to operate during the period of December 16, 2025, through March 16, 2026, a per MWh charge will not enable TransAlta to recover any of its fixed costs of complying with the Emergency Orders. Accordingly, TransAlta proposes to collect the fixed charge in the form of lump sum payments from Bonneville and CAISO for the period from December 16, 2025, to March 13, 2026, and from Gridforce and SPP for the period from March 14, 2026, through March 16, 2026. TransAlta states that its application is concerned solely with its own cost recovery and is not intended to prejudice or limit any subsequent filings that may or must be provided by Bonneville, CAISO, Gridforce, SPP, or any other person, for those entities to recoup costs allocated to them.[24]

13. TransAlta states that it will continue to incur costs to comply with any further FPA section 202(c) orders issued to it by DOE. TransAlta proposes to collect costs incurred for each subsequent 90-day period and to file updated tariff sheets with the Commission to reflect actual costs once they are available. Further, TransAlta avers that as Centralia was slated to retire as of December 31, 2025, its ability to remain available to operate throughout 2026 may require significant capital investment and maintenance work in the event DOE issues additional FPA section 202(c) orders applicable to Centralia Unit 2. TransAlta asserts that any capital costs that TransAlta must incur to comply with any future FPA section 202(c) order, should one be issued, will need to be fully recovered within the applicable 90-day order period to assure cost recovery as provided for in section 202(c). TransAlta states that it estimates future capital and maintenance costs in Q3 or Q4 of 2026 at $23,000,000 to repair and refurbish components of Centralia in connection with enabling it to remain capable of safe operation and otherwise available to operate, and that it may seek to recover these costs in a future tariff filing.[25]

III. Notice and Responsive Pleadings

14. Notice of TransAlta's filing was published in the *Federal Register*, 91 Fed. Reg. 24536 (May 6, 2026), with interventions and protests due on or before June 22, 2026.[26] Timely motions to intervene were filed by: Public Citizen, Inc.; SPP; Snohomish County Public Utility District No. 1; Gridforce; Public Power Council; Bonneville; CAISO; Northwest Requirements Utilities; Avista Corporation; Washington

[24] *Id*. at 11-12.

[25] *Id*. at 12-13.

[26] On May 27, 2026, an errata notice was issued to extend the comment due date to June 22, 2026.

Conservation Action; Tri-State Generation and Transmission Association, Inc. (Tri-State); NW Energy Coalition; the State of Washington and the Washington Utilities and Transportation Commission (Washington Entities); Sierra Club; the California Department of Water Resources State Water Project; and Northern California Power Agency. The California Public Utilities Commission filed a notice of intervention.

15. Comments and/or protests were filed by: Bonneville; SPP; Gridforce; CAISO; Tri-State; Washington Entities; and Northwest Requirements Utilities, Public Power Council, and Public Utility District No. 1 of Snohomish County, Washington (collectively, Joint Protesters. Gridforce filed an answer to Bonneville's comments. TransAlta submitted an answer to the protests and comments. Gridforce, CAISO, and Tri-State filed answers to TransAlta's answer.

A. Protests

1. Allocated Parties

16. Allocated Parties argue that the Commission should reject TransAlta's filing, as they have no relationship with Centralia, contractual or otherwise, that would support being allocated costs, and TransAlta's cost allocation proposal is unjust, unreasonable, and unduly discriminatory. Allocated Parties argue that TransAlta offers no sustainable legal or factual basis to impose costs on them or their ratepayers.[27]

17. Allocated Parties argue that TransAlta's proposal violates cost causation principles. Allocated Parties note that TransAlta attempts to rely on recent Commission orders accepting a proposal to allocate the costs of a generating facility subject to a separate DOE FPA section 202(c) order, but Allocated Parties assert that these orders do not support allocating costs to them. Allocated Parties assert that in those orders, the Commission determined that it is just and reasonable to allocate costs to load serving entities in PJM Interconnection, L.L.C.'s (PJM) region in accordance with the scope of the emergency as described by DOE's FPA section 202(c) order, which they contend was based on the overall resource adequacy need in the PJM footprint. Accordingly, Allocated Parties state, the Commission determined that these facts support a finding that the retention of the Eddystone units benefits the PJM region in general.[28]

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[27] CAISO Protest at 3-5; Gridforce Protest at 10-21; Gridforce Answer to TransAlta Answer at 3-4; SPP Protest at 9-14; Bonneville Protest at 3.

[28] CAISO Protest at 5-7; Gridforce Protest at 8-10; SPP Protest at 14-18; Bonneville Protest at 3 (citing *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,159 (2025); *Consumers Energy Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,158, *order on reh'g*, 193 FERC ¶ 61,228 (2025)).

18. Moreover, Allocated Parties assert that TransAlta has not demonstrated that its costs are just and reasonable, because TransAlta provides no work papers or documentary evidence supporting these costs. Allocated Parties explain that in some cases, such as estimated remediation costs, TransAlta has not yet incurred the costs and that, in other cases, such as recurring fixed costs, TransAlta has not demonstrated that it incurred the estimated costs during the prior period.[29]

19. CAISO and SPP argue that TransAlta's proposal violates the filed rate doctrine and the rule against retroactive ratemaking, which limit the ability of TransAlta to change its rates only prospectively.[30] CAISO and SPP argue that allocating costs to them in their role as RCs would be unjust and unreasonable.[31] CAISO and Bonneville argue that they were named in the Initial Emergency Order in error and, as a result, should not be allocated costs.[32]

20. Gridforce argues that TransAlta should have filed its cost recovery proposal under FPA section 205, which would have required the Commission to act on the proceeding within 60 days of the filing. Gridforce explains that TransAlta filed its application using type of filing code 75, which is reserved for compliance filings made in a new docket and does not trigger the 60-day action deadline, yet Centralia's application is not a compliance filing made in accordance with a Commission order. Gridforce asserts that TransAlta should instead have used a type of filing code that accurately reflected the nature of its submission—such as type of filing code 10, the code used by PJM in its own applications to establish cost allocation methods to effectuate FPA section 202(c) orders issued by the DOE. Nevertheless, Gridforce requests that the Commission issue a final order on the merits as expeditiously as practicable on a timeframe consistent with the statutory action date under FPA section 205.[33]

[29] CAISO Protest at 11-12; Gridforce Protest at 19-21; SPP Protest at 22-23; Bonneville Protest at 5.

[30] CAISO Protest at 11-12; CAISO Answer at 9-11; SPP Protest at 29-31.

[31] CAISO Protest at 4-5; SPP Protest at 9-14.

[32] CAISO Protest at 5; CAISO Answer at 4; Bonneville Protest at 3.

[33] GridForce Comments at 1-2.

2. Tri-State

21. Tri-State argues that TransAlta's proposed cost allocation method is inconsistent with cost causation principles.[34] Tri-State notes that TransAlta seeks to allocate its costs equally between the BAs and RCs authorized to dispatch the unit under the terms of the Emergency Orders. However, Tri-State argues that this chosen cost allocation does not properly consider the scope of the emergency area set forth in the Emergency Orders and therefore is not consistent with the requirement that "benefits are at least roughly commensurate with the allocation of the costs."[35] Tri-State argues that loads across the emergency area are the ultimate beneficiaries of DOE's directives, and therefore, the costs to comply with DOE's directives should be paid by the affected load or entities that serve such load.

22. Tri-State also argues that TransAlta's proposal to allocate all costs only to those entities that may direct dispatch of the unit is inconsistent with the Commission's prior precedent establishing just and reasonable cost allocation methods under FPA section 202(c)(1).[36] Furthermore, Tri-State argues that TransAlta's approach is not just and reasonable because the service territories of the controlling entities do not match the emergency area, which would lead to an over-allocation of costs to a subset of loads while allowing other loads in the emergency area to "free-ride." Tri-State argues that approval of this method would mean that only loads located within the boundary of entities that may dispatch the unit benefit, which would ignore the ability of neighboring balancing authorities to coordinate with the entities identified in the orders to request support due to continued availability of the unit and the broader system benefits of enhanced reliability.

23. Tri-State states that although it believes that the Commission must approve TransAlta's declarations establishing that it is entitled to recover the costs of making Centralia available, Tri-State requests that the Commission direct TransAlta to establish a cost allocation method that allocates costs to the entire emergency area identified in the Emergency Orders.[37] Tri-State also requests that, if the Commission accepts TransAlta's proposed cost allocation method without modification, the Commission confirm that its determination is limited to the specific facts of the proceeding and that it remains just and

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[34] Tri-State Protest at 2-3; Tri-State Answer at 2-3.

[35] Tri-State Protest at 5 (quoting *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,159 at P 33 (quoting *Ill. Com. Comm'n v. FERC*, 576 F.3d 470, 477 (7th Cir. 2009)).

[36] Tri-State Protest at 5-6; Tri-State Answer at 3-5.

[37] Tri-State Protest at 6-7.

reasonable for costs to be allocated across the full scope of the emergency area as identified in the Emergency Orders.[38]

3. Washington Entities

24. Washington Entities argue that because no temporary connections have been made, and no electricity has been generated, delivered, or transmitted, there is no jurisdictional service in this proceeding for which the Commission may set rates.[39] Washington Entities note that although the Commission has asserted jurisdiction over capacity transacted in organized wholesale markets pursuant to sections 205 and 206 of the FPA, that authority is not applicable here, as there is no organized wholesale market present and the Commission is acting under its more limited FPA section 202(c) authority. Washington Entities also argue that Centralia cannot be viewed as providing capacity for at least the 87 days under which the Emergency Orders listed Bonneville and CAISO as the entities responsible for dispatch as these entities are not in a position to direct dispatch of Centralia.[40]

25. In addition, Washington Entities argue that the Commission cannot force a business relationship between TransAlta and unwilling purchasers.[41] Washington Entities note that FPA section 202(c) confers the power to order facilities engaged in the generation or transmission of electricity to provide energy during an emergency but does not confer the authority to order an entity to purchase energy when they did not benefit from its use. Washington Entities notes that compelling the purchase of energy would raise serious questions under the Commerce Clause of the U.S. Constitution. Washington Entities further argue that while FPA section 202(c) allows the Commission to prescribe the terms of an existing arrangement, it does not allow the Commission to create a contractual relationship between parties where none existed before.[42]

26. Washington Entities argue that the Emergency Orders are invalid and, therefore, TransAlta cannot recover costs under FPA section 202(c).[43] Washington Entities state that the Emergency Orders do not demonstrate that there is a sudden, unforeseen, and

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[38] *Id*. at 7.

[39] Washington Entities Protest at 9.

[40] *Id*. at 9-11.

[41] *Id*. at 11.

[42] *Id*. at 11-12.

[43] *Id*. at 13.

imminent emergency, and instead rely on speculative future events and long-term resource adequacy concerns. Washington Entities note that it has sought judicial review of the Emergency Orders and recommends that the Commission stay adjudication of TransAlta's application until the legal validity of the Emergency Orders can be discerned.[44]

27. Finally, assuming the Commission allows TransAlta to recover costs in this proceeding, Washington Entities argue that the Commission should not accept TransAlta's proposed cost allocation method because it does not match costs with benefits.[45] Washington Entities note that TransAlta fails to explain how any of the named entities benefit from the Emergency Orders, and that requiring entities to pay costs for orders that actively harm them is inconsistent with the cost causation principle. Washington Entities also argue that the Commission should reject TransAlta's proposal to allocate 96% of the one-time fixed costs for complying with the DOE Emergency Orders to Bonneville and CAISO and that to the extent the costs are recoverable at all, they should be spread across relevant entities for the duration of all Emergency Orders.[46]

4. Joint Protesters

28. Joint Protesters argue that the Commission should dismiss TransAlta's application with respect to cost recovery from Bonneville.[47] Joint Protesters note that reference to Bonneville and CAISO in the Initial Emergency Order was in error, as the correct BA for Centralia was not Bonneville but Gridforce. Joint Protesters point out that TransAlta seems to acknowledge this fact in its application, and yet, continues to propose a cost allocation under which Bonneville and CAISO pay 50% of the alleged fixed costs to make Centralia available. Joint Protesters state that the Commission should only rely on the Amended Emergency Order for the purpose of evaluating the application. Joint Protesters further argue that there is no contractual relationship between Bonneville and TransAlta that warrants Bonneville paying for Centralia's costs.[48] Joint Protesters note that the record does not demonstrate that there is any contractual relationship between TransAlta and Bonneville for power purchases or services. Joint Protesters also argue that there is no interpretation of Bonneville tariff that would transform Bonneville's

[44] *Id*. at 14.

[45] *Id*. at 16-17.

[46] *Id*. at 18.

[47] Joint Protesters Protest at 2-3.

[48] *Id*. at 3-4.

provision of interconnection service or transmission service into a power or capacity purchase obligation under which Bonneville would be the customer.

29. Joint Protesters also argue that the Commission should dismiss TransAlta's application because it violates the filed rate doctrine and corollary rule against retroactive ratemaking. Joint Protesters argue that the Commission should reject TransAlta's proposal to allocate the fixed costs of Centralia as unjust and unreasonable. Joint Protesters state that TransAlta's proposed cost allocation is inconsistent with the cost causation principle. Joint Protesters also argue that the Commission should reject TransAlta's proposed tariff as unjust and unreasonable. Joint Protesters state that the proposed tariff contains unverifiable fixed and variable costs and that TransAlta offers no quantitative data or evidence supporting these costs. Joint Protesters argue that, as a result, TransAlta has not met its burden to demonstrate that its proposed costs are just and reasonable. Finally, Joint Protesters request that the Commission not allow cost recovery while the validity of the Emergency Orders are subject to pending challenges.[49]

B. Answers

1. TransAlta

30. TransAlta states that the Emergency Orders required Centralia Unit 2 to be made "available to operate" exclusively at the direction of the specific entities named in the orders, and that because no entity directed the unit to operate during that period, the costs at issue arise solely from maintaining the unit's availability. TransAlta states that the Commission's role in this proceeding is limited to determining the just and reasonable costs of compliance, identifying the parties responsible for paying those costs, and determining an appropriate cost allocation method. TransAlta asserts that its application provides a straightforward path by presenting the incurred costs, identifying the entities named in the Emergency Orders as the exclusive beneficiaries of Centralia's mandated availability, and proposing a per-day allocation among those entities consistent with cost causation principles. TransAlta emphasizes that FPA section 202(c) guarantees its right to recover compliance costs, that no party's refusal to bear responsibility negates this right, and that the Commission must therefore resolve the compensation issue by assigning the costs to the entities DOE empowered to direct Centralia's operation.[50]

31. TransAlta asserts that the Commission's role under FPA section 202(c) is narrowly confined to determining the just and reasonable costs TransAlta is entitled to recover, identifying which parties must bear those costs, and deciding the appropriate allocation. TransAlta argues that many of the protestors' claims challenge issues that fall

[49] *Id*. at 5-11.

[50] TransAlta Answer at 3-5.

outside the Commission's jurisdiction and should have been raised before DOE through rehearing or in the courts. TransAlta notes that while some parties pursued those remedies, CAISO, Bonneville, SPP, and Gridforce did not and cannot now avoid cost responsibility by attacking DOE's determinations in this forum. TransAlta emphasizes that it was required to comply immediately with the Emergency Orders, incurred real costs in doing so, and seeks only recovery of its actual compliance costs.[51]

32. TransAlta states that its application reflects the actual costs incurred to comply with the Emergency Orders, and it emphasizes that Commission precedent requires full cost recovery for generators compelled to remain available for reliability, similar to Reliability Must Run situations. TransAlta argues that protestors' demands for additional cost details largely concern future outage costs included for informational purposes for which TransAlta is not currently seeking recovery and reiterates that it is not seeking approval of any future outage-related capital or maintenance expenses at this time. TransAlta, in response to objections regarding the cost of coal inventory, explains that fuel had to be maintained on site to satisfy the Emergency Orders' requirement that Centralia be "available to operate," that Washington State law prevents burning unused coal, and that no buyer has been found for the remaining inventory.[52]

33. TransAlta states that its application satisfies the Commission's cost causation standard because the Emergency Orders expressly named only CAISO, Bonneville, Gridforce, and SPP as having exclusive authority to direct Centralia Unit 2's operation during the 90-day emergency period. TransAlta states that these named entities were the sole beneficiaries of Centralia's availability, as only they possessed the DOE-conferred ability to request operation, and any broader regional benefits existed only downstream of that control. TransAlta argues that cost causation arises from their authority to direct Centralia, not from actual energy deliveries. TransAlta further rejects Bonneville's attempt to limit its role to transmission service, noting that the Emergency Orders explicitly authorized Bonneville to direct operation, and argues that Bonneville's reliance on DOE's rehearing denial is misplaced. TransAlta asserts that the named entities' unused authority does not negate TransAlta's obligation to maintain availability or the costs incurred in doing so, and that CAISO, Bonneville, Gridforce, and SPP are properly treated as "parties affected" under FPA section 202(c) and must bear the associated compliance costs.[53]

34. TransAlta states that protestors' claims regarding the filed rate doctrine and the rule against retroactive ratemaking are false because cost recovery filings under FPA

[51] *Id*. at 5-7.

[52] *Id*. at 7-9.

[53] *Id*. at 9-11.

section 202(c) are not FPA section 205 rate filings and therefore cannot be evaluated under section 205 standards. TransAlta states that FPA section 202(c) is an emergency, backward-looking authority that empowers DOE to issue immediate directives and requires the Commission to provide "compensation" and "reimbursement" for costs already incurred in complying with such orders. TransAlta explains that FPA section 202(c) cost recovery will always concern a prior period, and thus the rule against retroactive ratemaking does not apply. TransAlta maintains that protestors misread both doctrines by attempting to import FPA section 205 principles wholesale into the FPA section 202(c) context. TransAlta further asserts that the Commission's responsibility is to make TransAlta whole for the mandatory service that DOE compelled it to provide, not to apply doctrines designed for prospective ratemaking under different statutory provisions.[54]

35. TransAlta states that it acknowledges Tri-State's proposed alternative cost -allocation approach, noting that while such methods have precedent in RTO settings, TransAlta's circumstances differ because it is a merchant generator operating in a bilateral market outside any organized RTO framework. TransAlta reiterates that its primary interest is ensuring a workable mechanism for full cost recovery under FPA section 202(c), regardless of the specific allocation method ultimately chosen by the Commission. TransAlta explains that unlike plants located within RTOs, no regional tariff or established cost allocation structure exists for distributing costs across the WECC Northwest assessment area identified in the Emergency Orders, and TransAlta itself lacks the necessary regional load data to implement such a system.[55]

36. TransAlta states it does not agree with Joint Protesters' suggestion to retroactively substitute Gridforce and SPP for CAISO and Bonneville throughout the entire 90-day period. TransAlta explains that its application properly seeks cost recovery only from the entities that DOE explicitly empowered to direct Centralia's operation during each day of the Emergency Orders.[56]

37. TransAlta further opposes Washington Entities' request to delay or deny compensation, arguing that such a stay would improperly leave TransAlta bearing substantial costs indefinitely and would undermine FPA section 202(c)'s purpose of ensuring timely reimbursement to complying entities. TransAlta also disputes Washington Entities' criticism regarding the absence of a "willing customer," explaining that serving any customer other than those named in the Emergency Orders would violate

[54] *Id*. at 12-13.

[55] *Id*. at 13-14.

[56] *Id*. at 14-15.

the orders themselves and that being "available to operate" constituted the compelled service for which compensation is required.[57]

38. Finally, TransAlta dismisses protestors' claim of delay, noting that FPA section 202(c) imposes no filing deadline, that cost recovery would have been retroactive regardless of timing, and that no entity is harmed by the timeline other than TransAlta itself.[58]

2. CAISO

39. CAISO asserts that TransAlta's answer fails to identify a sustainable reason to allocate costs to CAISO, as TransAlta continues to argue that parties named in the Emergency Orders should pay for its costs. CAISO asserts that there is no evidence that Centralia is capable of generating electricity, transmitting electricity, or delivering electricity, and Centralia's tariff appears to be drafted in a manner that seeks approval to foreclose its obligation to ever do so. CAISO argues that if Centralia cannot, and will not, produce electricity, then the recovery of any costs incurred by Centralia are not a matter for the Commission to determine because no jurisdictional sale of power can occur and the record does not establish that Centralia provided, or is capable of providing, service subject to the Commission's rate-making jurisdiction.[59]

40. CAISO argues that TransAlta did not take the necessary measures to make Centralia available to operate at the direction of CAISO and therefore did not comply with the Emergency Orders, making it unjust and unreasonable to assign compliance costs to CAISO. CAISO explains that Centralia was not part of RC West and did not otherwise document a commitment to comply with RC-issued operating instructions. CAISO explains that entities seeking to take RC services from CAISO must complete a required onboarding process. CAISO argues that TransAlta took no steps to secure RC West as its RC even though it argues that CAISO as RC West had authority to direct it to operate. CAISO asserts that because the Initial Emergency Order, directed TransAlta to "take all measures to ensure that Centralia [] is available to operate at the direction of… [CAISO]," bringing Centralia Unit 2 into CAISO's RC Area was a necessary measure. CAISO asserts that as a result, TransAlta did not comply with the Initial Emergency

[57] *Id*. at 15-16.

[58] *Id*. at 17.

[59] CAISO Answer at 3-8 (citing Gridforce Protest at 17-18).

Order and the Commission should reject TransAlta's application seeking cost recovery from CAISO or CAISO ratepayers.[60]

3. Tri-State

41. Tri-State argues that, contrary to protestors' arguments that TransAlta needs to demonstrate that Centralia's continued operations benefits the parties, Commission precedent has found that DOE's FPA section 202(c) orders justify cost allocation within the designated emergency area, the party seeking cost allocation need not make further demonstrations of the beneficiaries or benefits provided, and additional substantiation from the Commission is not required.[61]

42. Tri-State argues that the filed rate doctrine and rule against retroactive ratemaking are inapplicable to TransAlta's cost allocation and recovery under FPA section 202(c), as section 202(c) contains no prior notice requirement, does not require filing of rate schedules, and does not mandate prospective fixing of charges. Tri-State explains that both the plain text of FPA section 202(c) and Commission precedent confirm that appropriate compensation may be determined and recovered after the DOE FPA section 202(c) order's effective date, with the DOE order itself providing sufficient notice to customers in the emergency area.[62]

43. Tri-State argues that generator owners subject to DOE FPA section 202(c) orders are entitled to cost recovery while those orders are pending judicial review, explaining that the Commission has consistently rejected this argument in prior proceedings initiated under FPA section 202(c), finding that prompt action "can help to mitigate potential regulatory uncertainty."[63] Tri-State contends that holding this proceeding in abeyance would also present takings concerns under the Fifth Amendment of the U.S. Constitution.[64]

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[60] *Id*. at 11-21.

[61] Tri-State Answer at 5 (citing *Consumers Energy Co.*, 193 FERC ¶ 61,228, at PP 28-32 (2025); *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 196 FERC ¶ 61,095, at PP 35, 42 (2026)).

[62] *Id*. at 7-10.

[63] *Id*. at 10 (citing *N. Ind. Pub. Serv. Co. LLC v. Midcontinent Indep. Sys. Operator, Inc.*, 194 FERC ¶ 61,215, at P 39, *order on reh'g*, 196 FERC ¶ 61,095 at P 46).

[64] *Id*. (citing U.S. CONST. amend. V; *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 308 (1989)).

44. Tri-State asserts that all of TransAlta's costs of operating Centralia associated with the Emergency Orders are recoverable. Tri-State explains that in approving cost recovery mechanisms in proceedings involving generators subject to FPA section 202(c) orders, the Commission has recognized that costs of continued operation to address resource adequacy concerns may include the unrecovered fixed costs to maintain and operate the generating unit for its mandated availability.[65] Tri-State argues that the Commission has previously rejected arguments that TransAlta's market-based rate tariff governs any energy sales during the emergency period rather than a new cost allocation mechanism.[66] Tri-State argues that TransAlta provides adequate support for the costs incurred and notes that although FPA section 202(c) compensation or reimbursement must also be just and reasonable, the standard for supporting cost recovery under section 202(c) is not defined in the regulations. Tri-State asserts that the support requirements should not be identical to the requirements under FPA section 205 where utilities voluntarily incur costs through deliberate long-term operational, planning, and resource adequacy decisions.[67]

IV. Discussion

A. Procedural Matters

45. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2025), the notice of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

46. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2025), prohibits answers to protests or answers unless otherwise ordered by the decisional authority. We accept the answers filed by TransAlta, Gridforce, CAISO, and Tri-State because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

47. We find that TransAlta's proposal has not been shown to be just and reasonable and may be unduly discriminatory or preferential. Accordingly, we reject TransAlta's filing without prejudice. As discussed below, while we affirm that TransAlta is entitled

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[65] *Id*. at 11 (citing *Midcontinent Indep. Sys. Operator, Inc.,* 194 FERC ¶ 61,155, at P 47 (2026)).

[66] *Id*. at 13 (citing *Ind. Pub. Serv. Co. LLC v. Midcontinent Indep. Sys. Operator, Inc.*, 194 FERC ¶ 61,215 at P 40, *order on reh'g*, 196 FERC ¶ 61,095, at P 37; *PJM Interconnection L.L.C.*, 192 FERC ¶ 61,159 at P 34).

[67] *Id*. at 15-16.

to recover the costs it incurred to keep Centralia operational in compliance with DOE's directives in the Emergency Orders, we find that TransAlta's cost allocation proposal is not just and reasonable because it fails to allocate such costs based on the geographic scope of the emergency described in the Emergency Orders.

48. The DOE Organization Act gives the Secretary of Energy the authority pursuant to section 202(c) of the FPA that had been previously granted to the Federal Power Commission.[68] Responsibilities pursuant to section 202(c) include taking action to address an energy emergency:

> (c) Temporary connection and exchange of facilities during emergency (1) … [W]henever the Commission determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes, the Commission shall have authority, either upon its own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.[69]

Section 202(c)(1) also provides for affected parties to agree on terms, and if that fails, then, after a hearing, terms may be prescribed as follows:

> If the parties affected by such order fail to agree upon the terms of any arrangement between them in carrying out such order, the Commission, after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.[70]

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[68] 42 U.S.C. § 7151.

[69] 16 U.S.C. § 824a(c)(1). Section 202(c)(4)(A) further provides that a Commission order can be renewed, for another 90 days each time, as necessary to meet the emergency and serve the public interest. 16 U.S.C. § 824a(c)(4)(A).

[70] 16 U.S.C. § 824a(c)(1).

49. Section 205.376 of DOE's regulations provides that DOE will refer compensation issues to this Commission where parties cannot agree on terms.[71]

50. The Commission's rate analysis applies the cost causation principle, which requires that "all approved rates reflect to some degree the costs actually caused by the customer who must pay them."[72] We find that this is the relevant legal standard for evaluating whether the proposed method to allocate the costs of keeping Centralia in operation, in response to the Emergency Orders, is just and reasonable. Courts have explained that, to "the extent that a utility benefits from the costs of new facilities, it may be said to have 'caused' a part of those costs to be incurred, as without the expectation of its contributions the facilities might not have been built, or might have been delayed."[73] As a result, a cost allocation method can satisfy the cost causation principle if the Commission "has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with" the allocation of the costs.[74]

51. In applying the cost causation principle here, we find that it is just and reasonable to allocate the costs of keeping Centralia in operation in accordance with the geographic scope of the emergency as described by the Emergency Orders.[75] The Emergency Orders rest on NERC's 2025-2026 Winter Reliability Assessment pertaining to the WECC Northwest assessment area, including Montana, Oregon, Washington, and parts of northern California and northern Idaho. Specifically, the Emergency Orders describe an "elevated risk during periods of extreme weather" in this area, referring to NERC's 2025-2026 Winter Reliability Assessment.[76] Consistent with Commission precedent that

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[71] 10 C.F.R. § 205.376 (2025). We recognize that the United States Court of Appeals for the District of Columbia Circuit recently vacated a DOE FPA section 202(c) emergency order regarding the continued operation of a coal plant owned by Consumers Energy Company. *See People of the State of Michigan v U.S. Dep't of Energy*, Nos. 25-1159, 2026 WL 2671756 (D.C. Cir. Sept. 11, 2026). The 202(c) orders at issue in this proceeding are on appeal before the United States Court of Appeals for the Ninth Circuit and have not been vacated.

[72] *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992).

[73] *Ill. Com. Comm'n v. FERC*, 576 F.3d 470, 476 (7th Cir. 2009).

[74] *Id.* at 477.

[75] *PJM Interconnection, L.L.C.,* 192 FERC ¶ 61,159 at P 35, *order on reh'g*, 193 FERC ¶ 61,229 at P 25.

[76] Initial Emergency Order at 1.

assigns costs incurred to comply with FPA section 202(c) designations based on the geographic scope of the stated emergency,[77] we find that these statements support allocating costs to retain Centralia to all load in the WECC Northwest assessment area.

52. By contrast, TransAlta proposes to allocate the costs of keeping Centralia in operation to the BAs and RCs named in the Emergency Orders. We find that these entities' service areas do not align with the geographic scope of the emergency identified in the Emergency Orders as described above.

53. If TransAlta chooses to file another cost allocation and cost recovery proposal, it should identify the load serving entities (LSE) within the geographic scope of the emergency described in the Emergency Orders and propose a mechanism that allocates the costs of keeping Centralia in operation pursuant to those orders to such LSEs. We encourage LSEs within the WECC Northwest assessment area to intervene in any such future proceeding to ensure that their interests are represented.

54. With regard to protesters' arguments that the instant filing violates the filed rate doctrine, we note that under FPA section 202(c), unlike FPA section 205, rates do not need to be filed in advance, as section 202(c) contemplates that after an emergency section 202(c) order "takes effect," the Commission may issue "supplemental" orders regarding "compensation or reimbursement."[78] Therefore, under FPA section 202(c), the Commission need only find the terms of compensation or reimbursement to be just and reasonable "after hearing held either before or after [a DOE Order declaring an emergency] takes effect."[79]

55. With regard to arguments that TransAlta is not entitled to cost recovery because Centralia has not operated, we find that the Emergency Orders' statements that Centralia "shall not be considered a capacity resource" do not preclude the Commission from approving compensation for the costs that TransAlta incurred to keep Centralia operational.[80] Regardless of whether Centralia is treated as a capacity resource, the Emergency Orders cited resource adequacy concerns and the "shortage of facilities" for

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[77] *See, e.g.*, *Consumers Energy Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,158 at P 40 (accepting proposal to allocate costs to specific resource zones based on the geographic scope of DOE's stated emergency); *N. Ind. Pub. Serv. Co. LLC v. Midcontinent Indep. Sys. Operator, Inc.*, 194 FERC ¶ 61,215 at P 37 (same).

[78] 16 U.S.C. § 824a(c).

[79] *Id.*

[80] Initial Emergency Order at ordering para. H.

the WECC Northwest assessment area as the driver of the need for Centralia's continued operation.[81]

56. Despite Gridforce's assertion that TransAlta should have filed for cost recovery using eTariff filing code 10 instead of 75, we find that while TransAlta could have submitted the filing using a normal-type filing code,[82] it instead chose a compliance filing code without a statutory action date, and Gridforce provides no reason for us to reject the filing on this basis.

57. Because we are rejecting TransAlta's proposed cost-based tariff, we need not address protestors' arguments as to whether TransAlta provided sufficient cost support. Moreover, because we are rejecting the instant filing on the basis that the proposed cost allocation has not been shown to be just and reasonable, we need not address whether the costs TransAlta is proposing to recover are just and reasonable. Additionally, we find that protestors' arguments about cost recovery for future periods are outside the scope of this proceeding.

The Commission orders:

TransAlta's filing is hereby rejected, as discussed in the body of this order.

By the Commission.

(S E A L)

Carlos D. Clay,
Deputy Secretary.

[81] *Id.*

[82] Because TransAlta is registered in the M program rather than the E Program, a normal Type of Filing Code for TransAlta would be code 30.

EXHIBIT 147

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY
Southwest Region Office
PO Box 47775, Olympia, WA 98504-7775 • 360-407-6300

STATE ENVIRONMENTAL POLICY ACT

MITIGATED DETERMINATION OF NONSIGNIFICANCE

Date of Issuance: July 31, 2026

Lead Agency: Department of Ecology, Southwest Region Office

Agency Contact: Bobbak Talebi, bobbak.talebi461@ecy.wa.gov, 360-789-9500

Description of proposal:
The Applicant proposes to modify its existing boiler, known as "Unit 2," at the TransAlta Centralia Steam Plant (Plant), which ceased using coal as a fuel source at the end of December 2025 and will generate electricity from natural gas after completion of the Project. To supply fuel, the Applicant will construct and maintain a new 1,500-foot, 12-inch diameter natural gas lateral pipeline located in unincorporated Lewis County. The Project is proposed within an approximately 14-acre Project boundary on private land owned by the Applicant. Once converted, Unit 2 will burn natural gas to generate steam and convert that steam to electrical energy for use by the customer, Puget Sound Energy.

Coal firing equipment will be decommissioned in place, unless the conversion requires its removal to allow for modifications. The existing precipitators and flue gas desulphurization equipment will no longer be effective or required and will be bypassed. Unit 2 is expected to operate at a maximum of 723 net megawatts (MW). The Applicant expects to reduce the current minimum stable generation level for Unit 2 from 300 net MW to 190 net MW or lower as determined feasible by the Applicant.

The Applicant's Customer, Puget Sound Energy, is developing plans to address near-term energy capacity and supplies. TransAlta's Unit 2 is an appropriate option to meet this need because the Applicant can repurpose existing infrastructure at the Plant with minimal disturbance, given the existing facility's operating footprint and historic for generation of electricity.

Location of proposal:
The Project boundary is located in north central Lewis County (Figure 1), northeast of the City of Centralia and south of the Town of Bucoda and consists of approximately 14 acres within six tax parcels. The Project boundary is located approximately 6 miles northeast of Interstate 5 and is roughly bounded by State Route 507 on the west side, by Highway 26 on the north and northeast sides, and by Big Hanaford Road on the south side.

The Project boundary is focused on the six tax parcels of the Project boundary, primarily within the existing power plant footprint, including 023340005002, 023340005001, 023355002002 023340004000, 023355001006 and 023355001007.

Applicant/Proponent: TransAlta Centralia Generation LLC

Determination: Ecology has determined that this proposal will not have a probable significant adverse impact on the environment. Pursuant to WAC 197-11-350, the proposal has been clarified, changed, and conditioned to include necessary mitigation measures to avoid, minimize, and/or compensate for probable significant impacts. An environmental impact statement (EIS) is not required under RCW 43.21C.030(2)(c).

We have reviewed the revised Environmental Checklist and appendix to make this determination. Information is available on the SEPA Register at:
https://apps.ecology.wa.gov/separ/Main/SEPA/Record.aspx?SEPANumber=202603172

Ecology is issuing a **Mitigated Determination of Nonsignificance (MDNS)** for this proposal. This determination is based on the Environmental Checklist and Appendix, as well as the following specific findings and conclusions:

General:

- The Project is proposed within an approximately 14-acre Project boundary on private land owned by the Applicant.
- In 2011, TransAlta entered into a Memorandum of Agreement with the State of Washington pursuant to RCW 80.80.100, which established a timeline and requirements for the Plant to cease combustion of coal for electricity. The Project would help implement that Memorandum of Agreement by switching from combustion of coal to combustion of natural gas to produce electricity.
- Unit 2 is expected to operate at a maximum of 723 net megawatts (MW). The Applicant expects to reduce the current minimum stable generation level for Unit 2 from 300 net MW to 190 net MW or lower as determined feasible by the Applicant.
- The Project is **not** designed or intended to operate continuously or at a high capacity or baseload factor. The Project is expected to operate at a capacity factor of less than 20 percent of all hours on an annual basis over the life of the Project. In any event, the facility will **not** operate for more than 59 percent of all hours on an annual basis over the life of the Project.
- TransAlta will design, construct, and operate the Project in accordance with all applicable local, state, and federal laws and regulations.
- The Applicant is also subject to the Model Toxics Control Act and executed an Agreed Order with Ecology to govern the cleanup of contamination from previous operations in air, soil, groundwater, and sediment at the facility.

Air:

- Operational emissions are anticipated to be below the 2022-2023 baseline emissions except for volatile organic chemicals (VOCs) and lead. A Prevention of Significant Deterioration (PSD) permit will be required to address the increase in VOCs.
- The largest source of GHG emissions is expected to be from both the embodied and energy-related emissions from the operation of Unit 2. This includes emissions from combustion of natural gas at the Plant and carbon emissions resulting from procuring and transporting natural gas used at the Plant.
- The Applicant's analysis indicates that Unit 2 operating at 59 percent operational capacity, combusting 100 percent natural gas would generate 2,079,020 metric tons annually of carbon dioxide equivalent ($MTCO_{2e}$). At 20% operational capacity, the estimated emissions would be 718,068 $MTCO_{2e.}$ Based on an assumed Unit 2 life of 18 years, the estimated lifespan, maximum total emissions, including the embodied emissions, for the Project would be approximately 42,779,441, MTCO2e.

Environmental Health:

- The Project boundary has contaminants of concern in soils consisting of heavy metals, (arsenic, barium, cadmium, copper, selenium and zinc) confirmed above Model Toxic Controls Act (MTCA) cleanup levels. TransAlta has initiated cleanup planning near Unit 2 and the existing cooling tower within the Project boundary pursuant to an Agreed Order with Ecology executed under MTCA.

Ecology has identified the following conditions and mitigation measures:

- TransAlta must obtain all required regulatory permits and approvals for construction and operation of the Project and will comply with the terms and permit conditions of those approvals. Required permits include:
    - National Pollutant Discharge Elimination System Permit (NPDES) for stormwater during construction (Ecology).
    - Renewal and update of the existing industrial NPDES permit (Ecology).
    - Prevention of Significant Deterioration permit for volatile organic compounds (Ecology).
    - Air Discharge Permit (Southwest Clean Air Agency)
    - Building, grading and other local agency permits (Lewis County).

- The Project's greenhouse gas emissions will be subject to the annually reducing state-wide cap on greenhouse gas emissions under the Climate Commitment Act, and TransAlta will be required to acquire allowances or other compliance instruments for every ton of greenhouse gases it emits from on-site combustion per WAC 173-441.

  The State of Washington has established a comprehensive framework for managing and reducing GHG emissions from large sources through the Cap and Invest Program under the Climate Commitment Act, which applies to facilities like the Project with annual emissions that equal or exceed 25,000 MTCO2e. Revenue from the sale of allowances is invested by the state into projects to further reduce state-wide emissions, and to

mitigate and adapt to the effects of climate change. While Cap and Invest program requirements under the CCA help address and mitigate greenhouse gas emissions, the CCA is primarily focused on achieving the statewide decarbonization requirements in statute and the program is not designed to directly or fully mitigate the environmental impact of greenhouse gas emissions from any individual facility or project.

- In addition to the CCA-requirements, Ecology and TransAlta have come to agreement that a community clean energy grant program will be established to further address greenhouse gas emissions. Total program contributions will be based on actual plant operation capacity per year.

- The community clean energy grant program will be based on the grant program that was developed as part of the 2011 Memorandum of Agreement (MOA). The program will be modified to support weatherization and energy technologies in Lewis and Thurston counties. Conditions of the grant program will be established in a new MOA between TransAlta and Ecology after the comment period ends.

- Key components of the grant program include:
    - Grants will support eligible clean energy projects and fund weatherization for homes to increase energy efficiency in Lewis and Thurston County.
    - Grants will be open to local agencies, Tribes and 501(c)3 organizations
    - Annual funding for grants will be based on actual plant operations from the previous year, with a base amount per year assuming 20% capacity operations.
    - TransAlta has committed to funding a minimum of $7.8 million and up to a maximum of $21million over the life of the project.
    - Grant selections will be made annually by a board that consists of representatives from Ecology, TransAlta and other organizations and local agencies.
    - The grant program will begin when the facility begins natural gas operations of Unit 2 and end when the plant closes in 2044.

The comment period for this MDNS will close on August 31, 2026. All comments received **by 11:59 p.m. on that date** will be considered. Mitigation will be finalized after the comment period.

Please provide written comments at the following link:
https://ecology.commentinput.com/?id=UedgKGQbi

For more information, visit Ecology's website at ecology.wa.gov/transalta.

If you have questions about the draft MDNS, Meg Bommarito at meg.bommarito@ecy.wa.gov or 425-681-6236.

Responsible Official:

Bobbak Talebi, Southwest Region Director
Department of Ecology, Southwest Region Office

300 Desmond Dr.
PO Box 47775
Lacey, WA 98504-7775
360-789-9500

Signature_____ Date 7/31/2026

UNITED STATES OF AMERICA
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order TransAlta Centralia Generation	Order No. 202-26-44

DECLARATION OF BOBBAK TALEBI
IN SUPPORT OF
MOTION TO INTERVENE, REQUEST FOR REHEARING,
AND MOTION TO STAY BY STATE OF WASHINGTON

I, Bobbak Talebi, declare as follows:

1. I am over 21 years of age and am competent to testify herein. The facts set forth in this declaration are from my personal knowledge.

2. I am employed by the Washington State Department of Ecology (Ecology) as the Southwest Region Director. I am the State Environmental Policy Act (SEPA) Responsible Official for Ecology in the Southwest Region, and I oversee the regulatory and permitting issues related to the TransAlta natural gas conversion project (Project), and I am therefore knowledgeable about matters related to this Project.

3. Part of my work related to the Project involves development of a Mitigated Determination of Non-Significance (MDNS) under the SEPA and development of a Prevention of Significant Deterioration (PSD) permit. Ecology must issue the MDNS and TransAlta must obtain the PSD permit, along with other local and state approvals, before TransAlta can begin the demolition and construction activities that are required to implement the Project.

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
360-586-6770

4. Ecology held a combined public comment period for the MDNS and PSD permit from July 31, 2026 to September 15, 2026. Ecology also held a public hearing to consider the MDNS and PSD permit on September 14, 2026. During the public comment period and hearing, Ecology received a total of about 65 public comments.

5. Ecology will review the public comments and develop comment response documents during October and November 2026. If Ecology determines that edits to the MDNS or PSD permit are required, it will likely make those edits during October and November 2026.

6. Ecology is required to make a decision on the PSD permit by August 2027 but expects to issue a decision prior to that deadline. If Ecology does not make changes to the MDNS, the version issued on July 31, 2026, will become final. If Ecology does make changes, it would likely issue a final version of the MDNS in late 2027.

I declare under penalty of perjury of the laws of the state of Washington that the foregoing is true and correct.

DATED this _6th_ day of October 2026, in Olympia, Washington.



BOBBAK TALEBI
Department of Ecology

ATTORNEY GENERAL OF WASHINGTON
Ecology Division
PO Box 40117
Olympia, WA 98504-0117
360-586-6770

EXHIBIT 149

United States Court of Appeals

FOR THE DISTRICT OF COLUMBIA CIRCUIT

Argued May 15, 2026 Decided September 11, 2026

No. 25-1159

PEOPLE OF THE STATE OF MICHIGAN,
PETITIONER

v.

UNITED STATES DEPARTMENT OF ENERGY AND CHRISTOPHER A. WRIGHT, SECRETARY, UNITED STATES DEPARTMENT OF ENERGY,
RESPONDENTS

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC. AND CONSUMERS ENERGY COMPANY,
INTERVENORS

Consolidated with 25-1160, 25-1162

On Petitions for Review of a Final Order
of the Department of Energy

Lucas Wollenzien, Assistant Attorney General, Office of the Attorney General for the State of Michigan, argued the cause for petitioners States of Illinois, Michigan, and Minnesota. With him on the briefs were *Dana Nessel*, Attorney

General, *Michael E. Moody*, Assistant Attorney General, *Christopher Bzdok*, Special Assistant Attorney General, *Peter Surdo*, Special Assistant Attorney General, Office of the Attorney General for the State of Minnesota, and *Jason E. James*, Assistant Attorney General, Office of the Attorney General for the State of Illinois.

Benjamin P. Chagnon argued the cause for the Public Interest Organization petitioners. With him on the briefs were *Jennifer J. Yun*, *Michael Lenoff*, *Gregory E. Wannier*, *Sanjay Narayan*, *Elena Saxonhouse*, *Caroline Reiser*, *Gavin G. McCabe*, *Simi Bhat*, *Lauren Piette*, *Sameer H. Doshi*, *Christine A. Powell*, *Howard Learner*, *Danielle Fidler*, *Francis W. Sturges Jr.*, *Veronica Saltzman*, and *Tomas Carbonell*. *Michael C. Soules* and *Ada Statler* entered appearances.

Jennifer Danis was on the brief for amicus curiae Institute for Policy Integrity at New York University School of Law in support of petitioners.

Jonas Monast, *James P. Duffy*, *Alexandra L. St. Romain*, and *Susannah Landes Weaver* were on the brief for amici curiae Energy Law Scholars in support of petitioners.

Nicholas M. Gladd, *John B. Kenney*, and *Zachary Norris* were on the brief for amici curiae The Niskanen Center, et al., in support of petitioners.

Robert N. Stander, Deputy Assistant Attorney General, U.S. Department of Justice, argued the cause for respondents. With him on the brief were *Adam R. Gustafson*, Principal Deputy Assistant Attorney General, *Robert J. Lundman*, *Kyle Glynn*, and *Rebecca Jaffe*, Attorneys, and *Jonathan Brightbill*, General Counsel, United States Department of Energy.

Zachary C. Schauf argued the cause and filed the brief for respondent-intervenor Consumers Energy Company. With him on the brief was *Juliana Brint.* *Arjun R. Ramamurti* entered an appearance.

Adam S. Carlesco, *Daniel C.W. Narvey*, and *John Liskey* were on the brief for amici curiae Citizens Action Coalition of Indiana, et al., in support of respondent.

Before: SRINIVASAN, *Chief Judge*, PILLARD and WILKINS, *Circuit Judges*.

Opinion for the Court filed by *Circuit Judge* PILLARD.

PILLARD, *Circuit Judge*: Consumers Energy Company is a private business that owns and operates the J.H. Campbell Generating Plant, an aging coal-fired power plant in Michigan that was scheduled to shut down last year. The Company worked for several years to develop plans and secure regulatory approval to retire the old Campbell plant and replace it with a mix of expanded and new electricity-generation sources. Consumers Energy coordinated its planning with Michigan regulators and the Midwest Independent System Operator (MISO)—the 15-state regional transmission organization in which Michigan and Consumers Energy participate. The Company's closure-and-replacement proposal received comprehensive scrutiny from the public, private industry, and expert regulators. Finding that Consumers Energy's substitute sources would meet applicable reliability criteria, provide less polluting electricity at lower prices, and more than offset generation lost when the old plant closed, the Michigan Public Service Commission and MISO expressly approved the plan.

Shortly before Campbell's scheduled retirement, the Department of Energy (DOE or Department) unilaterally

commanded the unit's continued operation. The Department invoked a rarely used, short-term, federal emergency authority conferred in section 202(c) of the Federal Power Act to order the Campbell coal unit to stay open. Michigan petitioned for review of DOE's order. Illinois and Minnesota also petitioned, as did a group of environmental organizations, including the Sierra Club, Natural Resources Defense Council, Michigan Environmental Council, Environmental Defense Fund, Environmental Law and Policy Center, Vote Solar, the Ecology Center, Urban Core Collective, and the Union of Concerned Scientists. Consumers Energy intervened to "protect[] the company's right to recover the costs associated with DOE's order" from ratepayers, which is at issue in separate proceedings regarding recovery and allocation of costs currently pending before FERC. Resp.-Interv. Br. iv, 7.

We evaluate Petitioners' challenge to DOE's interpretation of its emergency power under section 202(c) by reference to statutory text and structure. And we deploy those interpretive tools against the backdrop of states' exclusive regulatory power over the generation of electricity.

The plain meaning of the text limits section 202(c) emergency authority to address an identified risk of a substantial energy supply shortfall that calls for immediate action. Section 202(c) gives DOE limited authority to sidestep states' jurisdiction over electricity generation to briefly compel generation or interconnection in times of war or other "emergency" situations. By its terms, section 202(c) allows DOE to command certain action "[d]uring the continuance of any war in which the United States is engaged," or when the Secretary determines that "an emergency exists" due to "a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for

generating facilities, or other causes . . . ." 16 U.S.C. § 824a(c)(1).

The structure of the Federal Power Act and the history of the respective regulatory roles of federal and state governments show that Congress intended to further limit DOE's section 202(c) emergency power to circumstances necessitating action by DOE in particular, as opposed to action by states.

Start with the Act's structure: The statutory provisions immediately preceding section 202(c)—sections 202(a) and (b)—confirm the primacy of states and their utilities in planning to prevent and responding to emergency electricity shortfalls. First, section 202(a) facilitates states' and utilities' planning to generate and contract for adequate supplies of electrical power. It does so by enabling them to coordinate their efforts through voluntary participation in Regional Transmission Organizations (RTOs). Next, section 202(b) provides for coercive federal action to ensure adequate supply—but only at the request of states or their utilities. When "necessary or appropriate in the public interest," a state or utility may request that the Federal Energy Regulatory Commission (FERC) order a generator to connect to and sell or exchange energy with other facilities. Lastly, section 202(c) authorizes DOE to intervene to temporarily order similar action—connection of facilities and provision of electricity—to avert an emergency. Congress's placement of section 202(c) after subsections (a) and (b), which more broadly authorize state-level means of preventing and responding to emergency electricity shortages, strongly implies that it meant use of subsection (c) to be essentially the last alternative among the three.

Consider next the history of states' jurisdiction over generation of electricity: The last-resort character of section

202(c) is strongly supported by the respective regulatory powers of states and the federal government under the Federal Power Act. There is no dispute that for almost a century states have exercised authority, preserved by the Federal Power Act, to regulate in-state power plants for the economic and environmental benefit of their citizens. It is the states—informed by federal, regional, and load-serving entities' assessments of available supply and reliability needs—that bear the responsibility to plan for and avert reliability risks on an ongoing basis. To that end, states decide which generation resources must be built, expanded, reduced, or shut down. The Act empowers the federal government, in contrast, to regulate wholesale marketing and interstate transmission of electricity. That demarcation of federal and state regulatory power is further reason to treat DOE intervention under section 202(c) as rare and authorized only when states, their utilities, and RTOs are unable or unwilling to respond. That is exactly how the federal government has used its section 202(c) authority until today—to address short-term crises, such as blackouts caused by war or extreme weather events, not as a substitute for the states' long-term reliability planning.

Our reading of the text, structure, and history leaves us unpersuaded by DOE's sweeping conception of its "emergency" authority under section 202(c). The Department's position would empower it to pick its preferred power sources in Michigan—or, presumably, any other state—and order them to operate without regard to the multiple procedural and substantive constraints built into state reliability planning processes. We hold that section 202(c) is best read to apply where the Department identifies a risk of substantial harm from inadequate electricity supply that calls for immediate action by DOE in particular, as opposed to by the states. Because the circumstances DOE identified in the challenged order do not warrant resort to section 202(c) as

correctly interpreted, we grant the petitions for review and vacate the Order.

I.

A.

1.

Until 1935, the federal government had no regulatory authority over the nation's electricity supply. Instead, "state and local agencies oversaw nearly all generation, transmission, and distribution of electricity." *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260, 265-66 (2016); *see Pacific Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983). In 1935, after the Supreme Court held that the Dormant Commerce Clause prohibited state regulation of certain interstate electricity transactions, *see Pub. Util. Comm'n of R.I. v. Attleboro Steam & Elec. Co.*, 273 U.S. 83, 89-90 (1927), Congress enacted the Federal Power Act (FPA or Act) to fill the resulting "regulatory void," *Elec. Power Supply Ass'n*, 577 U.S. at 266; *see* 16 U.S.C. §§ 824-824w.

The FPA affords the federal government authority to regulate "the transmission of electric energy in interstate commerce," *i.e.*, the movement of electric energy over long distances via high-voltage power lines. 16 U.S.C. § 824(b)(1). It also grants federal authority over "the sale of electric energy at wholesale in interstate commerce." *Id*. But the Act denies federal authority "over facilities used for the generation of electric energy." *Id.*

Federal regulatory authority over the nation's electrical supply is exercised by the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the North American Electric Reliability Corporation (NERC), each

of which plays a distinct role. The principal and substantial federal agency acting in the electricity sector is FERC, which is responsible for rules and practices directly affecting rates for wholesale electricity sales and interstate transmission. *See generally* 16 U.S.C. §§ 824(a), 824a(f), 824d(a), 824e(a); *see also Elec. Power Supply Ass'n*, 577 U.S. at 266. NERC, which FERC designated in 2006 as an independent entity to "develop and enforce . . . reliability standards that provide for an adequate level of reliability of the bulk-power system," conducts periodic reliability assessments of the electric grid and sets and modifies nationwide reliability standards that inform but do not control levels of energy generation within each state. 16 U.S.C. § 824*o*(c), (d), (g); *see also* NERC, 2025 Summer Reliability Assessment ("NERC Reliability Assessment") (J.A. 103-56). For its part, the Department of Energy's only direct authority over the generation of electricity is its temporary emergency power under section 202(c).

Because the Federal Power Act extends federal authority "only to those matters which are not subject to regulation by the States," 16 U.S.C. § 824(a), it "maintains a zone of exclusive state jurisdiction," *Elec. Power Supply Ass'n*, 577 U.S. at 266. The Act generally preserves states' "control over in-state 'facilities used for the generation of electric energy,'" *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016) (quoting 16 U.S.C. § 824(b)(1)); it contemplates incidental federal control of only those generation practices that "directly affect" FERC's exercise of its statutory authority over wholesale rates or interstate transmission. *Elec. Power Supply Ass'n*, 577 U.S. at 278. Accordingly, we have long and repeatedly recognized that the federal government "may regulate the transmission [interstate], but not the generation, of electricity." *NextEra Energy Res., LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024); *see La. Pub. Serv. Comm'n v. FERC*, 522 F.3d 378, 389-90 (D.C. Cir. 2008) (similar

regarding FERC authority over wholesale rates). States "retain the right to regulate the facilities responsible for the generation of electric energy," *New England Power Generators Ass'n, Inc. v. FERC*, 757 F.3d 283, 285 (D.C. Cir. 2014), and they determine their own mix of electricity generation, *see Citizens Action Coal. of Ind. v. FERC*, 125 F.4th 229, 238 (D.C. Cir. 2025).

States, as the regulators of electricity generation, are largely responsible for meeting the core policy goal of achieving "resource adequacy." That means it is up to the states to make sure that enough electricity is generated to safely and reliably meet users' needs. *See Sacramento Mun. Util. Dist. v. FERC*, 616 F.3d 520, 526 (D.C. Cir. 2010) (quoting *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274, P 3 (2006)) (defining resource adequacy). Indeed, FERC itself expressly recognizes that "[r]esource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there." *Devon Power, LLC*, 109 FERC ¶ 61,154, P 47 (2004). The supply of reliable electricity to serve fluctuating demand and avoid blackouts is accordingly a key consideration of state regulators when they determine whether to permit generation sources to be added to the grid or existing sources to retire.

In making those determinations, state regulators must meet additional legal obligations and policy priorities. Those obligations and priorities may include energy affordability, the environment and climate, and diversity of generation supply. *See, e.g.*, Mich. Comp. Laws. Ann. § 460.6t(8)(a). To achieve long-term resource adequacy consistently, efficiently, and with optimal legal compliance and public support, states, load-serving entities, voluntary regional transmission organizations (RTOs), and various other stakeholders engage in extensive, coordinated planning.

Under Michigan law, the state's public utility regulator, the Michigan Public Service Commission (Michigan Commission, Commission, or simply Michigan) is responsible for monitoring the supply and demand of electricity and ensuring resource adequacy. It reviews and approves applications to construct, expand, reduce, or retire generation resources as consistent with detailed and evolving projections of state and regional energy needs. *See* Mich. Comp. Laws. Ann. §§ 460.6a, 460.6s. As most directly relevant here, the Michigan Commission ensures that any retirement of a generation resource in Michigan is accomplished consistently with the adequacy of electrical supply to meet demands of electricity consumers.

Because Michigan law makes load-serving utilities responsible for securing sufficient generating capacity to serve their customers, *see* Mich. Comp. Laws. Ann. §§ 460.6t, 460.6w, much of the Michigan Commission's power over electrical supply is exercised by regulating those utilities' investment decisions. "Load" generally refers to customers' demand for electricity—the power that users draw from the grid—at a given time. A load-serving entity is a "a utility with an obligation created under law or contract to provide electricity service to end-use customers or to a distribution utility." *S. Car. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 90 n.12 (D.C. Cir. 2014); *see NRG Power Mktg., LLC v. FERC*, 862 F.3d 108, 110 (D.C. Cir. 2017). Michigan's State Reliability Mechanism requires load-serving utilities to demonstrate annually that they have sufficient generation capacity to meet projected demand four years in the future. *See id.* § 460.6w; *State Reliability Mechanism*, Mich. Pub. Serv. Comm'n (Nov. 21, 2017), https://perma.cc/CHH6-6NZ8. Separately, every five years, load-serving entities must file with the Michigan Commission longer-term "integrated resource plans" (IRPs) that report five-, ten-, and fifteen-year projections of the

capacity they will generate or procure to satisfy resource adequacy and reliability requirements calibrated by MISO to meet future capacity needs. *See* Mich. Comp. Laws. Ann. § 460.6t(3). Each load-serving entity's integrated resource plan reports its forecasted capacity needs, the supply-side generating resources it will draw on, and available demand-side resources it will deploy (*e.g.*, energy waste reduction measures and measures to reduce consumption). *Id.* § 460.6t(5).

By exercising the state's various regulatory powers over electrical supply as contemplated by the Federal Power Act, the Michigan Commission plays the leading role in ensuring sufficient generation to serve the state's electricity needs. To approve an integrated resource plan, the state Commission must determine that the load-serving entity's plan represents "the most reasonable and prudent means of meeting" that utility's current and future commitments to supply electricity. *See id.* § 460.6t(8)(a).

Michigan has authority to protect energy supply in the face of risks of imminent shortage. The Michigan Commission regularly monitors energy supply in the state and publishes a semiannual "energy appraisal" that highlights recent events affecting supply and prices, expected conditions, and changes over the upcoming six months. *See* Mich. Pub. Serv. Comm'n, *Michigan Energy Supply Monitoring*, https://perma.cc/MVF9-YGMU. In the event of an unexpected shortage, the Commission may issue a special update of its energy appraisal. *Id.* And, as explained below, state regulators can request that FERC order an interconnection and sale of energy to address a shortfall. If needed, Michigan's governor can declare a state energy emergency and order various mitigation measures, including restrictions on energy use in non-residential buildings, restrictions on energy sales to consumers, and

directives to an energy supplier to provide energy to any facility that provides essential services to the state. Mich. Comp. Laws. Ann. §§ 10.83-10.84.

States play the primary role in assuring resource adequacy, but they do not act alone. Regional entities are instrumental to Michigan's planning for resource adequacy. Michigan and its electric utilities participate in the Midcontinent Independent System Operator (MISO), the 15-state RTO whose territory stretches from Montana to Louisiana and includes Michigan. RTOs are "independent organizations that manage the transmission of electricity over the electric grid and ensure electricity is reliably available for consumers." *Md. Off. of People's Couns. v. FERC*, 164 F.4th 920, 924 (D.C. Cir. 2026) (quotation omitted). Here, we focus on MISO's role in ensuring reliable supplies of electric energy to serve expected load in member states.

MISO—like other RTOs—works in tandem with state regulators, including the Michigan Commission, to help ensure resource adequacy. MISO recognizes that "the states have the primary responsibility to maintain resource adequacy, including overseeing the planning or securing of new resources by load-serving entities . . . to adequately meet demand." *Resource Adequacy Metrics and Criteria Roadmap*, Midcontinent Indep. Sys. Operator 9 (Dec. 2024), https://perma.cc/8WNH-W33N. MISO supports the states to ensure resource adequacy in several ways. *Id.*

For starters, MISO sets a regional resource-adequacy standard, *i.e.*, it develops a mathematical model to estimate how much generation capacity the system will need to run reliably. Every year, MISO updates that model with new data, such as hourly load forecasts. *Id.* Next, MISO determines whether existing capacity can meet projected peak demand—

the highest projected level of energy consumption at any given time—under various conditions. In so doing, MISO builds in several time-tested reliability safeguards.

Most importantly, MISO subjects the existing generation capacity to a process called "resource accreditation." *Midcontinent Indep. Sys. Operator, Inc.*, 189 FERC ¶ 61,065, PP 3-4 (2024) (tariff revisions establishing accreditation methodology). Rather than simply adding up all the available generation units' nominal maximum-capacity figures, MISO assigns a realistic capacity value to each unit's expected contribution to system adequacy during periods of high demand. *See id*. In the case of a coal plant, the assigned capacity value discounts its total "nameplate" capacity to account for historical limits on its actual generation due to forced outages, required maintenance, and the like. *See* Midcontinent Indep. Sys. Operator, Inc., *Resource Accreditation White Paper Version 2.1*, at 10-11 (Mar. 2024), https://perma.cc/KP39-DKBX. In the case of solar- and wind-powered electrical generation units, their intermittent character is also accounted for. *Id.* at 11-12.

On the demand side, MISO does not stop with seasonal projections of system-wide peak demand. It also establishes annual "reserve margin" requirements to prevent shortages even in the face of extraordinary disruptions like extreme weather or outages that defy ordinary projection. *See Midcontinent Indep. Sys. Operator, Inc.*, 189 FERC ¶ 61,065, P 1; Energy Scholars Amicus Br. 15-16. States using MISO's projections of peak demand thus require load-serving entities to procure enough capacity to cover the specified reserve margin increment above expected peak demand. By adding a reserve margin to projected peak demand, MISO builds a reliability buffer into the target load figures states use in planning for resource adequacy.

MISO's resource adequacy standards provide an additional benchmark, not a substitute, for state reliability requirements such as integrated resource plans. *See Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215, P 13 (2020); *see also Midwest Indep. Sys. Operator, Inc.*, 119 FERC ¶ 61,311, P 75 (2007) ("From the beginning . . . , [FERC] has recognized the role that state resource planning plays in managing the resource adequacy of [MISO]."). MISO coordinates with states by supplying determinations of the electric capacity needed and that which is available in the system so that state regulators, generators, and load-serving entities can incorporate those figures into their resource-adequacy planning. Energy Law Scholars Amicus Br. 14.

MISO also administers its territory's electric capacity market. "In a capacity market, in contrast to a [real-time] wholesale-energy market, [a load-serving entity] purchases from a generator an option to buy a quantity of energy, rather than purchasing the energy itself." *NRG Power Mktg., LLC v. Maine Pub. Utils Comm'n*, 558 U.S. 165, 168 (2010). With those options contracts in hand, a load-serving entity "can meet high demands for electricity by calling on the generators to produce it when the need arises. Purchasing capacity, in other words, ensures that distributors can reliably meet predicted peak power demands in an upcoming month, season, or year." *Pub. Citizen, Inc. v. FERC*, 7 F.4th 1177, 1186 (D.C. Cir. 2021) (citation omitted). Load-serving entities "generally purchase more capacity, *i.e.*, rights to acquire energy, than necessary to meet their customers' anticipated demand." *NRG Power Mktg.*, 558 U.S. at 169; *see also Maine Pub. Utils Comm'n v. FERC*, 520 F.3d 464, 467 (D.C. Cir. 2008).

Concretely, MISO runs a competitive annual planning resource auction to enable load-serving entities to procure capacity to meet projected demand and satisfy their resource

adequacy requirements. *See* MISO, Planning Resource Auction Results for Planning Year 2025-26 ("MISO Planning Resource Auction") (J.A. 58-101). In the auction, generators offer capacity and load-serving entities submit bids for the amount needed to meet their "reserve margin" requirements. A crucial benefit of a competitive capacity market over command-and-control capacity requirements (including the Campbell Order at issue here) is that rising capacity prices in the market facilitate efficient resource adequacy planning by signaling to generators and regulators when they should invest in new generation resources or retain existing ones to ensure reliable supply of electricity; low or falling prices prevent over-investment in generation at ratepayers' expense. *See Midcontinent Indep. Sys. Operator, Inc.*, 187 FERC ¶ 61,202, P 9 (2024) (MISO tariff revisions aimed at "improving investment and retirement decisions by using price signals to properly time resource entry and exit"); Niskanen Center Amicus Br. 26-27.

If, despite states' best efforts at planning for resource adequacy, MISO identifies an imminent generation-shortage risk, it has numerous tools, like energy alerts and emergency energy procurements, to ensure adequate supply. *See* MISO Market Capacity Emergency 1-3 (J.A. 676-78). And, like the Michigan Commission, MISO has some power to defer a load-serving entity's decision to retire or suspend operations of a generation resource as needed to prevent a shortage. *See* MISO Tariff Section 38.2.7 (J.A. 887-893); *Generator Interconnection and Retirement*, Midcontinent Indep. Sys. Operator, https://perma.cc/WSS9-9AY7.

2.

The federal government, too, plays an important—albeit limited—role in the resource-adequacy scheme. Even as the

Federal Power Act generally preserves states' jurisdiction over electricity generation, it vests certain powers in the federal government to help protect the coordinated resource-adequacy system. Section 202 of the Act authorizes three tiers of federal action.

In the first tier, section 202(a), Congress called on FERC to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy." 16 U.S.C. § 824a(a). Acting under that provision, FERC encouraged the voluntary formation of RTOs to administer the transmission grid on a regional basis, and the formation of independent system operators (ISOs) that perform a similar function on a smaller scale. *See Amaren Servs. Co. v. FERC*, 880 F.3d 571, 574 (D.C. Cir. 2018); *see also Elec. Power Supply Ass'n*, 577 U.S. at 267-68. Regional coordination promotes efficient interstate sales of power from a state with available capacity to another state that may find itself short, for example, and prevents free-riding whereby load-serving entities in one state might "count on the capacity they expect others to buy in order to support their own reliability." *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 479 (D.C. Cir. 2009). FERC oversees ISOs and RTOs, including MISO, and reviews their electric capacity requirements, rates, and other rules under the "just and reasonable" standard. 16 U.S.C. §§ 824d, 824e; *see, e.g.*, *Conn. Dep't of Pub. Util. Control*, 569 F.3d at 478-79, 485 (reviewing FERC order affecting ISO capacity requirements).

The second tier, established by section 202(b), permits FERC to direct generators to connect to and sell or exchange energy with other facilities—a power afforded to FERC only upon "application of any State commission or of any person engaged in the transmission or sale of electric energy."

16 U.S.C. § 824a(b). So, if a state energy regulator, transmission entity (*e.g.*, an RTO or ISO), or load-serving entity requests FERC to do so, FERC may—"after notice to each State commission and public utility affected and after opportunity for hearing" and a finding that action is "necessary or appropriate in the public interest"—mandate a connection or sale. *Id.*

Importantly, even as the Federal Power Act gives FERC narrow authority to respond to requests to order electricity sales or exchanges, the Act expressly denies FERC authority to regulate generation facilities directly. *See* 16 U.S.C. § 824(b)(1). It is the prerogative of states "to forbid new entrants from providing new capacity, to require retirement of existing generators, to limit new construction to more expensive, environmentally friendly units, or to take any other action in their role as regulators of generation facilities without direct interference from the Commission." *Conn. Dep't of Pub. Util. Control*, 569 F.3d at 481. The final tier of federal power, conferred by section 202(c), is the sole exception.

The third tier falls outside of the coordinated resource-adequacy system altogether. Section 202(c) establishes a limited backstop mechanism empowering DOE to address certain electricity supply emergencies. That section authorizes the Secretary of Energy (Secretary) to compel generation of electricity only "[d]uring the continuance of any war in which the United States is engaged" or when the Secretary "determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." 16 U.S.C. § 824a(c)(1).

Congress enacted section 202(c) in response to a "serious power shortage" during World War I and contemplated that its use would be limited to addressing wartime shocks and "similar crises" like "[d]rought and other natural emergencies." S. Rep. No. 74-621, at 49 (1935). Until now, the Department has exercised its section 202(c) authority sparingly. During nearly a century of state responsibility for sufficient supply of electricity under the FPA, the federal government has rarely used section 202(c) authority outside of wartime. It "has never used its section 202(c) authority to require additional generation to address long-term resource-adequacy concerns; instead, it has always used that authority to address discrete and unexpected events that threaten immediate grid needs." Energy Scholars Amicus Br. 21 (citing Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789 (2025)). The federal government has, until now, issued stopgap generation orders in response only to transitory emergencies caused by war, extreme weather events, market manipulation, or unplanned, short-term unavailability of specific generation units. *See* Rolsma, *supra* at 805-07, 839-46 tbls. 1 & 2. When a section 202(c) emergency arises, the Department can order generation that "in its judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1).

Congress amended the Federal Power Act in 2015 to provide that section 202(c) emergency orders may override federal, state, and local environmental laws and regulations. Such an override must be cabined to circumstances in which compliance is not "practicable," any "adverse environmental impacts" are "minimize[d]," and the facility is ordered to operate only "during hours necessary to meet the emergency and serve the public interest." Pub. L. 114-94 § 61002, 129 Stat. 1772 (2015) (codified at 16 U.S.C. § 824a(c)(2)). Congress further specified that a section 202(c) order that "may

conflict" with environmental law "shall expire not later than 90 days after it is issued." 16 U.S.C. § 824a(c)(4).

As described above, Michigan's resource-adequacy regulation entails continuous, complex planning processes with intensive coordination by the state and MISO. That planning starts years in advance to prepare for future needs as well as near-term demand. FERC has peripheral—and limited—oversight of those entities, but no power to directly regulate generation facilities. And DOE has no role whatsoever in the resource-adequacy planning process. Instead, Congress in section 202(c) gave DOE narrow authority to intervene that is triggered only in the face of an electricity emergency not otherwise addressable by states or their utilities.

B.

The J.H. Campbell Generating Plant (Campbell), an aging coal-fired power plant in Michigan, is owned and operated by Consumers Energy Company, a load-serving entity that is part of MISO. Given its decades-old units, Campbell has become increasingly inefficient, polluting, and expensive to maintain. When in operation, the Campbell facility produces dangerous emissions, including SO_2, NO_x, and PM2.5, that cause approximately thirty excess deaths every year. Order Approving Settlement Agreement 9 (J.A. 454); State Add. 213. In June 2021, Consumers Energy filed with the Michigan Commission an integrated resource plan that proposed to retire the Campbell plant. Once an integrated resource plan is filed, the Michigan Commission reviews the plan through a year-long "contested case" process. *See* Mich. Comp. Laws. Ann. § 460.6t(a)(7). Interested parties may intervene, take discovery, submit expert testimony, and present and cross-examine witnesses at an evidentiary hearing. *See id.* §§ 460.6t(7)(ii), 24.271-24.288.

Dozens of interested parties, including environmental groups, the Michigan Attorney General, and several power companies, intervened in the Consumers Energy proceedings. In April 2022, Consumers Energy entered a multi-party settlement agreement with the environmental groups, the Michigan Attorney General, and the Michigan Commission's enforcement staff under which it memorialized its plan to retire the Campbell plant and obtain newer, cleaner, cheaper, and more reliable resources that would increase available generation capacity. *See* Settlement Agreement (J.A. 543-63). Specifically, the agreement provided that Consumers Energy would retire the Campbell plant on or before May 31, 2025. *See id*. 4-5 (J.A. 546-47). And it directed Consumers Energy to acquire a new gas plant, extend operations of two oil- and gas-fired units at one of its other plants, and add new solar energy generation and battery storage. *See id*. 3-9 (J.A. 545-51). The parties sought approval of the settlement by the Michigan Public Service Commission, Order Approving Settlement Agreement 1 (J.A. 446), which ruled on objections and granted approval on June 23, 2022, *id*. 95-97 (J.A. 540-42); *see also id*. 45-95 (J.A. 490-540).

In reviewing the settlement agreement, the Michigan Commission assessed whether the integrated resource plan Consumers Energy filed following the settlement met statutory requirements. *See id*. 4, 95 (J.A. 449, 540). By statute, the Michigan Commission must approve an integrated resource plan if it determines that "[t]he proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." Mich. Comp. Laws. Ann. § 460.6t(8)(a). In making that determination about the post-settlement integrated resource plan, the Michigan Commission assessed its impact on resource adequacy and on Consumers Energy's ability to serve

anticipated peak electric load. *See* Order Approving Settlement Agreement 88-95 (J.A. 533-40).

Upon review of Consumers Energy's expected procurements and operating adjustments, the Commission determined that "the approval of the settlement agreement will enhance resource adequacy in [the Campbell region] in both the near-term and long term." *Id.* 93 (J.A. 538). Ultimately, the Commission concluded, Consumers Energy's retirement plan was "the most reasonable and prudent means of meeting Consumers' energy and capacity needs and otherwise meets the requirements of MCL 460.6t(8)." *Id.* 95 (J.A. 540). On appeal, the Michigan Court of Appeals affirmed the Michigan Commission's order approving the settlement agreement and determined that there was substantial evidence that the agreement would improve resource adequacy. *In re Consumers Energy*, No. 3622954, 2023 WL 2620437, at *5-6 (Mich. Ct. App. Mar. 23, 2023).

MISO, too, determined that Campbell's retirement as planned—with substitute generation provided by cheaper, cleaner, and more reliable new and expanded generation—would support reliability. *See* Attachment Y Notice 156 (J.A. 322). That determination followed a technical evaluation of transmission system conditions that would result from the plant's retirement. *See* MISO Tariff Section 38.2.7 2-3 (J.A. 888-89). MISO's analysis confirmed that Consumers Energy did not need to operate Campbell to satisfy the RTO's reliability criteria.

As Campbell's May 2025 retirement approached, Consumers Energy, the Michigan Commission, and MISO continued to prioritize resource adequacy. Consumers Energy had already begun winding down the Campbell unit, transitioning to new generation resources, and developing

additional capacity. In its annual capacity-demonstration filing with the Michigan Commission, *see* Mich. Comp. Laws. Ann. § 460.6w(8)(a), Consumers Energy documented that it had procured sufficient capacity to meet the projected demand of its customers in summer 2025 and beyond, *see* Motion to Intervene 24 (J.A. 357); Consumers Energy Capacity Demonstration 15 (J.A. 632). And MISO's planning resource auction results for summer 2025 through spring 2026, published in April 2025, "demonstrated sufficient capacity at the regional, subregional and zonal levels." MISO Planning Resource Auction 12 (J.A. 69); *see also id.* 5 (J.A. 62) (showing that MISO attained a reserve margin of 9.8% for summer 2025, nearly two percentage points above its target).

The Michigan Commission, utilities in the state, and MISO saw no need to invoke 202(b) to request that FERC order provision of additional electricity. Neither did the governor of Michigan see any ground to declare an energy emergency in response to Campbell's planned closure. *See* Mich. Comp. Laws. Ann. §§ 10.83-10.84.

Just days before Campbell's scheduled retirement, however, DOE sidestepped Michigan's coordinated, years-long process of planning, including the detailed, judicially reviewed, multiparty settlement.

On May 23, 2025, the Secretary issued a section 202(c) Order declaring an emergency and compelling Consumers Energy to keep Campbell in operation for at least 90 days. The Order asserts that "an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes." DOE Order 202-25-3 1 (J.A. 1). As support, the Order identifies "potential tight reserve margins during the summer 2025" in MISO and

potential electricity supply shortfalls due to the "retirement of thermal generation capacity." DOE Order 202-25-3 1 (J.A. 1).

DOE pointed to fragments of two documents as showing that the region faced an emergency within the meaning of section 202(c). First, it quoted a statement in a NERC report that MISO is "at elevated risk of operational reserve shortfalls during periods of high demand or low resource output." DOE Order 202-25-3 1 (J.A. 1); *see* NERC Reliability Assessment 5 (J.A. 107). DOE characterized that statement as describing an emergency even though the very same report concluded that MISO had "adequate anticipated resources" for "peak load conditions." NERC Reliability Assessment 5 (J.A. 107).

Second, DOE quoted a slide from a deck describing MISO's planning resource auction results for its North/Central region, which stated that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" and that the summer months reflected the "highest risk and a tighter supply-demand balance." DOE Order 202-25-3 2 (J.A. 2); *see* MISO Planning Resource Auction 12-13 (J.A. 69-70). The first statement means that fewer capacity resources were *offered* in that region than in 2024; it does not conclude that the amount of capacity *purchased* was inadequate to serve load. *See* Michigan Attorney General Request for Rehearing 31 (J.A. 188). And, in context, the second statement is merely comparative: It explains that the supply-demand gap in summer 2025 was narrower than in fall, winter, or spring of that year. *See id.* 30-31 (J.A. 187-88). DOE acknowledges that both "MISO and Consumers ha[d] incorporated [Campbell's] planned retirement into their supply forecasts," and that MISO procured "sufficient capacity" for summer 2025. DOE Order 202-25-3 1-2 (J.A. 1-2). Brushing aside that vital context, DOE nonetheless concluded there was a risk of insufficient capacity

that warranted a section 202(c) emergency order. And it concluded, without explanation, that additional dispatch of Campbell in particular is "necessary to best meet the emergency and serve the public interest." DOE Order 202-25-3 2 (J.A. 2).

In June 2025, Michigan sought administrative rehearing, as did Illinois, Minnesota, and several environmental nonprofit groups. Rehearing was denied by operation of law when DOE failed to respond within 30 days. 16 U.S.C. § 825l(a). Petitioners then sought our review of the Order. On September 8, 2025, DOE issued a Rehearing Order that "modified" the Order in some respects and otherwise sustained it. DOE Order 202-25-3B 24 (J.A. 29).

The Rehearing Order reiterates that section 202(c) "specifically applies to the potential 'shortage of electric energy or of facilities for the generation or transmission of electric energy,'" which it describes as "exactly the situation that led to the issuance of the Emergency Order." Order 202-25-3B 4 (J.A. 9). DOE also announced a new interpretation of section 202(c) to authorize it to countermand the state's approval of a plant closing, even in the absence of a need for federal intercession to avert an imminent reliability risk beyond state or RTO control. Order 202-25-3B 7 (J.A. 12). It is enough, in DOE's view, that the Order "addresses [the] risk" that, in DOE's view, "if current retirement schedules and incremental additions remain unchanged, most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks within five years," Order 202-25-3B 14 (J.A. 19).

The Act limits to 90 days the duration of a section 202(c) order that conflicts with environmental law, *see* 16 U.S.C. § 824a(c)(4)(A)—which this one indisputably does. DOE has

nonetheless extended the Order's 90-day period four times. Order No. 202-25-7 (DOE Aug. 20, 2025); Order No. 202-25-9 (DOE Nov. 18, 2025); Order No. 202-26-16 (DOE Feb. 17, 2026); Order No. 202-26-22 (DOE May 18, 2026). In each extension, DOE asserted that the emergency conditions "will continue in the near term and are also likely to continue in subsequent years." *See, e.g.*, Order No. 202-25-7 7 (State Add. 88); Order No. 202-25-9 8 (State Add. 99). Thus, DOE has compelled Campbell's continued operation for a total of 450 days, claiming that extended compulsion is appropriate "[t]o ensure that the Campbell Plant will be available if needed to address emergency conditions." *See* Order No. 202-25-9 8 (State Add. 99). Petitioners timely sought review of the extension orders, and we held those petitions in abeyance pending the outcome here.

II.

We have jurisdiction to review the initial Order challenged in these petitions. 16 U.S.C. § 825*l*(b); *see* 42 U.S.C. § 7192(a). We must set aside an agency action that is "in excess of statutory jurisdiction, authority, or limitations, or short of statutory right." *Erie Blvd. Hydropower, LP v. FERC*, 878 F.3d 258, 266 (D.C. Cir. 2017) (quoting 5 U.S.C. § 706(2)(A), (C)). When determining whether an agency has exceeded its statutory authority, we interpret the relevant statutory provisions *de novo*. *See Loper Bright Enterprises v. Raimondo*, 603 U.S. 369, 400-01 (2024).

Petitioners claim that the Order exceeds DOE's statutory authority. Specifically, they argue that the circumstances DOE has identified—including an out-of-context quotation about an "elevated risk" of operational reserve shortfalls in summer 2025 and unspecified long-term reliability risks—do not constitute an "emergency" under section 202(c). The very

document DOE drew from established that there was in fact sufficient capacity due to Michigan's planning measures for resource adequacy and no anticipated electricity shortfall, so no "emergency." Petitioners also claim that the Order's finding that Michigan faced a section 202(c) emergency is not supported by substantial evidence and contravenes other limitations imposed by section 202(c). DOE responds that the Secretary has broad latitude to determine that a section 202(c) emergency exists and that the Order correctly identifies one here.

A.

We first address petitioners' statutory argument. And because we find that argument dispositive, we need go no further. DOE relies not on its core power to compel electricity connection or generation to meet emergency needs in wartime, but on its power to compel generation of electric energy when the Secretary "determines that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes." 16 U.S.C. § 824a(c)(1). The Act gives the Secretary authority to determine whether an emergency exists. That grant of authority does not grant a boundless license to ignore the statutory text; it allows the Secretary to exercise discretion within the Act's statutory limits. The statutory limits in section 202(c) confine DOE's authority to temporary emergencies that the Secretary reasonably determines are and will be unmet by the state's resource planning.

The parties disagree about what counts as an "emergency" under section 202(c). Petitioners contend that an "emergency" for section 202(c) purposes must be sudden, unexpected,

imminent, and require an immediate response. State Pet'rs Br. 26-27. DOE contends that the term encompasses any anticipated shortage of electric power, even if neither imminent nor beyond the capability of the state to address. DOE Br. 23-25.

We hold that a section 202(c) "emergency" means a grid-reliability risk that calls for an immediate response by DOE in particular. If the Department finds the state has not and will not timely take steps that must be taken immediately to avert unacceptable risk to reliability, the need for immediate action can trigger statutory authority for DOE to step in.

In arriving at the best interpretation, "we begin with the text." *Pacific Gas & Electric Co. v. FERC*, 113 F.4th 943, 948 (D.C. Cir. 2024) (citation omitted). The Federal Power Act does not define "emergency," so "we look to the word's ordinary definition." *CSX Transp., Inc v. Ala. Dep't of Revenue*, 562 U.S. 277, 284 (2011). Definitions of "emergency" include an "unforeseen occurrence or combination of circumstances which calls for immediate action or remedy," a "pressing necessity," and an "exigency." *Webster's New Int'l Dictionary of the English Language* 716 (2d ed. 1930); *see also* 3 *Oxford English Dictionary* 119 (1933) (defining emergency as "a state of things unexpectedly arising, and urgently demanding immediate action").

The key consideration in determining whether a situation amounts to an emergency is whether it demands immediate action by DOE outside the ordinary process for assuring reliability. While the suddenness, imminence, and unexpectedness of a reliability risk will often make it more likely to warrant immediate action, it is, as we explain further below, *see infra* at 29-32, the combination of urgent need for action with circumstances showing that a federal response is

called for that epitomizes a section 202(c) emergency. And, contrary to petitioners' arguments that an emergency can stem only from an imminent and unforeseen energy shortage, *see* PI Pet'rs Br. 24; State Pet'rs Br. 25, the need for an immediate federal response might arise even when a crisis is foreseeable or will occur in the future: If, for example, a deteriorating nuclear power plant poses risks of a serious outage in three years absent immediate action to ensure repairs, and if DOE has reason to believe that the state cannot or will not act in time to reasonably respond, an emergency may exist even though the outage is foreseeable and far-off.

Based on the text, the need for immediate federal action to ensure adequate supply of electricity is the touchstone for a section 202(c) emergency. DOE's arguments to the contrary are unpersuasive.

DOE contends that the text of section 202(c) uses "emergency" broadly to include any shortages of electric energy. DOE Br. 23-25. The Department asserts that section 202(c) "spells out what constitutes a section 202(c) 'emergency' by capacious examples," including "'a shortage of electric energy'; 'a sudden increase in the demand for electric energy'; a shortage 'of facilities for the generation or transmission of electric energy'; a shortage 'of fuel or water for generating facilities'; or for 'other causes.'" DOE Br. 24 (quoting 16 U.S.C. § 824a(c)(1)). But DOE misreads the text. What it quotes in section 202(c) as statutorily identified emergencies are no such thing. They are potential *causes* of emergencies, not *examples* of emergencies. As the statute says, an emergency may "exist[] by reason of" a shortage of electric energy or of facilities for the generation or transmission of electric energy. 16 U.S.C. § 824a(c)(1). The statutory text plainly does not say those potential causes are themselves emergencies.

Next, DOE argues that the text of neighboring section 202(d) shows that the term "emergency" in section 202(c) cannot mean that immediate action is required. DOE Br. 28. Section 202(d) permits a utility that is not subject to FERC's jurisdiction to connect temporarily to the interstate grid during "any emergency requiring immediate action," and to do so without thereby subjecting itself to FERC's jurisdiction. 16 U.S.C. § 824a(d). The apparent role of this provision is to encourage such voluntary connection to help meet emergency conditions. DOE argues that the word "emergency" by itself in section 202(c) cannot refer to circumstances requiring immediate action because that would treat the modifying phrase accompanying the word "emergency" in section 202(d)—"requiring immediate action"—as surplusage. That is wrong. Even if there were no section 202(c) at all, the phrase in section 202(d) would be surplusage because, as the dictionaries and common usage establish, the word "emergency" standing alone denotes an acute situation requiring an immediate response. *See supra* at 27. The fact that "emergency" conveys the same meaning more succinctly than the more emphatically worded "emergency requiring immediate action" is no reason to eschew the word's ordinary meaning in section 202(c). After all, "the canon against surplusage is not an absolute rule," and it "certainly does not require us to favor an unusual meaning that will avoid surplusage over a more natural one." *Stanley v. City of Sanford*, 606 U.S. 46, 56 (2025) (quotation omitted).

For purposes of section 202(c), the ordinary meaning of "emergency" as an event that requires immediate action does not complete the analysis. "It is a fundamental canon of statutory construction that the words of a statute must be read in their context and with a view to their place in the overall statutory scheme." *Sturgeon v. Frost*, 577 U.S. 424, 438 (2016) (quotation omitted). Given the structure and context of the

Federal Power Act, section 202(c)'s grant of emergency authority is triggered only when there is a need for immediate, essentially last-resort action *and* the circumstances require action by DOE in particular, as opposed to action by the state or states responsible for resource adequacy.

To start, Congress carefully structured the Federal Power Act, and section 202 within it, to preserve the primacy of state authority over electricity generation. At its outset, the Act clarifies that the limited federal authority it confers extends "only to those matters which are not subject to regulation by the States." 16 U.S.C. § 824(a). And it expressly denies federal authority "over facilities used for the generation of electric energy." *Id.* § 824(b)(1). To help ensure that generation suffices to meet long-term demand, section 215 authorizes NERC to establish nationwide reliability standards. 16 U.S.C. § 824*o*(d). But that section, which expressly denies NERC power to demand additional generation capacity, makes clear that NERC's standards are to guide state planning, not to authorize federal intervention to direct electricity generation. FERC, too, facilitates production of an "abundant supply of electric energy," principally by prompting states and their utilities to engage in "voluntary interconnection and coordination" at the regional level. 16 U.S.C. § 824a(a). If those efforts prove deficient, a state, transmission organization, or load-serving entity may request, under section 202(b), that FERC direct a generator to sell or exchange energy with other facilities. *Id.* § 824a(b). But FERC only has authority to do that in response to a request. Permitting DOE to compel generation in a situation that can be resolved through the ordinary resource adequacy planning mechanisms or a request under section 202(b) would render meaningless the constraints on federal power that Congress imposed throughout the Act.

The only other court to consider Section 202(c)'s scope has come to the same conclusion. In *Otter Tail*, the court distinguished section 202(c), which enables a federal response "to react to a war or national disaster and order immediate interconnection of the facilities to maintain electrical service during such emergency," from section 202(b), which "applies to a crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the [Federal Power] Commission." *Otter Tail Power Co. v. Fed. Power Comm'n*, 429 F.2d 232, 234 (8th Cir. 1970). So there, too, the court treated the federal government's section 202(c) power as limited by the primacy of other, less top-down and coercive mechanisms to ensure resource adequacy.

The structure of the Federal Power Act makes clear that compelled generation under section 202(c) is generally appropriate only when DOE faces a type of reliability emergency that is unaddressed by actions contemplated by sections 202(a) and (b), so necessitates federal intervention. Section 202(c) is essentially a narrow, last-resort backstop. It provides for DOE to exercise emergency authority when coordinated state and regional resource adequacy planning, per section 202(a), and invocation of section 202(b) both fall short. When those mechanisms function as intended to address potential resource adequacy issues, there will typically be no "emergency" within the meaning of section 202(c).

The circumstances requiring use of section 202(c) are rare. If generation shortfalls or other reliability risks are anticipated, states, generators, and regional entities have every incentive and tool to make plans to procure replacement resources or prevent scheduled retirements. And even for imminent or unforeseen shortfalls, the coordinated resource-adequacy system includes alternative solutions. For instance, MISO may provide for energy imports from neighboring systems or deploy

operating mitigations like load-modifying resources—that is, demand-side measures to reduce energy consumption. *See* NERC Reliability Assessment 16 (J.A. 118); MISO, *Market Redefinition: Load Modifying Resource Reforms* 6 (Nov. 6, 2024), https://perma.cc/AZ69-Q3VN. MISO may also issue energy emergency alerts or operational alerts that require its stakeholders to take energy conservation actions. *See* MISO Market Capacity Emergency 21-26 (J.A. 696-701). States may declare energy emergencies pursuant to which they restrict consumption or command an energy supplier to redirect its energy to a needed facility. *See, e.g.*, Mich. Comp. Laws. Ann. §§ 10.83-10.84. And states, transmission organizations, or load-serving entities contemplating imminent shortages can call on FERC under section 202(b) to require generators to sell or exchange energy with other facilities. *See* 16 U.S.C. § 824a(b). For virtually all risks of energy shortages, alternatives to DOE intercession suffice.

When DOE exercises its section 202(c) authority to compel generation other than as a last resort, including by reversing a generator's long and carefully planned retirement as it did with Consumers Energy's Campbell unit, the results are disruptive. Unjustified use of section 202(c) upends existing resource-adequacy decisions made based on years of planning with intensive expert input and broad stakeholder participation. As DOE itself acknowledges, resource adequacy planning and adding generation capacity is a "many-year" process. *See* DOE Br. 33. States and RTOs closely scrutinize the impact of generation retirement or reduction and engage in sophisticated planning of expansion or construction of generation units and facility interconnections. They do so with public notice and input by a broad range of stakeholders. And they seek to achieve resource adequacy in a manner that serves the public interest in affordable, environmentally sound, reliable resources going forward. *See id.* at 33-34. Contrary to

DOE's position, DOE Br. 31-36, the complexity and advance planning that go into states' assurances of resource adequacy do not imply that DOE must have vast, top-down emergency power to pick its favorite generators to run at all costs, or to abruptly order disfavored units to shut down earlier than planned. Rather, the complexity of state planning processes helps to explain why the Federal Power Act leaves resource adequacy to be managed by states, utilities, and their RTOs.

The Department's reading of "emergency" invites frequent federal interventions that are unsupported by the statute and threaten the stability of the energy market. By directing a generator approved for retirement to remain operative while effectively walling it off from planning and market frameworks, the Order challenged here interferes with ordinary methods to assess a region's true generation capacity and distorts price signals that otherwise prompt appropriate capacity investments. *See* Energy Law Scholars Amicus Br. 16. DOE's use of its expansive interpretation of "emergency" to prevent planned retirements of generators slated to close, for example, will likely discourage development of needed new resources by artificially lowering capacity market prices and destabilizing those markets. *See id.* 16-20. Such distortions may be justified in the face of the rare emergency requiring DOE's immediate, short-term intervention. But unless DOE's involvement is needed in response to a genuine emergency as defined by section 202(c), it must be avoided.

The text and statutory structure are alone sufficient to settle the "best" understanding of FERC's section 202(c) authority. *See Loper Bright*, 603 U.S. at 370. The correctness of our reading is powerfully confirmed by the executive branch's consistent interpretation and limited exercise of that

authority over nearly a century. *See id.* at 386 (citations omitted).

The reading of section 202(c) we provide today is a familiar one. In *Richmond Power & Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978), we held that the Federal Power Commission (predecessor to both FERC and DOE) acted within its sound discretion in eschewing reliance on Section 202(c) to address electric supply problems caused by the 1973 oil embargo. 614-15. The Commission had determined to "invoke section 202(c) only if its emergency powers could have provided the sole authorization" to alleviate the shortage. *Id.* at 614. Rejecting the position of midwestern generators seeking compelled purchases of their capacity under section 202(c), the Commission treated continued reliance on foreign oil, despite a national policy discouraging such reliance, as not among the "'temporary' emergencies, epitomized by wartime disturbances" to which section 202(c) applies. *Id.* at 615. Given that the anticipated need could be mitigated by a temporary regional agreement to increase energy conservation and transfers from energy-rich states to those facing shortages, the Commission saw no role for last-resort federal compulsion under section 202(c). *Id*. at 613-14.

DOE's own rule—adopted shortly after we decided *Richmond Power & Light*—defines a section 202(c) "emergency" along similar lines as "an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power." 10 C.F.R. § 205.371. That rule lists as examples of events that might cause an emergent inadequacy in electricity supply "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent"; unanticipated shortfalls might also result from "a

sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities." *Id*. DOE explained when it adopted the rule that section 202(c) did not empower it to issue orders to "replace prudent utility planning and system expansion." Department of Energy, Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984, 39,985 (Aug. 6, 1981). As the rule specifies, a section 202(c) order is "envisioned as meeting a specific inadequate power supply situation," not solving a long-term problem. 10 C.F.R. § 205.371.

The historical uses of section 202(c) further reinforce its limited scope. *See Loper Bright*, 603 U.S. at 386 (emphasizing that the "'longstanding practice of the government'—like any other interpretive aid—'can inform [a court's] determination of what the law is'" (quoting *NLRB v. Noel Canning*, 573 U.S. 513, 525 (2014) (modification in original))). Outside of wartime, section 202(c) has been used sparingly. Between World War II and the Federal Power Commission's dissolution and replacement by the Department of Energy in 1977, the Commission issued only seven section 202(c) orders, typically in response to local requests and based on impending outages, operating and construction difficulties, or drought. *See, e.g.*, *City of Cleveland v. Cleveland Elec. Illuminating Co.*, 47 F.P.C. 747, 748-50 (1972) (operating difficulties); *Crisp Cnty. Power Comm'n v. Ga. Power Co*., 35 F.P.C. 629, 630-31 (1966) (multiple system outages); *Tex. Elec. Serv. Co*., 7 F.P.C. 574, 575 (1948) (construction delays, generator outage, and drought); *see also* Rolsma, *supra*, at 843-46 tbl. 2.

After Congress transferred section 202(c) authority from the Federal Power Commission to DOE in 1977, DOE saw no

need to use it for decades. Before 2025, DOE had issued section 202(c) orders only at the request of local entities and to alleviate discrete crises, such as those caused by severe weather events or unexpected construction delays that required an immediate response. *See, e.g.*, DOE Order 202-20-2 1-2 (Sept. 6, 2020), https://perma.cc/7GEU-86C8 (extreme heat wave); DOE Order 202-17-1 1 (Apr. 14, 2017), https://perma.cc/6QJC-2SEG (unpredicted convergence of lightning strike and flooding); DOE Order 202-05-2 (Sept. 30, 2005), https://perma.cc/WH4A-LV8A (serial strikes of Hurricanes Rita and Katrina); *see also* Rolsma, *supra*, at 839-42 tbl 1.

In sum, an emergency under section 202(c) refers to an electricity shortage that is or will in the future be acute and is not being timely addressed by planning for resource adequacy by the state, its utilities, or an RTO. Those circumstances require immediate, essentially last-resort action by DOE outside the ordinary reliability planning process.

We next consider whether the circumstances identified by DOE are facially sufficient to meet the statutory requirement of an emergency. Because we conclude that they are not, we need not reach petitioners' substantial-evidence claims or their challenges to DOE's decision to choose Campbell as the source of additional capacity and to command it to run beyond the "hours necessary to meet the emergency." 16 U.S.C. § 824a(c)(2).

B.

The Order initially describes the emergency as "the potential for electricity supply shortfalls" in summer 2025 caused by the "retirement of thermal generation capacity." DOE Order 202-25-3 1 (J.A. 1). It warns that summer 2025 presented a risk of "potential loss of power to homes and local

businesses in the areas that may be affected by curtailments or outages." DOE Order 202-25-3 2 (J.A. 2). DOE continues to defend the Order on that basis, arguing that "emergency conditions existed . . . due to a shortage that would cause unacceptable reliability risks in the near-term." DOE Br. 31.

Those indeterminate assertions of summer electricity shortfalls are not what Congress meant by "emergency" in section 202(c). Had DOE pinpointed a concrete supply issue beyond the state's competency that was likely to trigger a blackout in an identified area if temperatures peaked, immediate intervention might have been appropriate. But the mere possibility of an electricity supply shortfall—with no specifics about its potential severity, timing, location, or likelihood—does not warrant an emergency federal response. Rather, reasonable alternatives to DOE's intervention were available, and in fact appear to have forestalled outages.

Because the circumstances DOE identified plainly did not necessitate immediate action by DOE, it did not meet the definition of an emergency under section 202(c). NERC's Reliability Assessment—the very document on which the Department relies to support its emergency determination—describes MISO mitigation measures to prevent operating shortfalls, including accessing load-modifying resources, requesting energy transfers from neighboring systems, and issuing energy emergency alerts. *See* NERC Reliability Assessment 16 (J.A. 118). MISO also instructs its stakeholders to lower energy use and increase output from backup generators. *See* MISO Market Capacity Emergency 21-26 (J.A. 696-701). Michigan's governor can declare an energy emergency to restrict energy consumption and direct supply to needed areas. *See* Mich. Comp. Laws. Ann. § 10.84. Such an intervention is modulated—in ways that DOE's section 202(c) order is not—by the governor's direct political accountability

to electricity users in the state and familiarity with state energy conditions. And, as already discussed, state regulators, transmission organizations, and load-serving entities have other mechanisms to address shortages, including requesting intervention from FERC under section 202(b).

DOE's Rehearing Order identifies an alternative basis for its emergency determination. The agency asserts that "most regions—including the MISO region relevant to the Emergency Order—will face unacceptable reliability risks within five years," and that requiring Campbell's continued operation "addresses that risk." DOE Order 202-25-3B 14 (J.A. 19). On appeal, DOE continues to defend the Order by pointing to longer-term reliability and resource adequacy concerns. *See* DOE Br. 79.

That added rationale falls even farther outside the meaning of "emergency" under section 202(c) than did the first. Long-term resource adequacy risks generally do not necessitate immediate action by DOE. They are routinely resolved through coordinated, forward-looking decision making within the ordinary resource adequacy system. That entire system prioritizes averting unacceptable long-term reliability risks. Again, Michigan addresses long-term reliability risks by reviewing generators' integrated resource plans and by approving or rejecting the construction and retirement of generation facilities. Regional entities like MISO facilitate states' responses to long-term reliability risks by setting resource adequacy requirements and encouraging new resource entry through effective administration of the capacity market. MISO has also adopted reliability initiatives aimed at improving its processes and transmission capabilities, such as implementing resource accreditation reforms, constructing new transmission lines, and expediting approval of new electric generation resources. *See* Testimony of Jennifer Curran 2

(J.A. 1140) (House Subcommittee testimony of MISO executive). And, if long-term resource adequacy continues to present a threat, NERC may modify its nationwide reliability standards. The federal government generally lacks statutory authority to address long-term reliability risks; much less is DOE empowered to make unauthorized use of section 202(c) emergency authority as a partial substitute for and disruption to the states' planning processes.

Because we conclude that DOE exceeded its statutory authority, we do not address petitioners' other challenges to the Order. *See MCI Telecomms Corp. v. FCC*, 765 F.2d 1186, 1188 (D.C. Cir. 1985).

III.

We vacate the Order. An order of a federal agency "that exceeds the scope of its statutory authority is, by definition, not in accordance with the law and subject to vacatur." *All Am. Telephone Co., Inc. v. FCC*, 867 F.3d 81, 89 (D.C. Cir. 2017); *see Calif. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 396 (D.C. Cir. 2004) (vacating order that FERC had no authority to make or enforce). To determine whether vacatur is the appropriate remedy, we evaluate (1) "the likelihood that deficiencies in an order can be redressed on remand" and (2) "the disruptive consequences of vacatur." *N.J. Conservation Found. v. FERC*, 111 F.4th 42, 64 (D.C. Cir. 2024) (quotation omitted).

The Order's deficiency cannot be redressed on remand because it depends on DOE's misconception of the nature and scope of its emergency authority under section 202(c). Because the circumstances identified by DOE do not amount to a section 202(c) emergency, the agency cannot claim any serious possibility that it will be able to "substantiate its decision on remand." *Id.* (quoting *Allied-Signal, Inc. v.*

Nuclear Regul. Comm'n, 988 F.2d 146, 151 (D.C. Cir. 1993)). And vacatur will not be disruptive because the Order under review has already expired.

***

For the foregoing reasons, we grant the petitions and vacate the Order.

So ordered.

EXHIBIT 150
Part 1 of 2
(Introduction through page 36)

NERC

2026 State of Reliability

Technical Assessment of 2025 Bulk Power System Performance

June 24, 2026

2026 SOR Snapshot

2026 SOR Overview

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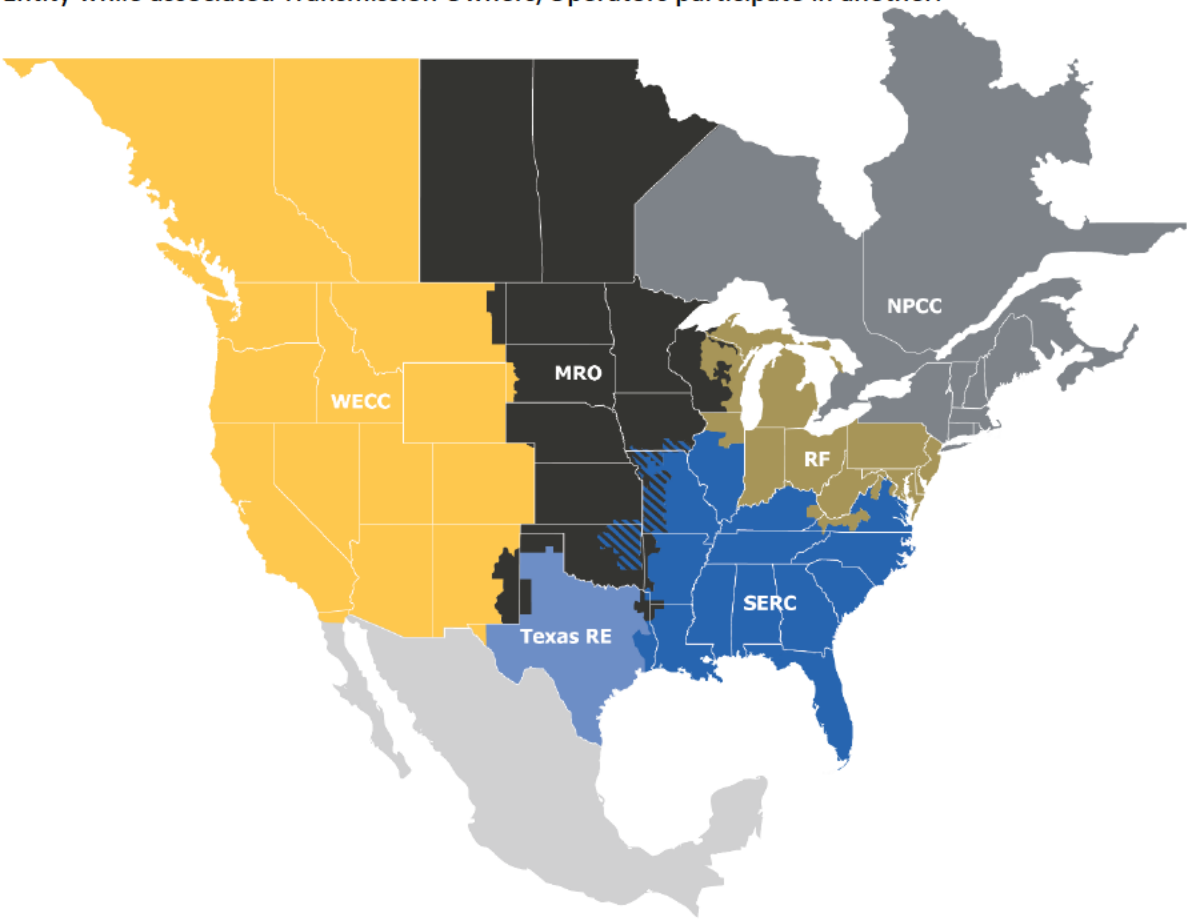
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Preface

Electricity powers our modern life and is the bedrock of our economic wellbeing. The Electric Reliability Organization (ERO) Enterprise—comprised of NERC and the six Regional Entities—is firmly committed to assuring a highly reliable, resilient, and secure bulk power system (BPS) in North America. The ERO Enterprise enables collaborative engagement with industry, regulators, and stakeholders, embracing innovation and supporting the needs of nearly 400 million people.

RELIABILITY | RESILIENCE | SECURITY
POWERING TODAY. PROTECTING TOMORROW.

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About This Technical Assessment

Introduction

The *State of Reliability* (SOR) report seeks to inform regulators, policymakers, and industry leaders on the most significant reliability risks facing the BPS and describe the actions that the ERO Enterprise has taken and will take to address them. This year's SOR report is comprised of two publications: this *2026 SOR Technical Assessment*, which provides NERC's comprehensive annual technical review of BPS reliability for the 2025 operating (calendar) year, and the *2026 SOR Overview*, which is a high-level summary of the Technical Assessment with the following details:

- The *2026 SOR Overview* replaces the key findings previously found in the Technical Assessment.
- This *2026 SOR Technical Assessment* details major occurrences and provides in-depth analysis of risks and resilience, grid transformation and performance, and related performance metrics.

Purpose of the SOR

Both the Overview and the Technical Assessment provide objective and concise information for policymakers, industry leaders, and regulators on issues that affect the reliability and resilience of the North American BPS. Specifically, the SOR report does the following:

- Analyzes performance trends and emerging reliability risks
- Reports on the relative health of the interconnected system
- Measures the success of mitigation activities

NERC, as the ERO, works to assure the effective and efficient reduction of reliability and security risks to the North American BPS. Annual and seasonal risk assessments look to the future, and special reports on emergent risks serve to identify and mitigate potential risks. This assessment identifies performance trends and provides strong technical support for those interested in the detailed analytics.

NERC defines the reliability[1] of the interconnected BPS in terms of two basic and functional aspects: adequacy and operating reliability.

The *2026 SOR* report focuses on BPS[2] performance during the prior calendar year as measured by an established set of performance metrics, other reliability indicators, and more detailed analysis performed by ERO staff and technical committee participants. Data used in the analysis comes from the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Misoperation Information Data Analysis System (MIDAS), voluntary reporting into the Event Analysis Management System (TEAMS), Bulk Power System Awareness monitoring and processes, and the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group. ERO staff developed this independent assessment with support from the Performance Analysis Subcommittee (PAS).

[1] Learn About NERC provides background information about NERC, the definition of reliability, and the electric grid.

[2] The term BPS is defined in Section 215 of the Federal Power Act as facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and electric energy from generating facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy. 16 U.S.C. § 824o(a)(1). Bulk Electric System (BES) is a subset of the BPS and is a defined term under the NERC Glossary as approved by the Federal Energy Regulatory Commission (FERC). As the Electric Reliability Organization, NERC is responsible for developing and enforcing Reliability Standards to ensure an adequate level of reliability of the BPS and assessing reliability of the BPS. NERC's regulatory model is designed to ensure that entities capable of affecting the reliability of the BPS are registered and subject to Reliability Standards. North Am. Elec. Reliability Corp., 187 FERC ¶ 61,196, P 53 (2024).

NERC also produces the following regular assessments to evaluate BPS security as well as present and future BPS reliability:

- *Long-Term Reliability Assessment* (LTRA)
- Summer and Winter Assessments
- Electricity Information Sharing and Analysis Center (E-ISAC) *End-of-Year Report*

Considerations

- Data in the SOR report represents the performance for the January–December 2025 operating year unless otherwise noted.
- Unless specified otherwise, analysis in this report is based on data from 2021–2025 that was available in Spring 2026, and it provides a basis to evaluate 2025 performance relative to performance over the last five years. All dates and times shown are in Coordinated Universal Time (UTC).
- The SOR report is a review of industry-wide trends and not the performance of individual entities.
- When analysis is presented by Interconnection, the Québec Interconnection (QI) is combined with the Eastern Interconnection (EI) unless specific analysis for the QI is shown.

Chapter 1: Major Occurrences for 2025

Overall, the BPS was reliable[3] throughout 2025. This chapter highlights major occurrences and reports that were issued in 2025. These occurrences and reports did not constitute a key finding but had a notable impact on the BPS.

Figure 1.1 highlights important numbers and facts about the North American BPS. Table 1.1 shows the five-year trend of these numbers.

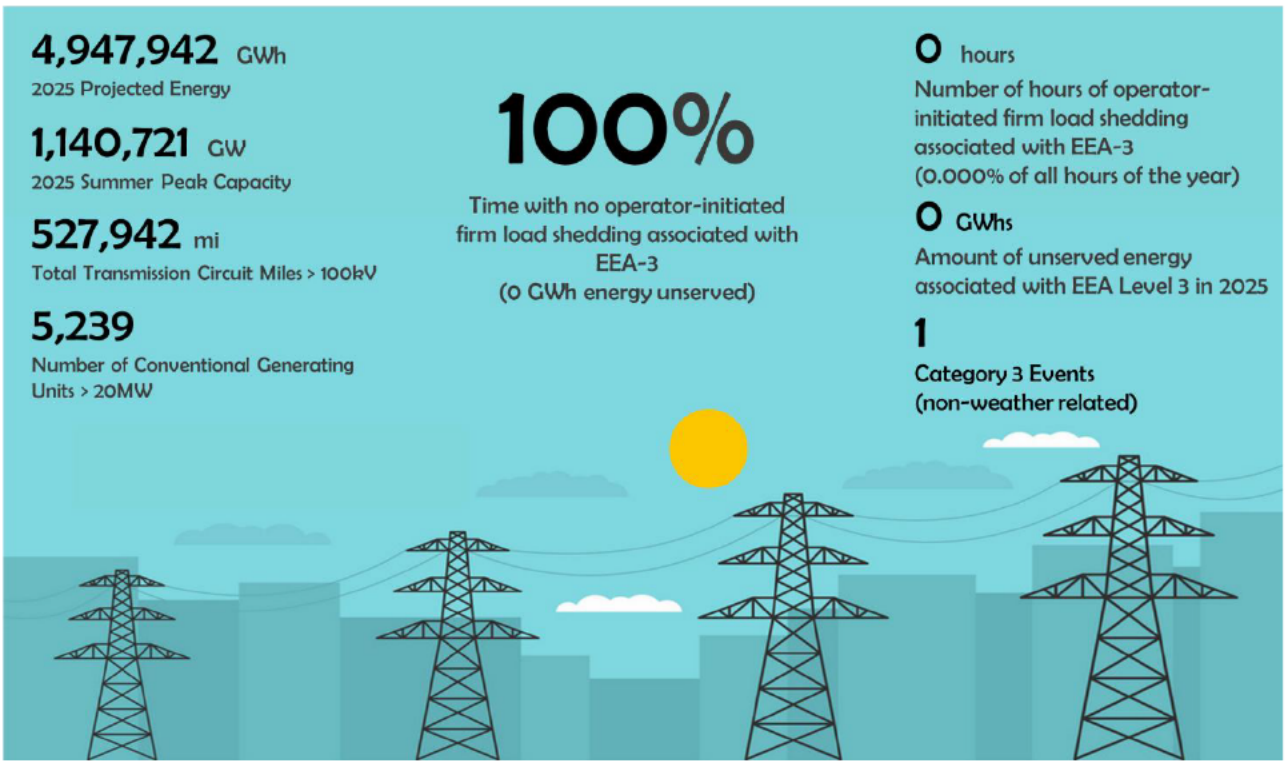


Figure 1.1: 2025 BPS Inventory and Performance Statistics

Table 1.1: Five-Year BPS Inventory and Performance Statistics

Rank	2021	2022	2023	2024	2025
Projected Energy (GWh)	4,585,939	4,674,290	4,687,894	4,856,251	4,947,942
Actual Energy (GWh)	4,626,790	4,695,921	4,663,574	4,787,277	N/A
Summer Peak Capacity (MW)	1,056,980	1,057,455	1,071,370	1,087,354	1,140,721
Total Transmission Circuit Miles >100 kV miles	508,766	522,433	529,344	526,853	527,942
Count of Transmission Circuits >100 kV	28,411	29,165	29,932	30,014	30,666
Count of Transformers with a Low-Side Voltage >100 kV	5,715	5,773	5,805	5,832	5,866
Number of Conventional Generating Units >20 MW[4]	5,375	5,453	5,290	5,243	5,239

[3] Learn About NERC provides background information about NERC, the definition of reliability, and understanding the grid.
[4] 2025 methodology was updated to only include mandatorily reported units that submitted at least one performance record.

Table 1.1: Five-Year BPS Inventory and Performance Statistics					
Rank	2021	2022	2023	2024	2025
Reported MW of Installed Conventional Generation[5]	913,103	926,302	902,018	896,430	876,982
Reported MW of Installed Wind Generation[6]	112,811	124,039	129,963	135,866	138,190
Reported MW of Installed Solar Generation[7]	N/A	N/A	N/A	N/A	N/A
Portion of Hours in the Year with No Operator-Initiated Firm Load Shedding Associated with Energy Emergency Alert Level 3 (EEA 3)	99.2%	99.4%	100%	>99.9%	100%
Category 3 Events (Non-Weather Related)	0	1	0	1	1
Amount of Unserved Energy Associated with EEA 3 (GWh)	1,015.5	96.2	0	0.1	0
Number of Hours with Operator-Initiated Load Shed	71	56.5	0	0.4	0

Major Weather Events

Although 2025 was generally temperate, major weather events continue to be considered the greatest risk to reliability due to the increase in frequency, footprint, and duration; NERC's *ERO Reliability Risk Priorities Report*[8] identified resilience to extreme events, including extreme natural weather events, as one of the five risk groupings that represent evolving risks to reliability. Major weather events in 2025, including severe winter storms, thunderstorms, and tornadoes, were analyzed and collectively found to have had less of an impact on the BPS than in previous years. Of the 23 billion-dollar events highlighted in **Figure**,[9] only three appeared in the **Severity Risk Index** and six in the **Analysis of Transmission System Resilience** section. Although numerous economically impactful events also occurred in Canada in 2025 (**Figure**), none were considered to have had a major impact on the BPS based on data used in the severity risk index (SRI) and transmission system resilience analysis.

[5] MW of installed conventional generation is calculated based on highest net dependable capacity reported in GADS performance for the given year. Only units >20 MW are required to report for GADS. Units that did not complete performance reporting are excluded from this total.

[6] Includes plants with a total installed capacity >75 MW.

[7] During this year's data analysis, NERC identified significant GADS solar data reporting errors and numerous missing plants compared to EIA 860 data. NERC will be coordinating with Regional Entity staff to perform industry outreach and resolve these errors in 2026.

[8] NERC's ERO Reliability Risk Priorities Report

[9] In alignment with evolving priorities, NOAA's National Centers for Environmental Information (NCEI) will no longer be updating the Billion Dollar Weather and Climate Disasters product. Climate Central, a policy-neutral 501(c)(3) nonprofit now generates a similar product.

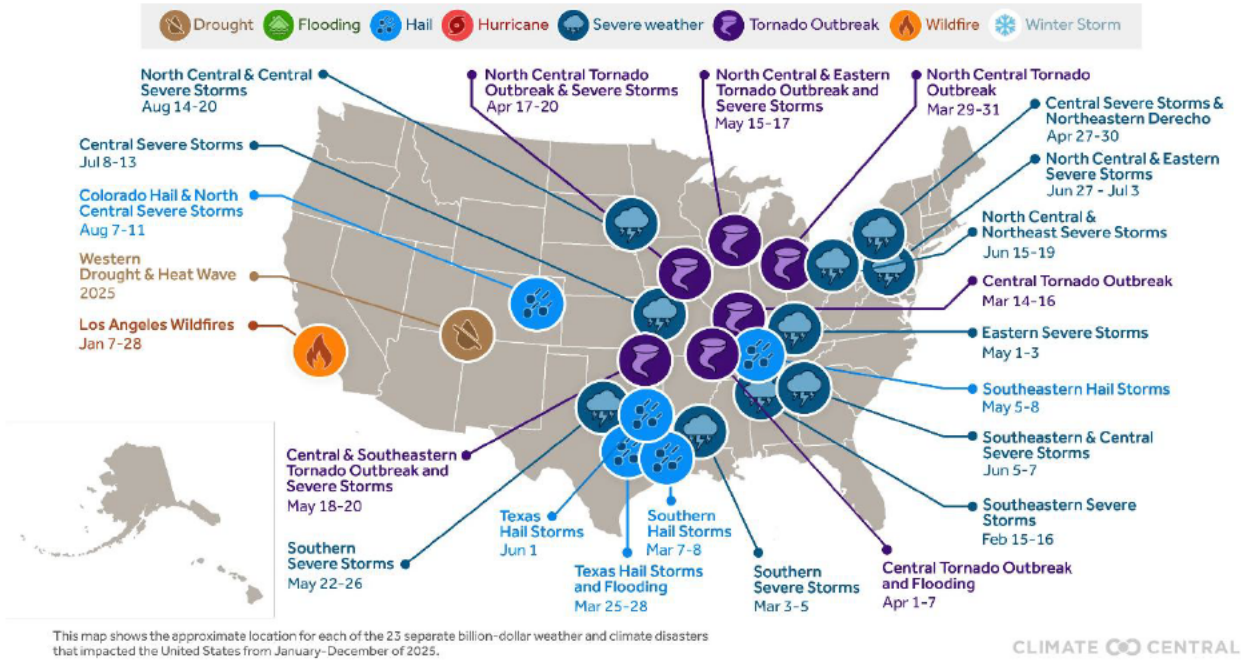


Figure 1.2: 2025 U.S. Billion-Dollar Weather and Climate Disasters[10]



Figure 1.3: 2025 Canadian Insured Catastrophic Losses[11]

[10] The peer-reviewed methodologies behind this dataset remain unchanged at Climate Central, where the project will continue to be led by Adam Smith, who served as the lead scientist for the project at NOAA from 2010 to 2025. U.S. Billion-Dollar Weather and Climate Disasters | Climate Central

[11] Severe weather-related insured losses in Canada exceed $2.4 billion in 2025

Major System Events and Observations

The following sections highlight major system events and observations that occurred last year. While these events were notable and may have impacted many customers, NERC has determined that they do not belong in the SOR Overview as no industry-wide or policy action is being proposed.

Wyoming System Event

As further detailed in the WECC and NERC joint disturbance report,[12] in the early afternoon of November 13, 2025, the northeast portion of the Western Interconnection (WI) experienced a system disturbance that triggered cascading outages affecting about 250,000 customers for up to nine hours. The event impacted parts of several states, including Montana, South Dakota, Wyoming, and Nebraska, with one Transmission Operator (TOP) experiencing a complete blackout across facilities located on the seam between two Reliability Coordinators (RC). This is a low-load, generation-rich portion of the Interconnection.

The disturbance began with a planned outage of a 500 kV transmission line, part of a critical path necessary to deliver wind and thermal generation to distant load centers in the WI. The outage was scheduled for 8:00 a.m. Mountain but postponed until 12:00 p.m. Mountain due to delays in field personnel availability at remote stations. During this delay, wind generation increased more than 50% above the day-ahead operational planning analysis (OPA) studied flows.

A remedial action scheme (RAS) is in place to automatically trip wind generation for unplanned outages to ensure system balance. Prior to switching, the TOP raised the RAS arming setpoint, effectively disabling its tripping function. Operators relied on real-time contingency analysis (RTCA) tools but were unaware of disabled alarms in their RTCA contingency modeling and the inaccurate megavolt-ampere reactive (Mvar) generation parameters that masked the issues that would occur for opening the 500 kV line.

With real-time tools showing no issues, the TOP removed the line from service. Power shifted to an adjacent 500 kV line, causing a rapid voltage collapse to approximately .30 per unit. Protective relays correctly tripped the line within 0.4 seconds, and, with the RAS disabled, there was no action to reduce wind generation.

Most of the western grid remained intact as power flows shifted across the area; however, the system experienced a rapid loss of more than 4,800 MW of coal, natural gas, solar photovoltaic (PV), and wind generation within six seconds. The sudden imbalance caused frequency to dip to 59.758 Hz, after which it gradually recovered and stabilized over the next six minutes. Underfrequency load shedding mechanisms were appropriately triggered in the region before the blackout occurred. Total load loss was just over 1,100 MW.

Coordinated restoration was delayed due to limited RC visibility and competing mitigation priorities. High voltages and seam coordination challenges slowed progress, including instances where equipment was energized across TOP boundaries without prior notification. Most load was restored within nine hours. The entity performing the initial line switching returned most of its generation within eight hours, but one thermal plant required more than four days, and one thermal unit experienced catastrophic damage.

Opportunities for Improvement

Personnel

- Communications during system events should be clear and concise and ensure that mutual understanding has been achieved prior to actions being taken.

[12] WECC and NERC Joint Wyoming Disturbance Report

- System restoration training should be re-evaluated for effectiveness with respect to the RCs and TOPs to improve the effectiveness of restoration, focusing on their system status by thorough assessments, and communication and coordination among the entities.

Processes

- RCs should verify how far to model across seams to provide overlapping visibility of potential contingencies and operating limits.
- Entities should use conservative decision making in verifying any discrepancies between RTCA results.
- RCs/TOPs should evaluate the variability of the generation resources in their OPA and set appropriate max/min parameters within system operating limits (SOL) to prompt additional operator actions.

Tools

- Entities should investigate the use of additional offline tools to confirm/evaluate online tool results.
- To ensure mutual understanding, RCs and TOPs should clearly define the information needed and the means of communication to be used.
- Entities should ensure consistent modeling of system parameters such as RAS status.

Load-Pocket Shoulder Season Challenges

In recent years, shoulder seasons have become increasingly challenging for BPS operators to manage, resulting in several recent instances of pre-contingent load shedding.[13] In all these cases, RTCA indicated that significant issues, such as cascading outages or widespread voltage instability, would likely occur following the next loss of a transmission element.

Shoulder seasons are the spring and fall periods between summer and winter peak load periods and have historically been used for planned maintenance. Because of this common industry practice, fewer generators and transmission lines are available for operators to utilize during these periods, which has historically been offset by the lower peak loads. Spring in particular also coincides with more frequent thunderstorms. In recent years, tightening reserve margins and an increasing baseline load have compounded with a rapid increase in variable energy resources (VER), which present an inherent level of uncertainty, to significantly increase operating challenges during these periods.

Instances where these challenges align in specific small areas within a Balancing Authority's (BA) footprint that have limited transmission lines connecting them to the remainder of the system, also known as load pockets, have been the catalyst of several recent instances of pre-contingent load shedding.[14]

Opportunities for Improvement

As the Interconnections are changing in both resource mix and load characteristics coupled with weather variability during shoulder seasons, a different approach may be needed when coordinating facility outages. Entities should consider the following:

- Planning a higher level of operating margin and committing additional generation in load pockets to account for larger real-time variabilities in generation, load, and weather
- Including demand-side management in the mitigation plans for insufficient capacity in load pockets

[13] *Incident Review: Load-Pocket Shoulder Season Challenges*

- Considering more extreme scenarios when determining which outage requests to approve
- Considering PRC-023 loadability requirements when determining contingent overload thresholds that trigger cascading analysis
- Periodically revisiting planned outages and considering updated and expected system conditions to determine whether such outages should be postponed
- In market areas, reviewing processes to ensure that reliability studies (OPA) are using accurate generation dispatch and availability as determined from the latest day-ahead market analysis (coordinating processes that eliminate discrepancies between the day-ahead market unit commitment plan and the OPA studies)

Chapter 2: Severity Risks, Impact, and Resilience

This chapter identifies and examines the highest-stress days on the BPS in 2025 using established measures.

Severity Risk Index (SRI)

The SRI provides a quantitative measure of the relative severity of the combined impact of load, generation, and transmission loss on the BPS daily and offers a comprehensive picture of the performance of the BPS, allowing NERC to assess year-on-year reliability trends. For 2025, load-loss data voluntarily reported to the IEEE Distribution Reliability Working Group was used to estimate the daily load-loss component; generation and transmission components are calculated from data collected by NERC.

By comparing the daily SRI scores in descending order for each of the past five years, the overall performance of the BPS can be evaluated (Figure 2.1). The inset chart in the upper right of Figure 2.1. provides a detailed comparison of the top 10 SRI days for each year. The annual cumulative SRI shown in Table 2.1 sums each day's SRI for the year by component.

The cumulative performance of the BPS is calculated by summing each day's SRI for the year. Table 2.1 shows the annual cumulative SRI for the five-year period of 2021–2025.

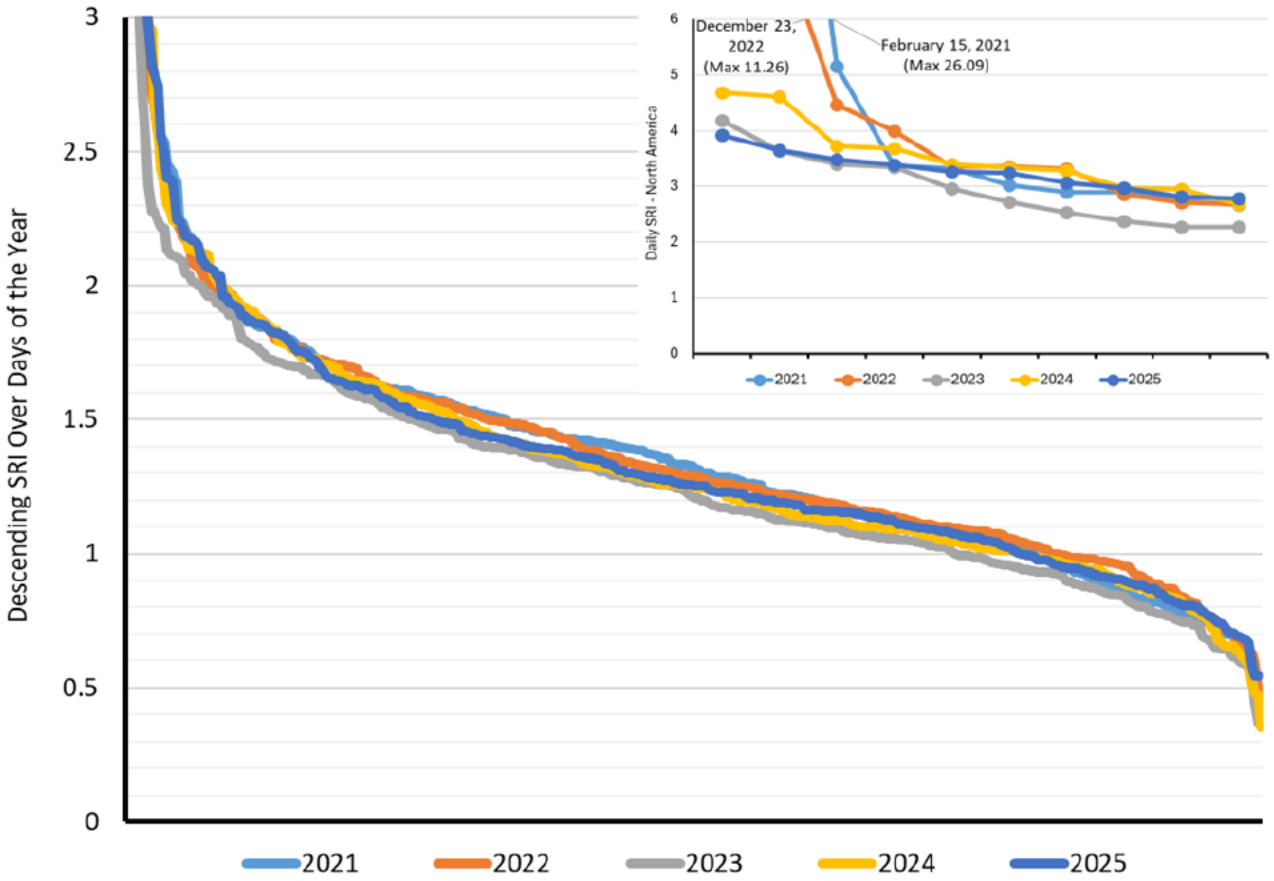


Figure 2.1: NERC Descending SRI by Day of the Year

Table 2.1: Annual Cumulative SRI					
Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2021	375.9	63.9	96.6	536.4	1.47
2022	404.1	59.7	55.2	518.9	1.42
2023	356.9	64.1	50.5	471.5	1.29
2024	383.7	60.6	51.8	496.1	1.36
2025	395.0	55.7	45.3	496.0	1.36

Figure 2.2 plots the 10 highest SRI days daily and the SRI scores for 2025 against control limits that were calculated by using the seasonal daily performance of the prior four years. A general normal range of performance is represented by the gray-colored band, showing the daily seasonal 90% control limits.[14] Days that extend above the seasonal control limit indicate irregularities for the season but may not have a high enough SRI to rank in the top 10.

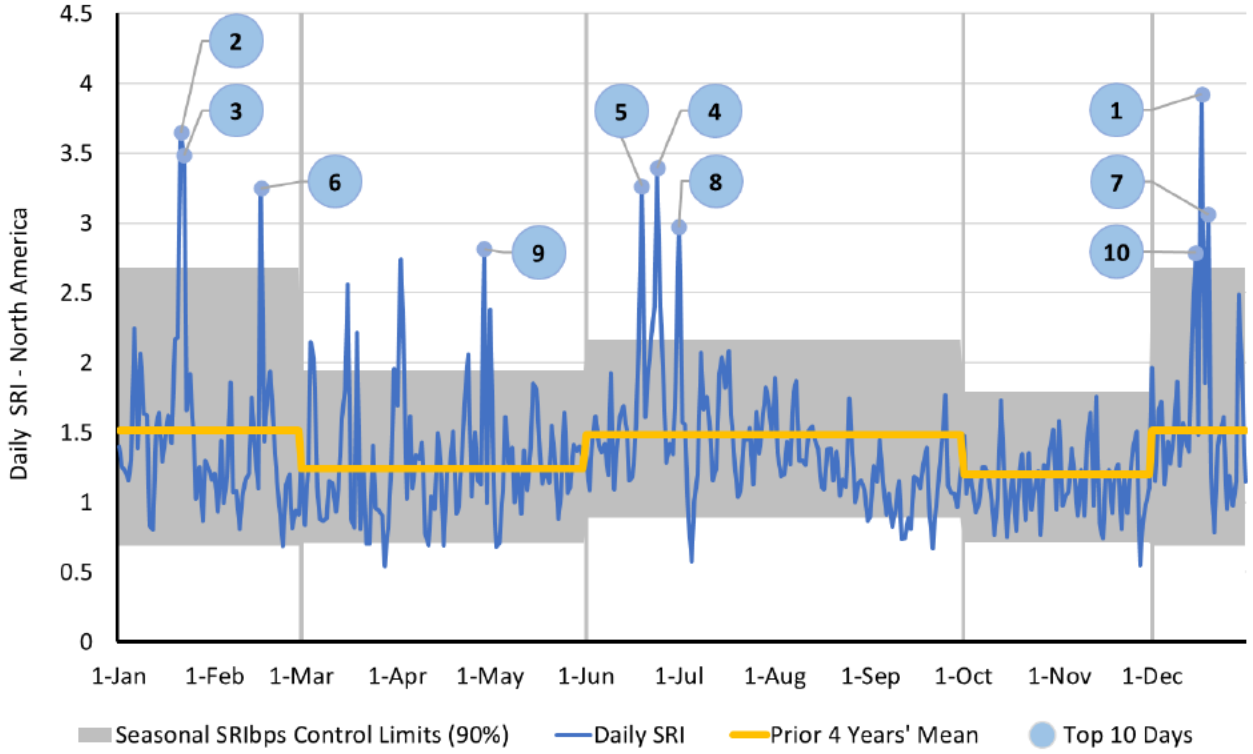


Figure 2.2: 2025 Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

Table 2.2 details the scores for the top 10 SRI days during 2025. The table identifies where atypical weather conditions were ongoing during the day and the general location by Regional Entity. Weather conditions in 2025 were fairly temperate with no hurricanes making landfall and only a few large, major winter storms and thunderstorms. The most impacted day was the result of an atmospheric river, a phenomenon that resulted in high winds and heavy rainfall in the Northwestern United States.

[14] The shaded area reflects the 90% confidence interval (CI) of the historic values between the 5th and 95th percentiles.

Table 2.2: 2025 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	17-Dec	3.92	2.34	0.95	0.64	Northwestern Atmospheric River	WECC
2	21-Jan	3.65	3.24	0.32	0.09	Winter Storm Enzo	RF, SERC
3	22-Jan	3.49	3.27	0.14	0.07	Winter Storm Enzo	RF, SERC
4	24-Jun	3.39	2.75	0.24	0.40	Thunderstorms	NPCC, RF, SERC
5	19-Jun	3.27	1.35	0.26	1.65	Thunderstorms, Tornadoes	MRO, RF, SERC
6	16-Feb	3.25	1.91	0.21	1.13	Severe Storm in Southeast	SERC
7	19-Dec	3.06	1.56	0.31	1.19	Northwestern Atmospheric River	WECC
8	1-Jul	2.97	2.75	0.16	0.06	Coincidental Generator Outages	All Regions
9	29-Apr	2.81	1.03	0.28	1.51	Thunderstorms	MRO, NPCC, RF
10	15-Dec	2.79	2.47	0.10	0.22	Winter Storm	RF, SERC, Texas RE

SRI Performance Trends

To put the severity of days in 2025 into context with historic BPS performance, the top 10 days over the five-year period are updated annually. Historically, the PAS has identified days with an SRI below 5 to generally be low impact to the BPS. Table 2.3 identifies the top 10 SRI days occurring for 2021–2025 with the contribution of the generation, transmission, and load-loss components to the SRI for each day; contributing event information; and the Regional Entities impacted by the event. For 2025, there were no days severe enough to be added to the top 10 SRI days of the past five years, with all days having an SRI under 4, which has historically been considered a very good year.

Table 2.3: 2021–2025 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 15, 2021	61.35[15]	5.54	0.78	55.02[16]	Winter Storm Uri	MRO, RF, SERC, Texas RE, WECC
2	February 16, 2021	18.31[17]	5.01	0.53	12.78[18]	Winter Storm Uri	MRO, RF, SERC, Texas RE, WECC

[15] IEEE DRWG data supplemented with Eagle-I information.
[16] Ibid.
[17] Ibid.
[18] Ibid.

Table 2.3: 2021–2025 Top 10 SRI Days							
Rank	Date	SRI and Weighted Components				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
3	December 23, 2022	11.25	8.16	0.84	2.26	Winter Storm Elliott	All
4	December 24, 2022	7.44	6.43	0.95	0.05	Winter Storm Elliott	All
5	December 11, 2021	5.16	1.01	0.70	3.45	Severe Storms	MRO, NPCC, RF, SERC, WECC
6	September 27, 2024	4.69	1.44	2.40	0.85	Hurricane Helene	SERC
7	January 9, 2024	4.61	1.59	0.68	2.35	Northwestern Winter Storm, Eastern Tornadoes and Severe Storms	RF, SERC, Texas RE, WECC
8	June 14, 2022	4.46	1.52	0.38	2.57	High Temperatures and Derecho	MRO, NPCC, RF, SERC, Texas RE
9	April 1, 2023	4.19	1.10	0.44	2.65	Hurricane Florence	MRO, NPCC, RF, SERC
10	June 15, 2022	3.99	1.59	0.19	2.21	High Temperatures and Derecho	MRO, NPCC, RF, SERC, Texas RE

Impact of Extreme Event Days

Extreme Event Days

Extreme event days are identified as event days above the 95th percentile upper bound relative to the past four years' severity measures for any season within North America or a specified Interconnection. This analysis expands on the transmission and generation components that contribute to the SRI reported in the previous **SRI Performance Trends** section to explore the causes of the extreme days.

The impacts of extreme days on BPS resources are characterized by the amount of transmission or generation reporting immediate forced outages or derates starting on a given day. By analyzing the impact and causes of extreme event days, it is possible to identify which conditions pose the highest risk to the BPS. While this analysis does not address every potential scenario, learning from performance during extreme events helps provide insight into how the system may respond to a range of conditions and events.

- Extreme-day outages for transmission and generation by Interconnection are presented in **0**. The analysis provided in the following subsections is reported separately for transmission and generation. The total estimated megavolt-amperes (MVA) transfer capacity[19] reported in TADS or

[19] Severity Risk Index

net maximum capacity reported to GADS for all Regional Entities or by Interconnection is shown at the top of each figure in this chapter.

Transmission Impacted

In 2025, 12 days met the criteria of extreme transmission days for the BPS as compared to 19 in 2024. The most extreme transmission-impacting day was December 17, primarily due to a combination of storms throughout the Northwestern United States as part of an atmospheric river phenomenon, affecting a total of 16 states (Figure 2.3), where the MVA capacity impacted due to automatic transmission outages was 5.8 times as high as the associated season's average. Other extreme days include March 14–15 due to a widespread winter storm, March 9 due to a series of severe thunderstorms, and the November 13 Wyoming System Event.

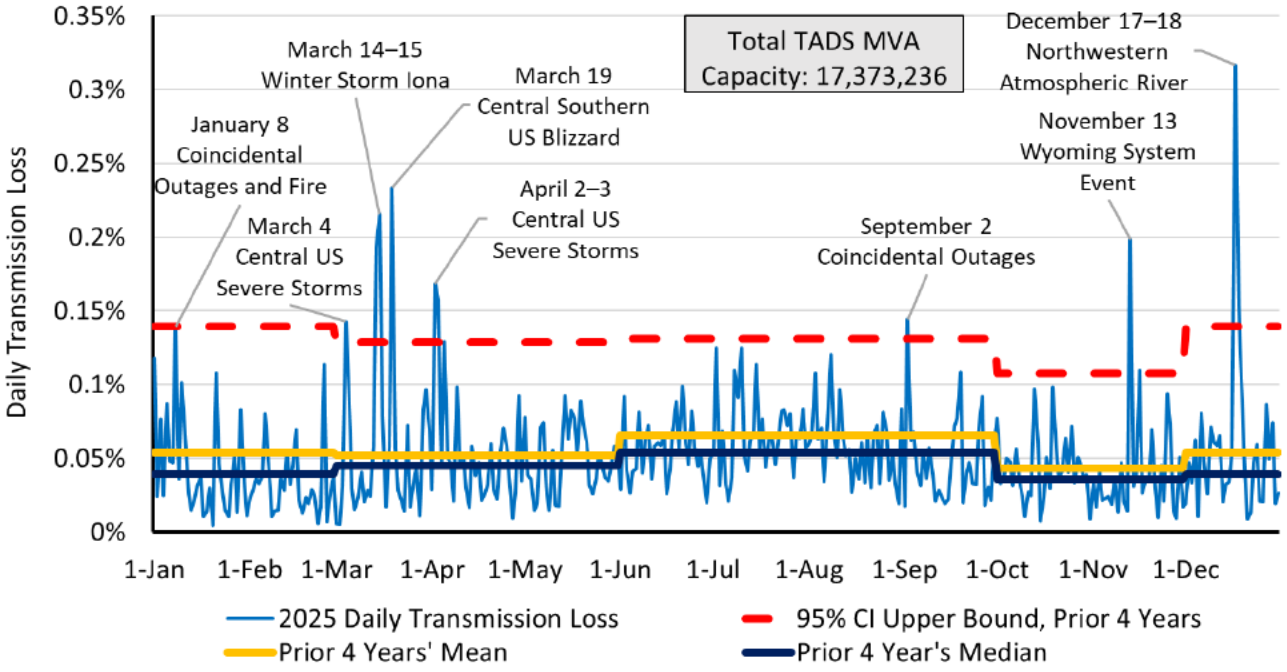


Figure 2.3: 2025 Sustained Transmission Outages During Extreme Days

The top causes reported for outages that occurred on extreme days are shown in rank order of MVA loss for North America and each Interconnection (Table 2.4). Causes for outages are based on those Interconnections' extreme days, shown in Appendix A. The number one outage cause for 2025 was Weather (Excluding Lightning), which affected almost five times more MVA capacity than any of the other top causes for the year across the Bulk Electric System (BES) and within each Interconnection.

Table 2.4: Top Transmission Initiating Outage Causes on Extreme Days Ranked by MVA Capacity					
Area	**Cause #1**	**Cause #2**	**Cause #3**	**Cause #4**	**Cause #5**
All NERC Regional Entities	Weather (Excluding Lightning) 156,789	Failed AC Substation Equipment 31,586	Unknown 31,515	Power System Condition 28,585	Contamination 23,963
Eastern–Québec Interconnections	Weather (Excluding Lightning) 142,446	Failed AC Substation Equipment 35,696	Lightning 24,057	Human Error 19,268	Failed AC Circuit Equipment 15,094
Texas Interconnection	Weather (Excluding Lightning) 18,052	Failed AC Substation Equipment 10,536	Lightning 6,993	Power System Condition 4,911	Unknown 4,315
Western Interconnection	Weather (Excluding Lightning) 49,701	Unknown 39,187	Fire 37,074	Power System Condition 30,008	Other 20,165

Conventional Generation Impacted

Based on analysis of GADS data, a total of 20 days in 2025 qualified as extreme for North America's BPS (Figure 2.4) compared to 26 in 2024. The four highest-impact days for generation loss were the January 19–22 winter storms. On these days, conventional generating units experienced outages that were 1.8–2.9 times as severe as the associated season's average. One of the extreme generation loss days coincided with extreme days identified for transmission (December 17 Atmospheric River Event). The days on which generation outages were slightly above the seasonal bounds that do not have a specific cause listed have been investigated and were either found to coincide with severe thunderstorms or high temperatures or saw many coincidental outages that were not a result of adverse weather conditions.

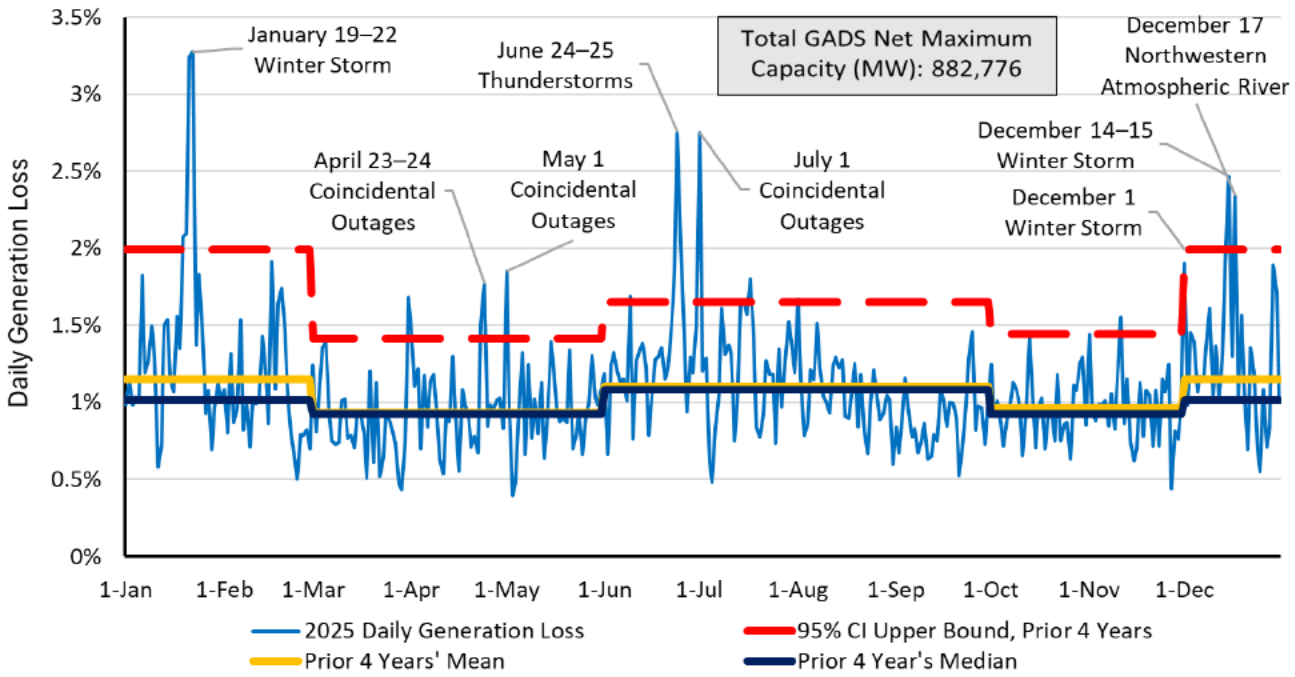


Figure 2.4: 2025 Generation Impacted During Extreme Days

The top causes reported for outages that occurred on extreme days are shown in ranked order by Interconnection (Table 2.5). Causes for Interconnections are based on those Interconnections' extreme days, shown in Appendix A.

Table 2.5: Top Generation Outage Causes on Extreme Days Ranked by Unavailable Net Maximum Capacity

Area	Cause #1	Cause #2	Cause #3	Cause #4	Cause #5
All NERC Regional Entities	Fuel, Ignition, and Combustion Systems (32,263)	Electrical (25,877)	Boiler Tube Leaks (21,524)	Controls (20,850)	Auxiliary Systems (20,596)
Eastern–Québec Interconnections	Fuel, Ignition, and Combustion Systems (29,278)	Electrical (22,638)	Boiler Tube Leaks (19,109)	Auxiliary Systems (17,338)	Miscellaneous (Gas Turbine) (14,908)
Texas Interconnection	Electrical (11,433)	Controls (9,391)	Boiler Control System (9,094)	Boiler Tube Leaks (7,432)	Feedwater System (5,504)
Western Interconnection	Controls (6,951)	Electrical (6,565)	Auxiliary Systems (5,941)	Turbine (5,740)	Miscellaneous (External) (5,529)

Analysis of Transmission System Resilience

The analysis of large transmission events evaluates transmission outages related to severe weather events that involve 20 or more automatic outages. Outage and restoration processes for transmission elements are analyzed, not the disruption and restoration of distribution customer load. Restoration of the transmission system to serve customer load is always the priority.

The analysis of the 2025 transmission outages identified 13 large transmission events, 12 of which were caused by weather and one non-weather event (**Wyoming System Event**) and quantified the resilience and restoration statistics for them. The resilience statistics enable the measurement and tracking of some abilities of the transmission system to withstand, adapt, protect against, and recover during and after major weather events.[20]

This section provides a detailed description of the December 17 Atmospheric River Event as the largest outage event on the transmission system in 2025. Multiyear statistics by associated weather type and changes in the severity and duration of these events as measured by the number of transmission outages reported for each cause are compared for two five-year periods: 2020–2024 and 2021–2025.

TADS Outage Grouping and 2025 Large Weather Events

The outage grouping algorithm[21] considers automatic outages reported in TADS based on Interconnection and associated start and end times. The resulting transmission outage events are determined to be weather-related if at least one outage in the event is initiated or sustained by one of the following TADS cause codes: Weather (Excluding Lighting), Lightning, Fire, or Environmental. The procedure produces groupings of outages that are further reviewed and compared with the weather information from external sources to confirm or refine the events. The TADS data was supplemented by Velocity Suite as a source to identify utility company footprints, and weather sources like the National Oceanic and Atmospheric Administration (NOAA) and Ventusky were used to visualize the weather events. Matching the data from these sources provides a much clearer picture of outages within the event. This combination of automatic and manual procedures results in a set of transmission events that can cross boundaries of different utilities and Regional Entities to capture significant events caused by major weather occurrences, such as hurricanes and severe winter storms.

In 2025, the grouping algorithm identified 13 large events; 12 of the 13 were weather-related events, in addition to the **Wyoming System Event** that started on November 13. **Table 2.6** lists these events in chronological order and shows the severe weather/event type for each event with statistics that quantify the impact of the event on the transmission system.

In 2025, the largest event was the December 17 Atmospheric River in the WI with 137 outages, affecting 5,343 miles and 48,418 MVA of capacity, making it the highest-impact storm of the year on the transmission system (shown in **blue** in **Table 2.6**).

The second largest event, as identified by the grouping algorithm, was the March 14 severe storm event, which saw everything from blizzards in the north to tornadoes in the south (with 124 transmission outages reported) and occurred in the EI (shown in **red** in **Table 2.6**). Though it was the second largest event in terms of the number of outages, it had the largest amount of transmission capacity affected (MVA) and the highest number of element-days lost of any event in 2025 with 52,678 MVA affected and 359 element-days lost.

[20] *Resilience Framework, Methods, and Metrics for the Electricity Sector* | IEEE Power & Energy Society Resource Center (ieee-pes.org)

[21] *Impact of Extreme Weather on North American Transmission System Outages* | IEEE Conference Publication | IEEE Xplore

It is also worth noting that the **Wyoming System Event**, though not weather-related, had enough outages to be considered a large transmission event. This event (shown in **purple** in **Table 2.6**) had the quickest recovery of all large transmission events in 2025, with a time to 95% element restoration of just 0.1 days and a final restoration duration of 1 day.

Table 2.6: 2025 Large Transmission Outage Events

Event Start	Event Outage Count			Interconnection	Extreme/Severe Weather Event	Transmission Capacity Affected (MVA)	Miles Affected	Final Restoration Duration (Days)	Time to 95% Restoration, Elements (Days)	Element-Days[22] Lost	Most Simultaneous Unavailable Capacity (MVA)
	All Automatic	Sustained Automatic	Momentary Auto.								
21-Jan	22	19	3	ERCOT	Blizzard	11,714	581	.8	.6	5	5,899
16-Feb	31	23	8	Eastern	Thunderstorms	13,391	1,023	2.9	1.8	13	5,855
25-Feb	29	24	5	Western	Winter Storm	13,931	940	6.1	6.	30	5,541
4-Mar	31	23	8	Eastern	Blizzard	8,745	867	3.3	2.9	18	4,934
14-Mar	**124**	**104**	**20**	**Eastern**	**Tornadoes, Blizzard**	**52,678**	**4,510**	**54.2**	**12.3**	**359**	**27,011**
19-Mar	79	70	9	Eastern	Tornadoes, Blizzard	30,617	1,899	13.5	7.5	92	18,915
24-Mar	28	15	13	Eastern	Blizzard	9,487	507	44.5	3.7	52	4,741
2-Apr	39	29	10	Eastern	Thunderstorms Tornadoes	15,361	1,550	58.1	9.2	96	7,424
5-Apr	35	32	3	Eastern	Thunderstorms	11,545	1,332	6.5	4.9	37	5,835
29-Apr	51	47	4	Eastern	Thunderstorms	16,352	1,056	5.5	4.4	53	8,567
21-Jun	22	17	5	Eastern	Derecho	7,948	2,098	68.7	17.7	118	6,429
13-Nov	**46**	**46**	**0**	**Western**	**Wyoming System Event**	**25,357**	**1,924**	**1.0**	**0.1**	**2**	**12,320**
17-Dec	**137**	**129**	**8**	**Western**	**Northwestern Atmospheric River**	**48,418**	**5,343**	**36.7**	**6.1**	**235**	**27,190**

[22]The definition for element-days is provided in Appendix B of the NERC *2022 SOR*.

Outage, Restore, and Performance Curves

Table 2.6 illustrates the variability in event sizes and duration. However, these statistics do not completely explain what happened during the events; the outage, restore, and performance curves of the events provide more details on how the events unfolded.[23] Figure 2.5 serves as an example to describe transmission outages during an event. These curves track the number of elements out or the MVA transmission capacity impact on the vertical axis versus time on the horizontal axis.

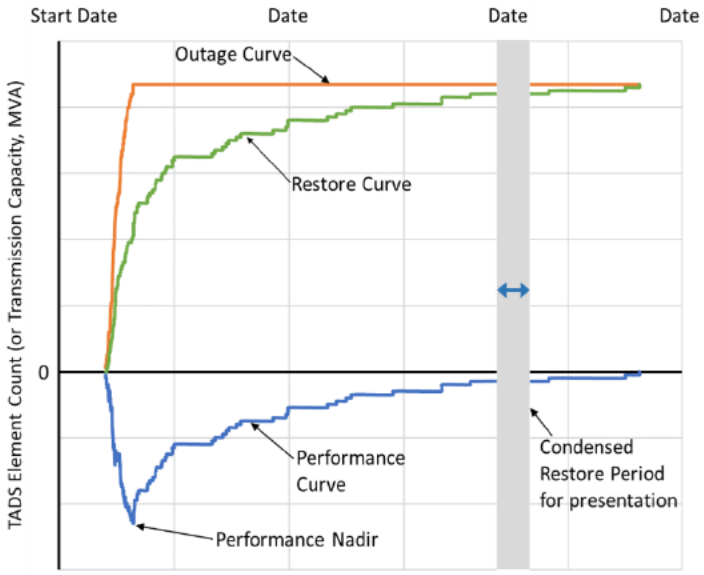


Figure 2.5: Example of Outage, Restore, and Performance Curves for a Large Transmission Outage Event

The outage curve is the cumulative number of elements or cumulative equivalent MVA capacity impact at the time shown on the horizontal axis.

The restore curve is the cumulative number of elements restored or cumulative equivalent MVA restored at the time shown on the horizontal axis.

The performance curve is the number of elements or equivalent MVA capacity impact out simultaneously at the time shown on the horizontal axis. The value is equal to elements or MVA capacity restored minus the elements or MVA capacity (i.e., the performance curve is the restore curve minus the outage curve). The performance curve combines information on degradation and recovery during the event.

The curves enable the calculation of several resilience metrics.[24] These metrics help quantify the abilities of a resilient power system to effectively absorb, withstand, adapt, protect against major weather events (event size, outage process duration and outage rate, time to first restore, the most degraded state in the event, the total element-days and MVA capacity days lost), and recover from and reduce the durations and impacts of major weather events (i.e., event duration, time to first restore, time to substantial restoration, instantaneous restore rate).

[23] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems

[24] Resilience statistics are defined in Appendix B in the *2022 SOR*.

Resilience Curves and Statistics for the WI Atmospheric River, the Largest Transmission Outage Event in 2025

The atmospheric river that made landfall along the U.S. Pacific Northwest coastline on December 17, 2025, brought heavy snow and rain as well as high winds in the area before moving into British Columbia and the northern Midwestern United States. At the storm's peak, there were about 950,000 customer outages across British Columbia, Washington, Oregon, Colorado, and Montana.[25]

The atmospheric river also caused a large transmission outage event in the WI that impacted 18 Transmission Owners. With 137 automatic outages, this event was the largest transmission event in 2025 but less impactful than top historic hurricane events, such as the 2024 Hurricane Helene (431 outages) and the 2017 Hurricane Irma (352 outages).

Out of the 137 automatic outages caused by extreme weather, 133 were ac circuit outages (8 momentary and 125 sustained), two were transformer outages (both sustained), and two were ac/dc back-to-back converter outages (both sustained). The total affected mileage was 5,343 ac circuit-miles, and the total transmission capacity affected was 48,418 MVA. The reported event duration was 36.7 days, with a single 230 kV ac circuit outage continuing until January 22, 2026. The element- and MVA-based curves for the atmospheric river event are shown in Figure 2.6 and Figure 2.7, respectively. The curves are truncated at 01/01/2026 0:00 UTC with one ac circuit outage still unrestored.

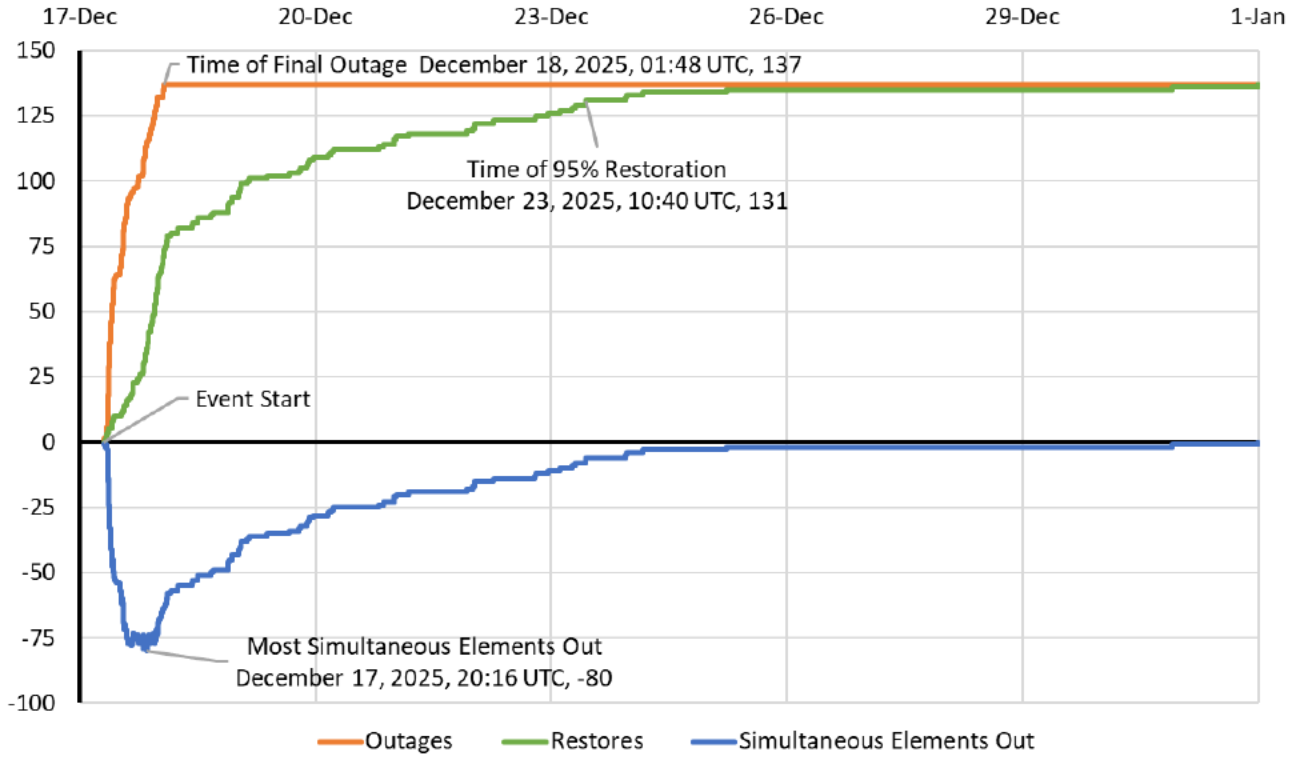


Figure 2.6: Transmission Element Outage, Restore, and Performance Curves for Atmospheric River Event in the Western Interconnection, December 17, 2025–January 22, 2026

[25] Customer outage data sourced from Eagle-I.

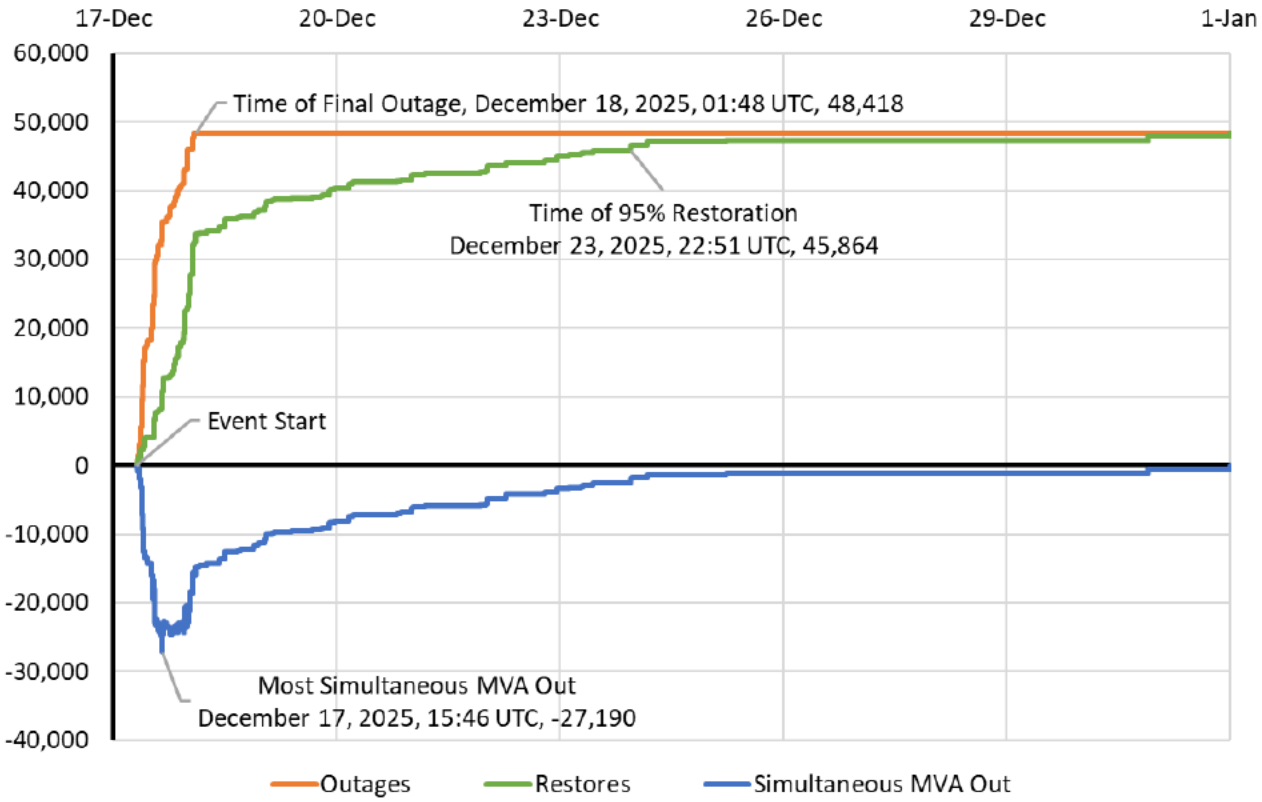


Figure 2.7: Transmission Capacity (MVA-Based) Outage, Restore, and Performance Curves for Atmospheric River Event in the Western Interconnection, December 17, 2025–January 22, 2026

The outage process shown in Figure 2.6 and Figure 2.7 by orange curves started as a cluster of quickly accumulating outages and continued for 18 hours with an average outage rate of 7.4 outages per hour (2,631 MVA per hour). Due to multiple outages of the same ac circuit, a total of 137 outages occurred on 123 distinct ac circuits.

The restoration process shown in Figure 2.6 and Figure 2.7 by green curves started with a momentary restoration 28 minutes after the first outage began, with the first sustained outage restoration 50 minutes after the event started. As is typical for large events, the restoration process progressed rapidly;[26] however, restoration times slowed with a larger percentage of equipment still out than usual. By applying a fitted curve for the restore process[27] to Figure 2.6 it can be estimated that the maximum instantaneous restore rate of 4.3 restores per hour was reached 4 hours and 16 minutes into the event. The restoration rate was 2.4 elements per hour at the time half of the outages were restored (about 19 hours into the event), and only 0.1 elements per hour at the 95% element restoration level. The maximum number of transmission elements simultaneously out was 80 and was observed twice: a momentary nadir occurred about 13 hours after the event started, followed by another 13 minutes later, which lasted 2 minutes. The maximum amount of transmission capacity simultaneously out (27,190 MVA), represented by the nadir of the MVA-based performance curve in Figure 2.7, was observed only once and more than 4 hours earlier than the element-based nadirs. It occurred when a 500 kV ac circuit went out and ended 4 minutes later, when a different 500 kV ac circuit was restored. When the 80 elements were out simultaneously for the element-based nadirs,

[26] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems.

[27] S. Ekisheva, D. K. Pratt, M. Kachadurian, W. G. Martin, J. Norris, and I. Dobson, "Grid Restoration after Extreme Weather Events", 2023 IEEE PES Innovative Smart Grid Technologies Europe (ISGT) Conference.

the total value of transmission capacity unavailable was about 24,000 MVA—notably lower than the MVA out at the MVA-based nadir.

A substantial 95% restoration was reached after 147 hours (17% of the event duration). The substantial 95% restoration for transmission capacity (MVA) took longer, 159 hours or 18% of the event duration. The total loss for the event, calculated as the area between a blue performance curve and the time axis, was 235 element-days lost (Figure 2.6) and 77,097 MVA-days lost (Figure 2.7).

The longest outage was 36.6 days on a 230 kV ac circuit that sustained tower damage. A small number of disproportionately long outages is common in large transmission events. These very large outage durations are often caused by inaccessibility of a portion of the line, damaged structure or equipment or, in some cases, a utility postponing the restoration of a single remaining element because this element is considered not critical for reliability of the grid.[28]

Transmission System Resilience Statistics by Associated Weather Type: 2021–2025

Weather Types

The outage grouping procedure identified 59 large transmission events in the years 2021–2025, two of which were not weather-related (a 2023 contamination event and a 2025 frequency event).[29,30] The 57 large weather-related events were caused by the weather types listed in **Figure 2.8**. If several weather factors were observed together (e.g., hurricane, tornado, and wind), the dominant cause of transmission outages was determined to be the weather type. Multiple sources (i.e., NERC's daily BPS awareness reports, Velocity Suite, NOAA, Ventusky, public media reports) were used in conjunction with cause codes to determine if a weather event was associated with each large transmission event.

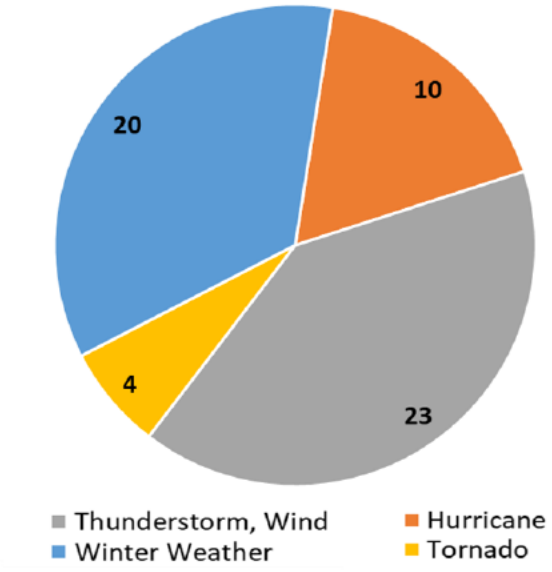


Figure 2.8: Weather Types of Large Transmission Events, 2021–2025

[28] S. Ekisheva, I. Dobson, R. Rieder, and J. Norris, "Assessing transmission resilience during extreme weather with outage and restore processes," 2022 17th International Conference on Probabilistic Methods Applied to Power Systems.
[29] A 2023 large event in SERC with 30 outages caused by Bird Contamination; the event duration was 2.5 days.
[30] A 2025 large event in WECC with 46 outages caused by Power System Condition; the event duration was a day.

Figure 2.9 shows selected resilience statistics for the 2021–2025 events by weather type. Hurricanes caused the largest transmission events, with the average one having 123 outages, while other groups had average outage counts that ranged from 43–64 outages. The maximum number of elements simultaneously out (the most degraded state in an event as indicated by the nadir of the performance curve) fell between 51–67% of the event size on average.

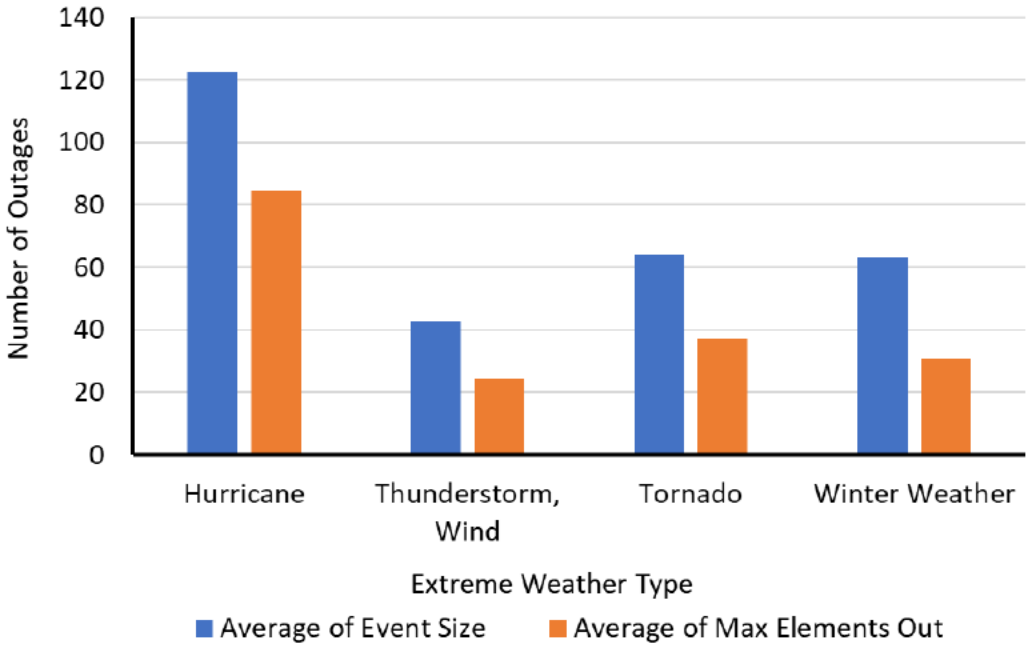


Figure 2.9: Resilience Statistics for 2021–2025 Large Weather-Related Events

Figure 2.10 compares the average event duration with the average substantial restoration duration (the time to restore 95% of outages and 95% of MVA capacity) and shows the time to first restore.

Hurricanes were the highest in average event duration, second for 95% outage restoration duration, and lowest for 95% MVA restoration duration. Tornadoes were the second highest in event duration with the highest average 95% restoration duration for both outages and MVA capacity. While some value can be extracted from evaluating the average event duration, the time to 95% restoration is typically more indicative of overall performance.[31]

[31] *How Long is a Resilience Event in a Transmission System?: Metrics and Models Driven by Utility Data* | IEEE Journals & Magazine | IEEE Xplore

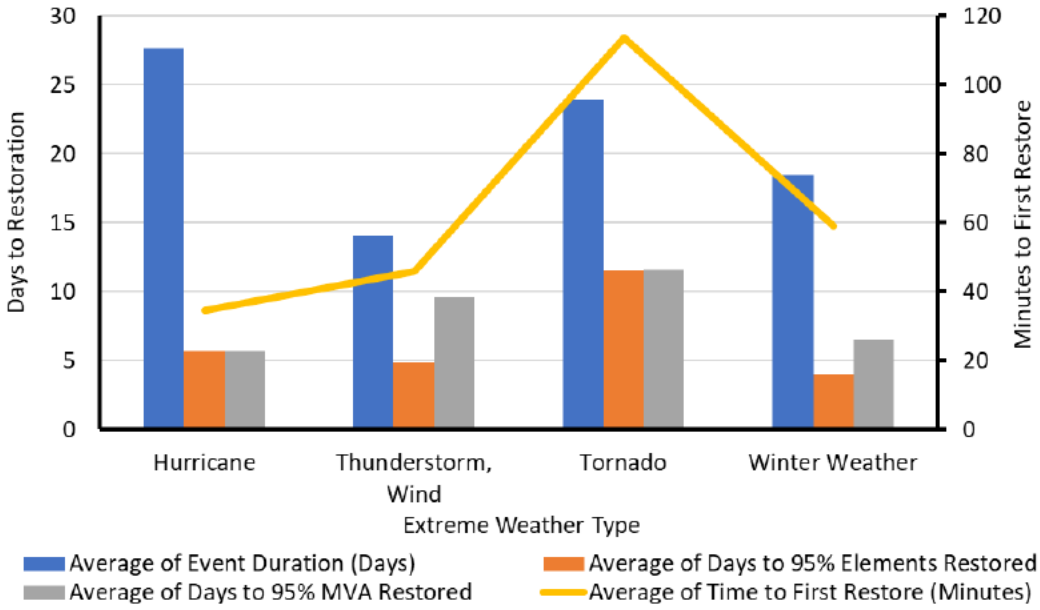


Figure 2.10: Average Event Duration vs. Average Sustained Restoration Duration

Changes in Resilience Statistics: 2021–2025 Events vs. 2020–2024 Events

To draw conclusions about improving, stable, or declining transmission resilience against weather, the analysis focuses on capturing changes in the several metrics that quantify resilience over years. The resilience statistics are calculated for large weather-related events for the years 2020–2024 and 2021–2025, and changes in the metrics by weather types were analyzed. The five-year period is selected due to the small annual number of events in some groups.

The bubble chart in Figure 2.11 shows the groups of large weather-related transmission events by weather type; the five patterned bubbles correspond to the groups for combined 2020–2024 data, and the five solid-colored bubbles show the same groups for combined 2021–2025 data. The size of a bubble represents the average time (in days) to restore 95% of outages for the events in this group (displayed in the center of each bubble). The X-axis of a bubble shows the number of events, and the Y-axis shows the average event size. The bubble color indicates the average MVA-day loss for each group: Below 30,000 MVA-days is shown in blue, between 30,000 and 100,000 MVA-days is shown in yellow, and above 100,000 MVA-days is shown in red.

Change in size or position of a bubble for the same weather type in Figure 2.11 indicates changes in the impact of that weather resulting from a combination of the weather frequency and severity and improved or declined resilience performance. There was a decrease in the number of events in all categories except for winter weather as reflected by the bubble position change along the X-axis in Figure 2.11.

Comparing 2020–2024 vs. 2021–2025, the number of Hurricane; Tornado; and Thunderstorm, Wind events decreased while Winter Weather increased. No weather type changed category for MVA-days lost as reflected by the color of the bubbles (shaded for previous range and solid for new). A comparison of the values for the average number of days to 95% element restoration between the year ranges indicates that the average increased by about one day. Tornado is an exception, which increased by 4.2 days because of some smaller tornadoes dropping out of the year range. Most categories had a similar average event size, except for Hurricanes. This decrease was because 2020, which is outside the most recent five-year window, had record-setting hurricanes and no hurricanes made landfall in 2025.

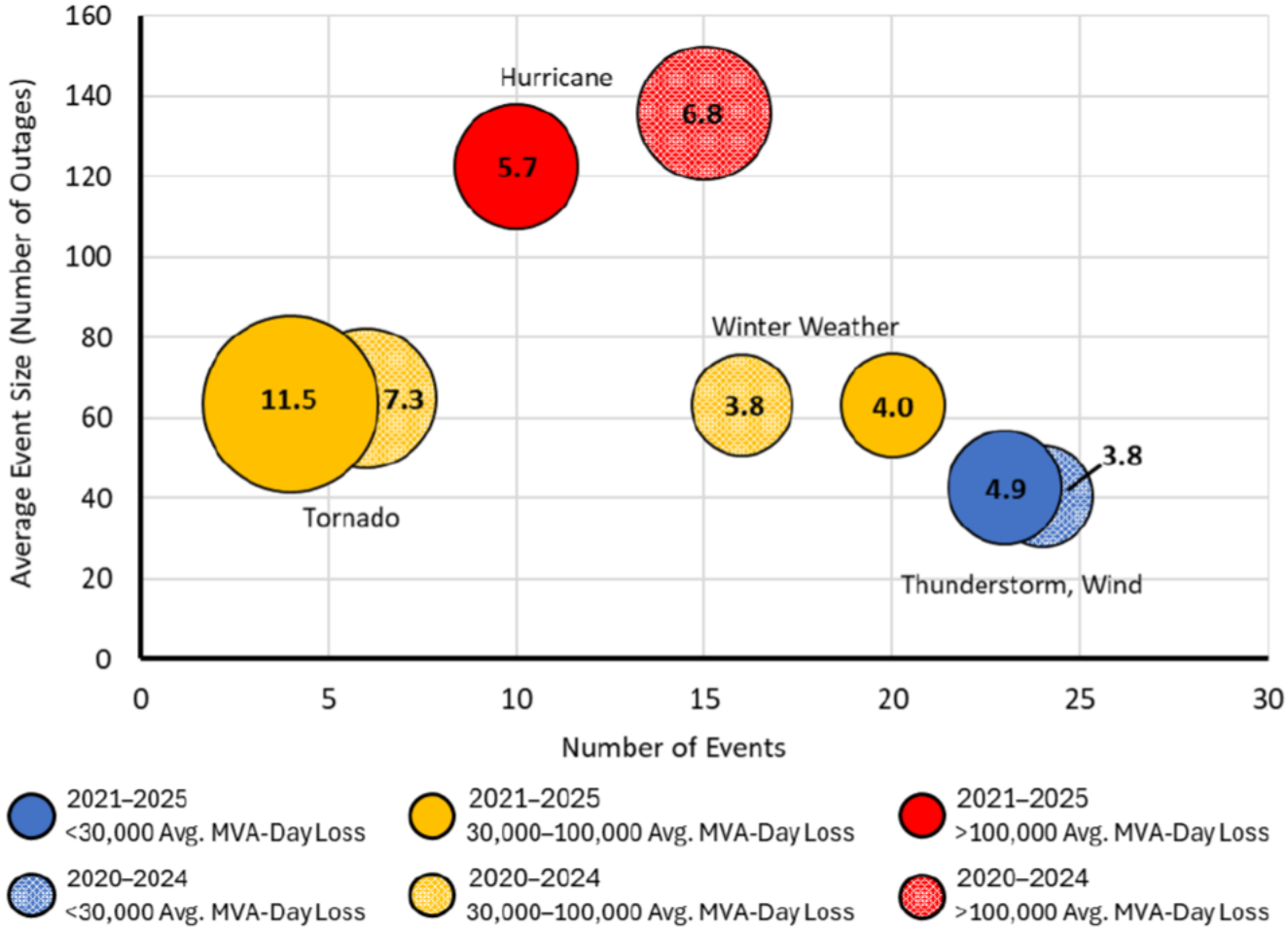


Figure 2.11: Statistics for Large Transmission Events by Weather Type for 2020–2024 vs. 2021–2025

Chapter 3: Grid Transformation

Resource Adequacy

Highlights

- In comparison to five years prior, 2025 saw tightening reserve margins across most notably Manitoba, New England and PJM with MISO, SaskPower and especially ERCOT seeing improvements in the level of anticipated reserve margins heading into last year's peak season.
- In 2025, anticipated resources exceeded Reference Margin Levels (RML) across all assessment areas.
- Improved performance of the thermal generation fleet and delivery of natural gas supplies to generators during arctic events of Winter 2024–2025 compared to prior extreme cold events.
- As of the 2025 LTRA, solar photovoltaic (PV) is no longer the sole, predominant generation type planned over the next 10 years as new battery resource projects have grown to match solar projections.

2025 Planning Reserve Margins

Planning Reserve Margins are a long-term resource adequacy indicator. Anticipated Reserve Margin (ARM) expresses the level of additional resource capacity that an area has above its peak summer (June–September) and winter (December–February) seasonal demand. It is calculated as the difference in anticipated resources and net internal demand divided by net internal demand and shown as a percentage. Each assessment area's ARM is compared against its RML—the threshold margin established by the state, provincial authority, Independent System Operator/Regional Transmission Organization (ISO/RTO), or other regulatory body to provide the level of resources needed to meet reliability criteria (e.g., maintain loss-of-load expectation below 1-day-in-10 years).

Figure 3.1 shows the ARM percent difference from the area-specific RML as calculated using data from the 2021 and 2025 seasonal assessments for each area's peak season. In 2025, all assessment areas except for NPCC-Maritimes had ARMs in excess of the area RML. Assessment areas with improved reserve margins relative to 2021 include MISO, SaskPower, New York, Québec, the eastern and southeastern SERC regions, British Columbia, and—most notably—ERCOT. A realignment of the WECC United States assessment areas in 2025 precludes comparison with 2021 values.[32]

The notable improvement in ERCOT is attributable to a 29% (7,010 MW) increase in solar capacity, continuing a trend of robust solar penetration, and a 94% (7,414 MW) increase in energy storage installed capacity. The large increase in available capacity reflects (1) new rules for managing state of charge (SoC), including a requirement to maintain a certain SoC to participate in ancillary services, (2) installation of systems with longer durations, and (3) improvements in battery operational practices.

The five-year comparisons also reveal tighter reserve margins across Manitoba, Ontario, SPP, Florida, and SERC-Central relative to 2021. In addition to having the most precipitous drops in reserve levels relative to 2021, NPCC-Maritimes, NPCC-New England, and PJM, where generator retirements and significant load growth continue to present challenges, also display discernible year-over-year trends of tightening reserve levels across the 2021–2025 period.

[32] 2025 Western Assessment, 2025–2026 Winter Reliability Assessment Western Overview

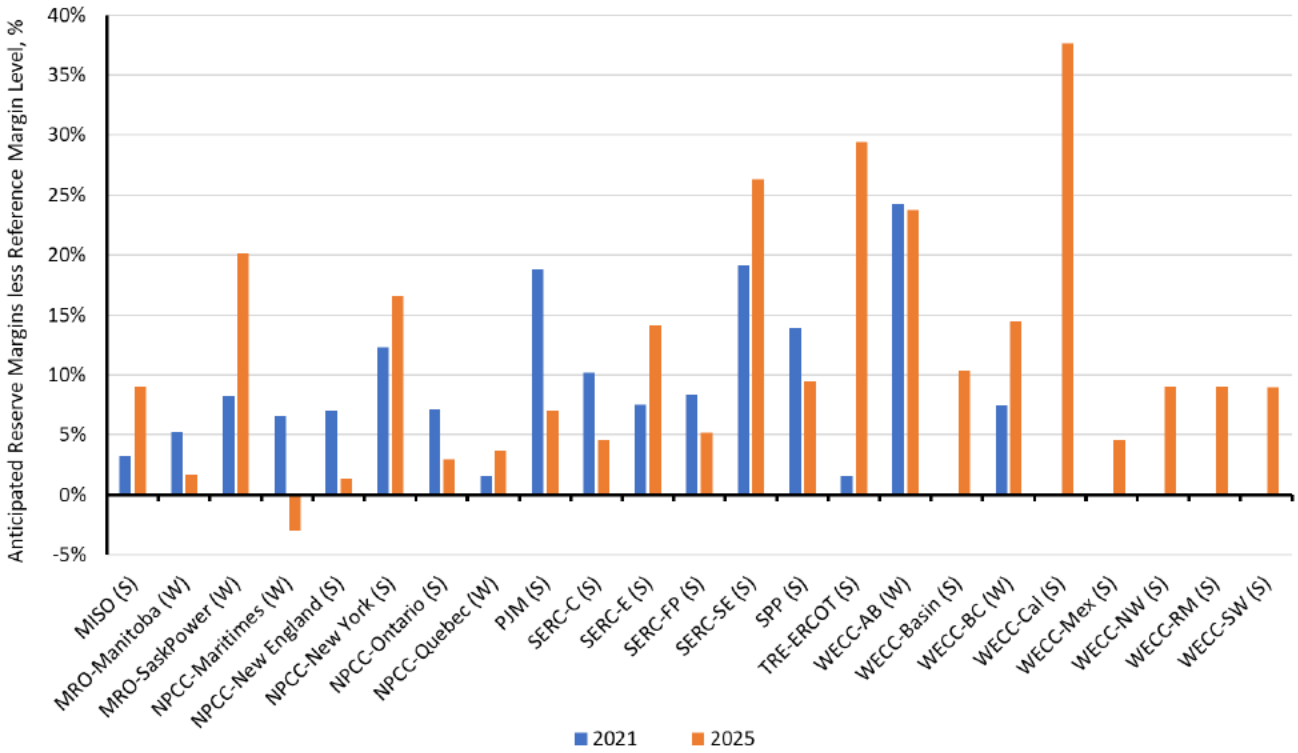


Figure 3.1: 2021 and 2025 Peak Season Planning Reserve Margins Less Reference Margin Levels[33]

Energy Emergency Alerts (EEA)[34]

The purpose of an EEA is to provide a real-time indication of potential and actual energy emergencies within an Interconnection. An EEA 3 is reported when firm load interruption is imminent or in progress. EEA trends may provide an indication of BPS capacity, energy, and transmission insufficiency.

Figure 3.2 shows that 10 EEA 3s were declared in 2025, a reduction of 11 EEA 3 declarations over 2024. None of the EEA 3 declarations in 2025 included load shed, versus 0.108 GWh of firm load shed in 2024.

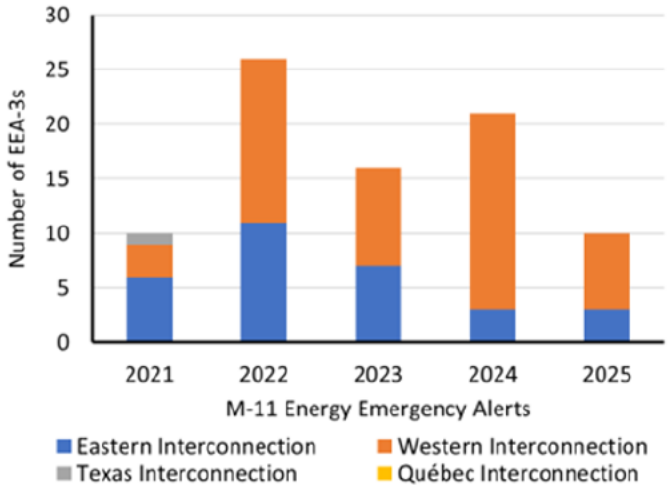


Figure 3.2: EEA 3 by Year and Interconnection

[33] M-1, Reserve Margin displayed as the difference between ARM and area's RML.
[34] M-11, Energy Emergency Alerts

All 10 of the EEA declarations in 2025 were associated with periods of reduced generation or import capability combined with heavy load days. Seven EEA 3s were associated with two non-U.S. entities, both of which have weak connections to their neighbors. Of these seven, six are associated with a balancing area that has processes requiring the declaration of an EEA 3 prior to requesting assistance from neighbors. Table 3.1 shows the number of hours when operator-initiated firm load shed was deployed during each of the past five years.

Table 3.1: Hours with Operator-Initiated Firm Load Shed (Hours/Year)

Year	Event	Event Hours	Total Annual Hours
2021	Winter Storm Uri	70.5	70.5
2022	June Heatwave	21.0	56.5
	Winter Storm Elliot	35.5	
2023	N/A	0.0	0.0
2024	WI: Generator Trip, Subsequent Failure of Dispatched Units	0.43	0.43
2025	N/A	0.0	0.0

2025 Seasonal Energy and Capacity Risk Analysis

The ERO assesses the risk of electricity supply shortfall in seasonal reliability assessments by considering Planning Reserve Margins, seasonal risk scenarios, and probability-based risk assessments. The expected impact of generator outages and extreme operating conditions on electricity supply and demand are also considered in NERC's seasonal reliability assessments. NERC evaluates the availability of supplies to meet normal seasonal peak demand as well as higher demand that may occur only once per decade, referred to as an extreme or 90/10 demand scenario. In the case of Texas RE-ERCOT and WECC CA/MX in the summer, the highest risk hour period is analyzed. The highest risk hour typically occurs after the peak demand hour when the sun has set, and solar PV resources are not contributing. Increased demand, which can be caused by extreme temperatures, higher-than-anticipated generator forced outages, and derates, can create conditions that lead system operators to take emergency operating actions. The maps in Figure 3.3 and Figure 3.4 highlight the assessment areas that NERC identified ahead of the Winter 2024–2025[35] and Summer 2025[36] seasons as at risk for resource deficiencies.

[35] NERC 2024-2025 Winter Reliability Assessment
[36] NERC 2025 Summer Reliability Assessment

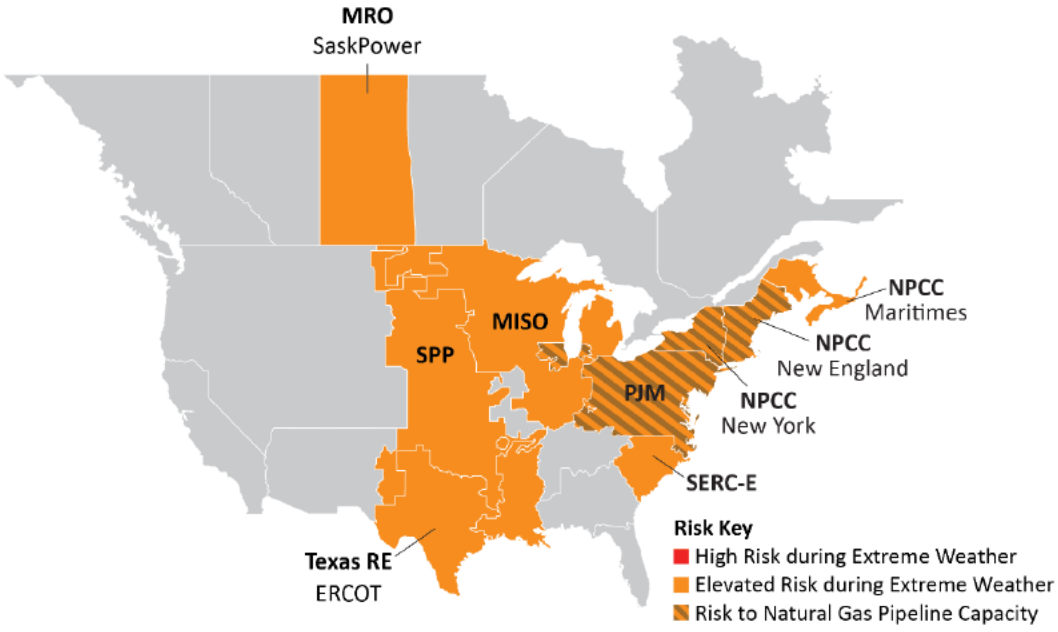


Figure 3.3: 2024–2025 Winter Reliability Assessment Risk Area Map

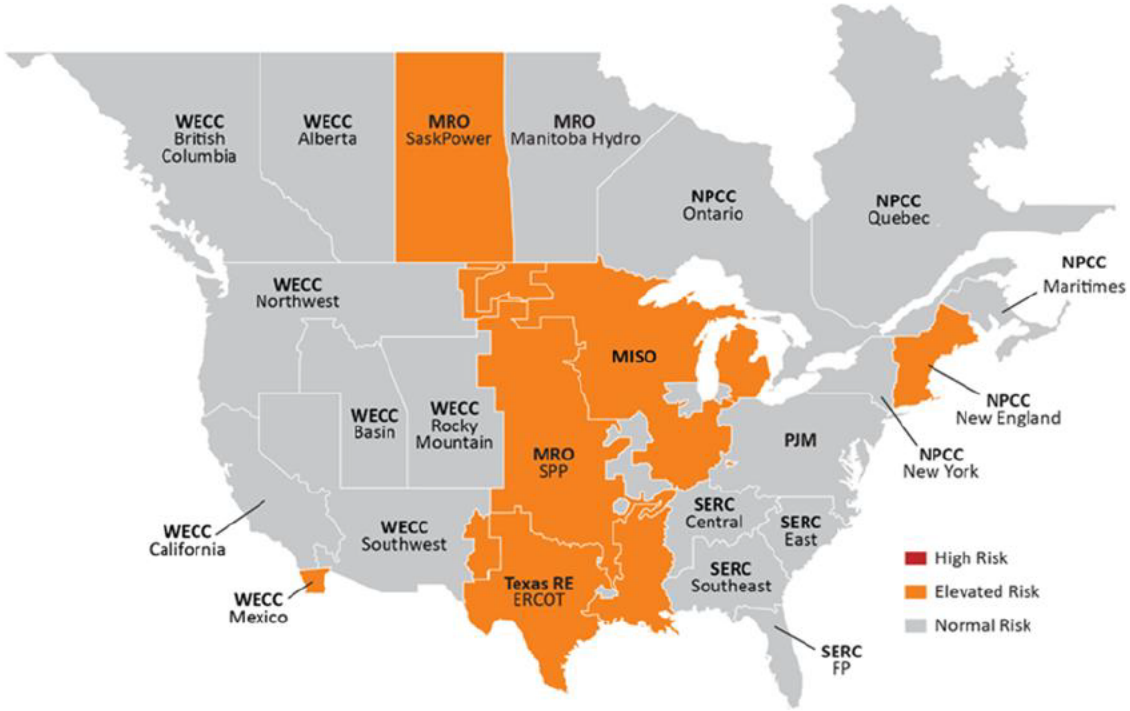


Figure 3.4: 2025 Summer Reliability Assessment Risk Area Map

Review of 2025 Capacity and Energy Performance

Periods of extreme temperatures in the summer and winter of 2025 challenged grid operators to maintain sufficient electricity supplies for demand in many parts of North America. Electricity demand is closely linked to temperature as electric load for space and equipment cooling varies with temperature. Seasonal weather extremes also affect electricity supply because generators of all types have weather-related limitations in some form. Table 3.2 and Table 3.3 provide demand and resource performance information for the peak demand hour of the summer and winter seasons in each assessment area. The tables include observed peak demand and resource output along with expected values from risk scenarios used in NERC's summer and

winter reliability assessments. Most assessment areas experienced peak demand that exceeded their normal 50/50 demand forecasts, and several areas exceeded their 90/10 (extreme) demand forecasts. As discussed below, winter arctic air events and summer heat domes contributed to generally high peak demand in North America.

Winter Operating Conditions

Meteorological winter (December 2024–February 2025) temperatures averaged 34.1 degrees Fahrenheit across the contiguous United States, 1.9 degrees above average, placing it in the warmest third of winters tracked by the National Oceanic and Atmospheric Administration. Total winter precipitation in the United States was nearly an inch below average, putting it in the driest third of recorded winters.[37] Canada experienced its fifth-warmest winter on record, with temperatures averaging 3.7 degrees Celsius above average.[38] Although the 2024–2025 Winter was warmer than average overall, a series of arctic events in January 2025 produced an extended deep freeze and harsh winter conditions over much of North America. As in past extreme winter storms, electricity demand surged while generator outages rose from freezing equipment and fuel supply issues. Nevertheless, during the January 2025 arctic events, operators did not require the use of manual load shedding and were able to maintain system balance using conservative operations, resource advisories, and other operational mitigations without resorting to EEA 3s.[39] A report of system performance prepared by the Federal Energy Regulatory Commission (FERC), NERC, and the NERC Regional Entities found that generators performed better during the January 2025 arctic events than in prior winter storms and attributed some improvements to additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations.[40] During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The natural gas system also performed better overall, delivering record levels of natural gas and experiencing only minor production declines and short-duration force majeure events.

A comparison of projected and actual Winter 2024–2025 peak/risk hour is provided in **Table 3.2**.

[37] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration

[38] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca

[39] See NERC's *2025–2026 Winter Reliability Assessment* for capacity and energy performance and operating narratives for each Interconnection (p. 51–52).

[40] *January 2025 Arctic Events | A System Performance Review by FERC, NERC, and its Regional Entities*, April 2025

Table 3.2: 2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	2025 Values Winter Reliability Assessment Scenarios										
	Peak Demand			Generation[1] (MWh)	Transfers[1] (MW)	Wind Actual[1] (MWh)	Solar Actual[1] (MWh)	Forced Outages Summary[4] (MW)	Peak Demand[2] (MW)	Wind Expected[3] (MW)	Solar Expected[3] (MW)
	Date	Time	MW								
MISO	Jan. 21	18:00	108,888*	101,655	-977	18,468	0	17,010	96,134 100,395	16,761	519
MRO-Manitoba Hydro	Jan. 20	8:00	5,132	5,292	-277	142	N/A	146	4,814 5,060	52	0
MRO-SaskPower	Dec. 18	18:00	3,785	3,641	-231	664	0	0	3,802 3,897	368	3
MRO-SPP	Feb. 20	8:00	47,981	40,898	-1,424	4,886	255	9,272	45,926 47,054	4,783	36
NPCC-Maritimes	Jan. 22	7:00	5,810	4,266	-1,174	368	3	*	5,907 6,498	261	5
NPCC-New England	Jan. 21	18:00	19,607	17,686	-1,896	285	4	624	20,308 21,814	329	23
NPCC-New York	Jan. 22	19:00	23,521	18,932	-4,589	654	0	4,835	22,998 24,023	728	0
NPCC-Ontario	Jan. 22	18:00	21,940	24,250	2,990	3,693	0	*	20,951 22,179	1,914	0
NPCC-Québec	Jan. 22	8:00	37,178	39,514	-766	1,463	0	*	36,061 39,545	1,449	0
PJM	Jan. 22	9:00	144,420	152,142	7,731	3,704	3,076	8,663	130,712 144,939	3,620	1
SERC-C	Jan. 22	8:00	47,815	40,898	-6,921	563	214	1,538	41,397 47,062	176	455
SERC-E	Jan. 23	8:00	47,130	41,810	-5,323	0	145	1,830	44,023 47,662	0	2,526
SERC-FP	Jan. 25	8:00	43,974	41,702	-557	0	362	2,824	45,714 54,239	0	1,684
SERC-SE	Jan. 22	8:00	46,490	48,227	1,741	0	592	2,210	43,670 45,116	0	3,861
TRE-ERCOT	Feb. 20	8:00	80,560	79,960	-191	9,397	1,586	5,742	731,935 904,055	15,697	15
WECC-AB	Dec. 18	17:00	12,241	12,711	-470	3,175	4	*	12,280 12,635	1,867	0

Table 3.2: 2024–2025 Winter Demand and Generation Summary at Peak Demand

Assessment Area	2025 Values Winter Reliability Assessment Scenarios										
	Peak Demand			Generation[1] (MWh)	Transfers[1] (MW)	Wind Actual[1] (MWh)	Solar Actual[1] (MWh)	Forced Outages Summary[4] (MW)	Peak Demand[2] (MW)	Wind Expected[3] (MW)	Solar Expected[3] (MW)
	Date	Time	MW								
WECC-BC	Feb. 3	18:00	11,359	11,415	44	70	0	839	11,996 12,749	279	0
WECC-CA/MX	Dec. 12	15:00	35,555	31,925	-4,669	4,021	11,547	1,627	35,359 36,823	569	0
WECC-NW	Feb. 12	8:00	54,278	48,437	-920	2,607	1,494	3,281	58,001 62,230	7,876	2,198
WECC-SW	Feb. 13	16:00	22,969	25,087	2,117	2,741	1,599	1,496	16,177 17,777	1,065	182

Highlighting Notes:

Actual peak demand in the highlighted areas met or exceeded extreme scenario levels

Actual wind output in highlighted areas was significantly below seasonal forecast

Actual solar output in highlighted areas was significantly below seasonal forecast.

Actual forced outages above or below forecast by factor of two.

Table Notes:

1 Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities.

2 See NERC 2024–2025 WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

3 Expected values of wind and solar resources from the 2024–2025 WRA for the projected peak hour; actual peak hour can impact solar contribution

4 Values from NERC GADS for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the 2024–2025 WRA.

5 Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand

scenarios found on p. 29 of the 2024–2025 WRA.

*Canadian assessment areas report to GADS on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Summer Operating Conditions

The summer of 2025 was the 12th-hottest on record for the contiguous United States[41] during the meteorological summer period (June–August) and the 11th-warmest summer in Canada.[42] Actual peak demand exceeded normal demand forecasts across most assessment areas and exceeded extreme demand projections from the *2025 SRA* in three assessment areas. A summer heat wave developed in early June for most of the eastern half of the continent, triggering system operators to issue resource advisories and other operating mitigations. The east experienced only brief periods of relief from high temperatures through the end of July. Twenty energy emergency alerts were declared during the June and July heat events, but operators were able to manage high loading without resorting to load shedding.[43]

Summer conditions were generally less severe in other parts of the North American BPS. Peak demand in the Western Interconnection was 168,206 MW, slightly below Summer 2024. Western Canada experienced a heat wave from late August and through early September, exacerbating the ongoing drought in western Canada and triggering some energy shortfall events that were managed without shedding load. Wildfire activity also increased due to heat and dry conditions. The western United States overall navigated last summer with the BPS experiencing relatively few emergency events. Demand in WECC U.S. assessment areas never reached or exceeded the projections for extreme demand from the *2025 SRA*. Texas experienced a relatively mild summer in 2025, yet, due to significant load growth, the Summer 2025 load levels were comparable to the far hotter 2023 summer load levels.[44]

A comparison of projected and actual Summer 2025 peak/risk hour is provided in Table 3.3.

Table 3.3: 2025 Summer Demand and Generation Summary at Peak Demand

Assessment Area	Actual Peak Demand[1]			SRA Peak Demand Scenarios[2] (GW)	Wind Actual[1] (MW)	Wind Expected[3] (MW)	Solar Actual[1] (MW)	Solar Expected[3] (MW)	Forced Outages Summary[4] (MW)
	Date	Time	GW						
MISO	Jul. 29	17:00	121.6	116.3 121.6	1,105	6,039	12,323	9,123	8,779
MRO-Manitoba Hydro	Aug. 29	17:00	3.5	3.4 3.6	0	48	0	0	252
MRO-SaskPower	Sep. 7	17:30	3.6	3.6 3.8	232	310	26	9	0
MRO-SPP	Jul. 29	16:00	54.5	54.8 57.5	8,130	5,556	810	492	4,370
NPCC-Maritimes	Aug. 11	17:00	3.6	3.3 3.5	151	314	69	0	33
NPCC-New England	Jun. 24	19:00	26.6	24.7 26.4	566	142	180	1,412	1,963
NPCC-New York	Jun. 24	19:00	32	30.0 31.7	1,256	446	164	243	1,372
NPCC-Ontario	Jun. 24	19:00	24.9	21.0 24.5	607	742	39	66	1,532
NPCC-Québec	Aug. 11	18:00	22.7	22.3 23.3	790	885	0	0	5,029
PJM	Jun. 23	18:00	160.7	146.2 158.7	4,515	1,855	7,730	6,244	15,945

[41] Assessing the U.S. Temperature and Precipitation Analysis in August 2025 | News | National Centers for Environmental Information (NCEI)

[42] Rapid Extreme Weather Attribution system: Top heat events of summer 2025 – ClimateData.ca

[43] See NERC Bulk Power Systems Awareness update to the Reliability and Security Technical Committee on September 10, 2025.

[44] See NERC's *2026 Summer Reliability Assessment* for capacity and energy performance and operating narratives for each Interconnection (p. 52–56).

Table 3.3: 2025 Summer Demand and Generation Summary at Peak Demand

Assessment Area	Actual Peak Demand[1]			SRA Peak Demand Scenarios[2] (GW)	Wind Actual[1] (MW)	Wind Expected[3] (MW)	Solar Actual[1] (MW)	Solar Expected[3] (MW)	Forced Outages Summary[4] (MW)
	Date	Time	GW						
SERC-C	Jul. 28	18:00	43.2	41.9 45.7	84	370	714	1,053	701
SERC-E	Jun. 24	17:00	44.8	42.5 45.7	0	0	3,200	5,022	2,407
SERC-FP	Jul, 28	17:00	54.6	49.8 50.8	0	0	8,035	5,749	1,599
SERC-SE	Jul. 28	16:00	46.4	45.7 55.9	0	0	3,366	7,728	1,380
TRE-ERCOT	Aug. 8	18:00	83.7	81.9 88.1	14,509	9,396	16,961	22,962	11,095
WECC-AB	Aug. 27	0:00 UTC	12.0	12.2 12.7	2,870	796	32	1,480	N/A
WECC-BC	Aug. 13	01:00 UTC	9.8	9.3 10.0	293	149	4.8	0	N/A
WECC-CA	Aug. 22	02:00 UTC	54	54.1 64.3	1,744	1,207	5,064	14,756	1,063
WECC-MX	Aug. 7	0:00 UTC	3.5	3.8 4.1	2.5	50	296	227	N/A
WECC-NW	Aug. 13	01:00 UTC	29.8	29.1 32.7	1,054	3,107	1,398	666	1,825
WECC-RM	Jul. 9	00:00 UTC	13.4	13.8 15.0	2,313	1,359	1,571	1,669	1,954
WECC-Basin	Jul. 9	01:00 UTC	13.8	13.6 15.0	931	911	2,660	2,231	0
WECC-SW	Aug. 8	01:00 UTC	36.9	35.1 39.0	1,230	1,091	4,472	4,293	2,323

Highlighting Notes

Actual peak demand in the highlighted areas met or exceeded extreme scenario levels.

Actual wind output in highlighted areas was significantly below seasonal forecast.

Actual solar output in highlighted areas was significantly below seasonal forecast.

Actual forced outages above or below forecast by factor of two.

Table Notes:

[1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from the assessment areas.

[2] See NERC *2025 SRA* demand scenarios for each assessment area (pp. 14–33). Values represent the normal summer peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand.

[3] Expected values of wind and solar resources from the *2025 SRA* for the projected peak hour, actual peak hour can impact solar contribution[4] Values from NERC GADS for the 2025 summer hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024 summer risk period scenarios in the *2025 SRA*.

*Values include both maintenance and forced outages.

**Canadian assessment areas report to GADS on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.

Changes in the Peak Resource Mix Over the Past 10 Years

The generation resource mix is changing as older nuclear and fossil-fired generators retire and natural-gas-fired generators and wind and solar PV resources are built (Table 3.4). Over the past 10 years, the BPS has reduced its on-peak[45] capacity of coal-fired generation by almost 118 GW and reduced its capacity of nuclear generation by 6.6 GW. During this time, the BPS added on-peak generation capacity: 57.6 GW of natural gas, 20.5 GW of wind, and 65 GW of solar PV.[46] Table 3.4 shows the resource contribution to meeting the seasonal peaks for years 2015 and 2025. The lower solar contribution to meeting the Winter 2025 peak is offset by increased gas generation and lower peak demand.

Table 3.4: Generation Resource Capacity by Fuel Type

Generation Fuel Type	Summer				Winter			
	2015 On-Peak		2025 On-Peak		2015 On-Peak		2025 On-Peak	
	GW	Percent	GW	Percent	GW	Percent	GW	Percent
Coal	289.2	28.0%	172.1	15.8%	286.6	27.4%	172.7	16.2%
Natural Gas	418.1	40.5%	489.0	44.9%	437.2	41.8%	512.9	48.2%
Hydro	128.9	12.5%	135.3	12.4%	128.9	12.3%	137.9	13.0%
Nuclear	112.2	10.9%	105.4	9.7%	112.2	10.7%	107.1	10.1%
Oil	48.1	4.7%	28.2	2.6%	51.2	4.9%	30.2	2.8%
Wind	13.0	1.3%	37.4	3.4%	13.6	1.3%	44.0	4.1%
Solar PV	3.9	0.4%	77.8	7.1%	0.6	0.1%	13.5	1.3%
Other	19.8	1.9%	44.2	4.1%	16.8	1.6%	45.3	4.3%
Total:	**1,033.3**	**100.0%**	**1,089.4**	**100.0%**	**1,047.0**	**100.0%**	**1,063.7**	**100.0%**

The resource mix and the pace at which it is changing varies considerably across different parts of the North American BPS. Figure 3.5 provides an Interconnection-level view of the generation resource mix since 2015.

[45] Individual assessment areas may peak in either the Winter or Summer season and thus on-peak in this context is the sum of the individual areas' non-coincident seasonal peak.

[46] Data obtained from NERC long-term reliability assessments

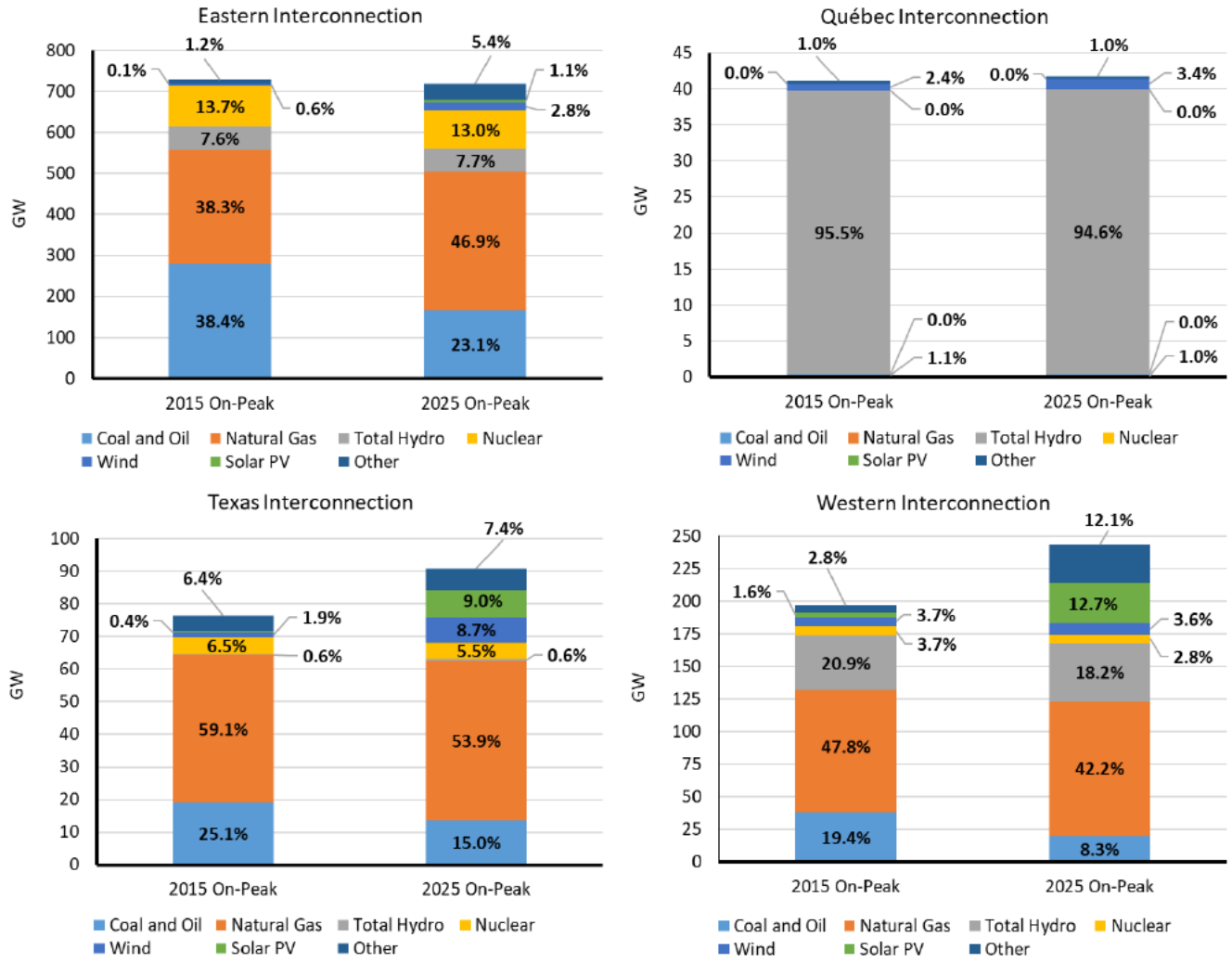


Figure 3.5: 2015 and 2025 Capacity Resource Mix by Interconnection

The growth of battery energy storage systems (BESS) arrived at an inflection point in 2025. Figure 3.6 below shows the recent growth in both nameplate and on-peak capacity for battery storage across all Interconnections. NERC's LTRA reports on both the current generation resource mix and projections for the next 10 years for each of the 20 assessment areas within the four Interconnections that encompass the North American BPS. As the *2025 LTRA*[47] notes, the shift toward a more variable resource mix continues. One key insight from the *2025 LTRA* is that solar PV is no longer the sole, predominant generation type planned over the next 10 years. New battery resource projects have grown to match solar projections, and, together, solar and battery capacity additions represent two-thirds of the Tier 1 and Tier 2 resources over the 10-year LTRA study period.

[47] *Long-Term Reliability Assessment*, 2025

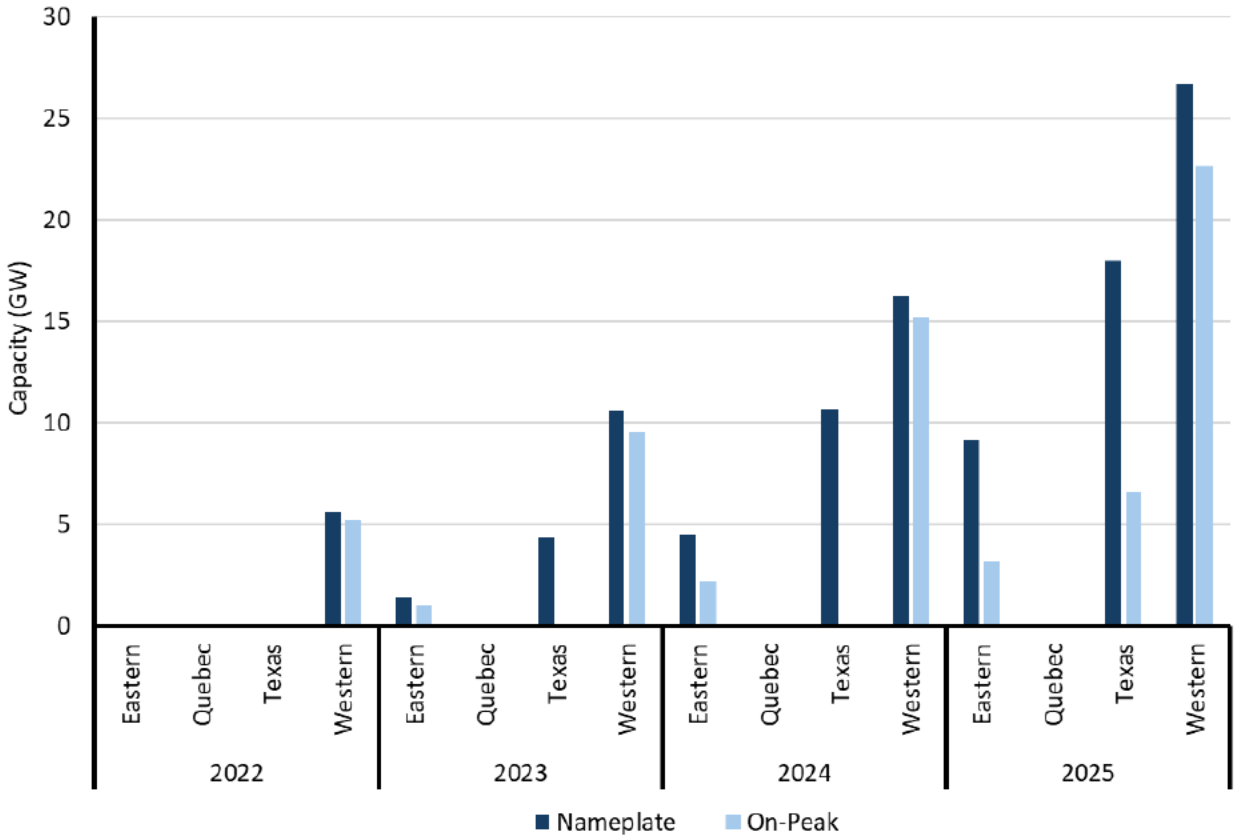
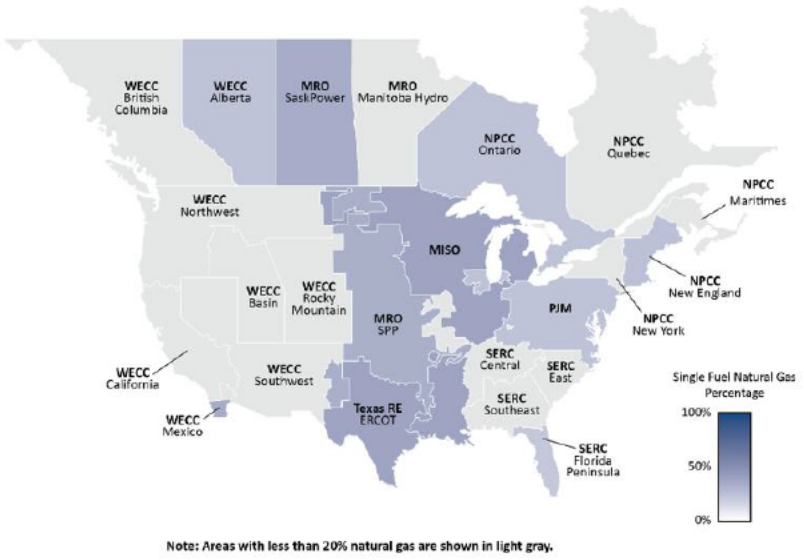


Figure 3.6: 2022–2025 Battery and Hybrid Capacity by Interconnection[48]

Critical Infrastructure Interdependencies

The natural gas and electric systems are constituent parts of an interconnected energy delivery system in North America. While natural-gas-fired generation is important in all seasons, it is especially vital to meet electricity demand in winter when solar and battery resources have less capability than in other seasons. Natural gas-fired generators can be exposed to risk of fuel supply curtailments in winter for a variety of reasons. One mitigation strategy used by generators in some areas is to have dual-fuel capability and maintain supplies of backup fuels. Single-fueled generators currently make up a large portion of the winter peak generating capacity in many parts of the BPS (Figure 3.7). These generators are at risk of outages or derates when fuel supplies are limited.

[48] Includes hybrid generation



Single-Fuel Natural-Gas-Fired Generation

	Winter Capacity (GW)	Contribution to Total Winter Resource Mix
MISO	63.9	38%
TRE-ERCOT	53.0	38%
WECC-MX	2.2	34%
MRO-SaskPower	2.5	34%
SPP	33.4	32%
NPCC-New England	12.1	24%
PJM	60.9	23%
WECC-AB	13.9	23%
NPCC-Ontario	8.0	23%
SERC-FP	45.6	21%
WECC-CA	35.9	18%
WECC-SW	21.5	17%
WECC-Basin	4.9	16%
WECC-RM	6.2	14%
SERC-C	17.0	13%
SERC-SE	21.5	13%
WECC-NW	8.7	12%
SERC-E	11.3	9%
NPCC-New York	5.0	8%
NPCC-Maritimes	0.5	7%
MRO-Manitoba	0.3	4%
WECC-BC	0.1	1%
NPCC-Quebec	0.0	0%

Figure 3.7: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the Winter Generation Mix in 2025[49]

January 2025 Gas-Electric System Performance

The arctic events in January 2025 presented challenging conditions for the natural gas and electric systems, requiring close coordination between operators. A review of BPS and natural gas system performance following the January winter storms found notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure force majeures.[50] BPS generator outages climbed during the extreme cold due to equipment freezing issues and some gas supply issues.[51] The January 2025 arctic events demonstrated again how closely linked the reliability of the BPS is to natural gas supplies and infrastructure. Because natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, protections can be unevenly applied, resulting in continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends.

Call to Action

NERC developed an Electricity-Natural Gas Strategy[52] to identify, assess, and facilitate ongoing and future treatment of the risks that arise from the growing reliance on natural gas for electricity generation. More information on NERC's response to the risks associated with gas-electric interdependence is provided on the NERC Reliability Initiatives[53] page.

Increasing Complexity of Protection and Control Systems

Together with the progression of interconnected power generation, transmission, and distribution assets, the landscape of automated tools and systems has transformed. This evolution spans an array of digital information platforms and microprocessor-driven devices, fostering a technologically diverse environment wherein operators can wield unprecedented control from virtually any location at a fraction of the historical

[49] *2025–2026 Winter Reliability Assessment*
[50] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[51] PJM January 2025 Cold Weather Operations Presentation
[52] Electricity-Natural Gas Strategy
[53] Reliability Initiatives

cost. When meticulously designed and executed, these automated tools offer a means to enhance the reliable and secure use of the technologies and concepts in the BPS. However, the proliferation of these systems introduces an increasing web of rules, algorithms, and interdependencies that amplify the intricacy of operation. The swift decision-making capabilities of modern relays, tripping circuits, or initiating alternative actions within milliseconds epitomize the accelerated pace at which these systems must navigate intricate operational scenarios. The increasing integration of inverter-based resources (IBR) also expands this complexity, requiring the deployment of additional automated tools and systems. Navigating this expanding labyrinth demands not only vigilant maintenance, prudent asset replacement, and strategic upgrades but also a nuanced understanding of the dynamic interplay between diverse system components. As the scope and scale of these challenges continue to increase, it is imperative to cultivate agile, adaptive solutions.

Protection System Misoperation Trends

Figure 3.8 presents the annual misoperation rates across all Regional Entities and separately for each Regional Entity over the last five years. The comparison of the misoperation rate of the first four years to the most recent year shows a statistically significant decreasing trend for MRO. There is no statistically significant trend for other Regional Entities nor for the ERO as a whole. The overall count of misoperations in 2025 was the lowest over the past five years (Table 3.4).

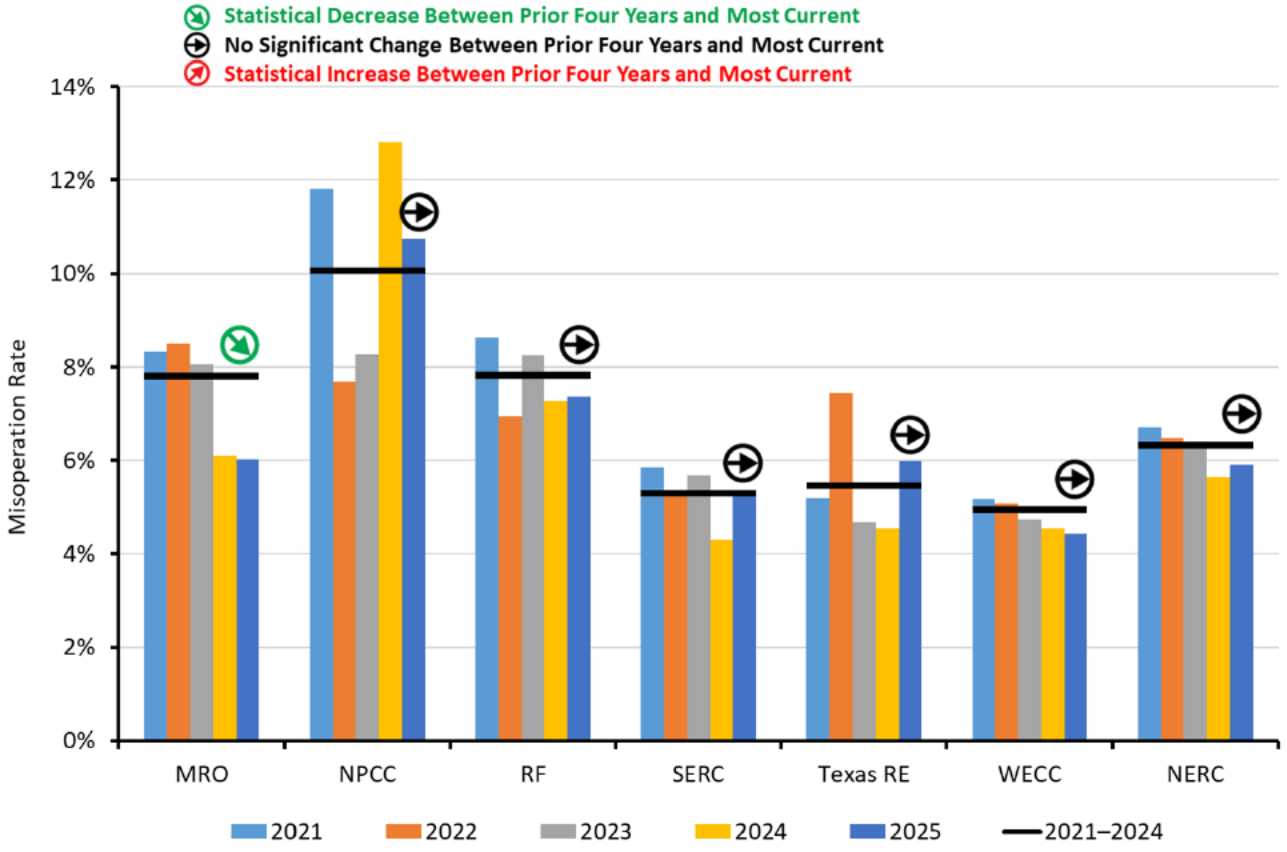


Figure 3.8: Changes and Trends in the Annual Misoperations Rate by Regional Entity[54]

[54] M-9, Protection System Misoperations Rate

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Table 3.5: Five-Year Protection System Operations and Misoperations 2021–2025										
Area	Protection System Operations					Misoperations				
	2021	2022	2023	2024	2025	2021	2022	2023	2024	2025
All Regional Entities	17,454	17,804	17,871	19,325	18,397	1,172	1,153	1,118	1,089	1,087
MRO	2,618	3,238	2,977	3,097	3,267	218	275	240	189	197
NPCC	1,362	1,664	1,752	1,521	1,275	161	128	145	195	137
RF	1,867	2,061	1,867	1,843	2,010	161	143	154	134	148
SERC	4,617	4,775	4,954	5,701	5,058	270	252	281	245	265
Texas RE	2,599	1,991	2,183	2,461	2,542	135	148	102	112	152
WECC	4,391	4,075	4,138	4,702	4,245	227	207	196	214	188

Leading Causes of Misoperations

Figure 3.9 shows the distribution of misoperation causes over the past five years. Incorrect settings and relay failures/malfunctions remain the most common causes of misoperations. While a relative increase in Unknown/Unexplainable occurred from 2024 to 2025, historically the misoperation rate for this cause code decreases as ongoing investigations reveal additional information and corrective action plans (CAP) remedy the situations causing the misoperations. There were minimal changes in the relative frequency of other causes from 2024 to 2025.

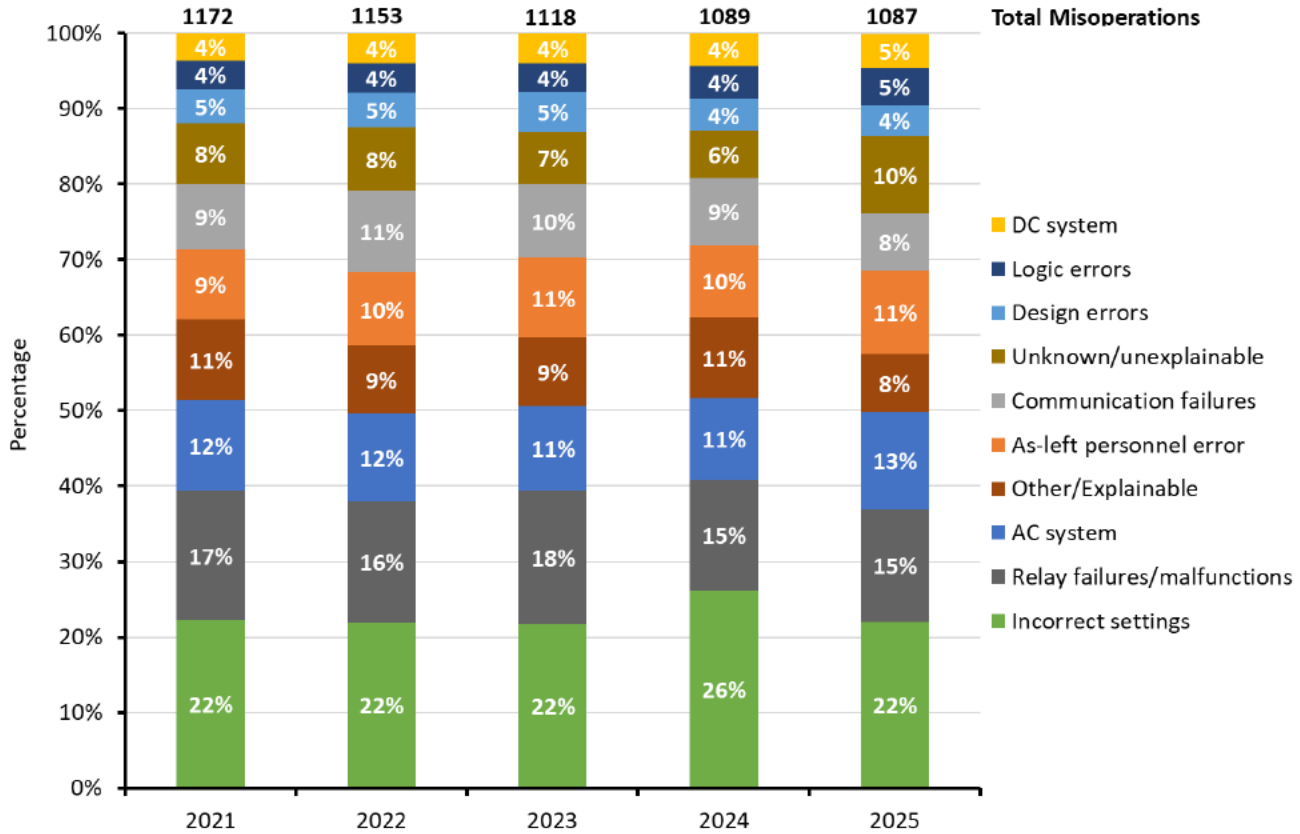


Figure 3.9: Percentage of Misoperations by Cause Code (2021–2025)

Misoperation Impact Score

The misoperation impact score measures the estimated impact of each misoperation on the BES, which is then aggregated to assess overall performance. This is done by summing weighted values for the facility voltage class, equipment type, cause, and category to determine the event's impact to BES reliability.[55] The maximum score of 1.0 implies the worst impact an event is projected to have on the BES, while a minimum score of 0.3034 reflects the least impact an event is projected to have on the BES.

In 2025, there was a statistically significant increase in the average misoperation impact score compared to the prior four years for Texas RE and NERC-wide (Figure 3.10). No statistically significant change occurred for any other Regional Entity. Further analysis identified that the Texas RE increase was primarily driven by an increase in misoperations reported by new Generator Owners (GO), increasing misoperations on 345 kV equipment (the highest voltage in the region) and the use of the "unknown" cause code.

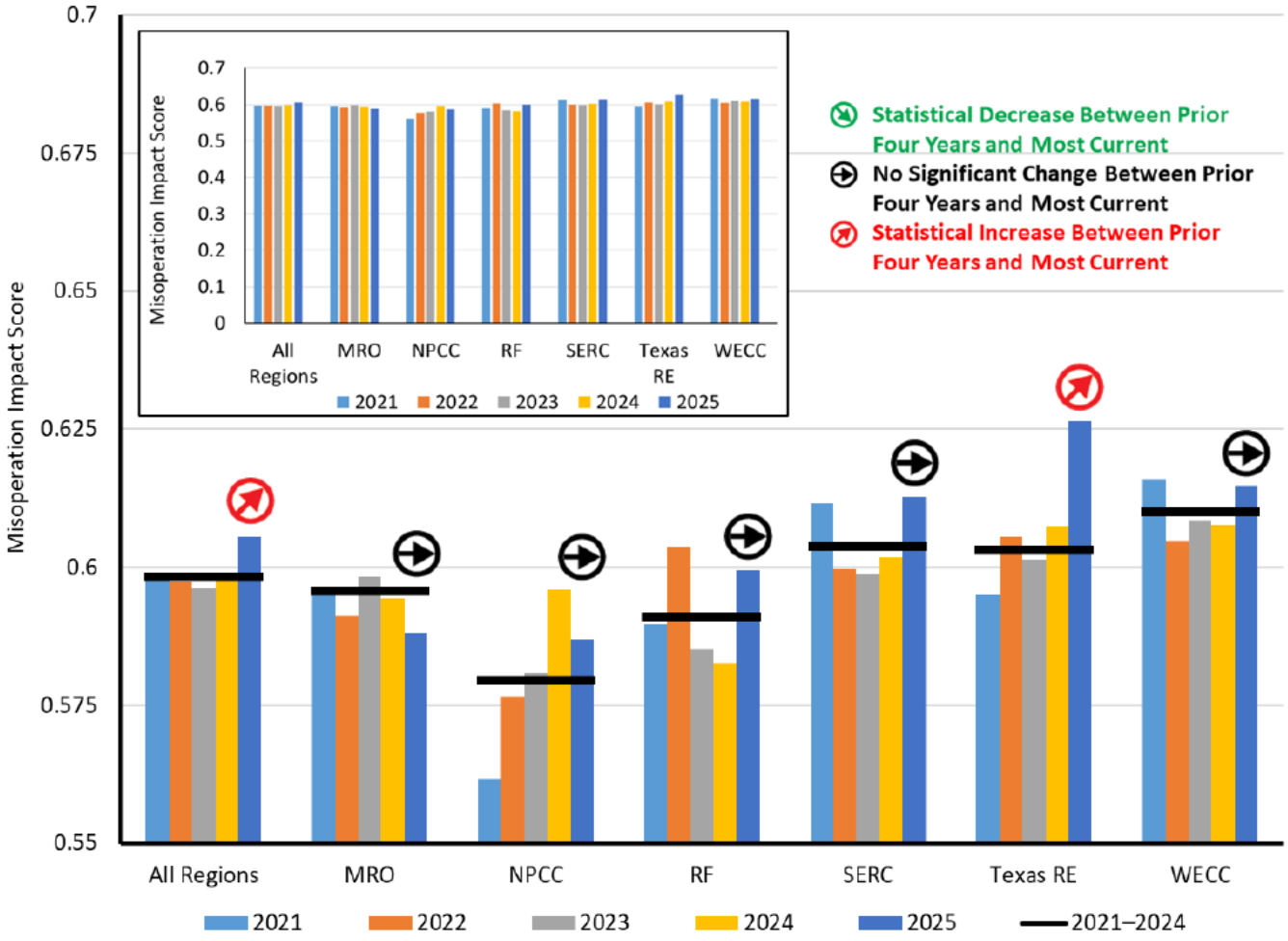


Figure 3.10: Misoperation Impact Score

Protection System Failures Leading to Transmission Outages

Protection system failures may result from or be the cause of transmission circuit outages, unnecessarily removing equipment from service. AC circuits saw a slight decrease in the number of outages due to protection system failures in 2025, but this decrease was not statistically significant. Transformers saw a statistically significant decrease in the number of outages for 2025 (Figure 3.11).

[55] Misoperations Impact Score

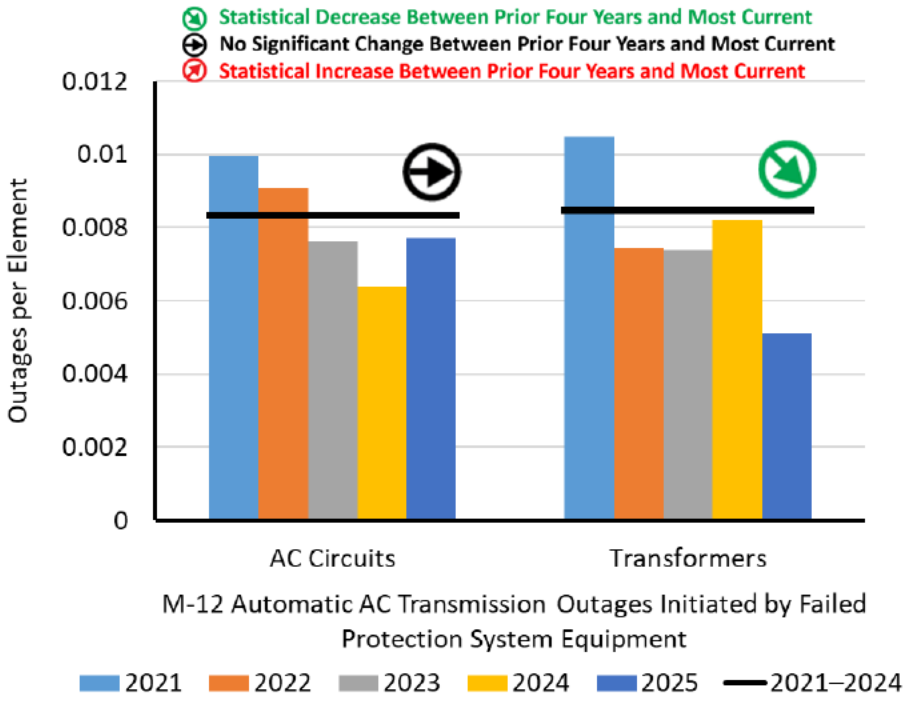


Figure 3.11: Failed Protection System Equipment Outages[56]

Event-Related Misoperations[57]

An analysis of events meeting published criteria[58] reported through the ERO Event Analysis Process (EAP) found that there were 51 transmission-related events in 2025, 32 of which (63%) involved misoperations (Figure 3.12). In comparison, 2024 saw 60 transmission-related events, of which 34 (57%) had associated misoperations. While the percentage of events with misoperations increased, the overall numbers for events and misoperations continue to decrease. This reduction is likely attributable in part to the ERO Enterprise and industry stakeholder efforts to reduce protection system misoperations through initiatives such as various task forces, workshops, and analytical efforts.

[56] M-12, Automatic AC Transmission Outages Initiated by Failed Protection System Equipment

[57] When reviewing ERO Event Analysis misoperations data, it is important to differentiate between it and analysis of MIDAS. These are different datasets and processes. This results in datasets that both relate to protection system misoperations and have overlap but often have significantly different sources, intents, and results.

[58] ERO Event Analysis Process - Version 5.0 (Effective January 1, 2024)

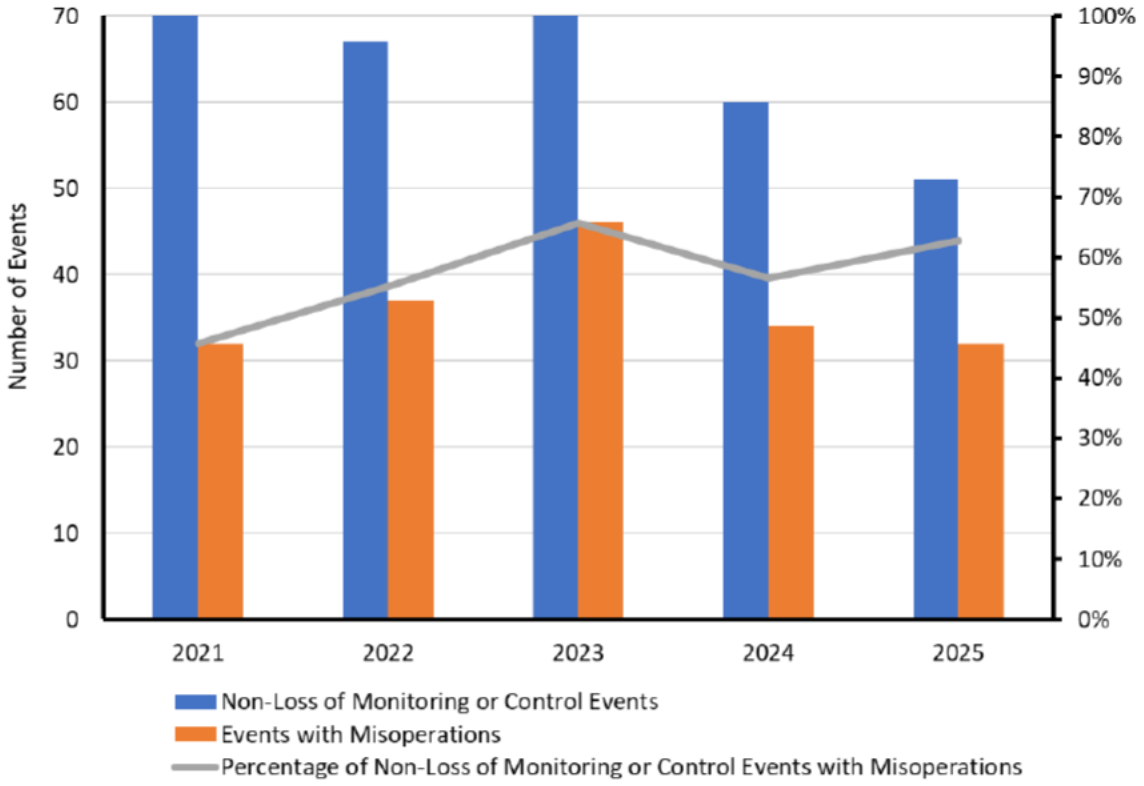


Figure 3.12: Events with Misoperations

Loss of Situational Awareness

The BPS operates in a dynamic environment where physical properties are constantly changing. To ensure reliability, it is essential to maintain situational awareness to anticipate events and respond effectively before or as they occur. Various tools are employed to support situational awareness and uphold BPS reliability. These tools include energy management systems (EMS), transmission outage planning, load forecasting, forecasting for geomagnetic disturbances and weather, data sharing with neighboring entities, and effective communication both within organizations and with adjacent systems.

Without the appropriate tools and up-to-date data, system operators may experience degraded situational awareness, which can affect their ability to make informed decisions about BPS reliability. Unexpected outages of communication systems or monitoring and control equipment, along with planned outages that lack proper coordination or oversight, can result in diminished visibility for operators. For system operators, the EMS is essential for maintaining situational awareness.

Impacts from the Loss of EMS

An EMS is a computer-based set of tools that system operators use to monitor, control, and optimize the performance of both the generation and transmission systems. The EMS enables operators to oversee and manage various factors, including frequency, the status (open or closed) of switching devices, and the real and reactive power flows on BES tie-lines and transmission facilities within their control area. Additionally, it provides oversight of critical EMS applications, such as state estimation (SE), RTCA, automatic generation control, and alarm management.

There were 36 categorized[59] events associated with an EMS in 2025; there were no categorized EMS-related events that caused loss of generation, transmission lines, or customer load. Figure 3.13 illustrates a trend of the categorized EMS events by loss of EMS functions over the 2021–2025 period.

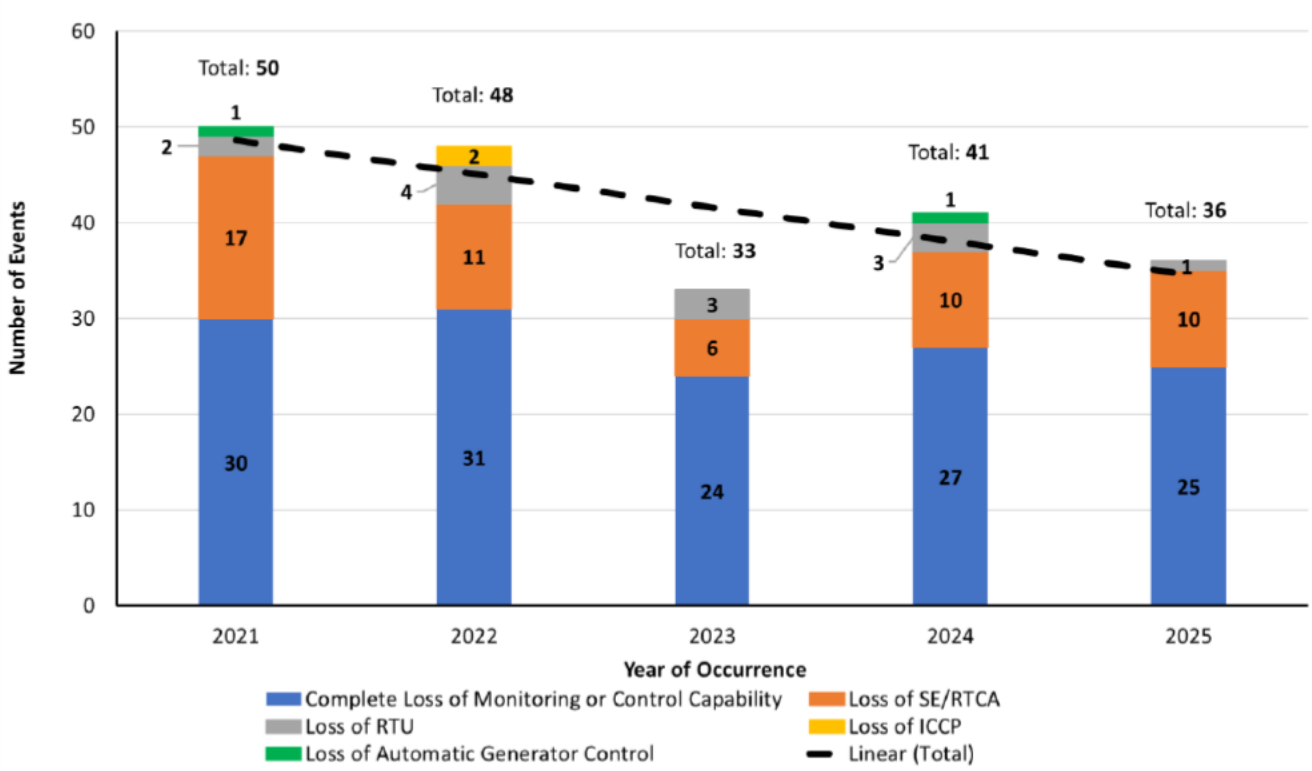


Figure 3.13: Number of EMS-Related Events (2021–2025)

In 2025, there were 25 categorized events involving a complete loss of monitoring[60] or control[61] capability. Two new themes to these events were identified:

- **Lack of effective communication between working departments**

  Maintenance typically involves the collaboration of various working departments, each playing a vital role in ensuring the efficiency and reliability of systems. Effective communication between these teams is crucial, especially when they handle the same equipment or systems that are interdependent. Prioritizing the clear exchange of work and maintenance schedules among departments will significantly reduce the likelihood of overlapping tasks that could negatively affect the utility's equipment and overall operations.

  To address the issues that have arisen from insufficient communication between working groups, a series of recommendations were developed during the analysis of the EMS events. These recommendations aim to foster a more cohesive approach to maintenance and ensure that all teams are informed and coordinated, ultimately enhancing operational safety and efficiency:

  - **Pre-Maintenance:** Planning and risk mitigation before the work starts.

[59] Category 1h. See Electric Reliability Organization Event Analysis Process Version 5.0
[60] The ability to accurately receive relevant information about the BPS in real time and evaluate system conditions using real-time data to assess existing (pre-contingency) and potential (post-contingency) operating conditions to maintain reliability of the BPS.
[61] The ability to take and/or direct actions to maintain the reliability of the BPS in real time via entity actions or by issuing operating instructions.

- Establish Communication Channels: Set up a bridge call with all stakeholders during the work to enable quick communication and coordination between groups.
- Move Active Server to Hot Standby: Move the active server to the hot standby site before work begins to reduce potential impact.
- Transfer Operational Activities: Shift all operational activities to an alternate location until the telecom work is finished.
- Verify Equipment Status: Perform a status check on all equipment prior to beginning any work.

- **During Maintenance:** Real-time monitoring and active communication
  - Monitor Progress: Supervision should actively monitor scheduled work to ensure no conflicts occur between groups.
  - Ensure Real-Time Status Updates: Communicate work status continuously between shifts and work groups, especially when multiple groups share the same equipment.
  - Implement Immediate Escalation: If schedules cannot be met, the group performing the work must immediately notify supervision and other scheduled teams.
- **Post-Maintenance:** Post-activity verification and closure
  - Ensure Final Status Handoff: Ensure the final equipment status is communicated to the next shift or work group before closing the bridge.
  - Verify System Reversion: Verify the system before moving traffic back to the primary servers.

- **Inadequate monitoring of operational support system resource usage**

  Operational support systems are vital for ensuring situational awareness and facilitating real-time decision-making across various operations. Unfortunately, several EMS events have arisen due to overwhelming demands for computer resources and the depletion of disk space. A recurring issue revealed through these incidents is the lack of a proactive framework for managing resource margins. This framework is essential for maintaining operating reserves akin to those established for ensuring BES reliability.

  To enhance the effectiveness of infrastructure monitoring, it is important to:

  - Incorporate a multi-tiered system of alert thresholds,
    - Perform a thorough trend analysis and detection of rate-of-change.
    - Enable early interventions to address issues before they escalate into emergencies.
  - Manage temporary file lifecycles and govern system logs as they are integral components of reliability controls.
    - Validate mechanism for cleanup in both normal operating conditions and potential failure scenarios.
    - Avoid unnecessary buildup of digital artifacts that could compromise system performance and reliability.

The loss of the categorized SE/RTCA was stable in 2025 (10 in both 2024 and 2025). External modeling was still the primary contributor to these events in 2025. Many entities have expanded their EMS models to monitor the impact of events and outages that occur beyond their own footprint. This expansion has raised

the risk of encountering inaccurate data points, faulty topology modeling, and communication issues that could lead to EMS events. Entities were encouraged to communicate changes to the BES, including the addition of new substations and new facilities and the removal of existing facilities, to neighboring entities well in advance. This proactive communication will allow neighboring entities to update their external EMS models promptly, ensuring that the data received through integrated communications control panel (ICCP) links is accurately aligned with the corresponding data points in their models.

Over the five-year period (2021–2025), the average partial or full function categorized EMS outage time (Figure 3.14) was 78 minutes, making the calculated EMS availability 99.994% during the term.

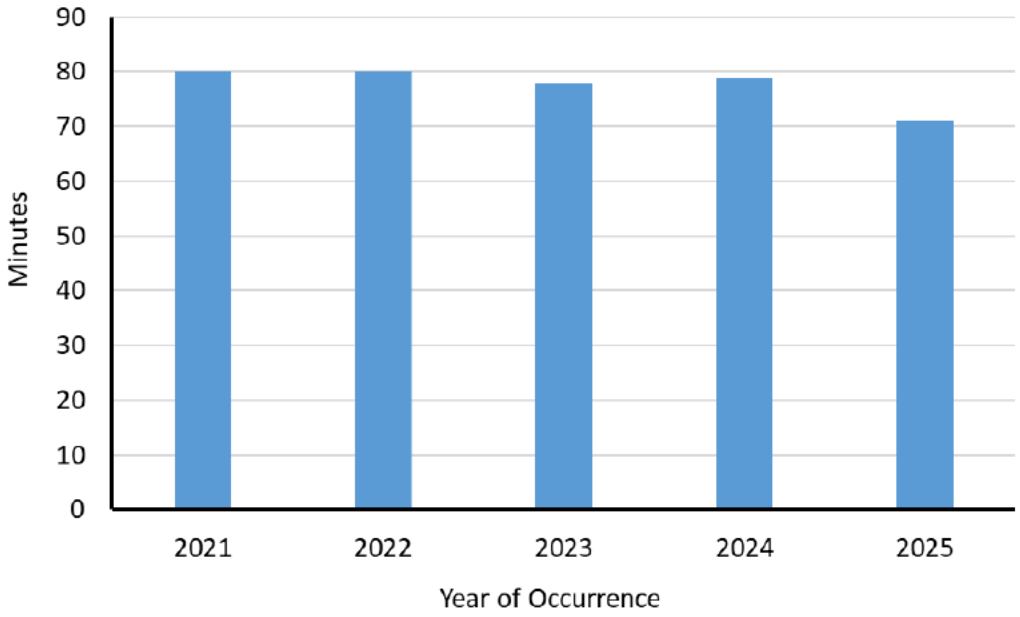


Figure 3.14: Average EMS Outage Time (2021–2025)

Largest Contributor to Loss of EMS

Reported EMS events can be grouped by the following attributes:

- **Software:** Software defects, modeling issues, database corruption, memory issues, etc.
- **Communications:** Device issues, less-than-adequate system interactions, etc.
- **Facility:** Loss of power to the control center or data center, fire alarm, ac failure, etc.
- **Maintenance:** System upgrades, job scoping, change management, software configuration, settings failure, etc.

Figure 3.15 illustrates that software was the primary contributor to EMS outages during the evaluation period from 2021 to 2025. This was followed by communication and maintenance challenges.

Figure 3.16 shows a trend in reported EMS events by the contributors of EMS function loss throughout the same period. In 2025, the main contributors were software and communications challenges, indicating a consistent overall trend from 2021 to 2025.

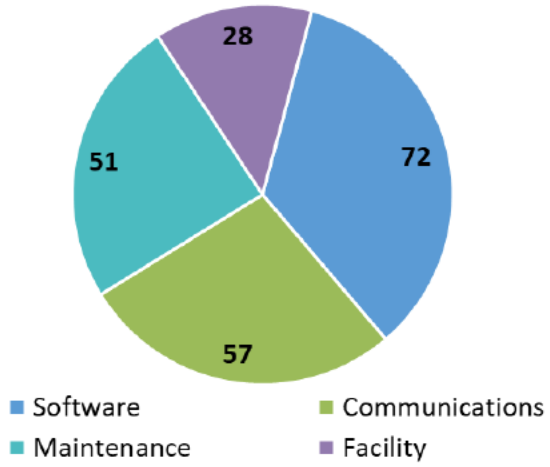


Figure 3.15: Overview of Contributors to Loss of EMS Functions (2021–2025)

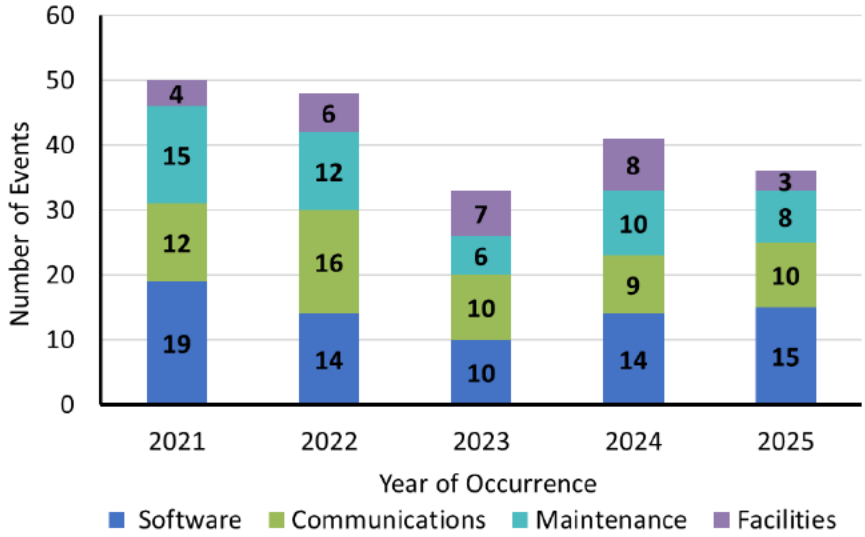


Figure 3.16: Trend of Contributors to Loss of EMS Functions (2021–2025)

Bugs often cause software failures, whether in vendor applications or in-house implementations. A software testing process should be in place to ensure that requirements are met. For effective systems and software assurance, a formal testing process model should be based on the development framework used to create the software. The testing scope should provide an assurance case for the software's operation under both known and unknown conditions and should include a data integrity check of the module. It is important to develop a team of dedicated and skilled in-house personnel who can troubleshoot and resolve issues. Providing in-house staff with real-time tools and training will enhance their knowledge and facilitate better knowledge transfer from software vendors.

Communications failure was typically related to device issues or less-than-adequate system interactions. The failure indicates that data exchange was degraded between substations and control rooms or between the entity and its RC/neighboring entities. An example is a spanning-tree protocol implementation in a network switch, causing a loop that generated an exceptionally high volume of traffic. The result was to shut down the communication network supporting the EMS. Another example is that the entity lost remote terminal unit (RTU) data from major substations as the telecom company's staff cut the fiber between the substations and the data center. Entities should maintain network devices on a schedule in accordance with

the latest vendor information, security bulletins, technical bulletins, and other recommended updates. Entities must also consider redesigning communications systems such that the most critical BES substations communicate simultaneously over entirely separate physical paths (and possibly separate vendors) to both control centers, eliminating the need for telecom company communication structure.

An analysis of the ERO EAP data reveals that 4.8% (or 10 out of 208) of the reportable EMS events lasting more than 30 minutes from 2021 to 2025 were linked to issues with external communication providers. This indicates that external communication provider-related problems are not a significant cause of EMS outages.

Human Causes

As human error can adversely impact the performance of the BPS and BES equipment, it is important to establish and adhere to robust processes to minimize the risks. In-depth analysis often identifies that primary human error causal factors are a result of latent errors as well as organizational and programmatic weaknesses. As the 2025 ERO *Reliability Risk Priorities Report*[62] states, "The BPS continues to evolve in complexity. The industry faces significant risk in staffing skilled workers due to new complexities, advanced technologies, the convergence of engineering and IT skillsets, and competition from other industries."

Transmission Outages

NERC's TADS collects transmission outage data, including on human error; human error as a cause of transmission outage is defined in the *TADS Data Reporting Instructions*.[63]

Statistical significance testing for automatic outages compared the event frequency of 2025 to the average event frequency of the prior four years. Statistical significance testing for operational outages was performed by outage frequency because they are not grouped into events. Automatic outage events involving human error improved a statistically significant amount, while operational outages did not change a significant amount for either ac circuits (**Figure 3.17**) or transformers (**Figure 3.18**).

[62] 2025 ERO Reliability Risk Priorities Report

[63] Human Error: relative human factor performance including any incorrect action traceable to employees and/or contractors of companies operating, maintaining, and/or assisting the Transmission Owner.

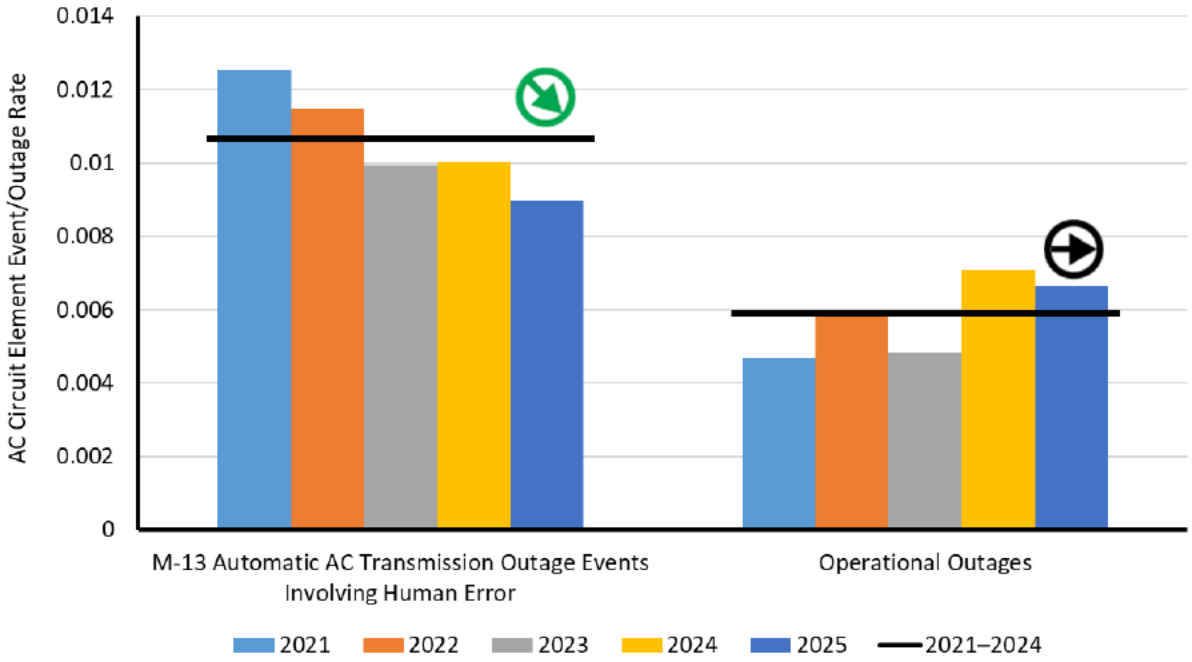


Figure 3.17: Automatic AC Transmission Outage Events and Operational Outages Involving Human Error[64]

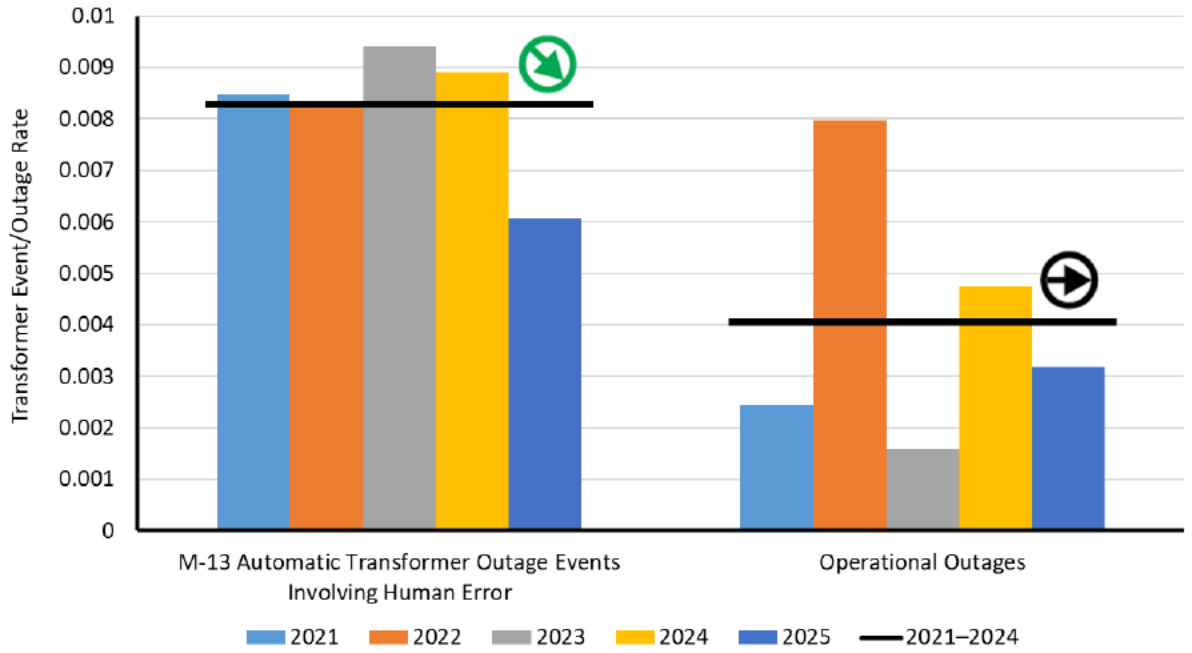


Figure 3.18: Automatic Transformer Outage Events and Operational Outages Involving Human Error[65]

Generation Outages

NERC's GADS collects generation availability data, including on outages associated with human error. While NERC continues tracking these outages, they historically represent approximately 1% of all forced outage

[64] M-13, Automatic AC Transmission Outage Events Involving Human Error
[65] Ibid.

events. Though there was a slight increase observed in 2025, it was not significant enough of a variance to warrant presentation.

Trends of Human and Organizational Root Causes[66,67]

In the ERO EAP, the cause sets of individual human performance and management/organization identify events or conditions that caused or contributed to the reported event. In 2025, organization/human performance was identified as the root cause for 41 processed events (Figure 3.19). This does not fully project the final 2025 number, as 66% of the 2025 events have been assigned a final root cause. The top five human and organizational performance root causes for the 2021–2025 period are listed in order of frequency below. These include the individual human error category, the management and organization performance category, and/or the design and engineering category:

- Design output scope less than adequate
- Job scoping did not identify special circumstances and/or conditions
- Management policy guidance or expectations are not well-defined, understood, or enforced
- Corrective action responses to a known or repetitive problem were untimely
- System interactions not considered or identified

Events from 2021 to 2025[68] saw the same top five human and organizational performance root cause identified events from 2020 to 2024.

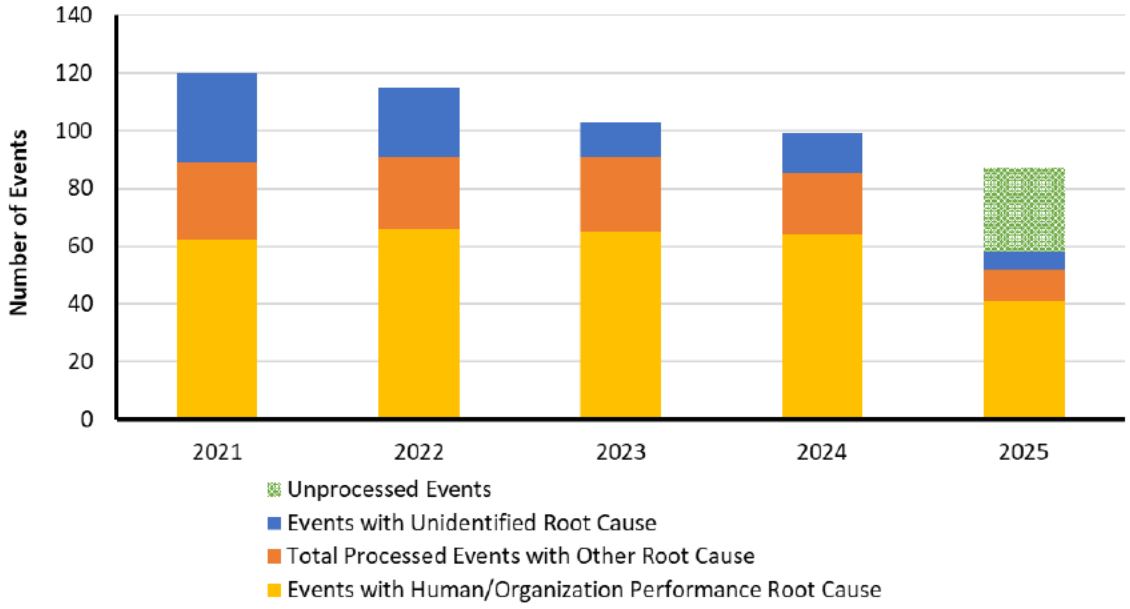


Figure 3.19: ERO EAP Organization/Human Performance Root Cause Identification by Year

Improvement opportunities exist for industry to increase BPS reliability through increased focus in the areas of management and organization performance and engineering and design. Management and organization

[66] Cause Code Assignment Process (Updated January 2026)

[67] When reviewing ERO Event Analysis Human and Organization Performance data, it is important to differentiate between it and GADS and TADS values. These are different datasets and processes. GADS and TADS are primarily focused on wholistic equipment availability and often not analyzed through the same methods nor depth used for the ERO event analysis (EA) process.

[68] Only includes 2025 events that have been processed as of data pull.

performance includes subcategories in which methods, actions, and/or practices are less than adequate. The engineering and design category includes ensuring that the engineering group employs a robust peer-review process to identify procedural errors and all considerations a design needs to be accountable. Some ways to improve human and organization performance would be to establish robust internal control mechanisms to ensure that processes and procedures such as peer reviews are in place to assist project leaders when considering the potential impacts and dependencies that may exist elsewhere on the system and to implement causal analysis when appropriate.

Protection System Misoperations

Human performance-related misoperations remain common, representing 42% of misoperations in 2025 and consisting of 11% As-Left Personnel Error, 4% Design Errors, 22% Incorrect Settings, and 5% Logic Errors (Figure 3.9). Figure 3.20 additionally shows the number of misoperations related to human error by Regional Entity for the past five years.

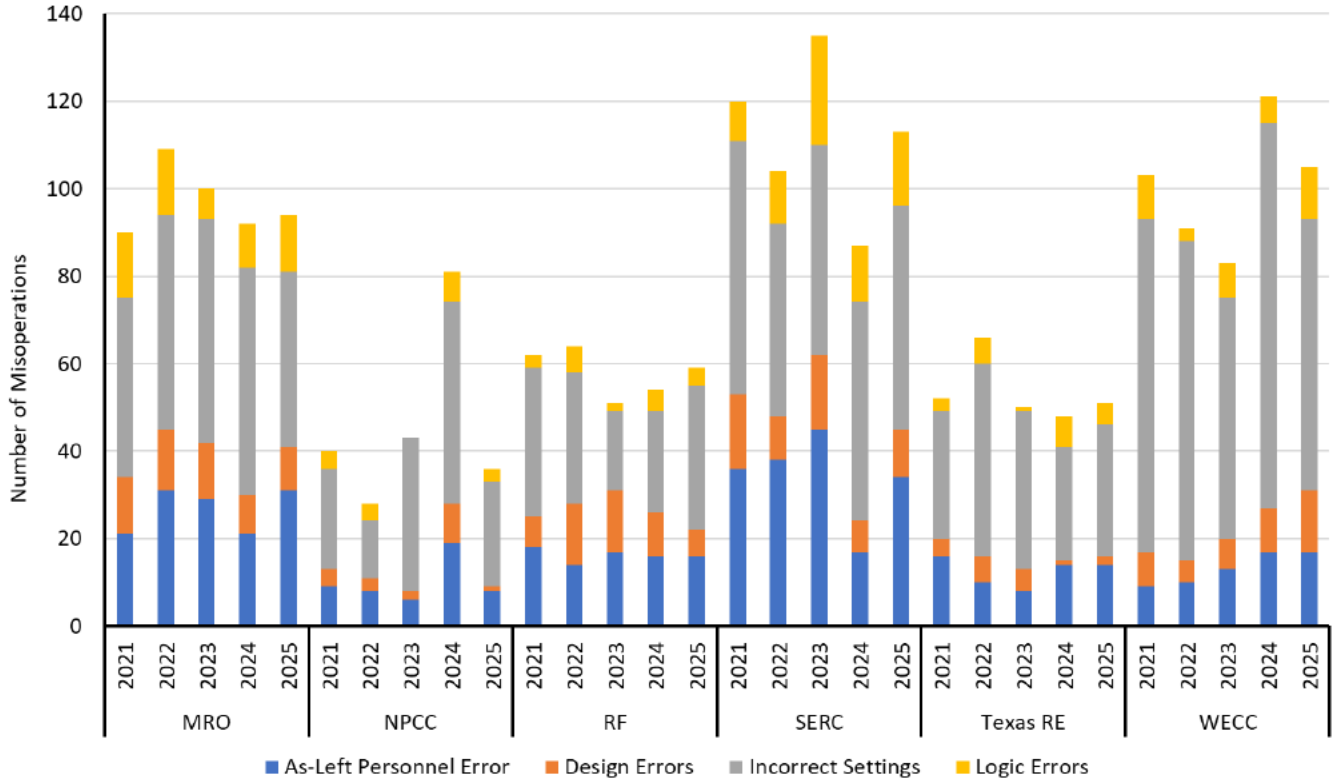


Figure 3.20: MIDAS Protection System Misoperations Due to Human Error by Regional Entity

Chapter 4: Grid Performance

Grid performance is evaluated through established reliability metrics and more in-depth analysis of specific aspects of the BPS:

- Reliability Metrics
- Frequency Response Performance
- Generation Performance and Availability
- Transmission Performance and Unavailability

Reliability Metrics

By calculating 2025 reliability metrics[69] and comparing the results to the previous years as well as the five-year average values, the reliability metrics discussed in this report can be categorized as either Improving, Stable, Monitor, or Actionable. Measuring and trending the relative state of the BPS and BES in this manner supports NERC's obligation to assess the capability of the BPS. Table 4.1 shows the status of the reliability metrics and includes a reference to the specific metric.

Table 4.1: Reliability Indicators

Metric Name		Metric Performance Status
M-1: Reserve Margin		Monitor: NPCC-Maritimes (Winter)
M-2: Transmission-Related Events Resulting in Loss of Load (Excluding Weather)		Monitor[70]
M-3: System Voltage Performance		Retired
M-4: Interconnection Frequency Response	Eastern	Improving
	Texas	Improving
	Western	Improving
	Québec	Stable
M-4.1: Inertia and Rate-of-Change-of-Frequency	Eastern	Improving
	Texas	Improving
	Western	Improving
	Québec	Actionable[71]
M-5: Activation of Under Frequency Load Shedding		Retired
M-6: Disturbance Control Standard Failures		Proposed Retirement
M-7: Disturbance Control Events Greater than Most Severe Single Contingency		Proposed Retirement
M-8: Interconnection Reliability Operating Limit (IROL) Exceedance		Monitor
M-9: Protection System Misoperations Rate		Stable
M-10: Transmission Constraint Mitigation		Retired
M-11: Energy Emergency Alerts		Improving
M-12: Automatic AC Transmission Outages Initiated by Failed Protection System Equipment	AC Circuits	Stable

[69] Current Approved Reliability Metrics; Metrics M-3, M-5, and M-10 are retired.
[70] Average lost load increased, but number of events decreased.
[71] See 2025 Interconnection Frequency Response section for details.

Table 4.1: Reliability Indicators		
Metric Name		**Metric Performance Status**
	Transformers	**Improving**
M-13 Automatic AC Transmission Events Involving Human Error[72]	AC Circuits	**Improving**
	Transformers	**Improving**
M-14: Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment	AC Circuits	**Stable**
	Transformers	**Monitor**
M-15: Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment (Number of Outages per 100 miles)		**Improving**
M-16: Transmission Element Availability Percentage and Unavailability Percentage	AC Circuits	**Stable**
	Transformers	**Monitor**
M-17: Transmission Outage Severity		**Stable**
M-18: TADS Physical Security Metric		**Stable**

Frequency Response Performance

2025 Interconnection Frequency Response

2025 analysis of frequency response performance and trends below indicates an adequate level of reliability. Further analysis is provided in NERC's *Frequency Response Annual Analysis* (FRAA).[73]

- For the stabilizing period (M4 metric), the EI, WI, and Texas Interconnection (TI) showed statistically significant improvements from 2021 through 2025, while the QI showed no statistically significant changes for the stabilizing period.
- For the arresting period (M4.1 metric), the EI, WI, and TI showed statistically significant improvements from 2021 through 2025, while the QI showed a statistically significant decline. It was noted in the 2024 SOR report that the decreasing trend in the arresting period metric for the QI was due to an overrepresentation of events in Summer 2023 (months that typically have lower inertia) compared to other years, in part due to the wildfire events in the region. A large number of events were also recorded in Summer 2025, which contributed to the declining trend. The QI has been experiencing low hydraulicity conditions since 2023. In 2025, this resulted in reduced energy exports and increased energy imports. Therefore, fewer hydro generating units were synchronized within the QI, particularly under summer light-load conditions, leading to lower system inertia during this period.
- For the underfrequency load shedding (UFLS) margin metric, the EI showed a statistically significant decline from 2021 through 2025. Although the decline is statistically significant, the magnitude of the decline, while measurable, is a very small magnitude. The year-over-year reduction in the mean and median UFLS margin values was only .003 Hz. During the five-year period, there have been changes to both the interconnection frequency response obligations (IFRO) and the minimum frequency bias settings, which will all have an impact on the UFLS margin metric. With UFLS starting

[72] Metric was revised in 2025 to evaluate the number of TADS events instead of outages. The change was made because a small number of events had resulted in a large number of outages. By tracking the frequency of human error events, the metric now tracks how often human error occurs instead of how many outages each instance happens to cause.

[73] 2025 FRAA Report

at .5 Hz off of nominal, the reduction is de minimis to reliability when the remaining margin to UFLS is taken into account.

- The number of valid events for the TI continues to decline. This was also noted in the 2024 SOR report. It was also noted in the 2024 SOR report that there was a declining trend for the number of events in the WI; however, the number of events measured in 2025 was back to within historical norms. This trend in the reduction of valid M4 events is suspected to be due to the retirement of large conventional generation as well as the ongoing integration of battery energy storage facilities in both Interconnections and is considered to be a positive indicator when considering impacts to Interconnection reliability.
- In both 2024 and 2025, there were multiple outlier events in the WI. The WI outlier events were reviewed and were not considered to be anomalous. This was also noted in the 2024 SOR report. These events represent the frequency response performance of the WI when a BA with a large battery energy storage system (BESS) fleet experiences a large resource loss. These events are becoming common place in both the WI and TI.

During the five-year period (Table 4.2), the WI had two events within the five-year period where the measured frequency response was less than the IFRO for the Interconnection. This was noted in the *2024 SOR*. Both events occurred in 2023 and had a starting frequency well above 60.00Hz and had a confirmed MW loss under 500 MW. These two factors combined eliminate any concerns that the WI frequency response is insufficient. The EI, TI, and QI did not have any events within the five-year period where the measured frequency response was less than the IFRO for the respective Interconnection.

Table 4.2: Five-Year Statistical Time Trend

Interconnection	M4 Stabilizing Period	M4.1 Arresting Period	Margin-C-UFLS	Comment
Eastern	Increasing	Increasing	Decreasing	No M4 events with FRM below IFRO
Texas	Increasing	Increasing	Increasing	No M4 events with FRM below IFRO
Western	Increasing	Increasing	Neither Increasing nor Decreasing	Two M4 events with FRM below IFRO in 2023
Québec	Neither Increasing nor Decreasing	Decreasing	Neither Increasing nor Decreasing	No M4 events with FRM below IFRO

Frequency response for all Interconnections indicates stable and improving performance for the stabilizing period as shown in Table 4.3 below.

Table 4.3: 2025 Frequency Response Performance Statistics for Stabilizing Period										
2025 Operating Year Stabilizing Period Performance										
	Number of Events					Mean Frequency Response	Median	Minimum	Maximum	Number of events with FRM below the IFRO
	2021	2022	2023	2024	2025	MW per 0.1 Hz				
Eastern	29	46	47	44	37	2,824	2,443	1,107	6,784	0
Texas	44	33	39	23	22	1,634	1,376	961	3,509	0
Québec	42	22	65	61[74]	63	1,319	644	225	23,800	0
Western	43	30	28	15	29	2,953	2,600	1,256	7,650	0

During the arresting period, the goal is to arrest the frequency decline for credible contingencies before the activation of UFLS. The calculation for IFRO under BAL-003 is based on arresting the point C nadir before the first step of UFLS for resource contingencies at or above the resource loss protection criteria (RLPC)[75] for the Interconnection. Measuring and tracking the margin between the first step UFLS setpoint and the Point C nadir is an important indicator of risk for each Interconnection. Figure 4.1 indicates the measurement periods used for analysis of the arresting period of events by looking at the frequency response between Value A and Point C as well as at the margin between Point C and the first step UFLS setpoint.

During the stabilizing period, the goal is to stabilize system frequency following a disturbance primarily due to generator governor action. Figure 4.1 indicates the measurement periods used for analysis of the stabilizing period of events by looking at the frequency response between Value A and Value B.

Frequency response for the EI, WI, and TI indicates stable and improving performance for the arresting period for 2025. Frequency response for the QI indicates a declining trend for the arresting period for 2025 as shown in Table 4.4 below.

Table 4.4: 2025 Frequency Response Performance Statistics for Arresting Period												
2025 Operating Year Arresting Performance												
	Number of Events					Mean Frequency Response	Median	Min	Max	Mean UFLS Margin	Median UFLS Margin	Min. UFLS Margin
	2021	2022	2023	2024	2025					For Loss of Generation M4 Events Only		
						MW per 0.1 Hz				Hz		
Eastern	29	46	47	44	37	2,104	1,980	1,036	3,400	0.452	0.451	0.439
Texas	44	33	39	23	22	786	764	504	1,382	0.608	0.610	0.544
Québec	42	22	65	63	63	119	123	51	196	1.078	1.149	0.649
Western	43	30	28	15	29	979	918	755	1,506	0.416	0.425	0.334

[74] GADS Events for 2024 has been updated

[75] BAL-003-2 specifies that the RLPC be based on the two largest potential resource losses in an Interconnection or the largest resource loss due to an N-2 RAS. This value is updated annually through the BAL-003-2 data collection process.

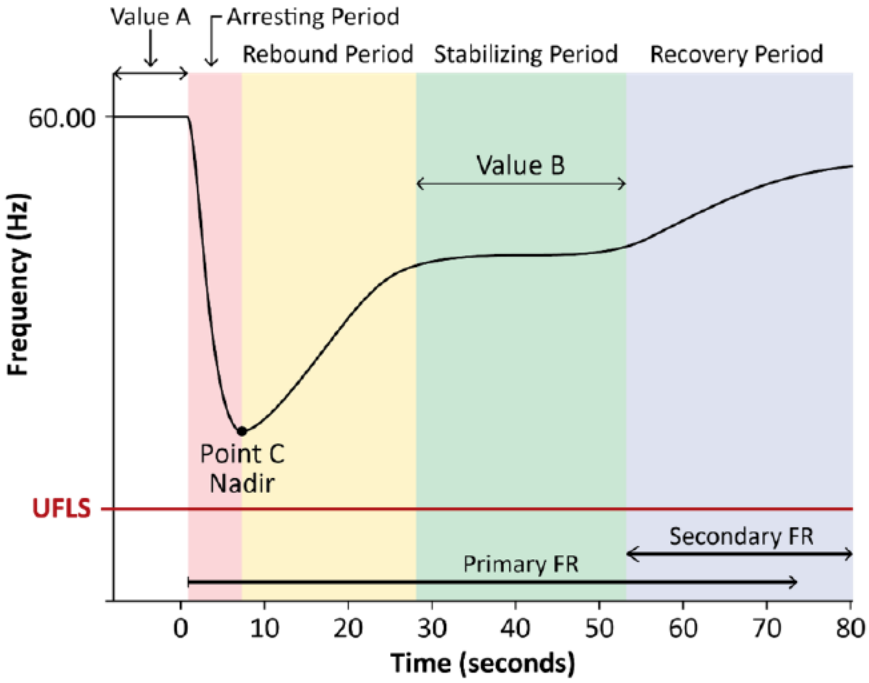


Figure 4.1: Frequency Response Methodology

Figure 4.2 represents an analysis of the arresting period of frequency response events. The Y-axis shows the percent UFLS margin from 100% (60 Hz) to 0% (first UFLS set point for the Interconnection). The X-axis represents the MW loss for the event, expressed as a percentage of the RLPC for the Interconnection. There were no events within the five-year period larger than the RLPC for any of the Interconnections. The largest events for the EI and TI were 50% as measured by percentage of RLPC. The largest events for the WI and QI were 88% and 96%, respectively, as measured by percentage of RLPC.

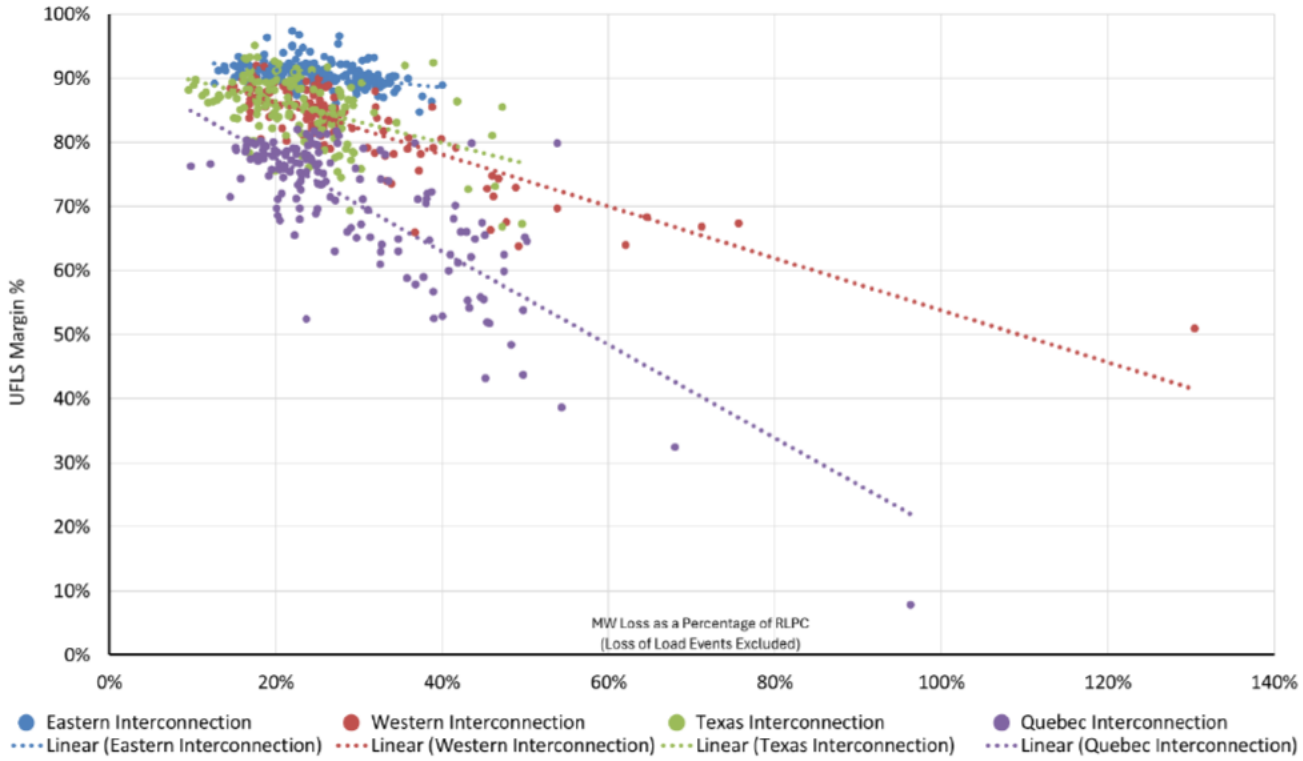


Figure 4.2: Operating Year 2021–2025 Qualified Frequency Disturbances and Remaining UFLS Margin

Interconnection Reliability Operating Limit Exceedances

2025 Performance and Trends

An IROL[76] is an SOL that, if exceeded, could lead to system instability, uncontrolled separation, or cascading that may adversely impact the reliability of the BES. The maximum time that an IROL can be exceeded is the IROL Tv. The IROL Tv must be less than or equal to 30 minutes. Each RC has a different methodology for determining IROLs based on the makeup of their area and what constitutes an operating condition that is less than desirable.

IROLs are established to ensure that corrective actions are taken to prevent and mitigate the exceedance of limits to either return to the Normal state or stay within the Alert state for certain conditions and contingencies that could otherwise cause the BPS to enter the extreme state, being at high risk of system instability, cascading, and uncontrolled separation.

The Texas and Western Interconnections both maintained stable trends with no IROL exceedances reported in 2025. In the Eastern–Québec Interconnections, there were 19 exceedances that lasted more than 10 minutes in 2025, more than the five-year rolling average of 11.8 exceedances as shown in Figure 4.3. The 10- to 20-minute range increased from a single exceedance in 2024 to 18 exceedances in 2025, while one exceedance lasted more than 20 minutes. The five-year average still declined slightly as year 2020 rolled off with 20 total exceedances.

[76] M-8, IROL Exceedance

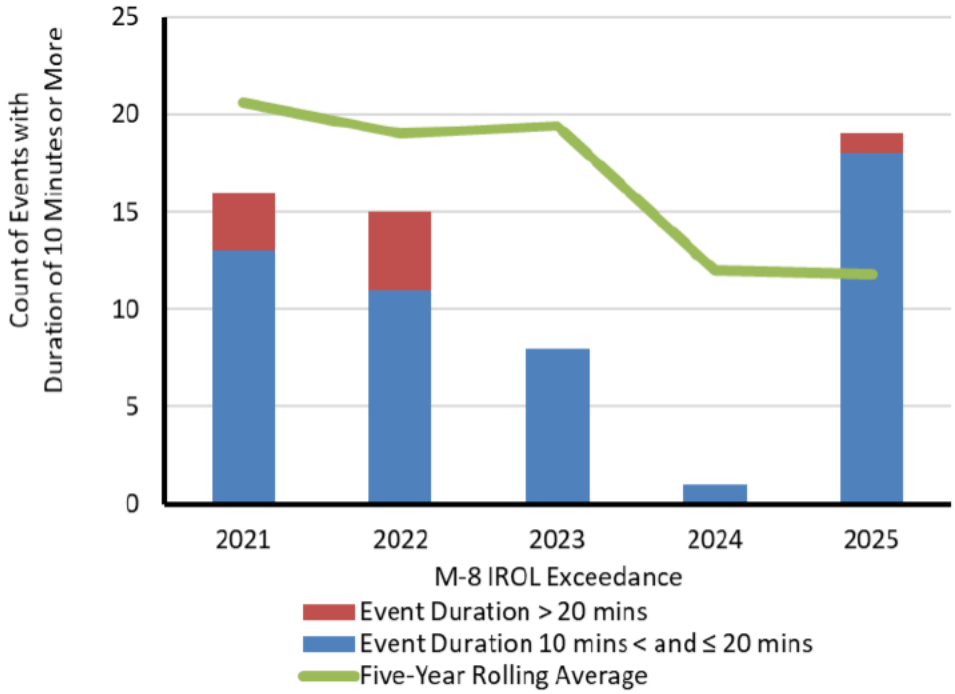


Figure 4.3: IROL Exceedance Counts

Generation Performance and Availability

GADS contains information that can be used to compute reliability measures, such as the weighted equivalent forced outage rate (WEFOR). GADS collects and stores unit operating information by pooling individual unit information, generating unit availability, performance, and calculated metrics.

Conventional Generation WEFOR

The horizontal lines in Figure 4.4 show the annual WEFOR compared to the monthly WEFOR columns; the solid horizontal bar shows the WEFOR for all years in the analysis period of 8.1%. The 2025 WEFOR rate of 9.2% is a notable increase over 2024 (7.6%) and above recent historical norms in the 7–8% range.

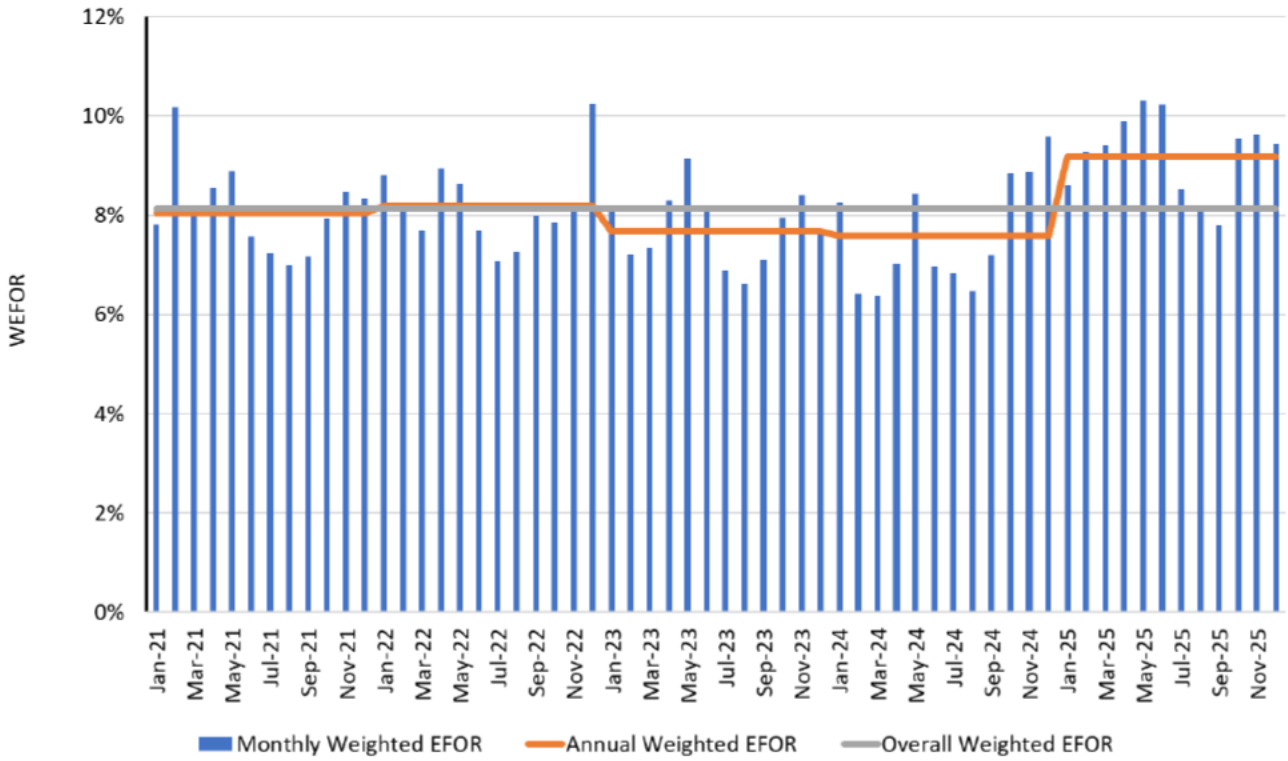


Figure 4.4: Monthly, Annual, and Five-Year WEFOR

Additional analysis identified that the increase is driven by combustion-based generators as shown in Table 4.5; further details are provided in the *2026 SOR Overview* report.

Table 4.5: Primary Fuel Type Year-Over-Year Change in MWh

Primary Fuel Type	2024 vs 2025 Year-Over-Year Change in GWh[77]	2024 WEFOR	2025 WEFOR
Gas - Steam Turbine	8,772	19.2%	22.4%
Gas - Simple Cycle Combustion Turbine	5,938	20.7%	22.8%
Gas – Simple Cycle w/Heat Recovery Steam Generator (HRSG)	-203	7.7%	7.0%
Combined Cycle	19,154	4.2%	5.7%
Coal	39,835	11.2%	14.1%
Oil - Steam Turbine	1,857	24.6%	25.6%
Oil - Combustion Turbine	2,427	48.2%	69.4%
Hydro	-3,171	8.4%	7.7%
Nuclear	-3,862	2.7%	2.2%
Other	-2,308	11.1%	8.4%
Total	68,440	7.6%	9.2%

[77] Measured by WEFOR numerator:
$\sum(([Forced\ Outage\ Hours] + [Equivalent\ Forced\ Derate\ Hours]) * [Net\ Maximum\ Capacity])$

The monthly WEFOR for major contributing fuel types is shown as a layered area chart with a relative capacity breakdown pie chart in Figure 4.5. The dashed line shows the monthly WEFOR of all fuel types reported to NERC, and the red line shows the mean outage rate of all fuel types reported to NERC over the five years in the analysis period. As stated above, in 2025, the annual WEFOR increased to 9.2%. Observing individual fuel types, coal experienced a fairly consistent increase in WEFOR throughout the year, simple cycle gas turbines experienced normal peak outage rates but with prolonged recovery, and combined cycle experienced both a baseline increase as well as two abnormal peak outage periods in early summer and early winter. These trends can be further contextualized by comparing the change in MWh of lost production due to forced unavailability from 2024 to 2025 in Table 4.5, examining each fuel's capacity percentage (Figure 4.5), and annual net actual generation (Figure 4.6).

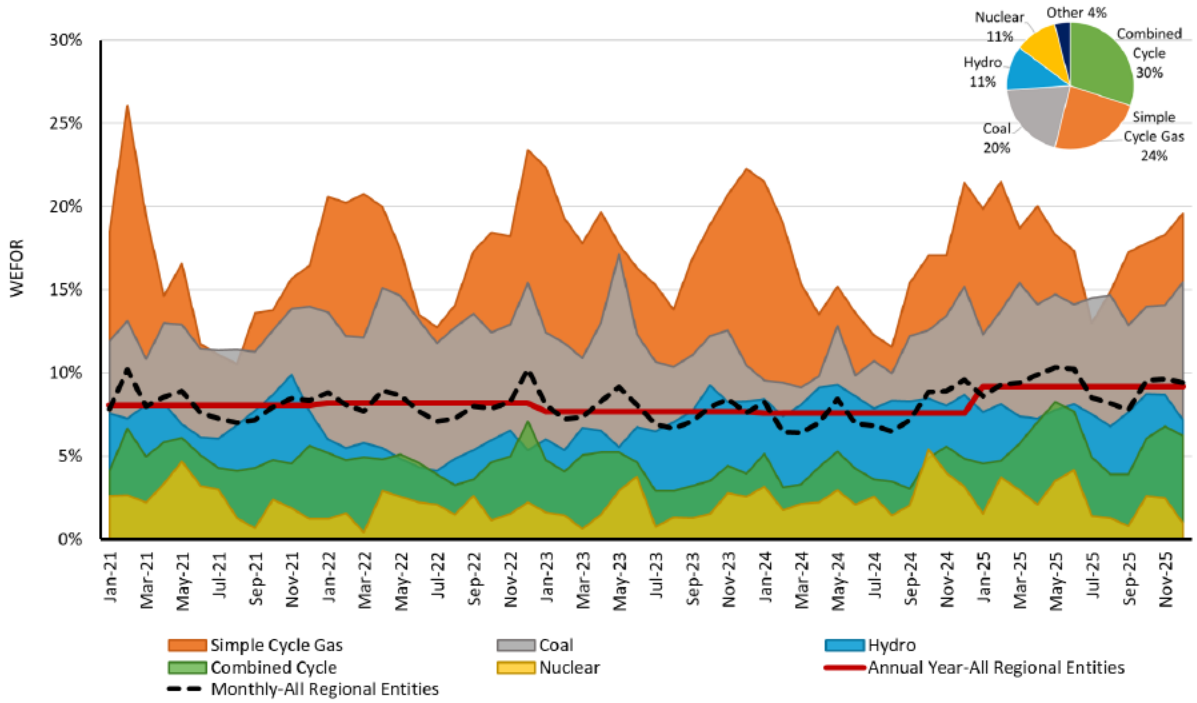


Figure 4.5: Five-Year WEFOR by Fuel Type and 2025 Resource Mix by Net Maximum Capacity

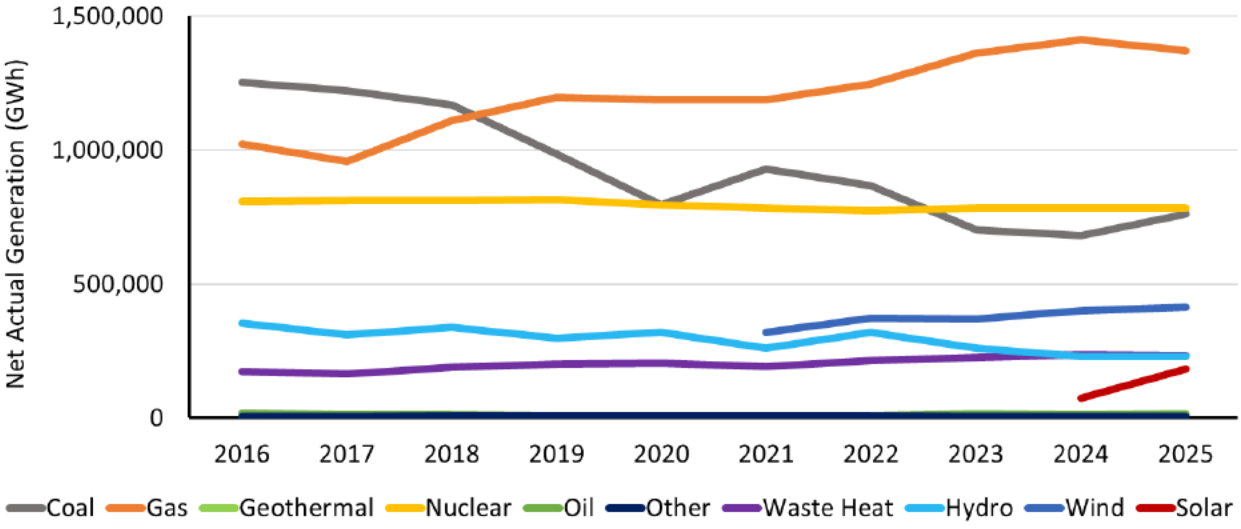


Figure 4.6: 10-Year Annual Net Actual Generation (GWh) by Fuel Type

Wind and Solar[78] Generation Weighted Factors

Figure 4.7–Figure 4.9 present various weighted factors for wind[79] plant data collected in GADS. Because no exact analog to conventional generation's WEFOR calculation exists, the data is broken down into different factors representing what percentage of the month the plants were in each state and presented as a stacked area chart representing the entire duration of the month. For the purposes of this report, the following calculation and data modifications have been made:

- Resource forced outage factor has been separated into resource forced outage factor (representing forced equipment outages) and resource unavailable outage factor (representing forced outages due to a lack of generating resource).
- Resource reserve shutdown factor is calculated the same way as other factors, with reserve shutdown as the numerator.
- Generation losses due to sub-optimal resource conditions are calculated by subtracting the resource net capacity factor from the resource generating factor. The value represents the portion of the month in which the plant was producing at less than full capacity. For example, if a wind plant has 100 MW of installed capacity but due to wind speed is only producing 60 MW and has no other constraints, this value would be 40%.

Wind data is presented in Figure 4.7–Figure 4.9, with each figure showing a different stage of data collection: plants >200 MW, 100–199 MW, and 75–99 MW.

NERC is continuing to develop unbiased, representative analysis for wind and solar analysis to best understand trends in the data and draw comparisons to more conventional resources. In 2025, equipment performances across all wind plant sizes were comparable to one another and would not be considered problematic compared to conventional generation, with a resource forced outage factor (RFOF) most like hydro generation's WEFOR. Energy generation at plants >200 MW declined in 2025, warranting further investigation.

[78] During this year's data analysis, NERC identified significant GADS solar data reporting errors and numerous missing plants compared to EIA 860 data. NERC will be coordinating with Regional Entity staff to perform industry outreach and resolve these errors in 2026.

[79] 2025_GADS_Wind_DRI

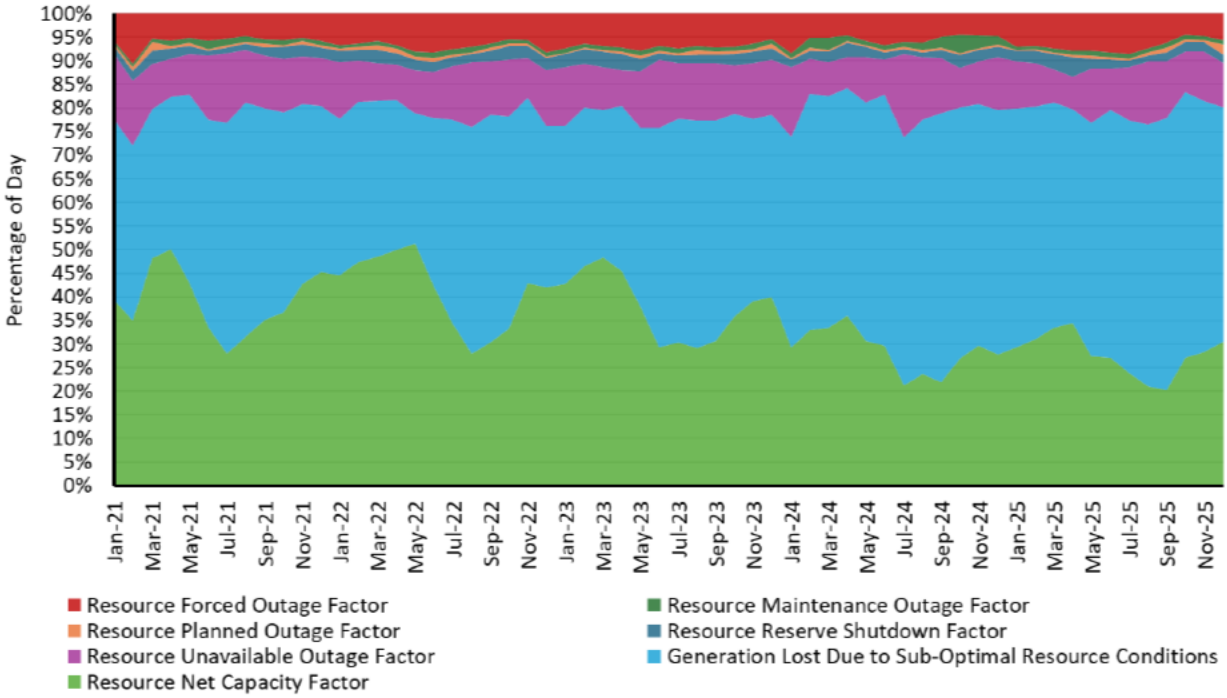


Figure 4.7: Monthly Net Output Factor and Weighted Resource Forced Outage Rate (WRFOR) Wind Plant Reporting Group 200 MW+

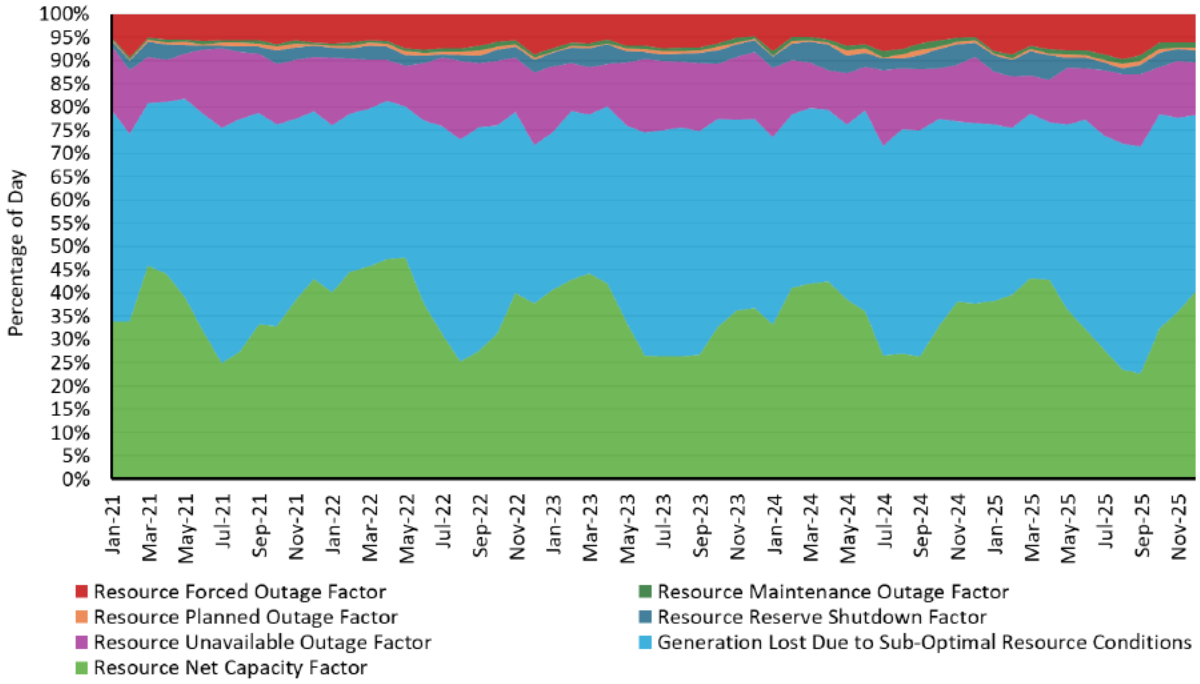


Figure 4.8: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 100–199 MW

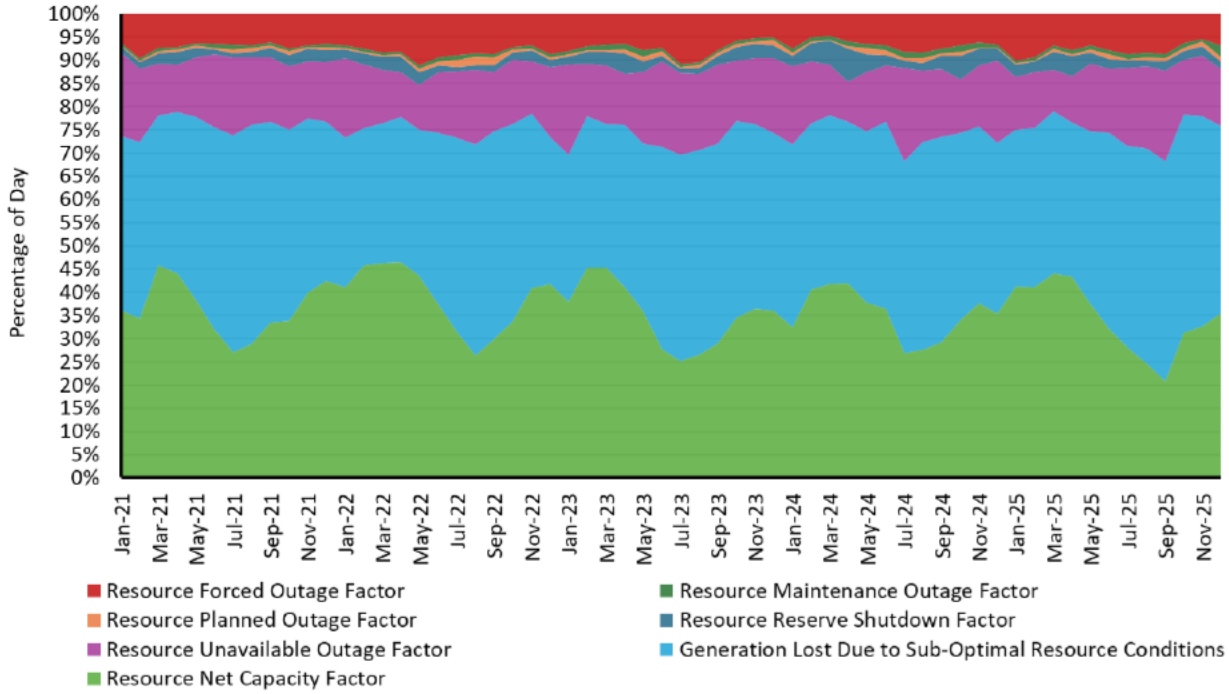


Figure 4.9: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 75–99 MW

Transmission Performance and Unavailability

When evaluating transmission reliability, an important concept is that transmission line outages have different impacts on BPS reliability. Some impacts can be very severe, such as those that affect other transmission lines and load loss. Additionally, some outages are longer than others, leaving the transmission system at risk for extended periods of time. Reliability indicators for the transmission system are measured by using qualified event analysis reporting not related to weather and outages reported to TADS.

Transmission-Related Events Resulting in Loss of Load

In 2025, a total of six distinct non-weather-related transmission events resulted in a loss of firm load that met the ERO EAP reporting criteria (Figure 4.10). The median firm load loss over the past five years was 88.0 MW, which is a decrease from 2020–2024's 90 MW. In 2024 the median load loss was 85.5 MW or 47.0 MW below the 2020–2023 median, and 2025 saw the median increase to 132.5 MW, which is 44.5 MW above the 2021–2024 median.

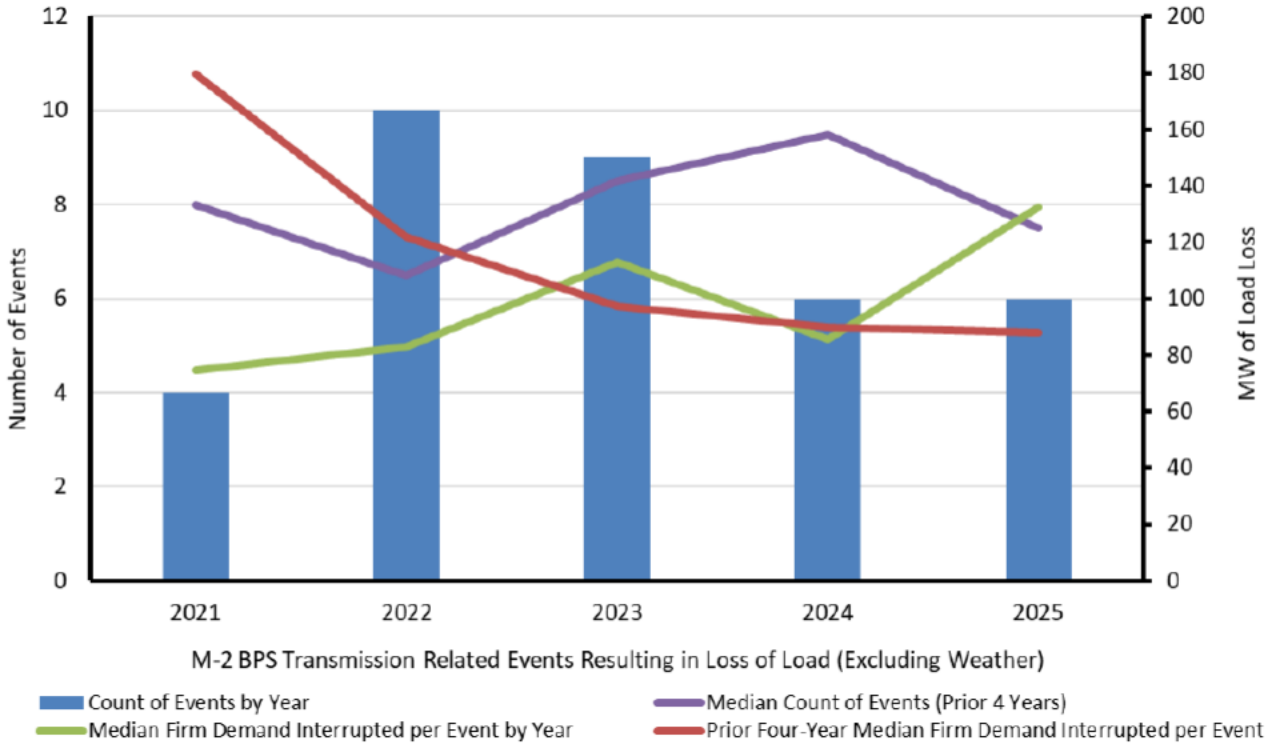


Figure 4.10: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[80]

TADS Reliability Indicators

A TADS event is an unplanned transmission incident that results in the automatic outage (sustained or momentary) of one or more elements. TADS event information was analyzed for the following indicators in this section:

- Transmission Outage Severity
- Automatic AC Transmission Outages
- Transmission Element Unavailability

Transmission Outage Severity

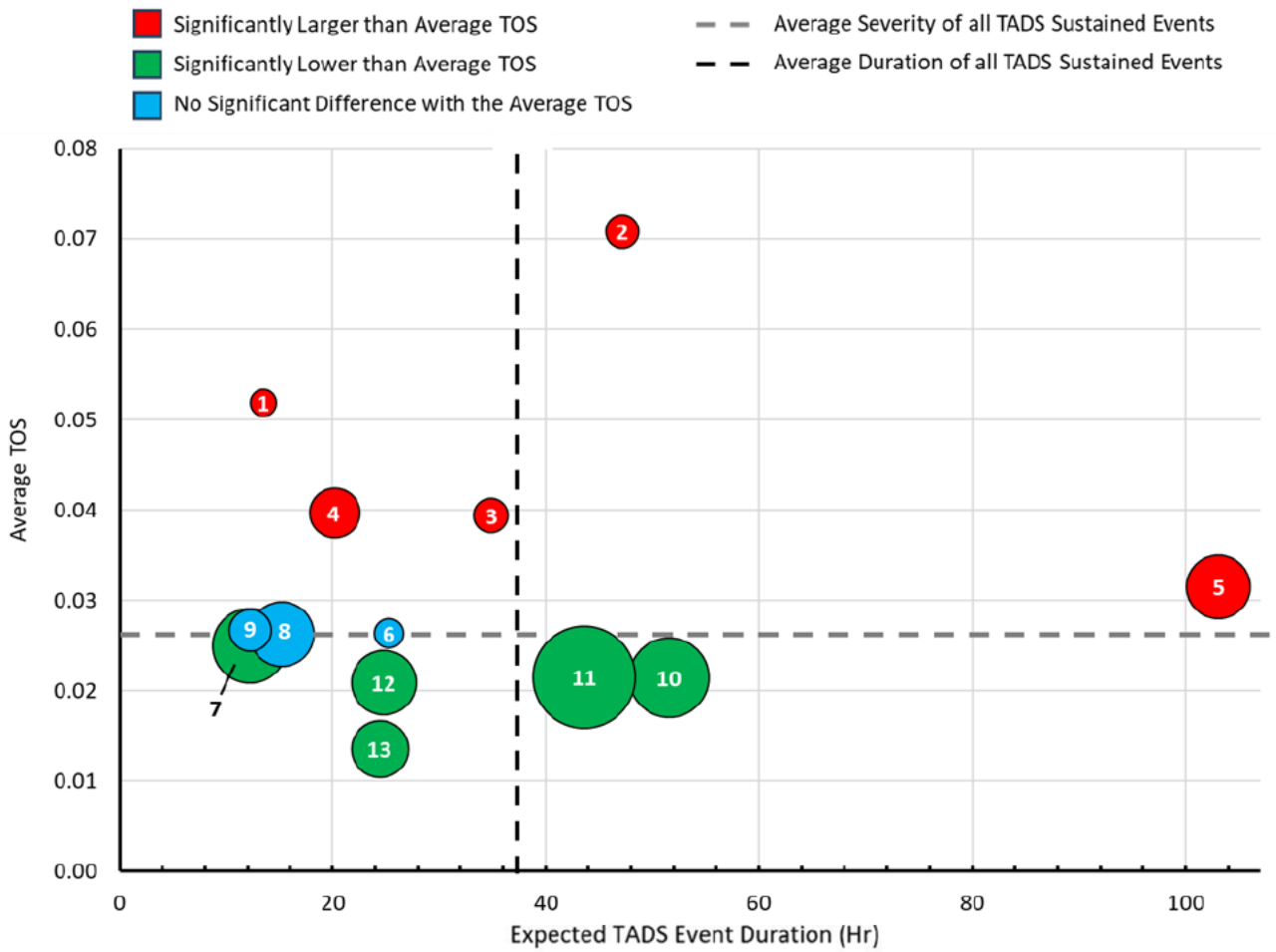
The impact of a TADS event on BPS reliability is called the transmission outage severity (TOS) of the event, which is defined by the number of sustained outages in the event and by the type and voltage class of transmission elements involved in the event. TADS events are categorized by initiating cause codes (ICC). These ICCs facilitate the study of cause-effect relationships between each event's ICC and event severity.

The number of events per hour, average event duration, and average TOS for each ICC group are shown in Table 4.6.

[80] M-2, BPS Transmission Related Events Resulting in Loss of Load (Excluding Weather)

Table 4.6: TOS vs. Expected TADS Event Duration				
TADS Event	Events per Hour	TOS		Average Event Duration (Hours)
		Average	Maximum	
Combined Smaller ICC Groups	0.018	0.039	0.318	34.9
Failed AC Circuit Equipment	0.099	0.021	0.249	51.5
Failed AC Substation Equipment	0.063	0.032	0.414	103.1
Fire	0.017	0.071	0.652	47.2
Foreign Interference	0.064	0.021	0.196	24.8
Human Error	0.027	0.027	0.377	12.3
Lightning	0.064	0.026	0.519	15.2
Misoperation	0.038	0.040	0.732	20.2
Other	0.013	0.026	0.327	25.2
Power System Condition	0.011	0.052	0.998	13.5
Unknown	0.086	0.025	0.365	12.2
Vegetation	0.050	0.014	0.494	24.4
Weather, Excluding Lightning	0.163	0.022	0.654	43.6

By examining the average TOS, duration, and frequency of occurrence for events with different ICCs (Figure 4.11) it is possible to determine which ICCs contribute most to reliability performance for the period under consideration. The average TOS for events with a specific ICC is displayed on the Y-axis. A higher TOS for an ICC indicates that more sustained outages or higher voltage elements were involved in an event. The average duration for events with a specific ICC is displayed on the X-axis; generally, events with a longer duration pose a greater risk to the BPS. The number of ICC occurrences is represented by the bubble size; larger bubbles indicate that an ICC occurs more often. Lastly, the bubble colors indicate a statistical significance of a difference in the average TOS of this group and the events from other groups.



1. Power System Condition
2. Fire
3. Combined Smaller ICC Groups
4. Misoperation
5. Failed AC Substation Equipment
6. Other
7. Unknown
8. Lightning
9. Human Error
10. Failed AC Circuit Equipment
11. Weather, Excluding Lightning
12. Foreign Interference
13. Vegetation

Figure 4.11: TOS vs. Expected TADS Event Duration

An analysis of the total TOS by year indicates that 2025 shows an improving trend compared to 2024, with the Unknown category improving to the point that it went from the No Significant Difference category (blue) in 2024 to the Significantly Lower than Average TOS category (green) in 2025. All other categories remained the same. Figure 4.12 shows the annual TOS, which is the lowest since TADS data collection began.

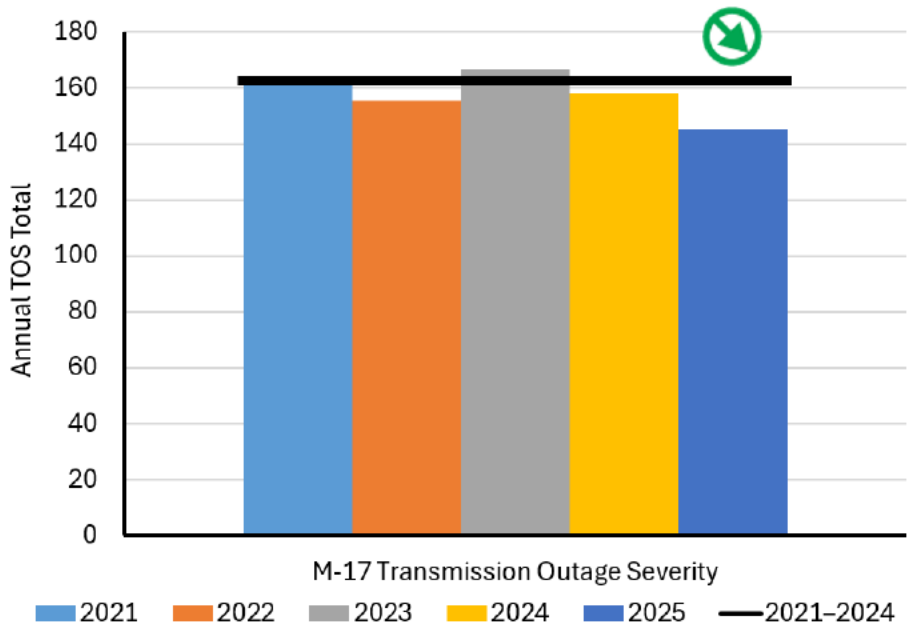


Figure 4.12: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[81]

Automatic AC Transmission Outages

The average number of outages per circuit due to failed ac substation equipment slightly decreased from 2024 to 2025 and is effectively equal to the previous four-year average (Figure 4.13). The number of sustained outages due to failed ac circuit equipment per 100 miles decreased in 2025 to the lowest of the past five years (Figure 4.14).

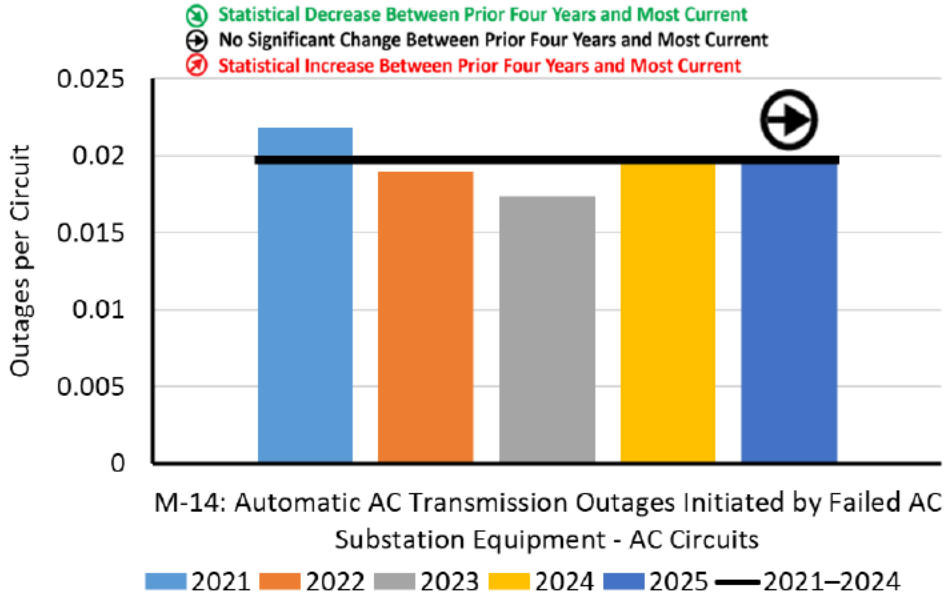


Figure 4.13: Number of Outages Per AC Circuit Due to Failed AC Substation Equipment[82]

[81] M-17, Transmission Outage Severity
[82] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

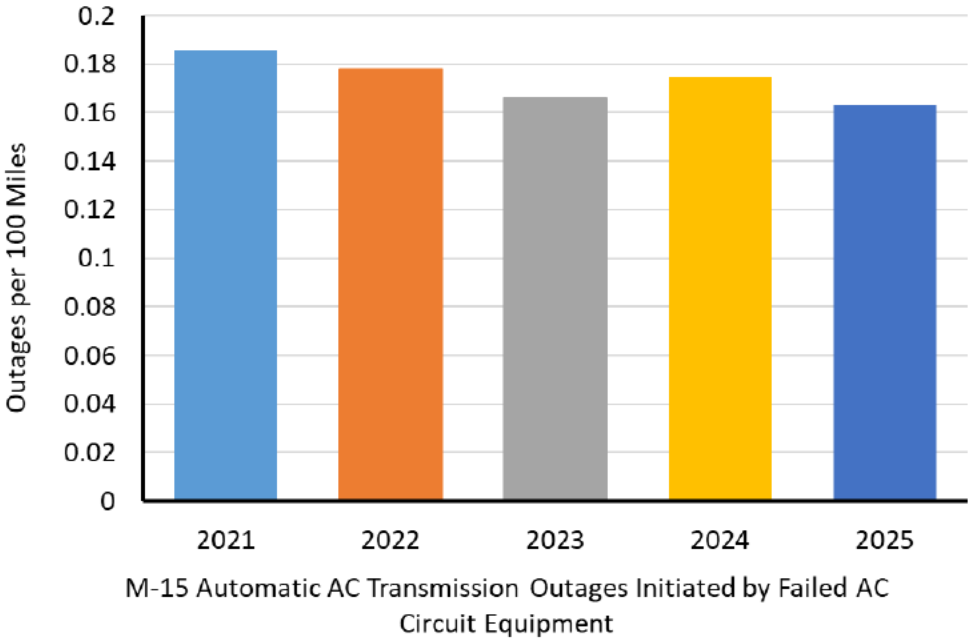


Figure 4.14: Number of Outages Per 100 Miles Due to Failed AC Circuit Equipment[83]

Automatic AC Transformer Outages

In 2025, there was a slight decrease in the number of automatic ac transformer outages per element caused by failed ac substation equipment, but there was no significant change compared to the prior four years. Though the decrease in outages is not statistically significant, as can be seen in Figure 4.15, this number remains the second highest over the past five years.

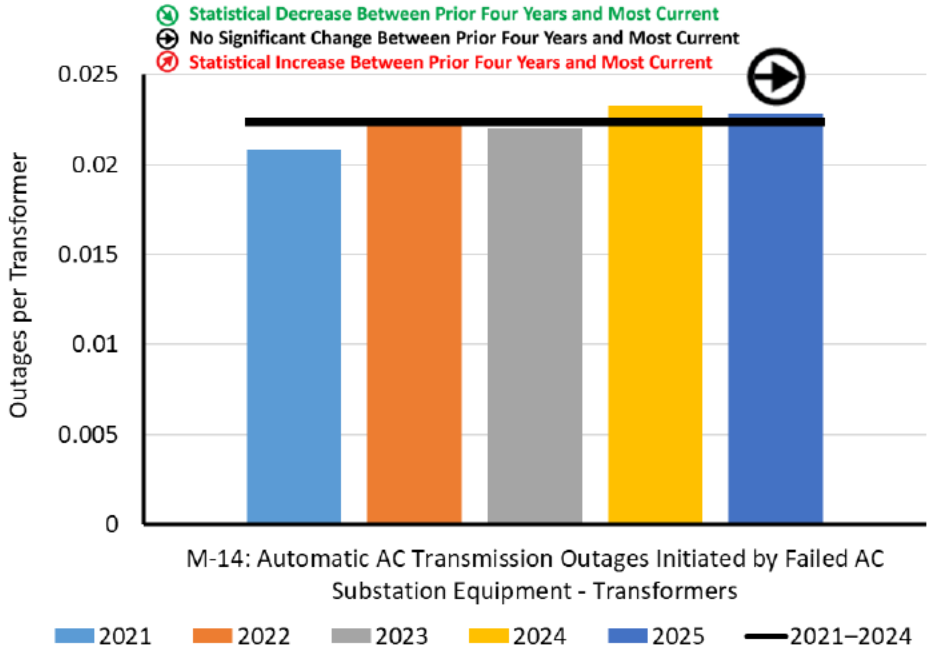


Figure 4.15: Number of Outages Per Transformer Due to Failed AC Substation Equipment[84]

[83] M-15, Automatic AC Transmission Outages Initiated by Failed AC Circuit Equipment
[84] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

Transmission Element Unavailability

In 2025, ac circuits over 200 kV across North America had an unavailability rate of 0.22%, representing the chance that a specific transmission circuit is unavailable due to sustained automatic and operational outages at any given time. Transformers also had an unavailability rate of 0.35% in 2025. Figure 4.16 shows that while there was a decrease in ac circuit availability in 2025, it was not statistically significant when compared to the prior four years.

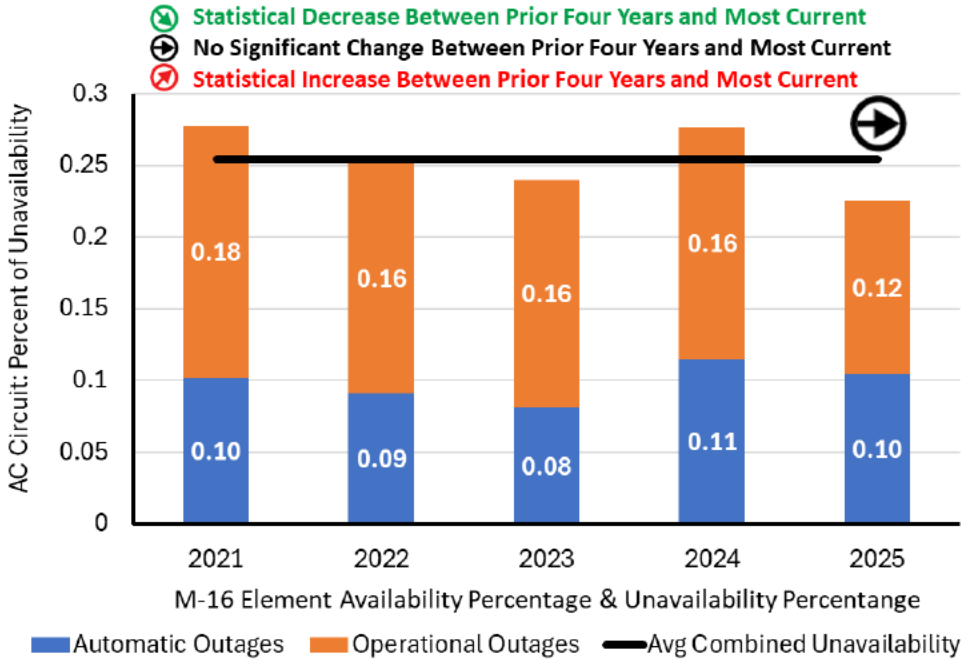


Figure 4.16: AC Circuit Unavailability >200 kV[85]

Figure 4.17 shows that 2025 is the highest year for transformer unavailability of the five-year analysis period, in large part due to an increase in the number of operational outages. Responses from voluntary outreach to utilities with the longest operational transformer outages in 2025 aligned with historically provided reasons for prolonged outages and did not indicate the need for immediate action. In addition to several one-off scenarios, common themes included removing transformers temporarily multiple times to maintain system reliability, system redundancy reducing restoration urgency, and two instances where supply chain constraints in the form of known long lead times prolonged outages.

[85] M-16, Element Availability Percentage (APC) & Unavailability Percentage

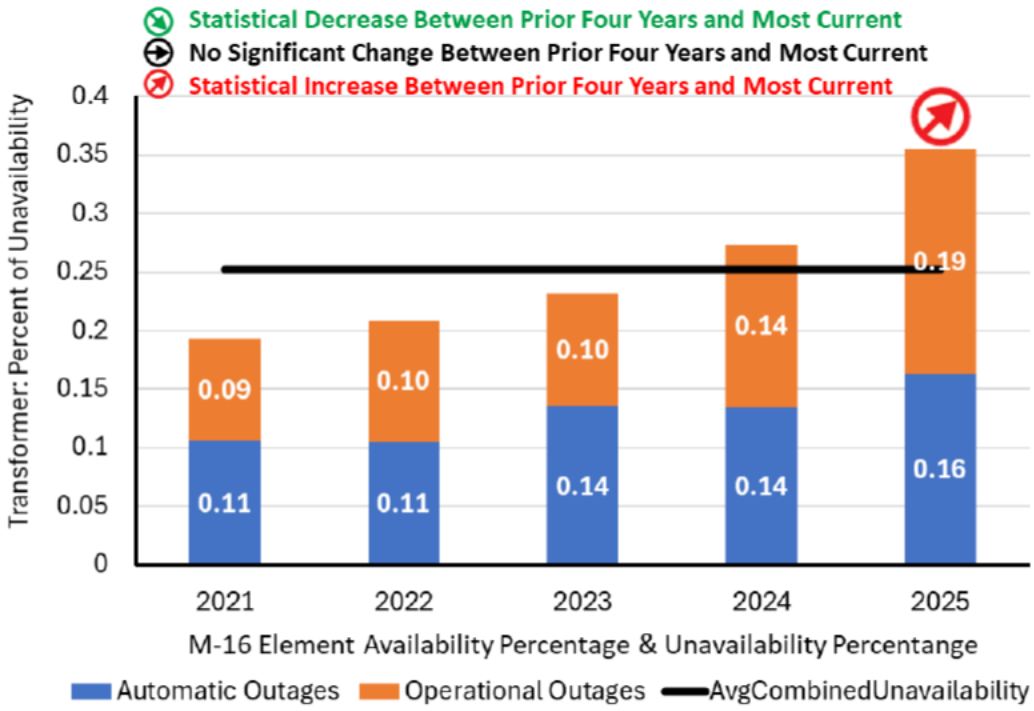


Figure 4.17: Transformer Unavailability >200 kV [86]

TADS Physical Security Metric

Over the past several years, there has been an increase in physical attacks on the BPS. To help measure the impact of these transmission physical security events on the BES and identify trends, a new metric was introduced, the TADS Physical Security Metric (M18), described as follows.

- The TADS Physical Security metric uses the data from TADS sustained physical security-related outages for transmission elements reportable in TADS with a voltage of 100 kV and above. Prior to 2024, these outages were reported using the initiating or sustained cause code labeled Vandalism, Terrorism, or Malicious Acts. Since 2024, these outages have been reported using the initiating or sustained cause code labeled Physical Security Incident. The metric is calculated by adding the number of outages, their average equivalent MVA, and their average duration, for a rolling five-year period that is then statistically compared to identify trends.
- The bubble chart in Figure 4.18 shows a rolling comparison of the TADS Physical Security metric of 2021–2025 to 2020–2024. The size of a bubble represents the total number of physical security outages (displayed in the center of each bubble). The X-axis of a bubble shows the average duration of the outages (in hours), and the Y-axis shows the average MVA capacity impacted for those outages.

[86] M-16, Element Availability Percentage (APC) & Unavailability Percentage

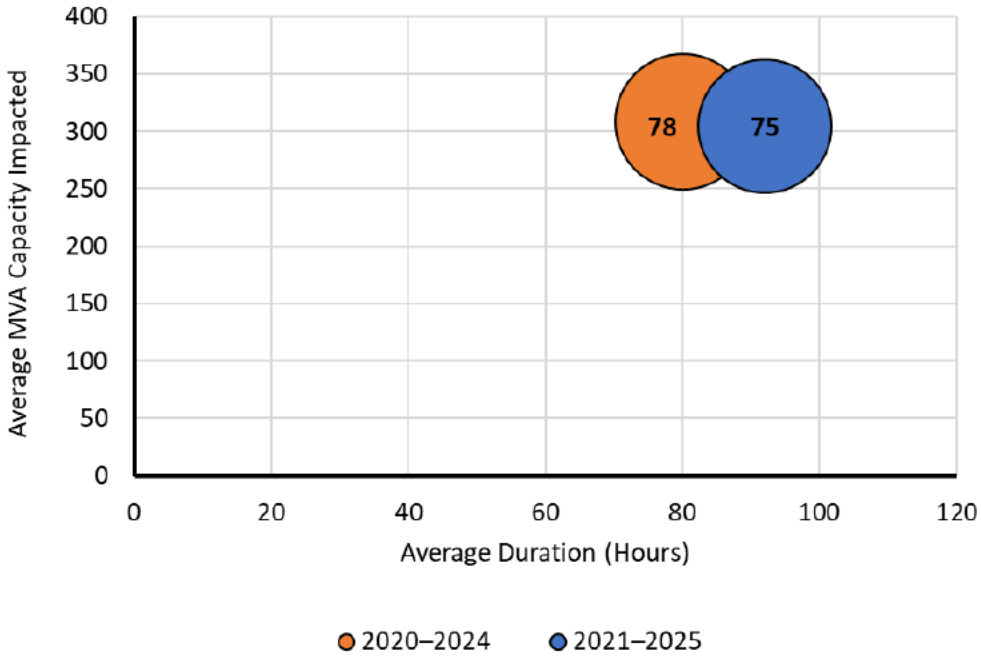


Figure 4.18: Comparison of TADS Physical Security Metric for 2020–2024 vs. 2021–2025[87]

Figure 4.18 shows a decreasing trend in both the total number of physical security outages (from 78 to 75) and average MVA capacity (from 308.5 MVA to 304.6 MVA) and an increase in the average duration for those outages (from 80 hours to 92 hours). Based on the rating criteria for this metric, the assessment rating for this metric is Stable.

Table 4.7: 2025 M-18 TADS Physical Security Metric		
	2020–2024	2021–2025
Outage Count	78	75
Average MVA	308.5	304.57
Average Duration (Hours)	80.15	92.03

Incident Tracking Context/Background

The E-ISAC tracks physical security incidents shared by asset owners across North America to reduce physical security risks to the sector by monitoring and reporting on relevant trends such as the criminal threat environment and the tactics, techniques, and procedures that result in operational impacts to the North American grid. In addition to physical security incidents reported to the ERO through mandatory mechanisms such as the DOE-417 and EOP-004 forms, the E-ISAC tracks incidents shared voluntarily by members on the E-ISAC Portal or shared directly with the E-ISAC through the Bulk Data Program. Approximately 91% of incidents tracked by the E-ISAC since 2021 were received through voluntary methods. Since 2021, the E-ISAC has tracked over 17,000 physical security incidents within the following categories: Assault, Ballistic Damage, Intrusion, Theft, Threat, Surveillance, Suspicious Activity, and Other. Of these 17,000, less than 3% have resulted in operational impacts since 2021 (Table 4.8), though the proportion typically fluctuates within shorter time periods between 2% and 4%.

[87] M-18, TADS Physical Security

Table 4.8: E-ISAC Severity Level Definitions and Data Summary (2021–2025)[88]		
Severity Level	**Definition**	**% of incidents**
Level 0	Non-criminal, potential security nexus	11%
Level 1	Likely criminal activity with no operational impacts; only monetary.	86%
Level 2	Some operational impacts; including limited customer outages, generation unavailability, or partial loss of control and monitoring.	2%
Level 3	Significant operational impacts; including extensive customer outages, generation unavailability or loss of control and monitoring.	<1%

Operational Impacts Increasing

Since 2021, Level 2 and Level 3 incidents shared with the E-ISAC have increased (Figure 4.19). While 2023 saw an increase in Ballistic Damage incidents resulting in operational impacts, the primary tactics that increased throughout 2024 and 2025 involved Theft or Vandalism. The change in tactics reflects the changing risk environment and can be attributed to copper market spikes and supply chain constraints, leading to increased targeting of copper through Theft and Vandalism. In 2025, the E-ISAC observed sustained levels of Vandalism and Ballistic Damage compared to historic norms, paired with an increase in operational impacts from Theft and continued targeting of fiber infrastructure.

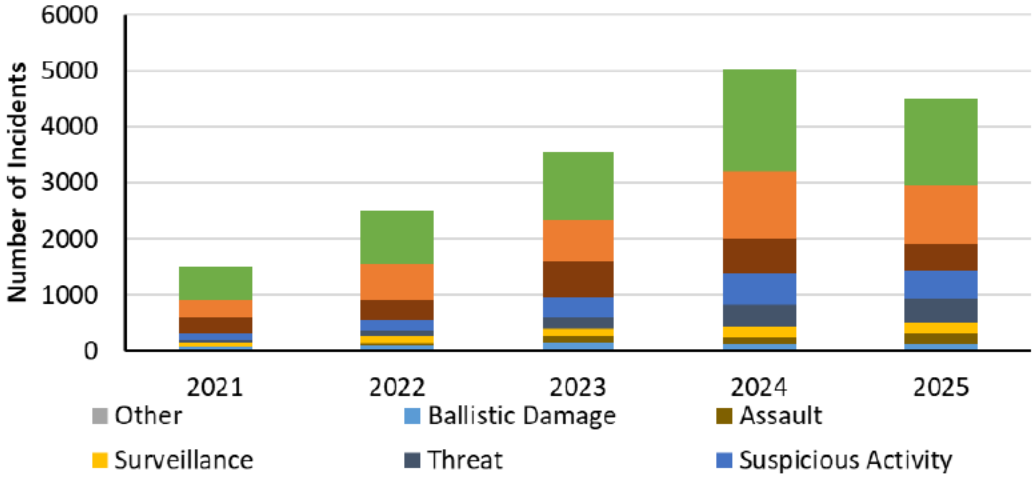


Figure 4.19: Incidents Resulting in Operational Impacts (Severity Level 2 and Level 3) by Tactic (2021–2025)

Unlike Operational Impacts, Overall Incidents Decreased

In 2025, overall incidents shared with the E-ISAC decreased by 11% compared with 2024 (Figure 4.19); this decline was relatively consistent between mandatory/voluntarily shared incidents for all severity levels. This is in contrast to incidents discussed above resulting in operational impacts. The differing volume trend observed between all incidents versus those resulting in operational impacts can be attributed to a shifting tactical focus by adversaries, with copper thefts increasingly affecting energized distribution (non-substation) assets, resulting in customer outages.

For more insight into the risks to industry related to physical security incidents that result in operational impacts, see the E-ISAC's annual Grid-Impacting Report (available to E-ISAC members on the Portal).

[88] https://www.eisac.com/portal/article/124886-Physical-Security-Incident-Severity-Level-Categorization

Appendix A: Supplemental Analysis at Interconnection Level

Severity Risk Index by Interconnection

Eastern and Québec Interconnections

The cumulative SRI for the EI and QI in Table A.1 shows a 3% increase compared to the average of the four-year period of 2021–2024. The 2025 cumulative SRI was the second highest among the five years analyzed.

Table A.1: Annual Cumulative SRI, Eastern and Québec Interconnections

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2021	346.3	53.7	65.8	465.9	1.28
2022	385.1	52.3	53.0	490.4	1.34
2023	324.5	64.4	47.2	436.1	1.19
2024	358.7	59.5	52.0	470.2	1.28
2025	**367.5**	**52.7**	**46.8**	**467.0**	**1.28**

The top 10 SRI days of the EI and QI were distributed throughout the year as shown in Figure A.1 (numbered circles). A total of 7 of the top 10 days that occurred in the EI and QI aligned with the top 10 SRI days reported for North America.

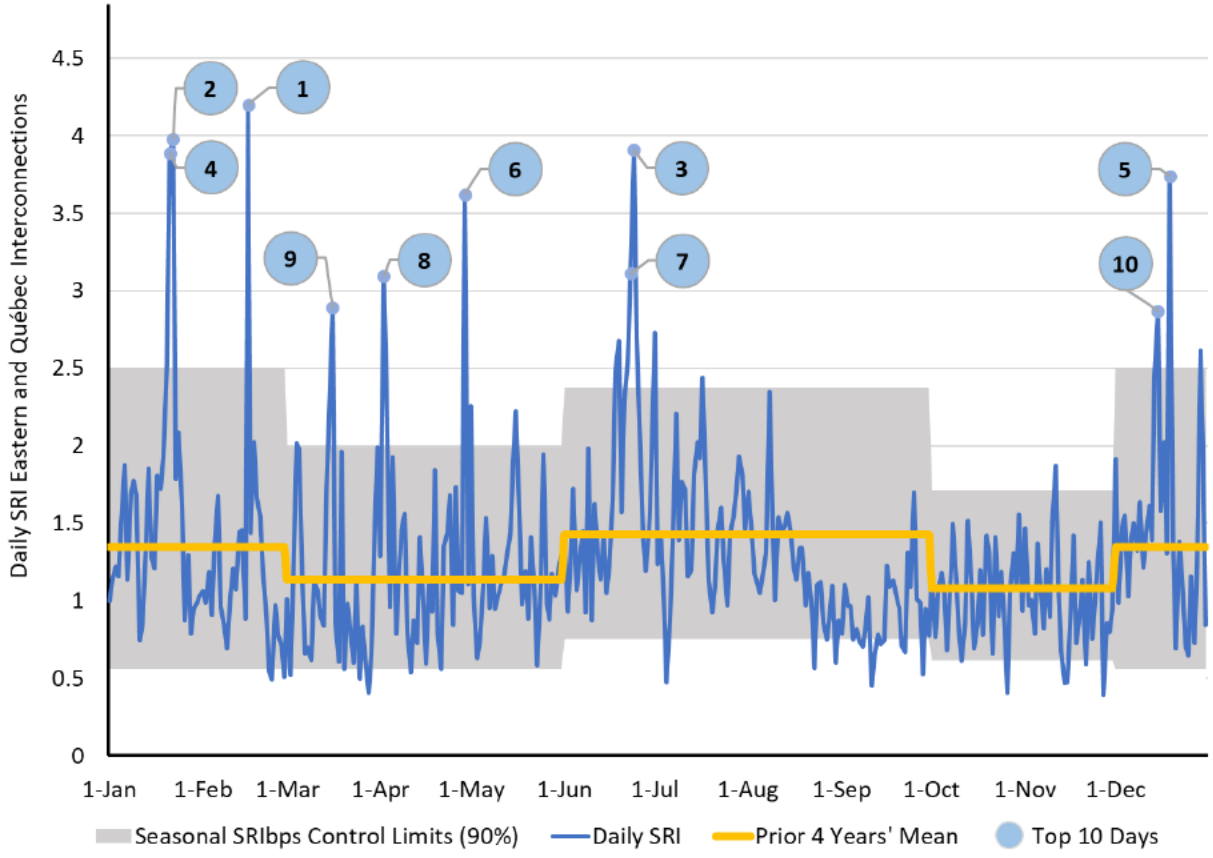


Figure A.1: 2025 Eastern and Québec Interconnections Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

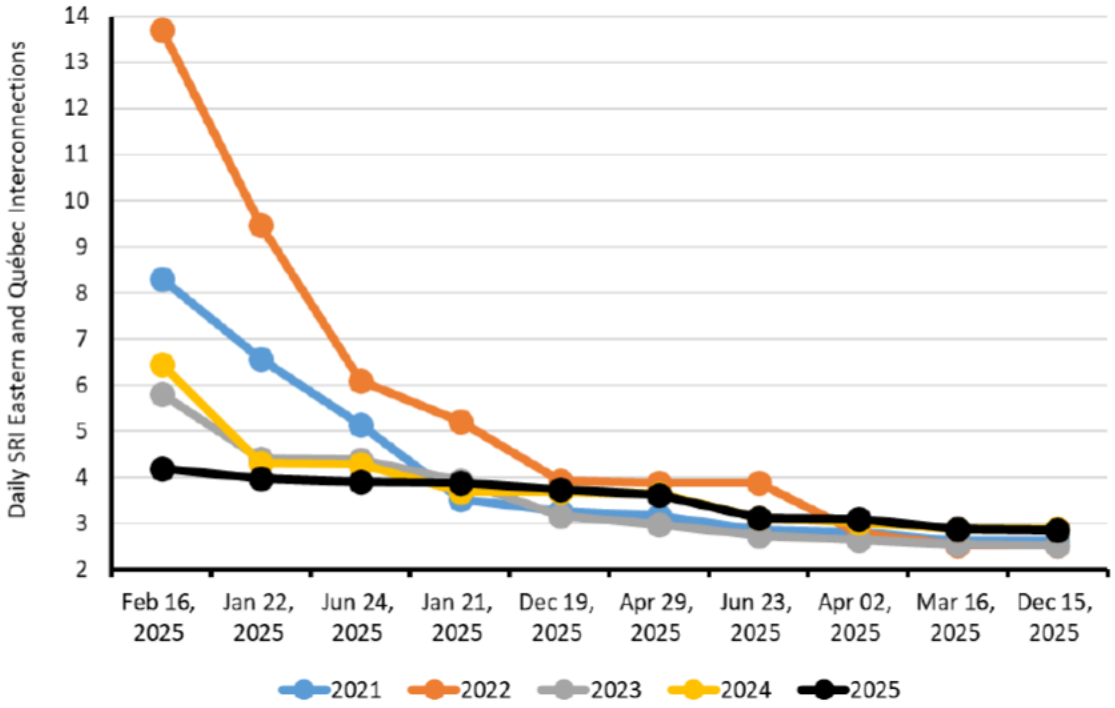


Figure A.2: Eastern and Québec Interconnections Top Annual Daily SRI Days, Sorted Descending

Figure A.2 shows the EI and QI's top 10 SRI days in 2025 relative to the four prior years, while Table A.2 provides details on each component's contribution to the top 10 SRI days. Out of the top 10 SRI days for the EI and QI, three were driven by load loss, one was driven by a combination of generation and load loss, none were driven by transmission, and the rest were predominantly driven by generation.

Table A.2: 2025 Top 10 SRI Days, Eastern and Québec Interconnections

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	February 16, 2025	4.20	2.20	0.31	1.68	Northwestern Atmospheric River	WECC
2	January 22, 2025	3.98	3.74	0.15	0.08	Winter Storm Enzo	RF, SERC
3	June 24, 2025	3.91	3.09	0.26	0.55	Thunderstorms	NPCC, RF, SERC
4	January 21, 2025	3.89	3.71	0.10	0.07	Winter Storm Enzo	RF, SERC
5	December 19, 2025	3.74	1.70	0.29	1.76	Northwestern Atmospheric River	WECC
6	April 29, 2025	3.62	1.06	0.37	2.19	Thunderstorms	MRO, NPCC, RF
7	June 23, 2025	3.11	2.13	0.16	0.82	Thunderstorms	NPCC, RF, SERC
8	April 2, 2025	3.09	0.99	0.55	1.56	Tornadoes & Severe Storms	MRO, RF, SERC
9	March 16, 2025	2.89	0.50	0.34	2.05	Tornadoes	MRO, RF, SERC
10	December 15, 2025	2.87	2.51	0.07	0.29	Winter Storm	RF, SERC, Texas RE

Table A.3 shows the top 10 SRI days for the EI and QI over the last five years with no dates in 2025.

Table A.3: 2021–2025 Top 10 SRI Days, Eastern and Québec Interconnections

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions	Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss		
1	December 23, 2022	13.70	8.88	0.90	3.92	Winter Storm Elliott	All
2	December 24, 2022	9.46	8.12	1.27	0.07	Winter Storm Elliott	All
3	February 16, 2021	8.31	4.10	0.58	3.63	Cold Weather Event	MRO, RF, SERC
4	December 11, 2021	6.57	0.92	0.92	4.73	Severe Storms	NPCC, RF, SERC
5	September 27, 2024	6.45	1.62	3.61	1.23	Hurricane Helene	SERC
6	June 14, 2022	6.09	1.70	0.49	3.90	High Temperatures and Derecho	All
7	April 1, 2023	5.80	0.74	0.63	4.43	Widespread Storms and Tornadoes	MRO, RF, SERC
8	June 15, 2022	5.22	1.63	0.24	3.36	Hurricane Isaias	NPCC, RF, SERC
9	February 15, 2021	5.15	3.62	0.54	0.99	Unnamed Tropical Storm	RF, SERC
10	June 22, 2023	4.42	1.34	2.95	0.13	High Temperatures and Derecho	All

Western Interconnection

The 2025 cumulative SRI for the WI shows an 9% decrease over the prior four-year period of 2021–2024. The 2025 cumulative SRI was the lowest among the five years analyzed (Table A.4).

Table A.4: Annual Cumulative SRI, Western Interconnection

Year	Cumulative Weighted Generation	Cumulative Weighted Transmission	Cumulative Weighted Load Loss	Annual Cumulative SRI	Average Daily SRI
2021	426.8	98.2	97.8	622.7	1.71
2022	423.8	87.3	60.1	571.2	1.57
2023	423.1	68.6	59.6	551.3	1.51
2024	418.0	74.3	50.1	542.4	1.48
2025	**402.5**	**76.2**	**42.2**	**521.0**	**1.43**

The top 10 SRI days of the WI for 2024 were distributed throughout the year as shown in Figure A.3. A total of 2 of the top 10 days that occurred in the WI aligned with the top 10 SRI days reported for North America.

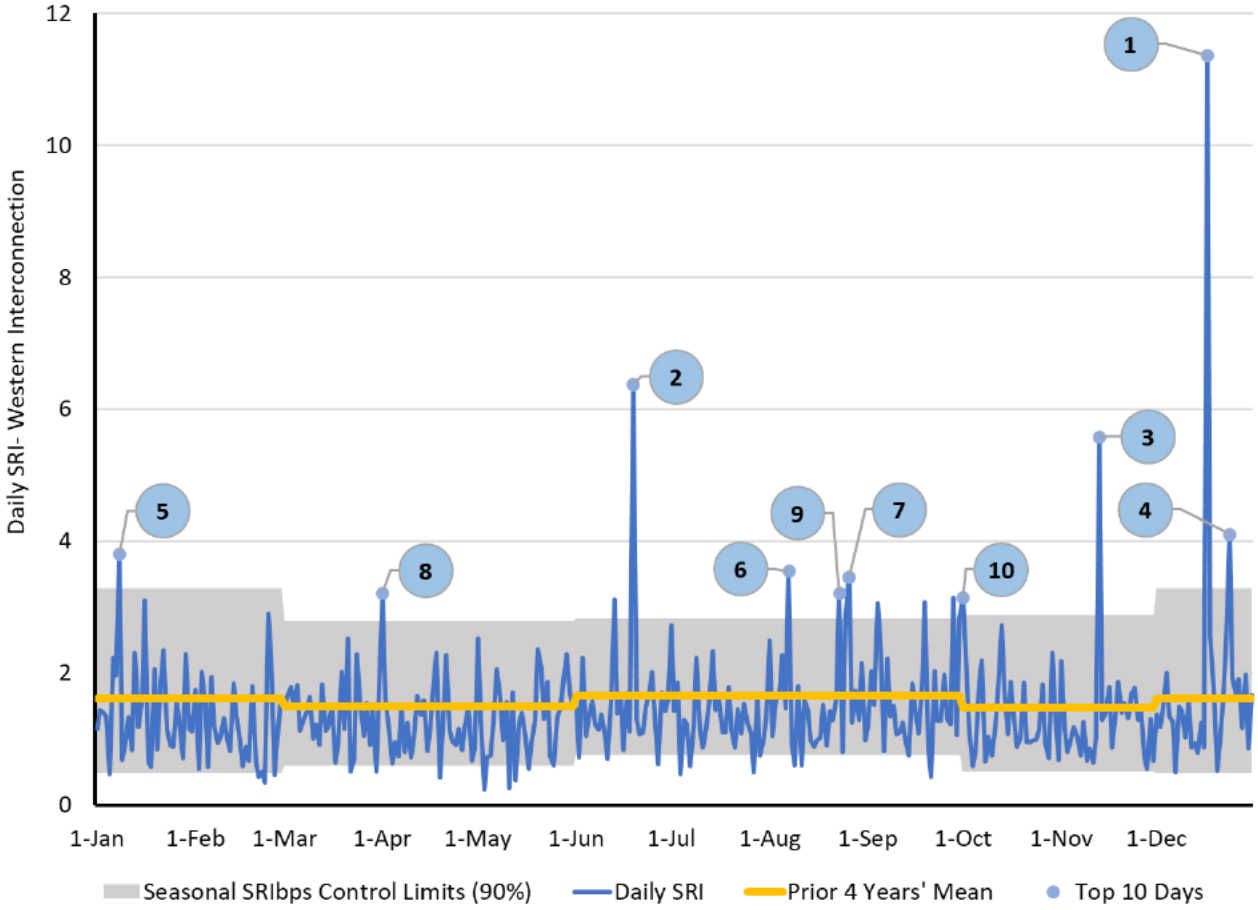


Figure A.3: 2025 Western Interconnection Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

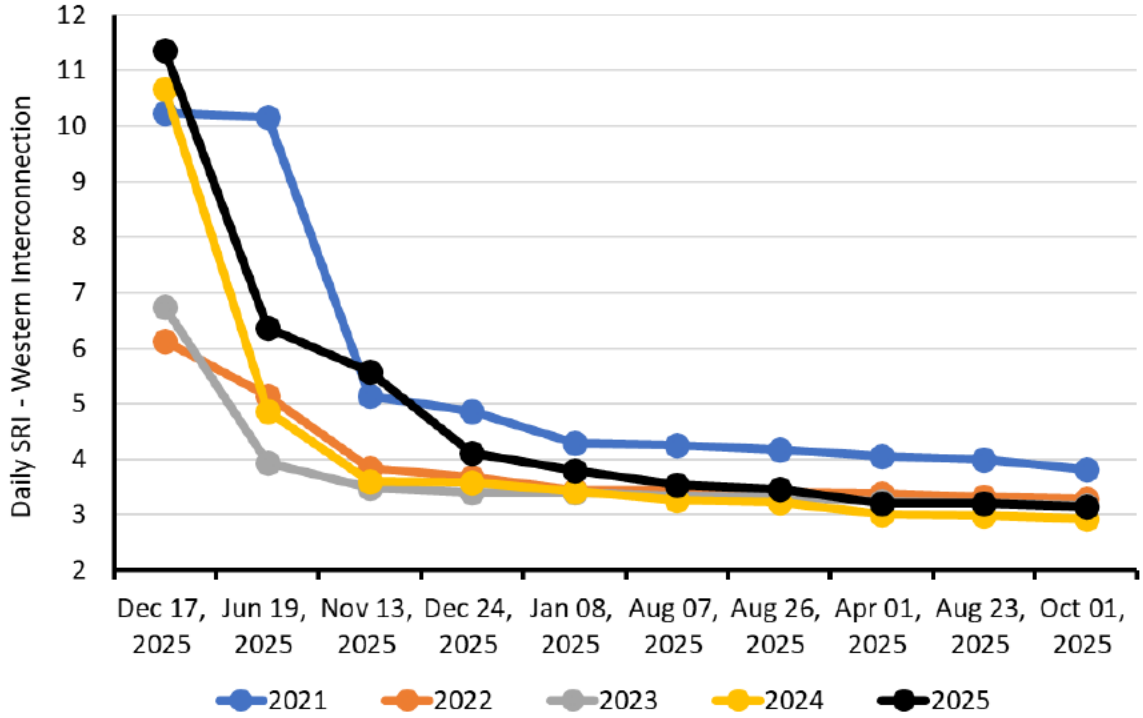


Figure A.4: Western Interconnection Top Annual Daily SRI Days Sorted Descending

Table A.5 details each component's contribution to the top 10 SRI days for the WI; WECC is the only Regional Entity in the WI. Out of the top 10 SRI days for the WI, one was driven by load loss, two were driven by a combination of transmission and generation, and the rest were predominantly driven by generation.

Table A.5: 2025 Top 10 SRI Days, Western Interconnection

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions Regional Entities
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	December 17, 2025	11.36	4.54	4.02	2.80	Northwestern Atmospheric River
2	June 19, 2025	6.38	0.87	0.44	5.07	Thunderstorms, Tornadoes
3	November 13, 2025	5.58	3.23	2.35	0.00	Wyoming System Event
4	December 24, 2025	4.11	1.07	0.87	2.16	Winter Storm
5	January 8, 2025	3.81	1.54	1.73	0.53	High Wind Conditions
6	August 7, 2025	3.55	2.73	0.67	0.14	Extreme Heat
7	August 26, 2025	3.46	1.99	0.57	0.90	Extreme Heat
8	April 1, 2025	3.21	2.80	0.18	0.23	Thunderstorms, Tornadoes
9	August 23, 2025	3.21	1.26	0.80	1.15	Extreme Heat
10	October 1, 2025	3.14	2.76	0.38	0.00	Thunderstorms

Table A.6 shows the top 10 SRI days for the WI over the last five years, with three days in 2025 highlighted in red.

Table A.6: 2021–2025 Top 10 SRI Days, Western Interconnection

Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
1	December 17, 2025	11.36	4.54	4.02	2.80	Northwestern Atmospheric River
2	February 4, 2024	10.67	0.34	0.31	10.02	Atmospheric River
3	November 15, 2021	10.23	1.42	0.40	8.41	Atmospheric River
4	January 13, 2021	10.16	1.86	3.83	4.48	Northwest Winter Weather
5	February 24, 2023	6.75	2.61	0.88	3.26	Winter Storm
6	June 19, 2025	6.38	0.87	0.44	5.07	Tornadoes, High Winds
7	November 5, 2022	6.13	1.75	1.77	2.61	Severe Weather

Table A.6: 2021–2025 Top 10 SRI Days, Western Interconnection						
Rank	Date	SRI and Weighted Components 2025				Atypical Weather Conditions
		SRI	Weighted Generation	Weighted Transmission	Weighted Load Loss	
8	November 13, 2025	5.58	3.23	2.35	0.00	Wyoming System Event
9	December 20, 2022	5.14	1.05	0.15	3.93	Winter Storm
10	February 13, 2021	5.14	1.14	1.30	2.70	Winter Storm Uri

Extreme-Day Analysis by Interconnection

The extreme-day analyses for transmission and generation for 2025 are presented by Interconnection. The maximum TADS reported MVA capacity or GADS reported net maximum capacity for 2025 is shown in the upper right or left corners of Figure A.5–Figure A.10. The largest outliers and extreme days correlating with NERC-wide extreme days have been labeled with any atypical weather conditions during those days. Interconnection extreme days that do not align with NERC-wide extreme days are dated, but the underlying conditions are not identified. The number of customers interrupted (CI) due to transmission or generation sources for the day is obtained from the IEEE PES Distribution Reliability Working Group (DRWG) benchmark data. All dates are shown in UTC.

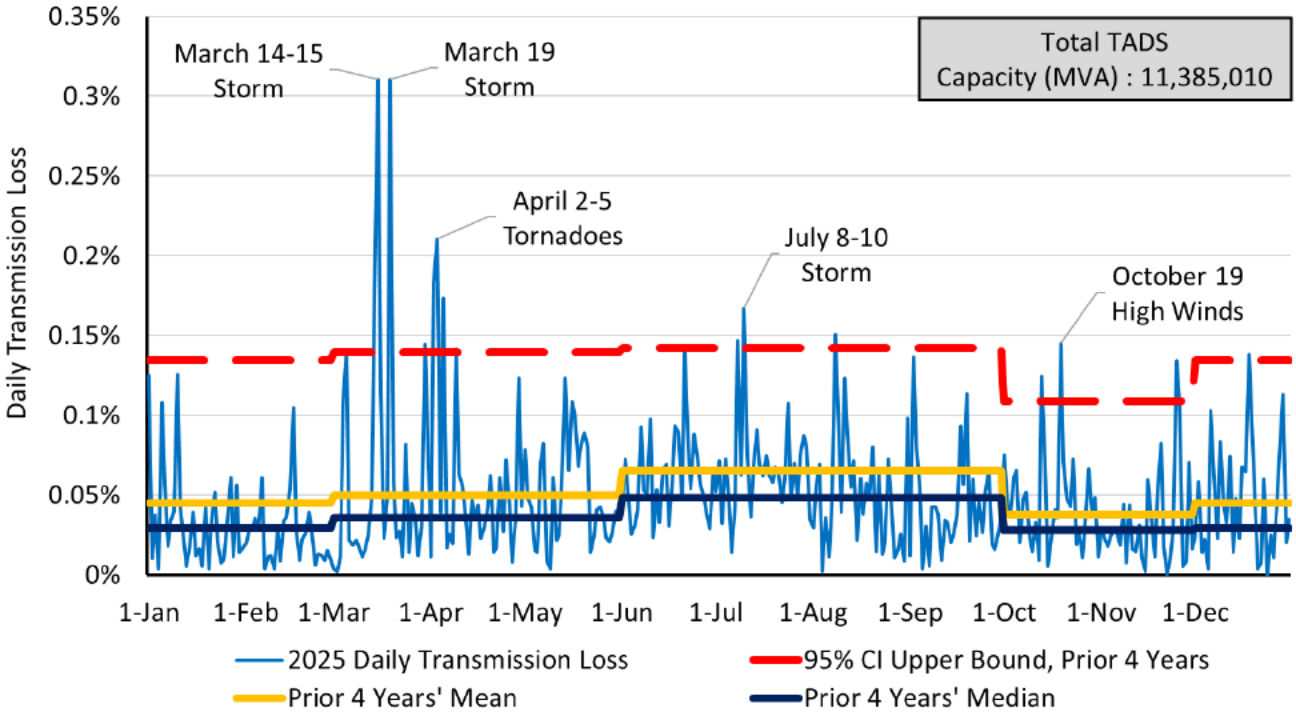


Figure A.5: Eastern and Québec Interconnections—Transmission Impacts During Extreme Days of 2025

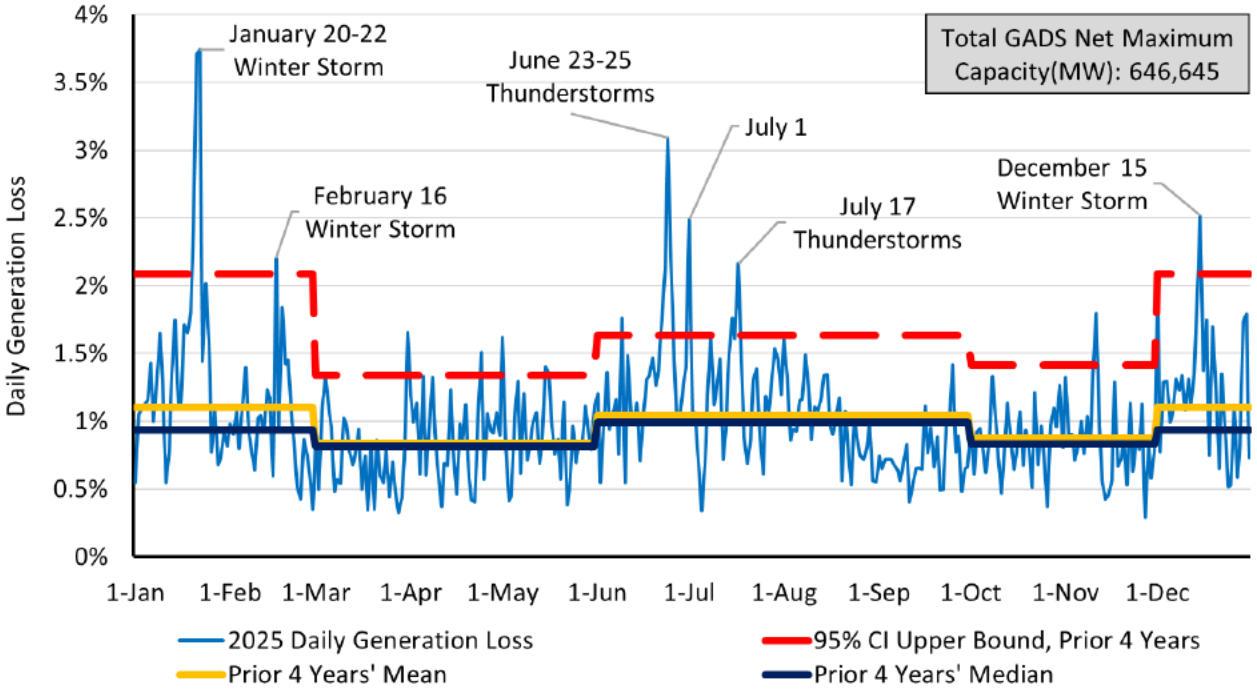


Figure A.6: Eastern and Québec Interconnections—Generation Impacts During Extreme Days of 2025

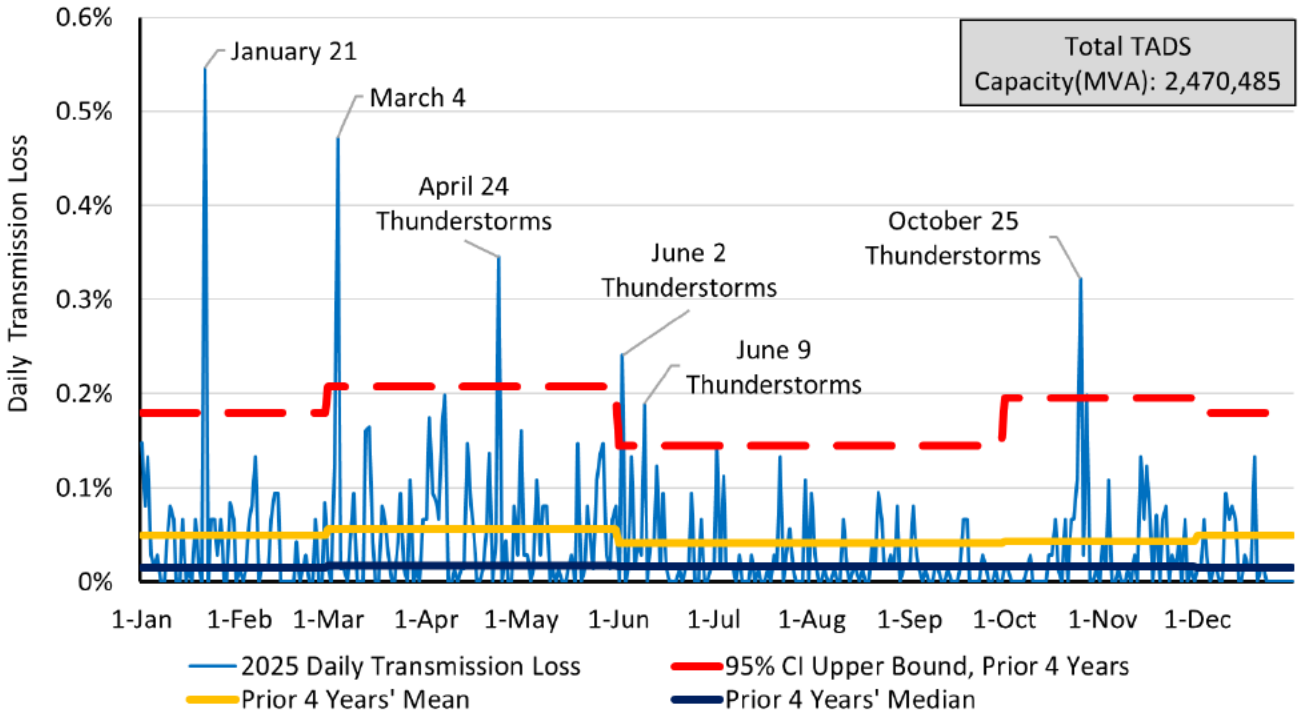


Figure A.7: Texas Interconnection—Transmission Impacts During Extreme Days of 2025

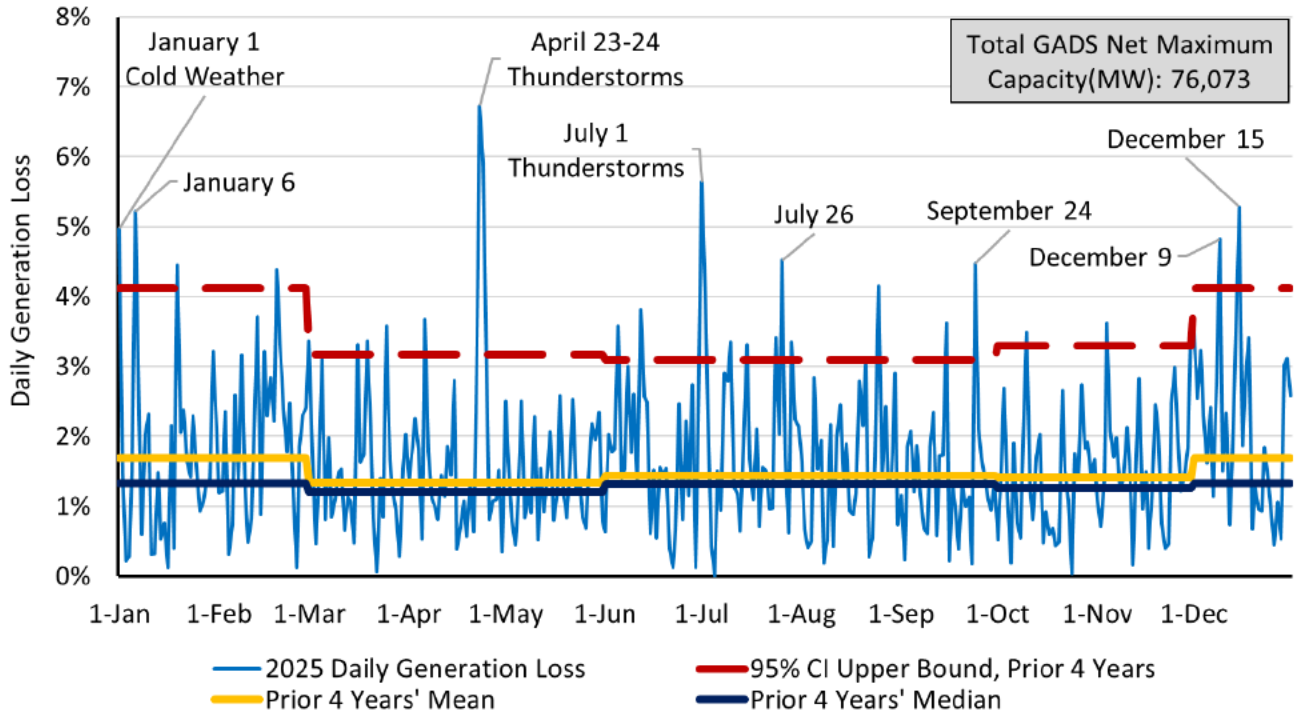


Figure A.8: Texas Interconnection—Generation Impacts During Extreme Days of 2025

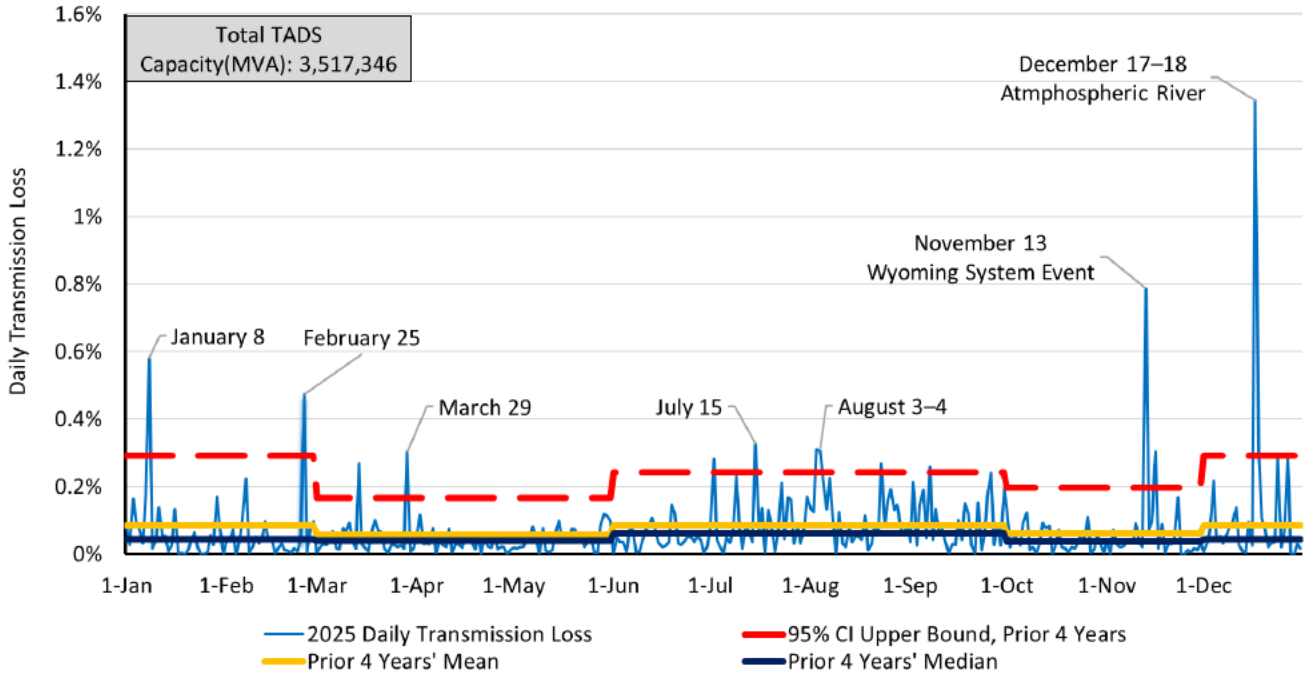


Figure A.9: Western Interconnection—Transmission Impacts During Extreme Days of 2025

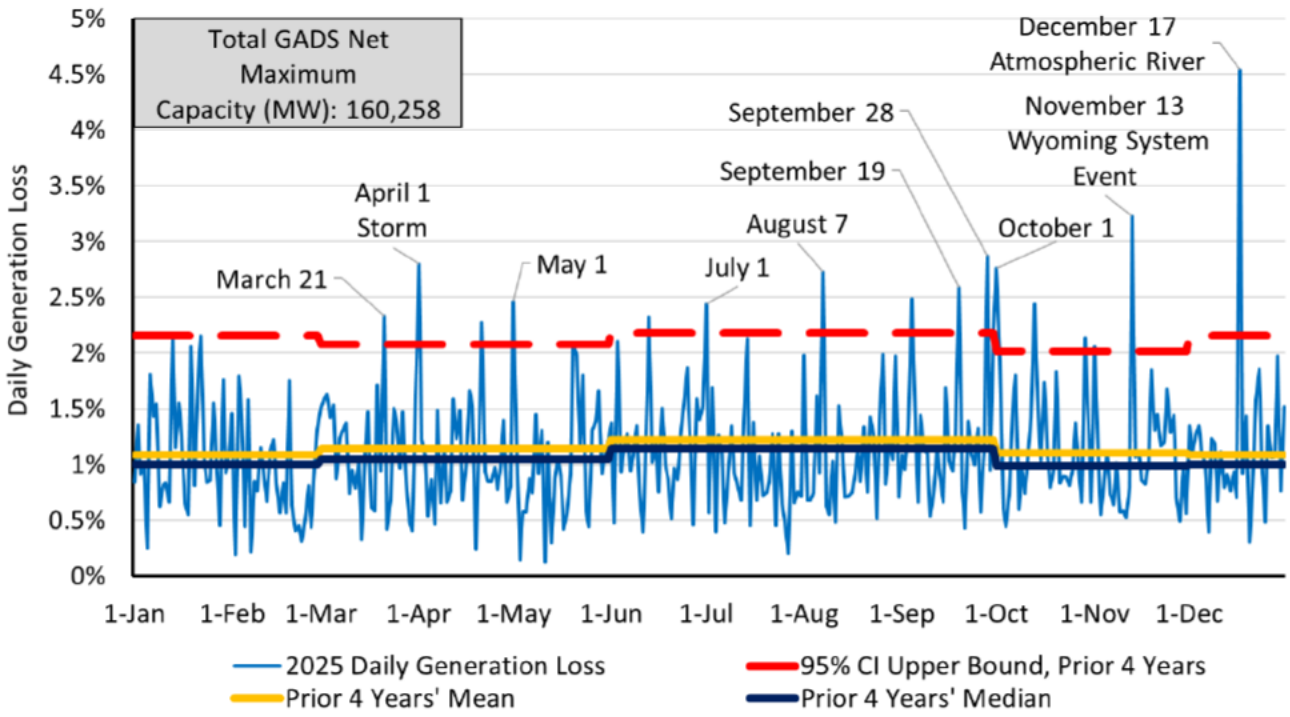


Figure A.10: Western Interconnection—Generation Impacts During Extreme Weather Days

Appendix B: Acknowledgements

NERC Industry Group Acknowledgements	
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