BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4-01
Public Interest Organizations' July 2026 Rehearing Request

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	Order No. 202-26-31

Motion to Intervene and Request for Rehearing and Stay of
Sierra Club, Vote Solar, 350 Colorado, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations")

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I. INTRODUCTION

For the third time, the Department of Energy ("Department") is unlawfully using Section 202(c) of the Federal Power Act to prevent the retirement of Craig Unit 1 ("Craig"). Craig generates power by burning coal, and the Department is acting pursuant to an unprecedented policy to exceed its carefully constrained emergency authority under Section 202(c) in order to prevent coal plant retirements. The policy is unlawful because Section 202(c) applies only to imminent, unexpected shortfalls, not to the Department's preference for specific types of energy generation.

Order No. 202-26-31 ("Order") renews the Department's Order No. 202-25-14 ("December Order") and No. 202-26-21 ("March Order"). Public Interest Organizations previously requested rehearing of both orders and, after the Department failed to act on that request, have petitioned the United States Court of Appeals for the District of Columbia Circuit for review of those orders. *Sierra Club et al. v. Dep't of Energy et al.*, No. 26-1060; Ex. 2-186 at *passim* (Public Interest Organizations' January 2026 Rehearing Request); *Sierra Club et al. v. Dep't of Energy et al.*, No. 26-1172, Ex. 3-05 at *passim* (Public Interest Organizations' April 2026 Rehearing Request).

The Order offers no lawful basis, rational reasoning, or evidentiary support for an emergency justifying the invocation of Section 202(c). In purporting to find an emergency in Colorado and portions of Wyoming, Nebraska, and South Dakota, the Department focuses on changes to the mix of generators. Generators burning coal and other fossil fuels are retiring, but are being replaced by new resources, including solar, wind, battery resources, and new thermal resources. Replacing dirty, expensive, and unreliable coal plants like Craig with modern technology is not an emergency. It is, instead, a result of market forces and prudent planning.

None of the sources the Department cites in the Order, collectively or separately, support the claimed near-term or "long-term" emergency. The Department looks for support from reliability reports published by the North American Electric Reliability Corporation ("NERC"), but these documents portray the region as having "normal risk." The same goes for the reports on which the Department relies from the Western Electricity Coordinating Council. The Department also cites a couple of executive orders and a presidential memorandum containing no relevant facts, as well as its own error-riddled and widely panned study that attempts to evaluate resource adequacy in 2030. Further, in reaching for data about the mix of generators in a single

state (Colorado) to support its purported multi-state emergency, the Department looks only at one side of the coin, focusing on planned retirements with no attention paid to planned additions. In fact, Colorado has added, and plans to add, more generating capacity than has been and will be retired, resulting in a significant net increase in generating resources. And just as in the December Order and the March Order, the Department commits an even more basic error; in pulling data from its own Energy Information Administration, the Department overstates what that data says about the amount of planned coal retirements by more than 900 MW.

Meanwhile, the Department fails to consider a multitude of evidence of which the Department is or should be aware. This list begins with the careful and detailed resource planning undertaken by all five of Craig's co-owners, including Tri-State Generation and Transmission Association ("Tri-State"), Platte River Power Authority ("Platte River"), PacifiCorp, and Xcel Energy (also known as Public Service Company of Colorado) ("Xcel") (collectively and together with Salt River Project, the "Craig Co-Owners"). For nearly a decade, the Craig Co-Owners have been planning to retire Craig on December 31, 2025, and otherwise ensure resource adequacy.

More broadly, the Department fails to address a host of studies and monitoring from state regulators, regional entities, and private utilities. These efforts undercut the Department's claimed emergency. The evidence shows that the established planning and monitoring efforts are resulting in sufficient supplies of electricity now and will continue to provide for resource adequacy and reliability through the end of the decade and beyond, particularly as planned resources enter service. The Department's failure to engage with these studies and efforts while reaching sweeping, unsupported conclusions is not reasoned decision-making. Moreover, the Department lacks authority to override the states' and utilities' decisions to retire the plant and bring on cleaner and cheaper resources.

Whatever needs our modern energy system has, Craig is not the answer. The plant is an old, dirty, expensive generator that is required to retire under Colorado law. Running Craig after December 31, 2025, violates state law and plagues the region with excessive amounts of harmful air pollution that clouds Colorado's treasured federal public lands in haze, including Rocky Mountain National Park, Flat Tops Wilderness Area, Eagles Nest Wilderness Area, Mount Zirkel Wilderness Area, and Rawah Wilderness Area. Pollution from Craig also causes premature deaths and tens of millions of dollars in health harms. Ex. 2-123 at PDF 5 (EPA COBRA Health Effects Estimate).

"All costs" incurred by the Craig Co-Owners to comply with the Order "end up on ratepayers." *See* Laura Sanicola, Barrons, *Who's Paying to Keep Coal Plant Alive? All Electricity Customers, Trump Advisor Says* (Jan. 14, 2026), https://www.msn.com/en-us/money/markets/who-s-paying-to-keep-coal-plant-alive-all-electricity-customers-trump-advisor-says/ar-AA1UdRHI. Tri-State avers that the Order is likely to require additional expenditures "in operations, repairs, maintenance and, potentially, fuel

supply, all factors increasing costs," and that the utility "is working to prepare filings in support of cost recovery." *Tri-State Makes Craig Generating Station Unit 1 Available to Operate in Compliance with DOE Emergency Order* (Jan. 23, 2026), https://tristate.coop/tri-state-makes-craig-generating-station-unit-1-available-operate-compliance-doe-emergency-order.

Craig's inability to operate reliably and economically is plainly apparent but not addressed in the Order. Craig's operator and co-owners have substantially reduced capital and major maintenance expenditures over the past few years in anticipation of retirement. In fact, Craig was broken when the Department issued the December Order, having suffered a mechanical failure that halted electricity generation. Tri-State, *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating for Next 90 Days* (Dec. 31, 2025), https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days. Restoring the plant to operable condition took more than four weeks, and the plant will require tremendous maintenance and other investments to function consistently. *See* Tri-State, *Tri-State Makes Craig Generating Station Unit 1 Available to Operate in Compliance with DOE Emergency Order* (Jan. 23, 2026), https://tristate.coop/tri-state-makes-craig-generating-station-unit-1-available-operate-compliance-doe-emergency-order.

The Order is costly, harmful, unnecessary, unwanted, and unlawful. Public Interest Organizations respectfully request that the Department grant intervention in the proceedings over the Order; stay the Order; grant rehearing of the Order; rescind the Order (and any renewals of the Order); and allow Craig to retire.

II. Statement of Issues and Specification of Error

The undersigned Public Interest Organizations move to intervene and request rehearing and a stay pursuant to Section 313(a) of the Federal Power Act, 16 U.S.C. § 825*l*(a), and the applicable rules of practice and procedure, 18 C.F.R. §§ 385.203, .212, .214, .713; *see* Ex. 2-10 at PDF 2 (Cooke Email to Alle-Murphy) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.").[1] Public Interest Organizations' motion and requests are based upon the following errors and issues:

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[1] Until sometime after June 18, 2025, the Department maintained a webpage with procedures for intervention and rehearing requests. U.S. Dep't of Energy, *DOE 202(c) Order Rehearing Procedures* (visited June 18, 2025), https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (attached as Ex. 2-11) [hereinafter "DOE Rehearing Procedures"]. The Department maintains another website that currently states, "All public comments and requests related to

A. The Department has not demonstrated that an emergency exists in any portion of the Western Electricity Coordinating Council Rocky Mountain assessment area as defined in the Order, or in any other area, as required by Section 202(c) of the Federal Power Act; nor has the Department demonstrated that an emergency exists as defined in the implementing regulations for Section 202(c). *See, e.g.*, 16 U.S.C §§ 824(a)–(b), 824a(a)–(c); 10 C.F.R. §§ 205.371–.375; *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power,* 46 Fed. Reg. 39984 (Aug. 6, 1981); *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150 (2016); *FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120 (2000); *Jarecki v. G.D. Searle & Co.*, 367 U.S. 303 (1961); *Citizens Action Coal. v. FERC*, 125 F.4th 229 (D.C. Cir. 2025); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009); *Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009); *Cal. Indep. Sys. Op. Corp. v. FERC*, 372 F.3d 395 (D.C. Cir. 2004); *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970); *Richmond Power & Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978); *Duke Power Co. v. Fed. Power Com.,* 401 F.2d 930, 938 (D.C. Cir. 1968).

B. Even if the emergency described by the Order did exist—it does not—the Department has not demonstrated a reasoned basis for its determination that requiring the Southwest Power Pool ("SPP") and the Craig Co-Owners to ensure Craig is available to operate and requiring SPP to "take every step to employ economic dispatch of [Craig]" will "best meet the emergency and serve the public interest." *See, e.g.*, 16 U.S.C. § 824a(c); 10 C.F.R. §§ 205.373; 205.375; *Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1 (2020); *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208 (2009); *Allentown Mack Sales & Service, Inc. v. NLRB*, 522 U.S. 359 (1998); *Motor Vehicle Mfrs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29 (1983); *NAACP v. Fed. Power Comm'n*, 425 U.S. 662 (1976); *Gulf States Utils. Co. v. Fed. Power Comm'n*, 411 U.S. 747 (1973); *Otter Tail Power Co. v. United States*, 410 U.S. 366 (1973); *California v. Fed. Power Comm'n*, 369 U.S. 482 (1962); *Pa. Water*

FPA section 202(c) should be sent via email to AskCR@hq.doe.gov. . . . Additional information about 202(c) procedures, if necessary, will be announced on this page. The provision of this process for submission of correspondence or comments on any pending application is for purposes of ensuring the receipt by the appropriate office and personnel within the Department. Establishment of this email address does not establish a 'docket,' and those submitting correspondence do not constitute parties or intervenors to any proceeding." U.S. Dep't of Energy, *DOE's Use of Federal Power Act Emergency Authority* (last visited Apr. 27, 2026), https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority (attached as Ex. 2-12) [hereinafter "DOE 202(c) Webpage"]. Public Interest Organizations' instant motion and requests are also pursuant to the DOE 202(c) Webpage and the DOE Rehearing Procedures.

& Power Co. v. Fed. Power Comm'n, 343 U.S. 414 (1952); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200 (D.C. Cir. 2013); *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133 (D.C. Cir. 2005); *Sierra Club v. Env't. Prot. Agency*, 353 F.3d 976, 980 (D.C. Cir. 2004); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105 (D.C. Cir. 2001).

C. The Order exceeds the Department's authority in its availability requirement and its decree concerning whether Craig shall be considered a capacity resource. *See, e.g.*, 16 U.S.C. §§ 824(a)–(b), 824a(b)–(c); *Gallardo v. Marstiller*, 596 U.S. 420 (2022); *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150 (2016); *FERC v. Elec. Power Supply Ass'n*, 577 U.S. 260 (2016); *Gomez-Perez v. Potter*, 553 U.S. 474 (2008); *Allentown Mack Sales & Service, Inc. v. NLRB*, 522 U.S. 359 (1998); *Fed. Power Comm'n v. Fla. Power & Light Co.*, 404 U.S. 453 (1972); *Conn. Light & Power v. Fed. Power Comm'n*, 324 U.S. 515 (1945); *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477 (D.C. Cir. 2009).

D. The Department has unlawfully failed to ensure that the Order requires generation of electric energy only during hours necessary to meet the emergency and serve the public interest, that operations are consistent with any applicable environmental laws and regulations to the maximum extent practicable, and that any adverse environmental impacts are minimized; there is no indication that the Department consulted with the primary Federal agency with expertise in the environmental interests protected by the laws and/or regulations with which the operations required by the Order may conflict; the Department has not included in the Order or made public any conditions that may have been submitted by that Federal agency; and the Department has not included in the Order or made public any explanation of why such conditions would prevent the order from adequately addressing the emergency. *See, e.g.*, 16 U.S.C. § 824a(c)(2); *Kingdomware Techs., Inc. v. United States*, 579 U.S. 162 (2016); Ex. 2-13 (DOE Order No. 202-22-4); Ex. 2-14 (Department Order No. 202-17-4 Summary of Findings); Ex. 2-21 (Department Order No. 202-26-01); Ex. 2-22 (Department Order No. 202-26-01A); Ex. 2-24 (Department Order No. 202-24-1).

III. INTERVENORS' INTERESTS

As further discussed below, each of the Public Interest Organizations has interests that may be directly and substantially affected by the outcome of this proceeding. Each party may therefore intervene in this proceeding. 18 C.F.R. § 385.214; *see* Ex. 2-11 (DOE Rehearing Procedures); Ex. 2-12 (DOE 202(c) Webpage); Ex. 2-10 (Cooke Email to Alle-Murphy).

Each of the Public Interest Organizations also demonstrates a concrete injury arising from the Order that is redressable by a favorable outcome. Each organization is therefore aggrieved by the Department's Order and may properly apply for

rehearing. *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112 (D.C. Cir. 2001); 18 C.F.R. §§ 385.203, 385.713; Ex. 2-11 (DOE Rehearing Procedures); Ex. 2-12 (DOE 202(c) Webpage); Ex. 2-10 (Cooke Email to Alle-Murphy).

A. Sierra Club

Sierra Club has a demonstrated organizational commitment to reducing pollution and harm from coal-fired power plants, including Craig. Sierra Club's Beyond Coal Campaign seeks to reduce the pollution currently being produced by coal-fired power plants such as Craig, and to reduce energy bills by ensuring that ratepayers do not fund the cost of continuing to operate uneconomic coal plants like Craig. To those ends, Sierra Club has long engaged in advocacy relating to Craig Station. Sierra Club has intervened in Tri-State's electric resource plans before the Colorado Public Utilities Commission (the "Colorado Commission") in order to ensure that the retirement of Craig remained on track and was part of Tri-State's approved resource plan. Craig's retirement has been a premise of much of Sierra Club's work in Colorado.

Craig is owned by five utilities that serve electric customers in several states, including Arizona, Colorado, New Mexico, Utah, and Wyoming. In each of these states, Sierra Club has members who receive electricity service from a utility that owns Craig. For example, Sierra Club has over 15,000 members in Colorado, including members who receive electricity from Xcel, Tri-State, or Platte River. The Order harms Sierra Club's members' financial interests, because they will likely have to pay their share of the costs to comply with the Order.

In addition, Sierra Club has members who live, work, and/or recreate in areas of Colorado that are affected by air pollution from Craig. The Order will harm Sierra Club's members' aesthetic, health, and environmental interests by leading to increased air emissions that will pollute scenic areas, harm human health, and impair air quality.

B. Vote Solar

Vote Solar is an independent nonprofit organization working to repower the United States with clean energy by making solar power more accessible and affordable through effective policy advocacy. Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale solar facilities, and to encourage common-sense electrification of the economy, all as part of the transition away from fossil fuel-powered energy consumption. Vote Solar has over 92,000 members nationally and nearly 3,000 members in Colorado, including members who are customers of the utilities that purchase electricity from Tri-State Generation and Transmission Association and customers of Craig's other co-owners. Vote Solar is not a trade group, and it does not have corporate members.

Pollution emitted by Craig harms Vote Solar's members, and the Order will harm these members by preventing the coal unit from retiring as planned and thus prolonging the time period it can emit pollution into nearby communities. In addition, Vote Solar's members will likely be harmed by the Order because Tri-State and the other Craig co-owners will incur increased costs to keep Craig online after its retirement deadline. The customers of the utilities that purchase electricity from Tri-State and customers of the other co-owners, including Vote Solar's members, will likely be responsible for paying these costs and will pay higher utility bills because of the Order. Vote Solar and its members have an interest in ensuring that Tri-State retires Craig as planned, and the Order extending the lives of these coal units harms Vote Solar's and its members' interests.

C. 350 Colorado

350 Colorado is a grassroots movement and organization working to build a fossil-free future powered by 100% renewable energy. 350 Colorado empowers communities to come together to dismantle oppressive systems that enable poverty, racism, and inequality. 350 Colorado engages at the local and state level to ensure that Colorado has a clear and immediate pathway to reduce emissions and secure 100% clean, renewable energy for all. 350 Colorado strives to protect vulnerable communities because all Coloradans deserve a safe and livable environment. 350 Colorado has around 20,000 members working toward a fossil-free future, including members who are customers of the utilities that purchase electricity from Tri-State Generation and Transmission Association and customers of Craig's other co-owners. Because the Order requires Craig Unit 1 to stay online past its retirement deadline, the Order harms 350 Colorado and its members by prolonging the time period that Craig can emit pollution. The Order will also harm 350 Colorado and its members by increasing their energy costs as Tri-State and the other Craig co-owners pass along the costs they have incurred to comply with the Order to their customers.

D. Public Citizen

Established in 1971, Public Citizen is a national research and advocacy organization representing the interests of household consumers. Public Citizen has members and supporters in every state, including those who pay electric utility bills in Colorado and the Western United States. Public Citizen is active before the Federal Energy Regulatory Commission promoting just and reasonable rates, and in supporting efforts for utilities to be accountable to the public. Financial details about the organization are on its website. Public Citizen, Annual Reports, www.citizen.org/about/annualreport/.

F. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a nonprofit membership organization with hundreds of thousands of members nationwide, including

approximately 10,000 members who live in Colorado and pay for and consume electricity in the state, and who are harmed by pollution from Craig's coal-burning operations. EDF's mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. Craig's retirement would help create an affordable, reliable, and low pollution energy system. Because the Order denies these and other benefits of the plant's retirement, the Order harms EDF members.

IV. BACKGROUND

A. The Primary Actors in the Electric Industry Already Protect Resource Adequacy Without Intrusion from the Department.

Multiple entities in Colorado and the Western Electricity Coordinating Council ("WECC") Rocky Mountain assessment area have consistently maintained resource adequacy in the region through a combination of resource adequacy assessments and long-term planning. Resource adequacy is "the situation where an electric system has enough capacity available to meet customer demand, plus a reserve margin on top, in most hours under most conditions based on a chosen standard." Ex. 2-01 at 2–6 (Current Energy Group January Report) (defining resource adequacy and including perspective from National Laboratory of the Rockies). The electric industry uses a variety of metrics to assess resource adequacy, though each metric gets to the same concept: whether there are sufficient resources available to both meet forecasted demand and provide an additional buffer. *See id.* However defined or measured, the entities and processes discussed below have for decades maintained an interconnected planning web that has sustained, and continues to sustain, resource adequacy across the region. That includes, of course, accounting for declared retirements, including Craig's long-planned retirement.

1. The Federal Energy Regulatory Commission Regulates Wholesale Electricity Markets and Mechanisms to Acquire Adequate Resources.

FERC regulates wholesale sales and transmissions of electric energy in interstate commerce. 16 U.S.C. § 824(b)(1). Federal authority over the electric grid dates back at least to 1935, when the Federal Power Act became law and the Federal Power Commission administered the Act.

The Federal Power Act did not give the federal agency plenary authority over the electric grid. Instead, Congress provided that federal regulation shall "extend only to

those matters which are not subject to regulation by the States" and provided that "[t]he Commission" does not have jurisdiction, "except as specifically provided in [the Federal Power Act], over facilities used for the generation of electric energy." *Id.* at § 824(a)–(b)(1). As such, authority over generation facilities belongs to the states. *See id.*

In 1977, through the Department of Energy Organization Act, Congress reorganized the agencies that administer the Federal Power Act. Congress created the Department of Energy and FERC. 42 U.S.C. §§ 7131, 7171(a). Congress also transferred certain functions of "the Commission" in the Federal Power Act to the Department and other functions to FERC, thereby abolishing the Federal Power Commission. *See id.* §§ 7151(b), 7172(a)(1). FERC retained authority over rates and charges for the transmission or sale of electric energy, and the non-emergency interconnection of facilities for the generation, transmission, and sale of electric energy. *Id.* § 7172(a)(1)(B). The Department's authority over functions of "the Commission" in the Federal Power Act include functions under some subsections of Section 202 of the Act. *See id.* § 7151(b). The 1977 reorganization did not expand the role of the "the Commission" at the expense of state authority or shrink states' authority over generation facilities. *See, e.g.*, *id.* § 7113 ("Nothing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction.").

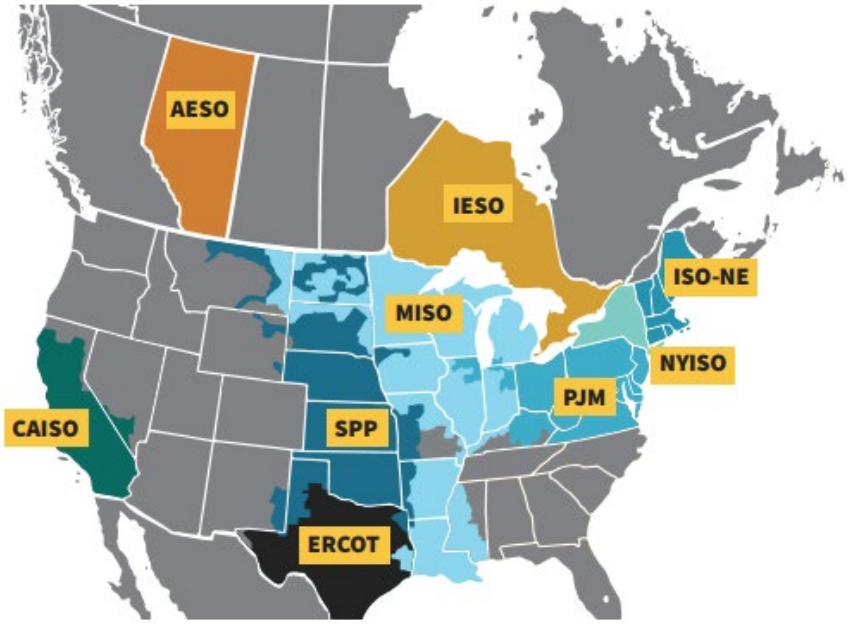
As part of its regulatory oversight, FERC has promoted the role of nonprofit entities, known as Independent System Operators or Regional Transmission Organizations. *See Fed. Energy Regul. Comm'n v. Elec. Power Supply Ass'n*, 577 U.S. 260, 267 (2016); *Regional Transm. Orgs.*, Order No. 2000, 65 Fed. Reg. 810, 811 (Jan. 6, 2000); *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transm. Servs. by Pub. Utils. and Recovery of Stranded Costs by Pub. Utils. and Transm. Utils.*, Order No. 888, 61 Fed. Reg. 21540, 21542 (May 10, 1996). FERC generally regulates these entities pursuant to its authority over rates and charges for wholesale sales and transmissions of electric energy. *See, e.g.*, Order No. 2000, 65 Fed. Reg. at 811. These entities, referred to here as Independent System Operators or RTOs, perform a variety of functions, including:

- Ensuring the electric grid operates reliably in a defined geographic footprint;
- Balancing supply and demand instantaneously and maintaining sufficient operating reserves;
- Dispatching system resources as economically as possible;
- Coordinating system dispatch with neighboring balancing authority areas;
- Planning for transmission in its footprint;
- Coordinating system development with neighboring systems and participating in regional planning efforts; and
- Providing non-discriminatory transmission access.

Ex. 2-19 at 53 (FERC Energy Primer). Some Independent System Operators "also operate capacity markets, which, along with underlying resource adequacy rules, ensure sufficient capacity is available." *Id.* at 68.

The Independent System Operators now span much of the country, excluding portions of the Southeast, Southwest, and Northwest regions of the country. *See id.* at 37. The map in Figure 1 below depicts the geographic footprint of the various Independent System Operators before April 1, 2026.

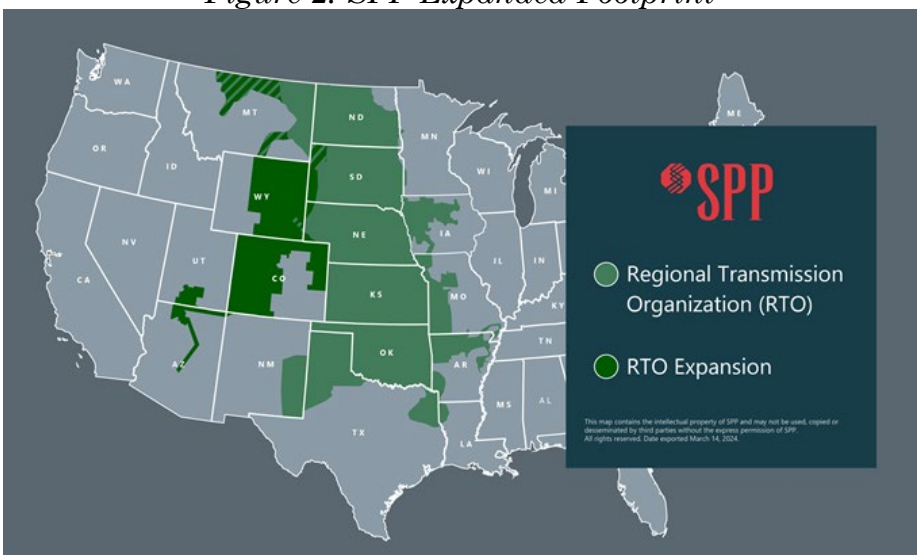
Figure 1: Boundary Areas of RTOs and ISOs



Source: Ex. 2-19 at 67 (FERC Energy Primer).

Beginning on April 1, 2026, the SPP RTO footprint expanded, as shown in Figure 2 below.

Figure 2: SPP Expanded Footprint



Source: Ex. 2-180 at PDF 1 (SPP RTO Expansion).

2. NERC Protects Reliability via Standards and Regular Assessments.

NERC is the "Electric Reliability Organization" under section 215 of the Federal Power Act. *N. Am. Elec. Reliab. Corp.*, 116 FERC ¶ 61,062, at P 3, *order on reh'g & compliance*, 117 FERC ¶ 61,126 (2006); *see* 16 U.S.C. § 824o(a)(2). This role dates back to 2005, after Congress added Section 215 to the Act and FERC certified NERC as the Electric Reliability Organization. Energy Policy Act of 2005, Pub. L. No 109-58, Title XII, Subtitle A, section 1211(a), 119 Stat. 594, 941 (2005), 16 U.S.C. 824o (2000 & Supp. V 2005); 116 FERC ¶ 61,062, at P 3.

As the Electric Reliability Organization, NERC is responsible for establishing and enforcing reliability standards for the bulk power system. 16 U.S.C. § 824o(a)(2); 18 C.F.R. § 39.1. NERC's reliability standards are subject to FERC's review and approval. 16 U.S.C. § 824o(d).

The NERC-developed and FERC-approved reliability standards apply to all users, owners, and operators of the bulk power system within the continental United States. *Id.* § 824o(b)(1); 18 C.F.R. §§ 39.2, 40.1(a), 40.2(a); *see id.* § 39.1 (defining "Bulk–Power System"). Each reliability standard identifies the types of entities that must comply with the standard, like generator owners, transmission owners, or transmission operators. *Reliability Standard Compliance and Enforcement in Regions with Regional Transm. Orgs. or Indep. Sys. Ops.*, 122 FERC ¶ 61,247, at P 4 (2008); *e.g.*, Ex. 2-117 at EOP-011-4 (NERC Emergency Operations) (stating requirements applicable to, *inter alia*, balancing authorities, reliability coordinators, and transmission operators for the purpose of "address[ing] the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are

implemented and coordinated within the Reliability Coordinator Area as specified within the requirements").

NERC performs other functions in addition to development and enforcement of reliability standards. For instance, NERC annually assesses seasonal and long-term reliability of the bulk power system and monitors system performance. *See* 18 C.F.R. § 39.11. Since it began providing standardized "risk" assessments by region in the summer of 2021, NERC has adhered to a three-tiered assessment of risk: areas facing the least risk are "low" or "normal" risk regions, areas facing the most risk are "high" risk regions, and areas in between are "elevated" risk regions. *See* Ex. 2-28 at PDF 75, 124, 170, 218 (2019–24 NERC Summer Reliability Assessments). NERC's determination of "elevated" risk generally indicates that there is a "[p]otential for insufficient operating reserves in above-normal conditions." Ex. 2-27 at 6 (NERC 2025 Summer Reliability Assessment). NERC typically provides specific context and details associated with its determination. *See id.* at 17–39.

NERC also delegates certain authorities to six Regional Entities that make up the Electric Reliability Organization Enterprise. Ex. 2-149 at 1 ("About WECC" Webpage). The largest of these, the WECC, is one of the key regional actors described below working to ensure that the power grid remains reliable. *Id.* at 1–2.

3. The Utilities that Own and Operate Craig Protect Reliability and Resource Adequacy in Their Service Territories.

The five utilities that own and operate Craig have service territories spanning a significant portion of the Western United States, including the Rocky Mountain assessment area. Tri-State is a wholesale electric cooperative that provides electricity to retail cooperatives in Colorado, New Mexico, Wyoming, and Nebraska. The geographic footprint of the Tri-State members is shown in Figure 3.

Figure 3: Tri-State Members



Source: Ex. 2-114 at 2 (Tri-State Members).

PacifiCorp serves customers in Washington, Oregon, California, Idaho, Utah, and Wyoming. Ex. 2-124 at 1 (2025 PacifiCorp_FactSheet). Salt River Project serves customers in Arizona. Ex. 2-125 at 1 (Service Area and Territory (Electric Power and Water) SRP). Platte River and Xcel serve customers in Colorado. Ex. 2-126 (Xcel, List of Towns Receiving Electric Service in Colorado); Ex. 2-127 (Who we serve - Platte River Power Authority).

The resource adequacy responsibility of the Craig Co-Owners can be broken down into two separate categories: responsibilities of the utilities that serve as balancing authorities; and their responsibilities as load-serving entities, i.e., entities that provide electricity directly to retail customers, and/or their responsibilities as wholesale providers that generate and transmit electricity to other retail utilities.

Currently, two of the Craig Co-Owners (Tri-State and Platte River) are members of an RTO (SPP West). In addition, balancing authorities perform many of the functions that RTOs perform, including balancing supply with demand and dispatching generation. *See* Ex. 2-115 (Department Explainer on Balancing Authorities) at *passim*; Ex. 2-116 at 1 (EIA Explainer on Balancing Authorities).

Four of the five Craig Co-Owners are load-serving entities that provide electricity directly to retail customers. The fifth, Tri-State, is a wholesale provider with obligations to meet the demand of its member cooperatives.

The utilities meet their reliability requirements through a variety of overlapping processes. At one end of the spectrum is long-term resource planning, which each utility conducts through resource planning. Platte River prepares and adopts an Integrated Resource Plan ("IRP") every four years. Tri-State and Xcel submit Electric Resource Plans ("ERPs") at least every four years for the Colorado Commission to approve. PacifiCorp prepares an IRP every two years, which it submits to state commissions in its service territory. Salt River Project updates its IRP every five years. While the cadence varies, each resource plan is, at its core, an exercise in forecasting electricity demand on a long-term basis and then adopting a plan to acquire the quantity of generating, storage, and demand-response resources needed to reliably serve forecasted demand.

Each utility also has various processes for acquiring resources on a shorter-term basis than is possible through an IRP. These processes include short-term purchases made on a seasonal basis; day-ahead purchases; and, at the shortest extreme, purchases made on an intra-hour basis through energy imbalance markets. For example, in its December 2025 Near Term Procurement Report, Xcel indicated it had made seasonal purchases of capacity for the winter and summer seasons in 2026. Ex. 2-93 at 29 (Table 8) (Xcel 2025 Near Term Procurement Report).

The utilities also participate in reserve-sharing agreements that allow them to call upon resources to deal with very short-term resource needs. For example, Salt

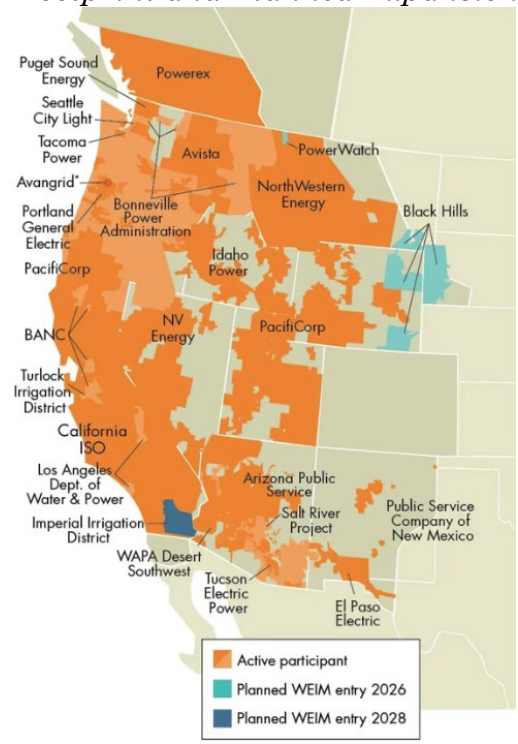
River Project and Xcel participate in the Northwest Power Pool Reserve Sharing Group:

> Along with participating in the [Western Area Power Administration] Balancing Authority, [Xcel] entered the [Northwest Power Pool] Reserve Sharing Program in September 2019. The [Northwest Power Pool] Reserve Sharing Program Agreement provides for sharing of contingency operating reserves among interconnected electric utilities operating in the Western Interconnection. There are presently 22 participating Balancing Authorities in the [Northwest Power Pool] Reserve Sharing Program. By pooling their contingency reserves, these utilities are able to carry less contingency reserve capacity than if they operated independently. Under the [Northwest Power Pool] Reserve Sharing Program Agreement, [Xcel] can call on and purchase contingency reserves (spinning and non-spinning), and the energy associated with such reserves, when they are activated in response to a sudden system disturbance. [Xcel] can also purchase emergency assistance under the [Northwest Power Pool] Reserve Sharing Program Agreement.

Ex. 2-94 at 118 (Xcel 2024 JTS, Volume 2 Technical Appendix).

In addition, each of the Craig Co-Owners either participates to varying degrees or has plans to participate in organized wholesale markets. As of April 2026, Tri-State and Platte River participate in a regional market operated by SPP, whereas PacifiCorp participates in the Western Energy Imbalance Market operated by the California Independent System Operator. Ex. 2-111 at 2 (Western Energy Imbalance Market Webpage). The footprint of the Western Energy Imbalance Market and its planned expansion is shown in Figure 4 below.

Figure 4: Western Energy Imbalance Market Footprint and Planned Expansion

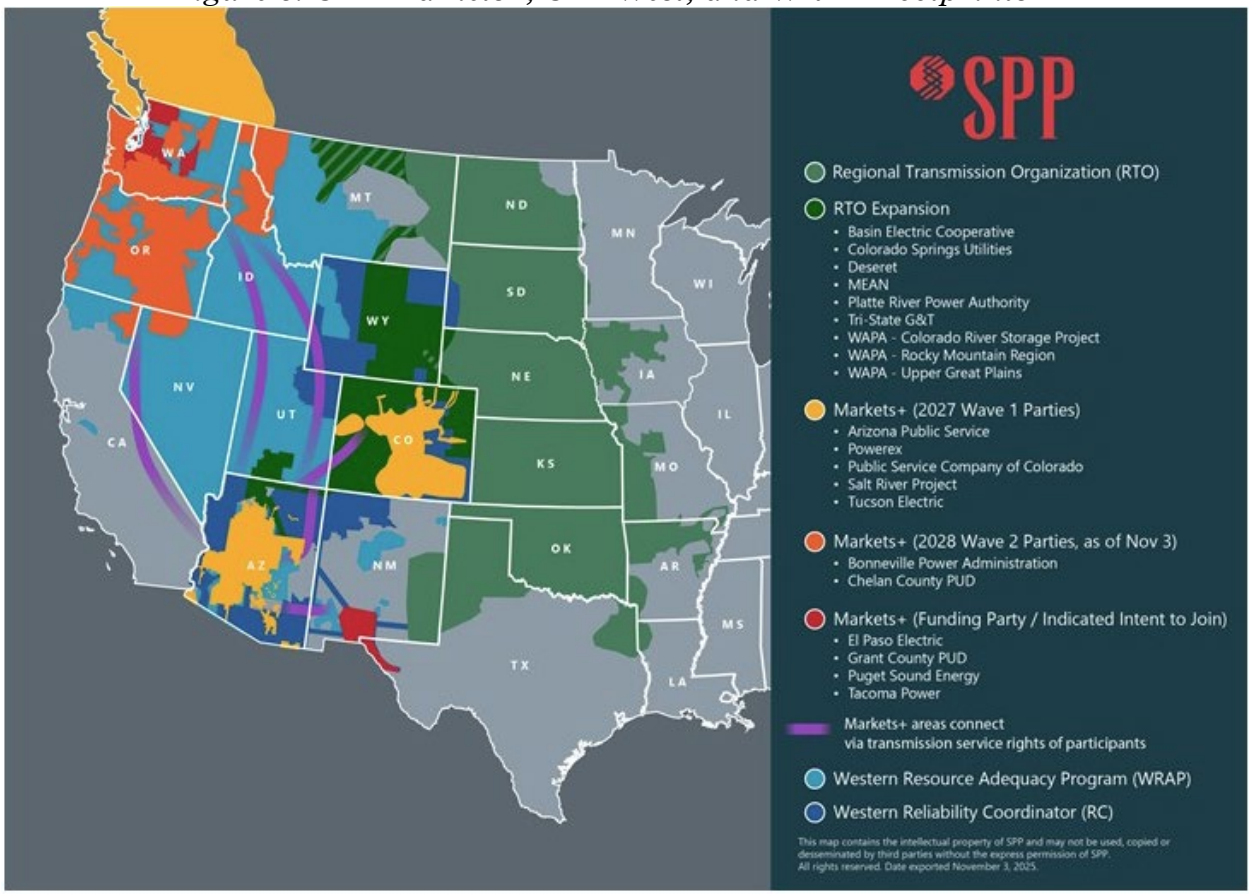


Source: Ex. 2-111 at 2 (Western Energy Imbalance Market Webpage).

Meanwhile, Xcel intends to join SPP's day-ahead and real time energy market offerings outside of the SPP's main footprint, called "Markets Plus" or "Markets+," in 2027. Ex. 2-167 at PDF 3 (SPP Markets+ Website). Under Markets+, SPP will perform centralized commitment and dispatch on a day-ahead and real-time basis for participating utilities. *Id.*

Effective April 1, 2026, Tri-State and Platte River are now members of the western expansion of the SPP RTO, called SPP West. Ex. 2-161 at 1 (SPP West Press Release). Under SPP West, SPP not only performs similar centralized dispatch and unit commitment functions that it will perform in Markets Plus, but also performs other reliability services for Tri-State, Platte River, and other Western utilities, such as transmission planning and assuming the role of balancing authority and reliability coordinator. As shown in the figure below, SPP West covers a portion of WECC's Rocky Mountain assessment area. The scope of SPP's expansion is shown in Figure 5 below.

Figure 5: SPP Markets+, SPP West, and WRAP Footprints



Source: Ex. 2-167 at PDF 2 (SPP Markets+ Website).

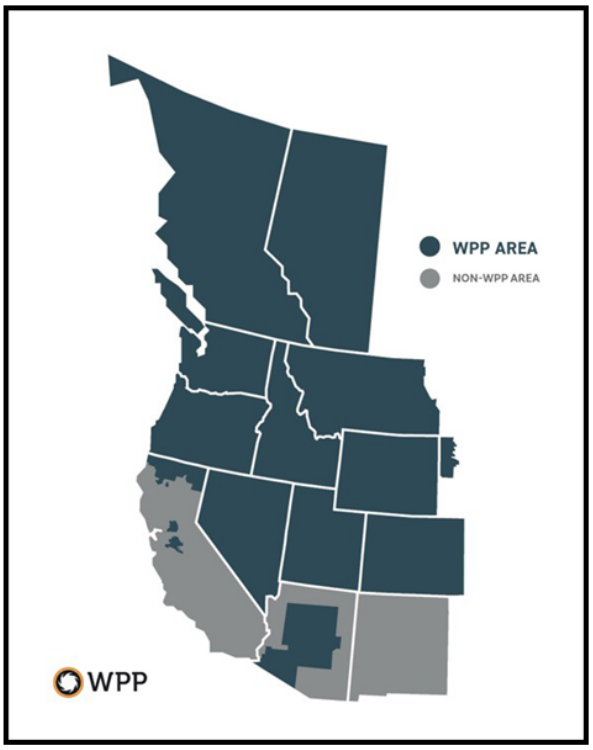
4. State and Regional Regulatory Bodies Protect Resource Adequacy Through Integrated Resource Planning and Annual Capacity Demonstration Requirements.

As noted above, state public utility commissions in the following states regulate at least one of the Craig Co-Owners: California, Colorado, Idaho, Oregon, Utah, Washington, and Wyoming. All seven of these state commissions have reviewed resource plans stating that Craig would retire by December 31, 2025. *See infra* secs. V.A.2, V.A.5. None of these seven state commissions has expressed any concern regarding retiring Craig by December 31, 2025. No state commission has directed any of the Craig owners to operate Craig past 2025. The attached report from Telos Energy describes the role of the Colorado Commission in ensuring resource adequacy and reliability for two of the Craig Co-Owners, Xcel and Tri-State. Ex. 2-5 at 7–9 (Telos Energy Report).

i. The Western Power Pool Is Implementing a Western Resource Adequacy Program and Forecasts Regional Resource Adequacy on an Annual Basis.

The Western Power Pool is a grouping of utilities and partners that coordinate and share resources in the Western Interconnection. Ex. 2-131 at 10 (FERC Western Energy Markets Explainer). The Western Power Pool's territory stretches from British Columbia and Alberta through all or parts of multiple states, *id*. at 9–10, as shown in Figure 6 below.

Figure 6: Boundary Area of Western Power Pool



Source: Ex. 2-131 at 9 (FERC Western Energy Markets Explainer).

The Western Power Pool organizes multiple programs to ensure that participants are protected against emergency events that would otherwise disrupt service or lead to blackouts. For instance, it operates a reserve sharing program, in which participating Balancing Authorities share contingency reserves to ensure that participants have access to sufficient power during emergencies. *See* Ex. 2-145 (Western Pool Reserve Sharing Program). The Western Power Pool also organizes more rapid-response grid stability coordination, including a frequency response sharing group in which participating entities work together to secure adequate ancillary services to maintain minute-to-minute grid stability. Ex. 2-146 (Western Frequency Response Sharing Group).

Of particular note to the question of resource adequacy oversight, in February 2023 the Western Power Pool secured approval from FERC to create a more comprehensive resource adequacy coordination regime, the Western Resource Adequacy Program. *Northwest Power Pool*, 182 FERC ¶ 61063 (2023). The Western Resource Adequacy Program was designed initially as a voluntary resource adequacy planning and compliance program for utilities in the West and is intended to supplement the resource planning and projections undertaken by utilities, states, and provinces. *Id.* at ¶ 5. As FERC identified in its order approving the Western Resource Adequacy Program, the operational program serves as "a resource of last resort—not a resource of first resort"—and participants are maintaining their own processes to plan ahead and ensure their own resource adequacy. *Id.* at ¶ 98. This makes the coordination offered by the Western Resource Adequacy Program entirely additional and complementary to the other planning processes discussed in this section. *Id.* at ¶ 5.

The Western Resource Adequacy Program has two distinct operational components: a forward-showing process and operational follow-through. Under the forward-showing component, participants in the program demonstrate seven months in advance of each summer season and each winter season that they have secured their proportional share of regional capacity, which includes a required planning reserve margin that is designed to meet a loss-of-load expectation ("LOLE") standard of 1-event-in-10-years. *Id.* at ¶¶ 6, 53. To avoid a charge, participants must also show that they have reserved at least 75% of the transmission necessary to deliver energy at the time of their forward-showing filings, and all of the necessary transmission during the activation period of the operating program. Ex. 2-147 at § 13.2 (WRAP Tariff). This transmission reservation must be at the highest level of reliability (NERC Priority 6 or Priority 7 firm point-to-point or network integration transmission service). *Northwest Power Pool*, 182 FERC ¶ 61063, at ¶¶ 54, 78.

Each participant's forward projection is then tested against a nearer-term forecast (week ahead or day ahead) in the operational phase of the Western Resource Adequacy Program process. Based on the results of the comparison, participants with surpluses may be required to hold back capacity for the benefit of other participants with a deficit, with fines levied for nonperformance of this obligation to hold back. *Id.* at ¶¶ 7, 94–95. In this way, the Western Resource Adequacy Program ensures that each balancing authority in the region is able to rely on imports from neighbors, thereby approximating one of the key benefits load-serving entities gain via participation in RTOs in other parts of the country. *See generally* 89 FERC ¶ 61,285.

As of October 31, 2025, 16 utilities committed to the Program's initial binding operational season, in Winter 2027/28. Ex. 2-148 (WRAP Notice). Even in its voluntary form, the Western Resource Adequacy Program has added to the tapestry of regional cooperation that has helped ensure the West continues to receive power reliably.

ii. WECC Assesses Resource Adequacy in the Region on an Annual Basis and Enforces Federal Standards.

WECC is the largest of the six Regional Entities that make up NERC's Electric Reliability Organization Enterprise. Ex. 2-149 at 1–2 ("About WECC" Webpage). Its service territory encompasses two Canadian provinces (Alberta and British Columbia), the northern portion of Baja California, Mexico, and all or parts of many Western states, *id.*, as shown below in Figure 7.

Figure 7: Boundary Areas of WECC Subregions



Source: Ex. 2-01 at app'x A at 1 (Current Energy Group January Report).

Under its NERC-delegated authority, WECC is responsible for setting regional reliability standards, monitoring compliance with those standards, enforcing standards, and overseeing reliability assessment and performance analysis within WECC's footprint. *Id.*; Ex. 2-150 at § 401 (NERC Rules of Procedure); *see N. Am. Elec. Reliab. Corp.*, 153 FERC ¶ 61,134, at PP 55–56 (2015). This work includes ensuring that regional contingency reserve standards are aligned with national standards and performing risk assessments of bulk power system users, owners, and operators on the reliability of the Western Interconnection. Ex. 2-151 at 13–14 (WECC Contingency Reserve Whitepaper) (finding that by reducing minimum contingency

reserve amounts, prior sequestered resources will be made available to match the less predictable response of variable generation resources and more development of variable generation sources may be encouraged); Ex. 2-152 (WECC Risk Factor Criteria).

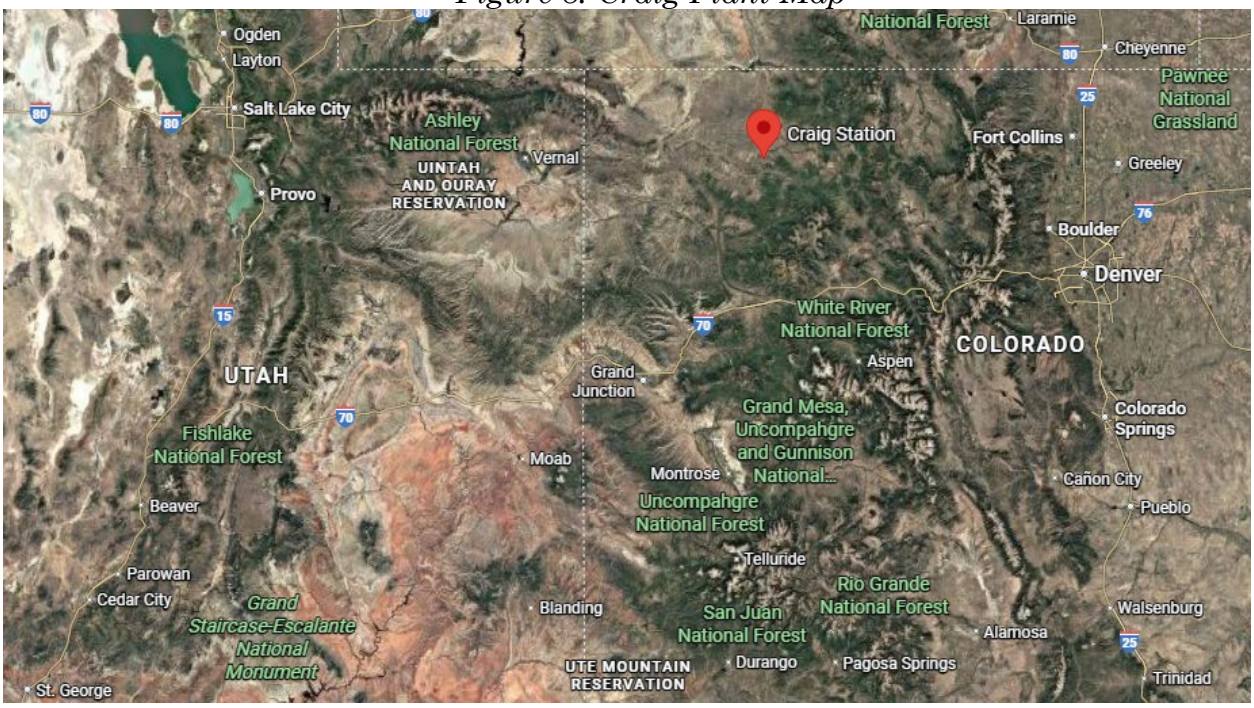
WECC also performs a yearly assessment of resource adequacy in its footprint, which is a useful resource for system planners. *E.g.*, WECC, *Western Assessment of Resource Adequacy: 2024* (last visited April 21, 2026), https://feature.wecc.org/wara/; Ex. 2-09 (2024 Western Assessment of Resource Adequacy). The yearly resource adequacy assessment performed by WECC is "an energy-based probabilistic" assessment, which evaluates resource adequacy under a variety of conditions. *Id.* It divides WECC's larger footprint into smaller subregions and provides detailed analysis of regional demand forecasts and planned resource additions for the next 10 years. *Id.* The scenarios modeled in the assessment include increased demand and slower buildout of generating resources. *Id*. These analyses provide information that helps inform NERC's reliability assessments of the entire country's energy system. Ex. 2-153 at 1 (WECC Reliability Assessment Webpage). Additionally, WECC contributes to NERC's assessments. *See* Ex. 3-07 at 14 (NERC 2026 Summer Reliability Assessment).

B. Craig's Retirement Was Planned for a Decade by Utilities and State Regulators.

1. Craig Is a Power Plant in Colorado Originally Built in 1980.

Craig began operations in 1980. The generator is located in Craig, Colorado, approximately 200 miles northwest of Denver and 45 miles west of Steamboat Springs. Craig's location is shown in Figure 8 below.

Figure 8: Craig Plant Map



Source: Google Earth.

Craig Unit 1 is part of a three-unit coal-fired generating facility (collectively, and with associated facilities, the "Craig Plant"). The Craig Plant's three units all rely on burning coal to generate electricity. Tri-State has committed to retiring Craig Unit 2 by September 30, 2028, and Craig Unit 3 by January 1, 2028. Ex. 2-89 at 5 (Tri-State 2025 ERP Annual Progress Report).

Figure 9: Craig Plant Photograph



Source: Ex. 2-53 (Colorado Sun Article).

2. Tri-State Operates and Partially Owns Craig.

Tri-State serves as the operator of Craig. As the operating agent, Tri-State is responsible for the daily management, administration, and maintenance of the facility. Ex. 2-49 at 6 (Tri-State Revised ERP Assessment of Existing Resources).

Tri-State is also a partial owner of Craig, holding a 24% interest. Ex. 2-03 at 3 (Powers Decl.). The other Craig Co-Owners, along with their respective shares, are as follows: PacifiCorp owns 19.28%; Platte River owns 18%; Xcel owns 9.72%; and Salt River Project owns 29%. *Id.* at 3–4 (citing utility filings).

3. Craig Is Old, Unreliable, Inflexible, Dirty, and Expensive.

i. Craig Is Old and Unreliable.

Craig is *past* the typical operational life of coal units. Ex. 2-03 at 5 (Powers Decl.) (citing Ex. 2-48 at 18 (IEA Report); Ex. 2-47 at 127 (Palgrave Handbook)). Its production and reliability have declined with age.

Data from the U.S. Environmental Protection Agency's ("EPA") Air Markets database indicates that Craig's gross output declined by 38% from 2022 through 2025, the most recent year for which annual data is available. The values are shown in Figure 10 below.

Figure 10: Craig Output from 2022 through 2025

Year	Production (MWh)
2022	2,797,335
2023	2,015,029
2024	1,824,100
2025	1,724,208

Source: Ex. 2-113 (Craig Station, AMD data 2020 through 2025) (EPA Air Markets Database). MWh values rounded to nearest integer.

In recent years, Craig has experienced a sharp increase in outages, which reflect aged, worn components that are expensive and may be difficult to repair or replace. Ex. 2-03 at 5, 7–8, 14–15 (Powers Decl.). The outages at Craig demonstrate an increasing inability to perform consistently, even under normal conditions. Tri-State and Platte River have explained that "as Craig Unit 1's operations are further extended past its intended lifespan, it is likely to experience more and longer periods of outage." Ex. 3-06 at 32 (Tri-State and Platte River April Rehearing Request). In fact, when the Department issued the December Order, Craig had a forced outage that began on December 19, 2025 due to a valve failure. Ex. 2-06 (Tri-State December 2025 Press Release). The December 2025 forced outage is characteristic of an old plant that is prone to mechanical failures. Ex. 2-03 at 7 (Powers Decl.); *see also* Ex.

3-06 at 41, 32 n.33 (Tri-State and Platte River April Rehearing Request) (describing Craig Unit 1 as an "aging coal plant" and that explaining that "forcing Craig Unit 1 to continue operating to address projected shortfalls in 2034, when it would be 54 years old, only exacerbates concerns about reliance on aging resources").

Craig's December 2025 forced outage is consistent with recent trends. Outside of scheduled maintenance periods, Craig has been unable to produce power during significant portions of recent years (known as the unit's "forced outage rate"). Ex. 2-03 at 7–8 (Powers Decl.) (citing Tri-State's filings with the Colorado Commission). For example, Craig experienced a sharp year-over-year forced outage rate increase between 2022 and 2023, increasing from 1.75 percent to 9.53 percent. *Id.* Craig's 9.53 percent forced outage rate translates into 835 hours that Craig could not operate in 2023, or approximately five weeks of forced unavailability. *Id.* Because of Craig's inconsistent and sharply increasing forced outage rate, it cannot meet the demands of an emergency. *See* Ex. 2-175 at 9 (Tri-State and Platte River January Rehearing Request) (stating that "Craig Unit 1 has had multiple breakdowns and required significant repairs to continue operating into 2025").

Craig's recent forced outages are a direct result of significantly decreased capital expenditures and maintenance at Craig. Ex. 2-03 at 6–7 (Powers Decl.). This is unsurprising, as the Craig Co-Owners announced the plant's retirement date in 2016. Because the co-owners anticipated that the plant would retire at the end of 2025, they did not undertake maintenance projects that they would have undertaken had they been expecting to operate the unit past 2025. *Id.* at 7; Ex. 2-175 at 9 (Tri-State and Platte River January Rehearing Request) (stating that the co-owners have deferred optional maintenance since 2019). In fact, in response to the December Order, Tri-State conceded that the "retirement decision has informed operational and maintenance decisions." Ex. 2-06 (Tri-State December 2025 Press Release). As evidenced by Craig's December 2025 outage, the plant requires additional investments in operations and maintenance because the Craig Co-Owners have been foregoing maintenance in recent years. *Id.*; Ex. 2-03 at 7 (Powers Decl.). In fact, in response to the December Order, the Co-Owners had to repair out-of-service equipment such as filter pumps, ash blowers, and feedwater heater tubes. Ex. 3-06 at 14 (Tri-State and Platte River April Rehearing Request). Foregone maintenance makes Craig more prone to failure and more likely to need to go on outage to fix broken parts or maintain the unit. Ex. 2-04 at 4 (Grid Strategies Cost Report); *see also* Ex. 2-06 (Tri-State December 2025 Press Release).

Tri-State transitioned from a preventative approach to a "fix it if it breaks" approach at Craig. Ex. 2-03 at 6–7 (Powers Decl.). As Tri-State and Platte River have explained, "Craig Unit 1's planned closure was announced a decade ago, and numerous steps, such as deferring maintenance, reducing staffing, and redirecting capital expenditures, have been undertaken since." Ex. 3-06 at 22 (Tri-State and Platte River April Rehearing Request). This approach is consistent with Tri-State's investment strategy for early retirement of coal units. Tri-State stated that it

"proactively works to reduce and eliminate capital expenses related to early retirement of resources as can be seen by the historical capital expense." Ex. 2-51 at 187 (Tri-State 2020 ERP). Tri-State's filings with the Colorado Commission further memorialize this "fix it if it breaks" approach for Craig. Tri-State represented that its "investments in [the Craig Plant] are being appropriately limited to only actions necessary for ensuring safe operations and regulatory compliance, given the impending retirement of these units." Ex. 2-50 at 10 (Insgold 2023 ERP Direct Testimony). As a result, "it is unlikely that Craig 1 can be depended upon to operate reliably." Ex. 2-03 at 5 (Powers Decl.).

ii. Craig Is Inflexible.

On top of Craig's reliability problems, the plant cannot respond on short notice. Ex. 2-03 at 8–9 (Powers Decl.). Coal units—including Craig—take a minimum of 12 hours to reach full load operation from a cold start. *Id.*; *see* Ex. 2-44 at PDF 3 (RMI Analysis of Coal Plants' Threats to Reliability); Ex. 2-33 at PDF 3 (IEA Flexibility Report).

iii. Craig Is Dirty and Environmentally Harmful.

Additionally, Craig is a significant source of pollution. Based on its 2025 activity, Craig can be expected to emit every three months over one billion pounds of carbon dioxide ("CO_2"), over one million pounds of nitrogen oxides ("NO_x"), and hundreds of thousands of pounds of sulfur dioxide ("SO_2"). *See* Ex. 2-03 at 12 (Powers Decl.).

Craig's air pollution results in several harms. NO_x and SO_2 both cause health concerns, including respiratory problems. *Id.* at 10. And CO_2 is the primary cause of global warming. *Id.* at 11. Pollution from coal generation can have drastic and deadly health effects. *See, e.g.*, Ex. 2-121 at 2 (Mercury Mortality Risks of Coal); Ex. 2-123 at PDF 4–5 (EPA COBRA Health Effects Estimate). On an annual basis, air pollution from Craig causes an estimated 4 premature deaths, and this pollution increases the likelihood of emergency room visits, heart attacks, and asthma attacks. *Id.*; Ex. 2-160 at PDF 2–3 (Clean Air Task Force Toll from Coal). In total, the health harms from Craig's air pollution result in over $56 million in estimated costs each year. Ex. 2-123 at PDF 5 (EPA COBRA Health Effects Estimate).

Air pollution from the plant also clouds Colorado's treasured federal public lands in haze. Craig's operation impairs visibility in several national parks and wilderness areas in Colorado, including (among others) Rocky Mountain National Park, Flat Tops Wilderness Area, Eagles Nest Wilderness Area, Mount Zirkel Wilderness Area, and Rawah Wilderness Area. Ex. 2-03 at 11 (Powers Decl.) (citing Ex. 2-71 at 47–48 (BART CALPUFF)). Therefore, alongside the health burdens of the pollution, the continued operation of Craig will harm the people who visit and recreate at these iconic landscapes.

In addition to air pollution, continued operation of Craig will worsen water scarcity in the state and the region. Craig uses approximately 250,000 gallons of water per hour of operation at its net capacity of 427 MW. *Id.* at 16 (citing Ex. 2-88 at 19 (Tri-State 2023 ERP Modeling Assumptions)). All the while, Colorado, the river basin that shares its name, and the surrounding states are in a water crisis. *See* Ex. 2-52 at 3 (Colorado 2023 Water Plan). Water conservation remains a key priority for Colorado, especially as the region experiences population growth, long-term warming trends, major wildfires, aridification, and multi-year drought. *Id.* (Colorado 2023 Water Plan). The energy sector drives water overuse in the state, and coal-fired power plants are water consumptive compared to renewable sources of energy. *Id.* at 21.

Retiring Craig would eliminate the plant's environmental harms. Meanwhile, the ongoing operation of Craig will guarantee that the plant's harmful air pollution and wasteful water practices persist.

iv. Craig Is Expensive.

Craig is also an expensive plant to run. In 2024, Craig cost over $80 million to operate. Ex. 2-04 at 3 (Grid Strategies Cost Report). Over the period 2022 to 2024, operating Craig cost nearly $85 million per year. *Id.* Operating Craig at its average output from 2022 through 2024 will cost more than $20 million for each 90-day period. Tri-State and Platte River have noted that if they "must continue to dispatch Craig Unit 1, as the unit has in the past, for the entire emergency period until 2034, costs could exceed millions in operating and maintenance costs, exclusive of fuel costs." Ex. 3-06 at 26 (Tri-State and Platte River Request for Rehearing).Craig is an uneconomic source of electricity. As Tri-State and Platte River have emphasized, there is "no economic benefit available from retaining the to-be-retired facility because it is *uneconomic to operate*." Ex. 2-175 at 20 (Tri-State and Platte River January Rehearing Request) (emphasis added); *see also* Ex. 3-06 at 40 (Tri-State and Platte River April Rehearing Request) (stressing that "Craig Unit 1 is an older, uneconomic unit"). The available data demonstrates that Craig's "cost of producing electricity is almost always higher than the value of that electricity." Ex. 2-04 at 6 (Grid Strategies Cost Report). Craig's fuel costs exceed the average market price, and considering variable costs makes Craig even more uneconomic. *Id.* at 3–4. All told, market prices do not cover Craig's variable costs in over ninety percent of hours. *Id.* at 6. In other words, the cost of producing electricity at Craig is overwhelmingly higher than the value of that electricity.

Further, Craig's foregone maintenance exacerbates the plant's already high operating costs. As coal plants age, they require sustaining capital expenditures and increasing O&M costs over time. When coal plants reach an age of 40–50 years, they require a significant increase in capital expenditure. *Id.* at 4 (citing Ex. 2-162 at 29, 62 (EIA Generating Unit Annual Capital and Life Extension Costs Analysis). Recent forced shutdowns—including the shutdown that began in December 2025—demonstrate the need for maintenance expenditures at Craig. Ex. 2-06 (Tri-State

December 2025 Press Release). Tri-State and Platte River stated that due to Craig's age and the extent of deferred maintenance, keeping the plant operable involves "particularly high costs . . . compared to possible alternatives." Ex. 3-06 at 40 (Tri-State and Platte River April Rehearing Request); *see also id.* at 19 ("Ongoing operations at Craig Unit 1 will require continual maintenance and staffing readiness, with further equipment failures requiring repair and staffing (including overtime).").

"All costs" incurred by the Craig Co-Owners to comply with the Order "end up on ratepayers." Ex. 2-163 at 1–2 (Trump Advisor Says Electricity Customers Pay for 202(c) Orders). Tri-State and Platte River have highlighted the unfairness of the "costs of compliance fall[ing] directly on their members and customers." Ex. 2-175 at 1, 4-5 (Tri-State and Platte River January Rehearing Request). Tri-State and Platte River have explained that DOE's 202(c) orders impose "a heavy economic burden" by requiring them to "incur various operations and maintenance costs to ensure Craig Unit 1 is ready and able to operate at SPP's direction." Ex. 3-06 at 20 (Tri-State and Platte River April Rehearing Request)." These costs include "additional investments in operations, repairs, maintenance and, potentially, fuel supply, all factors increasing costs," and Tri-State "is working to prepare filings in support of cost recovery." Ex. 2-166 at 1 (Tri-State January 2026 Press Release); *see also* Ex. 2-175 at 15, 17, 20 (Tri-State and Platte River January Rehearing Request) (describing operational, maintenance, and staffing costs); Ex. 3-06 at 18-20, 26 (Tri-State and Platte River April Rehearing Request) (describing operational and maintenance expenses and replacement fuel costs); Ex. 2-176 at 4-5 (Xcel Motion to Intervene in Petition for Rehearing) (stating that the co-owners have incurred "substantial additional operations, maintenance, and fuel costs," that Xcel's share of those costs was approximately $100,000 as of April 2026, and that Xcel intends to seek cost recovery).

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These harms can be avoided by retiring Craig. As further discussed below, the Craig Co-Owners—Tri-State, the Salt River Project, Platte River, PacifiCorp, and Xcel—wanted to retire the plant on December 31, 2025. Further, the state and federal regulators—including the Colorado Commission, the Colorado Department of Public Health and Environment, and the U.S. EPA—each approved the retirement. *See, e.g.,* Ex. 2-85 (Colorado Commission Decision in 20A-0528E) (approving resource plan where Craig ceases to generate electricity after 2025); Ex. 2-90 at 40 (Colorado Commission Decision No. C25-0612) (same); Ex. 2-65 (CDPHE Regulation No. 3); 83 Fed. Reg. 31332.

V. REQUEST FOR REHEARING

The Order is a manifestation of the Department's overarching policy to systematically misapply Section 202(c) of the Federal Power Act to preserve fossil-fueled power plants, including coal-fired plants, that otherwise would be retired. That

policy aims to bolster the fossil energy industry, irrespective of need, expense, and harm. In its zeal to implement its policy through issuance of the Order, (1) the Department has exceeded the authority Congress gave it, using its "emergency" powers in the absence of any imminent shortfall to impose federal control over basic generation and supply decisions; and (2) the Department has done so without reasoned decision-making and on the basis of purported "facts" that are not supported by credible evidence. *See Michigan v. EPA*, 268 F.3d 1075, 1081 (D.C. Cir. 2001) (explaining that, absent statutory authorization, an agency's action is contrary to law); *Allentown Mack Sales & Serv., Inc. v. Nat'l Labor Rel. Bd.*, 522 U.S. 359, 374 (1998) (explaining agency obligation to undertake reasoned decision-making); *Motor Vehicle Mfrs. Assn. of United States, Inc. v. State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983) (same); *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962) ("The agency must make findings that support its decision, and those findings must be supported by substantial evidence."); *Butte Cnty. v. Hogen*, 613 F.3d 190, 194 (D.C. Cir. 2010) ("[A]n agency cannot ignore evidence contradicting its position."). Numerous examples of the Department's unreasoned and unlawful decision-making are described throughout this section V. The only plausible explanation for these repeated legal errors is that the Department has prioritized implementing its policy over compliance with the law.

Congress never conferred on the Department the broad authority over the country's mix of power generation resources that the Department seeks to wield under the pretense of responding to claimed "emergencies." To the contrary, Congress explicitly reserved authority over resource adequacy and grid reliability to the states, to FERC, and to NERC. *See, e.g.*, 16 U.S.C. §§ 824(a)–(b), 824o; *Pac. Gas & Elec. Co. v. State Energy Res. Conserv. & Dev. Comm'n*, 461 U. S. 190, 205 (1983). Both the agency's new policy and the Order exceed the Department's authority and are therefore contrary to law.

Before tackling the Order's legal faults and issues, *see infra* secs. V.A through V.D, it is useful to understand the broader context of the Department's policy. The Department acknowledges that its Order is based on a government-wide policy—dictated by Executive Order—of promoting fossil-based energy through the use of any emergency powers executive departments and agencies could try to invoke. Order at 4–5. The Order relies upon the Energy Emergency Executive Order, 90 Fed. Reg. 8433, which directs the heads of all executive departments and agencies to use "emergency authorities" and "other lawful authorities" to facilitate the production, extraction, creation, and generation of coal and other fossil fuels. Order at 5 (relying on Ex. 2-36 (Energy Emergency EO)).

The Order also relies on another executive order, the Grid EO. *Id.* (relying on Ex. 2-37 (Grid EO)). The Grid EO was issued at the same time as three other executive actions aimed at giving a lifeline to the coal industry, and was announced at a White House political event focused on promoting coal. Ex. 2-38 (NY Times Coal Article). In essence, the Grid EO calls on the Department to assume the authority for resource

adequacy and grid reliability decision-making that the Federal Power Act reserves to others, and to "systemize" the issuance of Section 202(c) orders for that improper purpose. *See* Ex. 2-37, 90 Fed. Reg. at 15521–22 (Grid EO) (directing the Department to "streamline, systemize and expedite" the issuance of Section 202(c) orders; to develop a "uniform methodology" for assessing reserve margins and a protocol to retain generators the Secretary deems critical to system reliability; and to prevent certain generators from leaving the bulk power system or converting to a different fuel source).

The Department's words and actions following issuance of the Grid EO reveal its efforts to unlawfully arrogate to itself others' authority through systematic misapplication of Section 202(c) to prop up coal-burning power plants. The Department's initial steps included issuing a Section 202(c) order to prevent the well-planned retirement of the J.H. Campbell coal plant. *See* Order No. 202-25-3 at *passim*. The Department's order was clear on one point—Campbell cannot be allowed to retire—but left vague and unclear almost everything else. *See, e.g.*, *Consumers Energy Co. v. Midcontinent Indep. Sys. Op., Inc.*, 192 FERC ¶ 61,158, at PP 39–40 (2025) (recognizing the variety of interpretations of the Campbell order and settling on "the most reasonable reading of the DOE Order's intended scope"). The Campbell order failed to make clear even where the grid supposedly needed energy from Campbell, selectively quoted sources without examining their context and core findings, and flouted Congress' explicit limitations on the Department's Section 202(c) powers. *See* Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al. at *passim* (June 18, 2025), https://www.energy.gov/sites/default/files/2025-07/PIO%20Request%20for%20Rehearing%20of%20Order%20No.%20202-25-3.pdf.

After preventing Campbell's retirement, the Department continued to implement its policy. In addition to the Craig orders, the Department has issued Section 202(c) orders to prevent fossil-burning plant retirements in Michigan, Order Nos. 202-25-3, 202-25-7, 202-25-9, 202-26-16, and 202-26-22; Indiana, Order Nos. 202-25-12, 202-25-13, 202-26-19, 202-26-20, 202-26-29, and 202-26-30; Washington, Order No. 202-25-11, 202-26-18, and 202-26-28; in Pennsylvania, Order Nos. 202-25-4, 202-25-8, 202-25-10, 202-26-17, and 202-26-24; and in Florida, Order No. 202-26-26.

Additionally, on July 7, 2025, the Department published the "methodology" required by the Grid EO, which the Department explained will "guide reliability interventions," including the use of Section 202(c) orders. Ex. 2-35 at vi (July Resource Adequacy Report); *see also* Ex. 2-39 at 3–4 (DOE July 7 Press Release) ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act."). The report identifies no present or imminent emergency; at most, using deeply flawed methodology, it identifies a theoretical shortfall of generation in 2030.

Taken together, the Energy Emergency EO, Grid EO, July Resource Adequacy Report, and the Department's Section 202(c) orders reflect a policy to promote the long-term preservation of fossil-fueled electric generation, including coal-fired generation, by using the Department's emergency authority under Section 202(c). To the extent these actions left any room for doubt that the Department has such a policy, Energy Secretary Wright's own words have removed it. In his statement to the press when the Centralia Order issued, Secretary Wright emphasized, "The Trump administration will continue taking action to keep America's coal plants running." Ex. 2-181 (Department Press Release on March Centralia Order); *see also* Ex. 2-118 (Department Press Release on Centralia Order) (stating same); *see also* Ex. 2-34 (Secretary Wright's West Virginia Remarks) (reporting Secretary Wright's stated intention to stop the closure of coal plants and claimed authority to do so).

The Department has further reinforced this policy by renewing its application to Craig.

A. The Order Addresses Circumstances Beyond the Lawful Scope of an Emergency Under Section 202(c) and Fails to Provide Evidence or Reasoned Decision-Making Substantiating the Existence of an Emergency under Section 202(c).

The Order claims an emergency exists within the WECC Rocky Mountain assessment area. Order at 1. According to the Order, "the emergency conditions . . . will continue in the near term and are also likely to continue in subsequent years." *Id.* at 6. The Order then identifies the supposed emergency: "the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages." *Id.*

As discussed below, the Order's determination of an emergency in the WECC Rocky Mountain assessment area exceeds statutory authority and is both unreasoned and without substantial evidence.[2]

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[2] To the extent the Department claims an emergency in some region distinct from the WECC Rocky Mountain assessment area defined in the Order and by WECC, the Department's emergency declaration still exceeds statutory authority and is both unreasoned and without substantial evidence, including (but not limited to) because the Order does not claim an emergency exists in any such region, presents no reasoning associated with any such region, offers no credible evidence demonstrating an emergency in such region, and fails to examine the evidence detracting from an emergency determination in such region. Moreover, the Order is unreasoned and not based on substantial evidence in imposing requirements to best meet such an emergency and serve the public interest. Public Interest Organizations addressed in January 2026 the Department's prior claim, in the December Order, of an emergency

1. Legal Framework: Section 202(c) Empowers the Department to Respond Only to Imminent Concerns.

The Order invokes Section 202(c) of the Federal Power Act, which provides:

> During the continuance of any war in which the United States is engaged, or whenever 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 of transmission of electric energy . . . the Commission shall have authority . . . with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, deliver, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest.

16 U.S.C. § 824a(c)(1). That authority was transferred to the Department by the Department of Energy Organization Act. *See* 42 U.S.C. § 7151(b).

Section 202(c)'s text and context establish that an "emergency" enabling the Department to override state and private decision-making must be an imminent circumstance. 16 U.S.C. § 824a(c). As such, the Department may act only where there exists a pressing necessity or exigency that calls for immediate action or remedy from the Department. The constrained scope of Section 202(c)'s emergency authority is confirmed by the broader statutory context—in particular, the separate regime delineating federal authority over bulk-system reliability in Section 215 of the Federal Power Act, *id.* § 824o—as well the Department's regulations, caselaw applying Section 202(c), and the Department's consistent past practice.

i. The Text and Context of Section 202(c) Confine an Emergency to Imminent Circumstances.

Section 202(c)'s text empowers the Department to require generation only in an "emergency." *Id.* § 824a(c). Both the ordinary meaning of the term (which the statute does not expressly define) and statutory context limit the Department's emergency authority to circumstances of pressing necessity or exigency that call for immediate action or remedy from the Department. At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as, with emphasis added here, a "*sudden* or *unexpected* appearance or occurrence… An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency." Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency is

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in "WECC Northwest." See Ex. 2-186 at sec. V.A (Public Interest Organizations' January 2026 Rehearing Request).

"an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action." Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 812 n.147 (2025) (noting that dictionaries have given the term "emergency" the "same meaning for many years").

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency." The authority granted by Section 202(c) is, in the first instance, a war-time power. 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress"). An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example. 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light v. FERC*, 574 F.2d 610, 615 (D.C. Cir. 1978) (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

The text's use of the present tense accentuates its focus on imminent and certain concerns: It empowers the Department to act only where "an emergency *exists*." 16 U.S.C. § 824a(c) (emphasis added). The Section's title and text both emphasize that it provides a "temporary" authority, further emphasizing that its emphasis on immediate—not distant—needs. *Id.* § 824a(c), (c)(1); *see Dubin v. United States*, 599 U.S. 110, 120–21 (2023) (cleaned up) ("The title of a statute and the heading of a section are tools available" to resolve "the meaning of a statute," and "a title is especially valuable where it reinforces what the text's nouns and verbs independently suggest."). That near-term focus precludes use of Section 202(c) to pursue broader or long-term energy-policy goals, such as a "fear of overdependence" on foreign oil supplies, *Richmond Power & Light*, 574 F.2d at 617, or "energy independence," Ex. 2-35 at 1 (July Resource Adequacy Report); *see also Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections (202(a) and (b)) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course. 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into

regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy"); *id.* § 824a(b) (allowing federal government to order "physical connection . . . to sell energy to or exchange energy" upon application, and after an opportunity for hearing). The resulting statutory "machinery for the promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action"; in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action"; and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency." S. Rep. No. 74-651 at 49 (1935).

That tiered structure—placing primary emphasis on voluntary resource adequacy planning, 16 U.S.C. § 824a(a), specifying limited authority where that voluntary system fails, *id.* § 824a(b), and allowing for "temporary" central command-and-control only in case of an "emergency," *id.* § 824a(c)—requires that Section 202(c) remain narrowly confined to instances of an immediate and unavoidable "break-down in electric supply," S. Rep. No. 74-651 at 49 (1935), rather than a mere desire for more abundant supply in the future, *cf.* Order at 6 (emphasis added) (pointing to conditions that "will continue in the near term and are also *likely* to continue in *subsequent years*" that "*could* lead to the loss of power . . . in the areas that *may* be affected by curtailments or power outages, presenting a *risk* to public health and safety"). The tiered structure authorizes increasingly intrusive federal intervention, but under increasingly narrow circumstances. Interpreting Section 202(c)'s "emergency" powers to permit the Department to compel generation based on nothing more than the generalized challenges of operating a reliable bulk electric system in a transforming energy landscape, or concerns over longer-term resource adequacy, *see* Order at 1–5, would unwind the careful balance of voluntary, market-driven action and federal power set out in Sections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure. *See Otter Tail Power Co. v. Fed. Power Comm'n*, 429 F.2d 232, 233–34 (8th Cir. 1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

ii. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms That Generalized or Long-Term Bulk Power System Reliability Concerns Are Not an "Emergency" Under Section 202(c).

That the Department's Section 202(c) emergency powers do not extend to general supervision of bulk power-system reliability is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal authority to enforce mandatory reliability requirements for the bulk power system. 16 U.S.C. § 824o. Congress added Section 215 to the Federal Power Act in 2005

precisely because the Act as it then existed—including Section 202—did not give the federal government the power to enforce measures designed to ensure bulk-system reliability. *See Rules Concerning Certification of the Elec. Reliab. Org.; and Procedures for the Establishment, Approval, and Enforcement of Elec. Reliab. Standards*, 70 Fed. Reg. 53117, 53118 (Sept. 7, 2005) ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); Ex. 2-119 at page 7-6 (2001 National Energy Policy) (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "one factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (stating that Section 215 "changes our current voluntary rules system" for bulk-system reliability "to a mandatory rules system"); *see also Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce bulk-system reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and owners and operators of the bulk-power system" but with "fair stakeholder representation." 16 U.S.C. § 824o(c)–(d); *see also id.* § 824o(a)(3) (defining reliability standards as "a requirement . . . to provide for reliable operation of the bulk-power system"). FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition." *Id.* § 824o(d)(2)–(4). Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational. *Id.* § 824o(e). And Section 215 carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards. *Id.* § 824o(i)–(j).

Interpreting Section 202(c) to permit the Department to mandate generation based on its own unfettered assessment of bulk-system reliability needs would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific legislation, enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section 202(c). *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 &

149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one Section of the Federal Power Act "is strong evidence that [a separate Section] confers no such authority on [agency]."). Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure the reliability of bulk power electric system. In so doing, it has confirmed that the Department may not, through Section 202(c) "emergency" orders, use those reliability concerns to mandate the generation it views as required to address broad resource adequacy problems; the Department's emergency authority is confined to shortfalls requiring immediate response.

iii. The Department's Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s emergency authority is confined to imminent, certain, and otherwise unavoidable resource shortages, and does not provide a mechanism to address broad, long-term concerns as to the reliability of the bulk power system. The regulations recognize that an emergency under Section 202(c) requires, first, "a *specific* inadequate power supply situation." 10 C.F.R. § 205.371 (emphasis added). The Department's non-specific dissatisfaction with regional power planning does not, consequently, empower the Department to override that planning by emergency order. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . . *will* cause the applicant [for a 202(c) Order] to be unable to meet its normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers." *Id.* § 205.375 (emphasis added). The same provision suggests that an emergency will generally exist only when "the projected energy deficiency . . . without emergency action by the [Department], will equal or exceed 10 percent of the applicant's then normal daily net energy for load." *Id.*

The regulations further recognize that Section 202(c) does not provide a means of planning against months-off expectations or risks. They define an emergency as "an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown" of generating, transmission, or distribution facilities—not a tool to ensure future energy abundance, or override state and private planning that the Department deems inadequate. 10 C.F.R. § 205.371. Under the regulations, emergencies are characterized by shortages produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent." *Id.* Where the culprit is increased demand, it must be "a *sudden* increase in customer demand," *id.* (emphasis added), rather than demand projections producing non-immediate reliability concerns.

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can* result in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning. *Id.* (emphasis added). The regulations also recognize that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*." *Id.* (emphasis added). An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate. *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply). As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems." *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power,* 46 Fed. Reg. 39984, 39985–86 (Aug. 6, 1981).

iv. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Caselaw applying Section 202(c) further supports the narrow circumstances under which it permits the Department to seize command of the power system. *Richmond Power and Light* arose out of the 1973 oil embargo. The Federal Power Commission responded to the embargo by calling for voluntary transfer of electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England. 574 F.2d at 613. The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order. *Id.* Rather than issue such an order, the Commission facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool, leading it to withdraw its petition. *Id.* A dissatisfied utility sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition. *Id.* at 614.

The court easily upheld the Commission's decision not to invoke Section 202(c). *Id.* Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order. *Id.* The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, and there was no need for a Section 202(c) order. *Id.* at 615. The D.C. Circuit agreed. *Id.* The utility alternatively argued that "dependence on imported oil leaves this country with a *continuing* emergency." *Id.* (emphasis added). The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances." *Id.* Interpreting this statutory language, the court upheld the Commission's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor." *Id. Richmond Power*

and Light thus teaches that Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power*, a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. 429 F.2d at 234. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period." *Id.* at 233–34. To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect to the municipal power provider. *Id.* The utility argued that the Federal Power Commission used the wrong provision and should have used Section 202(c) instead. *See id.*

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency." *Id.* at 234. For non-emergency situations, "[o]n the other hand, Section 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission." *Id.* The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency. *See id.* The case law thus uniformly supports that Section 202(c) can only be used in short-term, urgent emergencies.

v. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Bulk-System Resource Adequacy.

The Department's consistent application of Section 202(c) prior to 2025 further corroborates the urgency of the emergency conditions that are the necessary predicate for any Department intervention under that Section 202(c). *See Fed. Trade Comm'n v. Bunte Bros., Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it is equally significant in determining whether such power was actually conferred."). Since obtaining authority under Section 202(c) in the 1970s and prior to 2025, the Department has consistently used Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts. *See, e.g.*, Ex. 2-13 at 1 (DOE Order No. 202-22-4) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between Christmas Eve and Boxing Day); Ex. 2-16 at 1–2 (DOE Order No. 202-20-2) (responding to shortages produced by ongoing extreme heat and wildfires); Ex. 2-20 at 1 (DOE Order No. 202-08-1) (ordering temporary connection of facilities in response to "massive devastation caused by Hurricane Ike," leaving "large portions"

of Texas "without electricity"); *see also* Rolsma, 57 Conn. L. Rev. at 803–04 (describing "sparing[]" use of Section 202(c) outside of war-time shortages during the twentieth century).[3] Public Interest Organizations are not aware of any instance in which, before 2025, the Department utilized Section 202(c) in response to generalized regional risks related to long-term resource adequacy without any immediate need for the Department to address a particular, defined generation shortfall, and for good reason: Any such use would exceed the Department's statutory authority.

2. The Order Primarily Focuses on Long-Term Bulk-System Reliability and Coal Plant Retirements, Neither of Which Is an Emergency Under Section 202(c), and Separately the Claimed "Long-Term" Emergency Is Unreasoned and Not Based on Substantial Evidence.

The Department's determination that an emergency exists rests on its assertion that "increasing demand and shortage from accelerated retirement of generation facilities . . . could lead to the loss of power to homes and businesses." Order at 6. This determination focuses on long-term concerns, noting that such conditions are "likely to continue in subsequent years" in concluding that an emergency designation is appropriate. *Id.* Those concerns—even if fully substantiated—would not be a basis to mandate Craig's continued operation. And they are not substantiated. Utilities and regulators have taken and are continuing to take steps to address longer-term adequacy to ensure no resource shortfall arises.

i. Even Assuming Arguendo Evidentiary Support, the Department's Long-Term Concerns, as Well as Its Concerns About Coal Plant Retirements, Are Not an "Emergency" Within the Meaning of 202(c).

As an initial matter, even if the Order's claimed emergency conditions were established (they are not), reliability concerns arising beyond "the near term . . . in subsequent years," Order at 6, do not qualify as an emergency under Section 202(c). Such concerns are neither imminent nor unexpected. The Department's stated concerns cannot plausibly be characterized as a "*sudden* increase in the demand for

[3] The Department has also narrowly tailored the remedies in Section 202(c) orders before 2025 to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment. *See, e.g.*, Ex. 2-13 at 4–7 (DOE Order No. 202-22-4) (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 2-16 at 3–4 (DOE Order No. 202-20-2) (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

electric energy" or a "shortage" in electric energy, generation, or transmission constituting an emergency. 16 U.S.C. § 824a(c)(1) (emphasis added).

At most, the Order describes long-term trends that may affect the reliability of the bulk power system in the future if left unaddressed. The Order's longer-term concerns are based on projections of demand increases, changes in the mix of power supply resources, challenges in resource development, and the Administration's view of foreign actors. *See* Order at 1–6.

While many of the Order's stated concerns are the province of state, regional, and private entities, Congress has provided certain mechanisms for the federal government to address the reliability concerns raised in the Order. The emergency provision in Section 202(c), along with the Department's claimed power to seize command-and-control authority over generating resources like Craig, are not among those mechanisms.

The congressionally provided mechanisms to the federal government include Section 202(a), which allows the federal government to pursue "an abundant supply of electric energy" but only by facilitating "*voluntary* interconnection and coordination of facilities for the generation, transmission, and sale of electric energy" 16 U.S.C. § 824a(a) (emphasis added). Additionally, under certain circumstances, Section 202(b) allows the federal government to require utilities to sell or exchange energy with other facilities, but only upon application and with "no authority to compel the enlargement of generating facilities for such purposes." *Id.* § 824a(b).

Another mechanism, Section 215, provides for mandatory, nationwide reliability standards developed and enforced by a federally certified but independent entity. 16 U.S.C. § 824o(d)–(e). "These standards," the Department explains, "ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability." Ex. 2-120 at 7 (Department Export Authorization EA-365-C (Oct. 21, 2025)). The standards cannot be enforced by ordering generation facilities to operate, and Section 215 specifically disallows requiring the "construction of additional generation" or "enforc[ing] compliance" with "adequacy" standards. 16 U.S.C. § 824o(e), (i)(2).

The Order purports to mandate generation based upon the Department's assessment of the bulk power system's long-term reliability needs, a power Congress chose not to provide *any* federal agency. *See* 16 U.S.C. § 824o(e) (specifying enforcement mechanisms for federal reliability standards). And what authority Congress has authorized to implement mandatory reliability standards it provided to FERC—not the Department. *Alcoa,* 564 F.3d at 1344. Reliability concerns in future years simply do not constitute an emergency within the meaning of Section 202(c).

An emergency under Section 202(c) must be imminent. Section 202(c) provides an explicitly "temporary" authority, 16 U.S.C. § 824a(c), preventing any interpretation

of its terms that might encompass a potential resource adequacy emergency in "subsequent years." Order at 6. The expansive interpretation of Section 202(c) implicit in the Order, stretching the meaning of "emergency" to cover resource planning concerns over "years" subsequent to the near term, is further precluded by the Federal Power Act's express background principles of permitting "Federal regulation" only of "matters which are not subject to regulation by the States," and disavowing "jurisdiction, except as specifically provided" over "facilities used for the generation of electric energy." 16 U.S.C. § 824(a), (b)(1); *see Duke Power Co. v. Fed. Power Comm'n,* 401 F.2d 930, 938 & 938 n.51 (D.C. Cir. 1968) (explaining that the Federal Power Act's policy declarations are "relevant and entitled to respect as a guide in resolving any ambiguity or indefiniteness in the specific provisions which purport to carry out its intent"). The Department knows that "resource adequacy planning and capacity requirements . . . have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs," *i.e.*, not the Department. Ex. 2-120 at 5 n.4 (Department Export Authorization EA-365-C (Oct. 21, 2025)).

Through the Order, the Department expressly seeks to override the decisions of utilities and their regulators pursuant to the procedures established by Congress to ensure abundant electricity supplies and the reliability of the bulk-electric system. In using an emergency declaration to engage in long-term resource planning, the Department is usurping the role of states and others charged with resource adequacy planning. Section 202(c) does not permit that effort to transform the statutory scheme from one driven primarily by market- and state-based decision-making to one consolidating centralized command-and-control in the Department. And it especially does not permit that transformation in service of the Department's desire to dictate "how much coal-based generation there should be over the coming decades"—a power that the Supreme Court has found Congress "highly unlikely" to have left to agency discretion. *West Virginia v. EPA*, 597 U.S. 697, 729 (2022). The retirements of generators burning coal and other fossil fuels to which the Order devotes significant attention do not constitute an emergency under Section 202(c). *See, e.g.*, *Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").[4]

[4] For the same reasons, the logistical and financial challenges of bringing back a decommissioned coal plant—i.e., the fact that keeping the Department's favored generation resource functional is costly—cannot constitute an emergency under Section 202(c). *Contra* Order at 1-2, n.6.

ii. The Order's Cited Evidence Does Not Demonstrate Any Long-Term Resource Adequacy Concerns.

In addition to being an invalid basis for Department action under Section 202(c), the Order's discussion of long-term concerns is unreasoned and without substantial evidence, including because the Order both overestimates the potential of a shortfall and underestimates the ability of existing processes to address any projected shortfall. The Order discusses six sources touching on long-term issues, some of which simply regurgitate the two previous orders' findings: (1) NERC's 2025 Long-Term Reliability Assessment; (2) the 2025 Western Assessment of Resource Adequacy; (3) the 2024 Western Assessment of Resource Adequacy; (4) data from the Energy Information Administration concerning generating capacity in Colorado; (5) executive orders and a presidential memorandum; and (6) DOE's July Resource Adequacy Report. Order at 1-6. None of these sources presents evidence of circumstances anywhere near an emergency in the Rocky Mountain region. And many other sources the Department knows or should know, yet fails to consider, further undermine the Department's claim.

NERC's 2025 Long-Term Reliability Assessment

In the "Background" section, the Order quotes and cites to the 2025 Long-Term Reliability Assessment. Order at 3. The Order recites the following factors listed in the Assessment: the WECC Rocky Mountain Region has an "[anticipated reserve margin] that falls below the [Reference Margin Level] in Summer 2034 and 2035, and Winter 2034-35"; the area "faces challenges from an aging thermal resource fleet"; and "solar and wind variability are year-round concerns." Order at 3.

The Order's reliance on the 2025 Long-Term Reliability Assessment is unreasoned. The Order cites statements that do state or even support the existence of an emergency under Section 202(c) while ignoring the remainder of the document, which undercuts the Department's claimed emergency. The 2025 Long-Term Reliability Assessment finds that the WECC Rocky Mountain assessment area has normal risk. Ex. 2-178 at 7, 159–62 (NERC 2025 Long-Term Reliability Assessment). In detailing its findings for 2027 and 2029, the assessment reports 0 MWh of expected unserved energy, 0 ppm of normalized unserved energy, and 0 hours of lost load risk. See Figure 11 below.

Figure 11: NERC Assessment Results

Base-Case Summary of Results			
	2026*	2027	2029
EUE (MWh)	N/A	0	0
NEUE (ppm)	N/A	0.00	0.00
LOLH (hours per Year)	N/A	0.00	0.00
*No prior results as the assessment area is new for the 2025 LTRA.			

Source: Ex. 2-178 at 161 (NERC 2025 Long-Term Reliability Assessment).

Moreover, the Department's own data reveals that actual conditions in distant years are more protective than depicted in the NERC data. The NERC assessment of lost load hours for the WECC Rocky Mountain assessment area is tied to "Tier 1" resources, *see id.* at 159–62, 168, but Department data reveals the area has a greater number of Tier 1 resources than included in the NERC assessment, Ex. 2-182 at 10 (Grid Strategies Analysis of NERC LTRA). Department data further reveals that there is a significant amount of Tier 2 resources planned for the WECC Rocky Mountain assessment area, even after accounting for likely resource cancellations. *Id.* at 11–12. NERC's assessment excludes Tier 2 supply-side resources, yet projects heightened demand through inclusion of data center demand akin to Tier 2 additions. *See* Ex. 2-178 at 9 (NERC 2025 Long-Term Reliability Assessment) ("To be counted in load forecasting, data center projects have advanced from speculative and exploratory stages into development commitments necessary to drive grid planning studies."); Ex. 2-182 at 19 (Grid Strategies Analysis of NERC LTRA) ("The LTRA includes all loads with 'development commitments necessary to drive grid planning studies.' In contrast, the LTRA only counts generators that have completed all planning studies and signed an interconnection agreement."). In sum, the supply-side picture in the NERC assessment underestimates likely-to-connect power resources, while there is good reason to believe the demand-side picture overestimates future data center needs, resulting in an analysis that is "too pessimistic." Ex. 2-182 at 4–5 (Grid Strategies Analysis of NERC LTRA).

In addition, projections about reserve margin levels in 2034–2035 cannot establish that an emergency exists, because utilities and grid operators have ample time to address any potential needs for incremental resources in 2034–2035. "The fact that a study such as the 2025 [Long-Term Reliability Assessment] might show a potential shortfall in 2034 and beyond if no further action is taken does not mean that shortfall will, or is likely to, actually occur in 2034. That is because each utility in the Rocky Mountain assessment area regularly forecasts whether it will need additional resources and then procures the resources needed to meet future customer demand." Ex. 2-185 at 9 (Current Energy Group April Report).

The 2024 Long-Term Reliability Assessment does not support the claimed emergency, either. The 2024 assessment finds that the WECC-NW region (which at that time encompassed the current WECC Rocky Mountain assessment area) has

normal risk. Ex. 2-07 at 6 (NERC 2024 Long-Term Reliability Assessment). And when Tier 2 resources are included, the 2024 Long-Term Reliability Assessment finds that the reserve margin in the WECC-NW region remains above reference levels through 2034. *See* Ex. 2-01 at 14–15 (Current Energy Group January Report); *see also* Ex. 2-02 at 7–8 (Grid Strategies Resource Adequacy Report). The 2024 Long-Term Reliability Assessment reaches this finding even while projecting demand growth of 18.7% in the WECC-NW region, more than double the 8.5% demand growth referenced in the December Order. *See* Ex. 2-01 at 15 (Current Energy Group January Report); Order at 3. Thus, even with the planned retirements of multiple coal and natural gas units in the region and the potential for increased demand, the WECC Northwest assessment area is within a region that the 2024 Long-Term Reliability Assessment assesses as "begin[ning] from a position of strong resource adequacy" and "finds no evidence of medium-term resource adequacy crisis." Ex. 2-01 at 15 (Current Energy Group January Report).

WECC's 2025 Western Assessment of Resource Adequacy

The Order references isolated statements from WECC's 2025 Western Assessment of Resource Adequacy, including that the "West could see energy shortfalls as early as 2028" and that "90% of planned resources over the next decade are inverter-based resources." Order at 3–4.

WECC's 2025 assessment contradicts the Department's determination that an emergency exists in the Rocky Mountain region. WECC's 2025 assessment finds that the Rocky Mountain region is at "normal"—not elevated—risk. Ex. 2-183 (2025 Western Assessment of Resource Adequacy); *see* Ex. 2-185 at 1 (Current Energy Group April Report). See Figure 12 below, which appears in WECC's 2025 assessment.

Figure 12: WECC's 2025 Subregional Risk Assessment



Source: Ex. 2-183 at PDF 3 (2025 Western Assessment of Resource Adequacy).

WECC's 2025 assessment shows little-to-no loss of load events and hours unless only two-thirds of planned additions are added, and even then the risk is years away. See Ex. 2-183 at PDF 8–11 (2025 Western Assessment of Resource Adequacy); Ex. 2-184 at PDF 38–42 (2025 WARA Supplemental Information); Ex. 2-185 at 6–8 (Current Energy Group April Report). WECC found that the Rocky Mountain region would experience zero loss of load hours over the next ten years if planned additions are completed on time, even in the high load scenario. Ex. 2-185 at 6–8 (Current Energy Group April Report).

The Order does not provide any evidence that planned resource additions have in fact been delayed or cancelled in the Rocky Mountain region. To the contrary, as explained below, the largest electric utilities in the Rocky Mountain region, such as Xcel and Tri-State, continue to bring new resources online and to procure additional resources. The Order also offers no reason or evidence that conditions beyond the Rocky Mountain region support the claimed emergency in the Rocky Mountain region.

The Order also quotes and cites to WECC's statement that 90% of planned resource additions "are inverter-based resources," while "the vast majority" of retiring generation is coal, natural gas, and nuclear. Order at 4. This is not evidence of a long-term shortfall in electricity or generating supplies. The Order does not even attempt to explain how the planned addition of generating capacity—even if from "inverter-

based resources"—and the resulting shift in resource mix can possibly qualify as evidence of, or contribute to, a shortfall in electricity or generating supplies. To the contrary, several reports from within the Department indicate that integrating much higher levels of wind, solar, and battery storage is compatible with meeting electricity demand and maintaining reliability. For example, the National Laboratory of the Rockies, which is housed within the Department, has conducted retrospective studies documenting that utilities have integrated large amounts of "inverter-based resources" while meeting electricity demand and satisfying reliability standards. Ex. 2-173 at 16-18 (2024 NREL Lessons from Renewable Integration Studies) ("Over the past two decades, dozens of studies have been conducted to evaluate questions associated with maintaining reliability in power systems with an increased deployment of variable renewable energy (wind and solar). . . . These lessons can support current utility plans to develop large amounts of economic renewable energy deployments while maintaining state and federal reliability standards."). Similarly, the National Laboratory of the Rockies has conducted prospective studies demonstrating that it is possible to integrate much higher levels of "inverter-based resources," particularly wind, solar, and battery storage, while meeting electricity demand and reliability standards. Ex. 2-174 at 39-43 (2021 NREL North American Renewable Integration Study).

Moreover, the Department's stated concern about a shifting resource mix in Colorado ignores the comprehensive processes regional planners undergo to ensure ongoing resource adequacy in their service territories. As those processes demonstrate, there is nothing sacred about electrons generated by coal plants that make them more suited than any other resource to maintain grid stability, and thus there is no cause for alarm at the prospect of coal dropping from 45% to 25% of Colorado's electric output. *See* Order at 4.

Resource adequacy planning, in which grid operators utilize a Loss of Load Model to compare the suite of available resources with projected peak loads and ensure that the region meets a certain grid reliability standard, "is a well-established practice across the country." Ex. 2-01 at 4 (Current Energy Group January Report). One key output of this process is a "Planning Reserve Margin," which describes the percentage of excess supply-side resources (i.e., beyond what are needed to serve projected peak load periods) that are or should be on the system to meet the standard.

Crucially, a well-run resource adequacy process will typically include an assessment of individual resources' ability to help alleviate potential shortfalls, i.e. during major storms and heat waves. This assessment is used to derate individual resources based on how likely they are to show up when supply is tight and/or demand is high; the process is often called "capacity accreditation." *Id.* at 5. The methodology for accrediting the capacity from generating resources naturally takes into account different sources of uncertainty for different resources—for instance, wind and solar units are limited mostly by the likelihood of different weather conditions, whereas

thermal units will be limited by both extreme weather events and periodic equipment failures—but the accredited capacity value that results is universal. This reflects the ultimate goal of the capacity accreditation process, which is to create apples-to-apples comparisons of the value different resource types provide: while resource accreditation values may change over time, one MW of accredited capacity from a wind farm is equivalent to that from a coal plant.

The Order also quotes and cites to WECC's statement concerning the amount of generation expected to retire "over the next 10 years," i.e., by the end of 2035. Order at 4. As a threshold matter, planned generator retirements do not, by themselves, support the Order's claim that there exists "a shortage of electric energy" or "a shortage of facilities for the generation of electricity." *Id.* at 1. While the Order cites WECC's estimate that 22 GW of generation may retire through 2035, *id.* at 4, the Order neglects to mention that WECC estimates that approximately 177 GW of new capacity additions are planned through 2035, Ex. 2-183 at 3, 15–16. It is fundamentally unreasoned, and arbitrary and capricious, for the Department to support its claim that a shortage of energy or facilities exists by focusing solely on generator retirements rather than considering both subtractions and additions to generating capacity. When WECC considered both sides of the equation (i.e., both retirements and planned additions), WECC found that the Rocky Mountain region would have zero loss of load hours through 2035 in the "All Additions" and "95%" scenarios. *Id.* at 8.

Moreover, the Department has claimed, while denying the Public Interest Organizations' rehearing request of the December Order, that it takes much less time than 10 years to bring new generating resources online. For example, the Department has asserted that "[i]t can take months, if not years" to bring new resources online, and claimed that the "typical" project took 55 months to bring online "from interconnection request to the beginning of commercial operations." Ex. 3-01 at 7 (December Rehearing Order, Order No. 202-25-14B). We do not concede that the Department's assertions about the length of time needed to bring new resources online are supported by substantial evidence and accurately reflect timelines in the Rocky Mountain Assessment Area. However, the Department's statements that new resources can be brought online in "months," and that the typical new project can be brought online in "55 months," undermines the Order's reliance on retirements planned more than 55 months in the future to support finding that a shortage of capacity or electricity exists or will exist. 55 months from the date the Order was issued would be March 2031. The 2025 WECC assessment that the Order cites to shows that planned retirements from 2031 through 2035 comprise more than a third of the 22 GW of planned retirements that the Order cites.

Even if the Department were correct that it takes 55 months to bring new generating resources online (it is not), and even if section 202(c) allowed the Department to consider long-term conditions (it does not), the Department could not support the existence of a shortage more than 55 months in the future—because new generating resources could be brought online to avert such a shortage. Moreover, the sole document that the Department cites for the proposition that the "typical" new generating project takes 55 months to bring online is a nation-wide average that overstates the time needed to bring new resources online in the Rocky Mountain Assessment Area. The Lawrence Berkeley National Lab found that interconnection timelines are "typically longer in FERC-jurisdictional ISOs" and that "ERCOT and the non-ISO regions (Southeast and West) have faster processing times." Ex. 3-02 at 40 (Queued Up: 2025 Edition); *see also id.* at 48. A significant number of the electric utilities in the Rocky Mountain Assessment Area do not have their interconnection process managed by an ISO or RTO, and thus the study's estimate of 55 months to bring new resources online overestimates the timeline for at least a portion of the Rocky Mountain Assessment Area.

The Department has failed to explain its inconsistent statements, and it is arbitrary and capricious for the Department to base its finding of a shortage on retirements that are expected to occur on a timeline longer than the Department has stated is needed to bring replacement generation online. That is particularly the case given the evidence presented in this request that utilities throughout the Rocky Mountain Assessment Area have plans to bring new generating, storage, and demand response resources online well before the end of 2035.

WECC's 2024 Western Assessment of Resource Adequacy

WECC's 2024 Western Assessment of Resource Adequacy, which the Department summarized in the Order and cited in the December Order as a basis for finding an emergency condition, also does not provide evidence of a long-term shortfall. The December Order references isolated statements from this document: a forecast of peak demand growth in "WECC's Northwest-Central subregion"; the fact that "most planned retirements are 'baseload generation, such as coal, natural gas, and nuclear'"; and the proposition that "571.3 MW of coal-fired generating capacity across six units at three locations have retired in Colorado." December Order at 2.

The Order is also unreasoned and not based on substantial evidence in failing to consider key facets of the 2024 Western Assessment of Resource Adequacy. The document serves to inform planning and does not identify an existing crisis or call for extraordinary measures outside of the normal planning process. Ex. 2-01 at 11–12 & app'x A at 25–27 (Current Energy Group January Report). Moreover, "[t]he study does not identify retirements as a primary cause of future reliability risks," including retirements of coal-burning generators like Craig. *See id.* at 12. Rather, according to the 2024 Western Assessment of Resource Adequacy, "the timely completion of new

generation is the key medium-term requirement for maintaining resource adequacy." *Id.* And in fact, the 2024 Western Assessment of Resource Adequacy shows the active planning and resource deployment in the region:

> The 2024 Western Assessment of Resource Adequacy demonstrates that the region has been actively planning for plant retirements and load growth through increased planned resource additions, including new capacity (~15 GW of new batteries and ~3 GW of new natural gas by 2027), and by moderating previously-assumed retirements downward from 2022. Generation additions across the WECC subregions appear to be on track with the 2024 assessment's expectations. In 2025, approximately 9.4 GW of new batteries, 6 GW of solar, 1.7 GW of gas, and 2 GW of wind were deployed across the interconnection. Of this 19 GW, more than 4.7 GW has been deployed in Colorado, Nevada, Utah, Idaho, Washington, Oregon, Montana, and Wyoming as of the November report [from the Department's Energy Information Administration], and 2.1 GW in the same states is expected to be completed in December.

Id. (footnotes omitted).

In addition, the few specifics from the 2024 Western Assessment of Resource Adequacy discussed in the Order do not support the claimed emergency. Both as an evidentiary and as a logical matter, the Order's references to forecasted demand and forecasted retirements cannot together or by themselves demonstrate the existence of a shortfall in electricity or in electricity generation, including because those two data points are insufficient to assess whether the overall level of expected supply is sufficient to meet expected demand. The Order fails to address, for instance, that planned generator additions exceed planned retirements. *See id.* at 17–18; Ex. 2-02 at 8–9 (Grid Strategies Resource Adequacy Report). Moreover, utilities have already accounted for demand growth in their electric resource plans, and have determined that they will not have a shortfall even after Craig's retirement. *See* Ex. 2-02 at 9 (Grid Strategies Resource Adequacy Report).

Energy Information Administration Data

Citing the Department's Energy Information Administration data to describe continuing long-term conditions, the Department focuses its attention on retirements of generators burning coal and other fossil fuels in Colorado and the amount of wind-powered generation in the state. Order at 4. But the mix of generating resources in a state is not, standing alone, evidence of an emergency either within that single state or in the Rocky Mountain assessment area on which the Order focuses. Merely tallying retirements of certain generator types, and calculating the amount of wind, does not indicate whether a particular area has a shortfall of energy or capacity. On

this ground alone, the Order's reliance on the data from the Energy Information Administration is unreasoned and does not constitute substantial evidence.

The Order's reliance on the data from the Energy Information Administration is further problematic due to basic mathematical errors. The Order overstates the amount of planned coal retirements shown in the data for Colorado by more than 900 MW. Ex. 2-01 at 17–18 (Current Energy Group January Report). The error is shown in Figure 13 below. The Public Interest Organizations pointed out this error in their Request for Rehearing of the December Order issued for Craig Unit 1, but the Department failed to correct the error and repeated it in the Order.

Figure 13: Discrepancies Between Order and EIA Data

	Order 202-25-14	EIA 860 M Data*	Discrepancy
Historical (2019-2024) Coal Retirements	571.3 MW	571.3 MW	None
Planned Coal Retirements by 2029	~3,700 MW[74]	2,789.6MW	~910 MW
Planned Natural Gas Retirements by 2029	656.8 MW	675.6 MW	18.8 MW

*As of November 2025 (released December 2025)

Source: Ex. 2-01 at 18 (Current Energy Group January Report).

The Order also presents an incomplete picture in its reliance on the Energy Information Administration data. The Order "cites EIA data to identify planned generation retirements but does not acknowledge that the same EIA data also show substantial new generation additions in Colorado." *Id.* at 18. According to that data, the historical and planned additions of new generating resources far exceed the retirements in Colorado, *see id.*, as shown in Figure 14 below. The Order is unreasoned and not based on substantial evidence because a complete picture of both retirements and additions shows that there will be a net increase in generating capacity in Colorado of more than 6,000 MW through 2029.

Figure 14: Retirements and Deployments in Colorado

	Retirements (MW)	Deployments (MW)
Historical (2019-2024) Retirements	845.9	4,827.6
Planned Retirements by end of 2029	3,455	5,793.5
Total (2019-2029)	**4,300.9**	**10,621.1**

Source: Ex. 2-01 at 18 (Current Energy Group January Report).

The Department fails to explain how this substantial net increase in generating capacity will not be sufficient to address the claimed future shortfall.

Executive Orders and a White House Memorandum

The Order also cites executive orders and a White House memorandum as evidence of "continuing emergency conditions." These sources are conclusory and therefore do not constitute substantial evidence. First, the Order cites the Energy Emergency EO and the Grid EO claiming that there is an energy emergency and that the grid is being stressed by unprecedented demand. Order at 5. In the quoted passages from the Energy Emergency EO, the President offers his perspective on issues relating to the nexus between energy usage and "our Nation's economy, national security, and foreign policy." Ex. 2-36 at 90 Fed. Reg. at 8433–34 (Energy Emergency EO). In the Grid EO, the President adds his view on the nature and drivers of electricity demand in the country. Ex. 2-37 at 90 Fed. Reg. at 15521 (Grid EO). In addition, the Order points to a White House memorandum claiming, with no factual basis, that coal is essential to national defense. Order at 5–6.

None of these executive documents supplies valid evidence of an actual energy emergency under Section 202(c), during the ninety-day term of the Order or any time. An emergency under Section 202(c) must be a specific inadequate power supply situation. *See supra* sec. V.A.1; *e.g.*, 10 C.F.R. § 205.371. Yet the executive orders and the presidential memorandum cited in the Order provide no factual evidence applicable to the WECC Rocky Mountain assessment area. *See* Ex. 2-36 at *passim* (Energy Emergency EO); Ex. 2-37 at *passim* (Grid EO). The executive orders and the presidential memorandum thus do not constitute useful evidence, much less substantial evidence. *See, e.g.*, *Chritton v. Nat'l Transp. Safety Bd.*, 888 F.2d 854, 856 (D.C. Cir. 1989) (defining substantial evidence). And reliance on unsupported, generalized conclusions in these documents is unreasoned. *Sinclair Wyo. Ref. Co. LLC v. EPA*, 114 F.4th 693, 714 (D.C. Cir. 2024).

Even if the declared national energy emergency were legitimate, a presidential declaration of an emergency does not unlock unlimited agency powers. *See Biden v. Nebraska*, 600 U.S. 477, 500–01 (2023) (presidential declaration of national emergency does not change the limitations on agency's emergency authority as written into statute). The Energy Emergency EO was issued pursuant to claimed authority from the National Emergencies Act.[5] Congress explained that the National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the

[5] Under the National Emergencies Act, no emergency powers unlocked by a Presidential declaration of a national emergency "shall be exercised unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act." 50 U.S.C. § 1631 (emphasis added). The Energy Emergency EO does not adhere to this requirement. Ex. 2-36, 90 Fed. Reg. at 8434 (Energy Emergency EO) (generically directing agencies to "identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the . . . generation of domestic energy resources.").

statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes." S. Rep. No. 94-1168, 3 (1976) (emphasis added). And Section 202(c)'s authority is not triggered by a Presidential emergency declaration; the statute requires that "the Commission determine[] that an emergency exists." 16 U.S.C. § 824a (emphasis added).[6] Thus, the burden is on the Department (which stands in the shoes of the "Commission") to demonstrate that there is an emergency within the narrow terms of Section 202(c); simply pointing to the Energy Emergency EO or the Grid Reliability EO without providing actual evidence that an emergency exists cannot provide the substantial evidence needed to sustain the Order.

July 2025 Resource Adequacy Report

Despite the Department's citation of its own July 2025 Resource Adequacy Report as supporting a "long-term" emergency in the WECC Rocky Mountain assessment area, Order at 6, nothing in that report supports such a conclusion. That is because the Order's discussion of the July 2025 Report is strictly limited to (1) mentioning that the report was issued pursuant to presidential directive and (2) inserting a conclusory quotation regarding "the Nation's power grid" found on page 1 of the report. *Id.*

Moreover, even granting for argument's sake that the July 2025 Report does not contain the myriad inaccurate assumptions and methodological flaws discussed below, the July 2025 Report undercuts the Order's emergency determination. According to the July 2025 Report, the normalized unserved energy in 2030 in the "West Non-CAISO" region[7] is lower than any other region of the country. *See* Ex. 2-01 at 16–17 (Current Energy Group January Report).

The lack of evidence for a long-term electricity shortfall is underscored by the fact that the Department's own analysis premises a resource adequacy shortfall on a type of demand increase (large load buildout) that the July 2025 Report goes on to admit would likely never actually be allowed to destabilize the grid. Ex. 2-35 at 2–3, 15–17 (July Resource Adequacy Report). Specifically, the report notes that its analysis "is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system." *Id.* at 14. In other words, even taking the report at face value, it does not identify a shortfall of a type and nature that could

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[6] The Department has exercised certain powers under Section 202(c) since the DOE Organization Act of 1977. *See* 42 U.S.C. § 7151(b).

[7] The "West Non-CAISO" region is roughly, according to the report's delineations, the Western continental United States excluding the California Independent System Operator and nearby areas. *See* Ex. 2-35 at 6, 35, 37 (July Resource Adequacy Report).

justify the invocation of the Department's Section 202(c) emergency authority. At best, the report highlights that data centers cannot be built at projected rates unless new generation is built, which is far from the type of emergency situation that could provide the basis for a Section 202(c) order.

The July 2025 Report does not credibly project conditions in 2030 because of its many inaccurate assumptions and methodological errors. *See* Ex. 2-02 at 9–10 (Grid Strategies Resource Adequacy Report). The Department is on notice of these flaws. *See, e.g.*, Ex. 2-40 at *passim* (PIOs' RFR of July Resource Adequacy Report); Ex. 2-40a at 2 (Department's Response to PIOs' RFR of July Resource Adequacy Report). Yet the Order cites the July 2025 Report without providing a reasoned explanation of how it could credibly rely on the report in light of the identified flaws.

Most glaringly, the Department's July 2025 Report overestimates demand growth and expected facility retirements while underestimating the likelihood of new entry. This biases the entire report in the direction of over-identifying resource adequacy concerns. Ex. 2-41 at 21–25 (Inst. Pol'y Integrity Report); Ex. 2-42 at 2–4 (GridLab Report); Ex. 2-40 at 34–35 (PIOs' RFR of July Resource Adequacy Report) (citing multiple expert reports and initiatives demonstrating the potential for flexibility of large data center loads, including Ex. 2-43 (Duke University Rethinking Load Growth Study)).

The July 2025 Report also "departs from best [modeling] practices by using a deterministic modeling rather than a probabilistic approach," and thereby fails to account for necessary uncertainties. Ex. 2-41 at 19 (Inst. Pol'y Integrity Report). And in many places, the Department simply does not explain its own methodology. The report states that its model is derived from NERC's Interregional Transfer Capability Study, which is focused on the ability of the transmission system to transfer power between regions. Ex. 2-35 at 2 (July Resource Adequacy Report). However, the July 2025 Report inexplicably excludes new transmission projects from its analysis, ignoring that transmission improvements can be the most cost-effective way to improve grid reliability. The July 2025 Report also departs from sound statistical reasoning by, for instance, calling out PJM for failing loss-of-load criteria under one realization of a possible weather year that would include Winter Storm Elliott, without considering that a system's loss-of-load expectation is averaged across all simulated weather years. Ex. 2-41 at 19 (Inst. Pol'y Integrity Report); Ex. 2-35 at 7, 9, 27 (July Resource Adequacy Report). The report also added more "perfect capacity" (in megawatts) within its modeling than actually needed to bring regions to its targeted Normalized Unserved Energy level. Ex. 2-41 at 26 (Inst. Pol'y Integrity Report); Ex. 2-35 at 19, 27, 30, 32, 40 (July Resource Adequacy Report). These analytical failings in and of themselves disqualify the report as a viable source of evidence for an emergency finding.

Finally, on its opening page, the July 2025 Report acknowledges that its analysis is general in nature, looking at the country as a whole, and that the various "entities

responsible for the maintenance and operation of the grid" have information "that could further enhance the robustness of reliability decisions" in the sections of the grid they administer. Ex. 2-35 at i (July Resource Adequacy Report). The report's generalized analysis based on incomplete information is simply insufficient to justify a Section 202(c) emergency finding for the WECC Rocky Mountain assessment area or any other specific region.

iii. The Order Fails to Consider Relevant Evidence That Demonstrates Ordinary Processes for Resource Adequacy Under the Federal-State Balance of Responsibilities

The Order fails to consider many other facts and processes that undercut its emergency claim. Utilities engage in regular, periodic electric resource planning to acquire the resources they will need to meet future customer demand. *See, e.g.*, *infra* secs. V.A.2, V.A.5; Ex. 2-01 at 3–8 (Current Energy Group January Report); Ex. 2-02 at 1–2 (Grid Strategies Resources Adequacy Report); Ex. 2-05 at 7–9 (Telos Resource Adequacy Report). The Order does not provide any evidence that utility planning processes, as well as state public utility commissions' proceedings and oversight, are insufficient to address any need for resources in 2031 and beyond.

Electric utilities have experienced periods of increased demand before, and they have successfully dealt with forecasted increases in demand. For example, during the 1970s, many electric utilities expected increased demand, and thus a number of new generating facilities were built in the 1970s and 80s. Ex. 2-108 at 6–7 (UT Austin Article).

The mere fact that a resource assessment indicates the need for new resources several years ahead of time is not evidence of an energy emergency—instead, this is a feature of utility resource planning, which exists in part so that utilities can procure new resources to meet any increase in demand. Electric utilities throughout the Rocky Mountain assessment area have been engaged in ongoing efforts to procure new resources to come online in future years to meet customer demand. For example, in the Near Term Procurement, Xcel proposed to acquire over 4,900 MW of resources that would come online between 2027 and 2030, Ex. 2-93 at 4–5 (Xcel 2025 Near Term Procurement Report), and in Proceeding No. 24A-0442E. Xcel will seek additional utility-scale generating resources with in-service dates through 2031, Ex. 2-94 at 154–73 (Xcel 2024 JTS, Volume 2 Technical Appendix) (showing the new resources that would be added for each of the portfolios that were modeled). In March 2026, the Colorado Commission approved up to 4,100 MW of new resources for Xcel in the Near Term Procurement. Ex. 2-169 at 1 (Colorado PUC Press Release, Feb. 18, 2026); Ex. 2-170 at 9–15 (Colorado PUC Feb. 2026 Decision). Also in March, the Colorado Commission issued an order marking the end of Phase I of Xcel's Just Transition Solicitation. *See* Ex. 2-171 at 1, 4, 8 (Colorado PUC March 31, 2026 Decision) (resolving the only remaining request for reconsideration of the Commission's Phase

I decision in the Just Transition Solicitation). As a result, Xcel will issue Requests for Proposals in summer 2026 for additional resources that can come online by the end of 2031. Xcel's recent and pending resource procurement proceedings focused extensively on load growth, and the procurements are designed to meet any need for new resources in light of load growth through 2031.

In fact, each of the Craig Co-Owners already has a plan in place for procuring any incremental resources needed on a longer-term basis. PacifiCorp, which is one of the largest utilities in the West, has pending procurements in Oregon and Utah for new resources that would come online between now and 2030. Ex. 2-109 at 1 (2025 PacifiCorp Oregon RFP Update) (noting that as of October 2025, PacifiCorp has issued its request for proposals for new resources to serve Oregon customers); Ex. 2-110 at 1 (2025 PacifiCorp Utah RFP) (stating that PacifiCorp is soliciting requests for generation resources "to meet 600,000 MWhs of average annual forecasted demand" for customers in Utah).

Tri-State, the operator of Craig, has found that even after Craig retires, Tri-State does not have a need for any new generating resources through 2035. Ex. 2-172 at 2-3 (Tri-State 2026 Annual Resource Adequacy Report) (showing that Tri-State has a capacity surplus for every year through 2035); Ex. 2-89 at 8 (Tri-State 2025 Annual Progress Report) (showing that Tri-State does not have a need for additional capacity until 2035). Platte River's Board has adopted the preferred portfolio in its 2024 IRP, which entails acquiring new generating and storage resources through 2030. Ex. 2-92 at 153, 176–81 (Platte River 2024 IRP).

The Order also fails to reconcile its findings with the Department's own findings elsewhere. For instance, according to the Department, "NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export." Ex. 2-120 at 6 (Department Export Authorization EA-365-C (Oct. 21, 2025)).

Engaging in reasoned decision-making based on a planning document necessitates following important basic principles. The fact that a study shows that, under certain conditions, a utility or region might, in a future year, fall below a specific resource adequacy goal that is based on a 1-in-10 LOLE standard does not by itself predict or guarantee that a loss of load event will actually occur. Instead, it indicates future conditions in which system planners might expect more than one shortfall per decade if both those future conditions materialize and if no actions are taken by the utilities and regional entities to address a potential, future shortfall. *See* Ex. 2-01 at 2–6 (Current Energy Group January Report). Importantly, a small deviation below the resource adequacy goal will be associated with a small increase in this likelihood (and vice versa). This fact is relevant in the context of system planning because the tradeoff between grid reliability and energy costs is a core part of system planning: no system

is ever 100% reliable, and ratepayers do not want to spend too much of their income on energy bills. *See id.* at 5; Ex. 2-159 at 4 (Email Correspondence with E3) ("Any electric system will have some level of resource adequacy risk."). Indeed, for this reason, both MISO and PJM have explicit conditions in their tariffs that allow for each grid operator to fall below the 1-in-10 LOLE threshold as part of their response to potential higher capacity prices. Thus, treating a potential short- or medium-term dip in the size of the planning reserve margin as an emergency belies both industry practice that explicitly allows for such dips and basic system planning principles.

In sum, even if there were a need for additional generating resources in some future year, the Order fails to consider that utilities have pending and scheduled procurements of new resources. There is no evidence that these pending and scheduled procurements will be insufficient to address any long-term resource needs. And in addition to the many relevant processes and sources the Order fails to consider, the Order is unreasoned in its reliance on the few sources it does cite. As such, the Order's claimed "continuing emergency conditions" are not based on reasoned decision-making and is not based on substantial evidence.

3. The Described Concerns Are Insufficiently Specific and Certain to Meet the Statutory Definition of an Emergency.

The Order is unreasoned, not based on substantial evidence, and otherwise contrary to law and regulation because the Order fails to provide any specific determination of the energy emergency that purportedly exists. Instead, the Order relies on vague and generalized assertions. For example, the Department rationalizes the Order based on the "prolific growth of data centers for the development of AI" and the resulting "new and unexpected source of load growth." Order at 5. But this statement fails to support the claimed near-term emergency. The Order does not provide any specific determinations as to the amount of claimed load growth and shortfall, the time period over which the claimed load growth and shortfall exists, and whether the claimed shortfall is for energy, capacity, or both.

First, the Order does not provide a specific, quantitative determination of the shortage of energy or capacity that allegedly exists. And the Department failed to identify the scale of the so-called "new and unexpected source of load growth" during its claimed emergency. The Order does not say, for instance, whether the load growth will result in a shortage of 1 MW, 100 MW, or 1000 MW. The Department does not even provide a range for the load growth or alleged shortage. Further, as described *infra* secs. V.A.4–.5, the sources cited and ignored by the Department do not support this contention.

Second, the Order does not specify over what time period the claimed emergency exists. The Order lasts for 90 days, but most or all of the Order's discussion of evidence for the claimed shortfall pertains to time periods much further in the future. The Order is unclear, for example, whether the Department has ordered Craig to

remain available solely because the Department believes that an emergency may arise at some future date.

Third, the Order is not clear as to whether the purported shortfall is for energy, capacity, or both. In the electric utility industry, there is a fundamental distinction between energy and capacity. Energy refers to the electricity produced over a given period of time, such as kilowatt-hours or megawatt-hours. Meanwhile, capacity refers to the maximum output a facility can provide, under specific conditions, and at an instant in time. The distinction between energy and capacity runs throughout the electricity industry, informing how contracts are structured (e.g., different payments for energy versus capacity) and how markets are organized (e.g., there are separate energy and capacity markets). The Order is not clear on whether the Department believes that there is a shortfall in energy, capacity, or both.

In relying on generalized assertions and failing to identify the information above, the Order is unreasoned. *Ariz. Pub. Serv. Co. v. United States*, 742 F.2d 644, 649 n.2 (D.C.Cir.1984) ("[M]ere conjecture and abstract theorizing offered in a vacuum are inadequate to satisfy us that the agency has engaged in reasoned decisionmaking."). The Order is also inconsistent with the Department's applicable regulations, which provide that "[a]ctions under this authority are envisioned as meeting a specific inadequate power supply situation." 10 C.F.R. § 205.371.

4. The Sources Cited in the Order Do Not Support the Existence of a Near-Term Emergency.

The Order's claimed near-term emergency is unreasoned and not supported by substantial evidence for many of the reasons discussed *supra* sec. V.A.2.ii. These reasons include the failure to grasp or even discuss the functions and conclusions of the sources cited in the Order; the focus on retirements without considering generator additions; the focus on projected demand growth without considering projected growth in supply; the mathematical mistakes and methodological errors committed by the Department; and the reliance on executive orders containing no facts. *See id.*

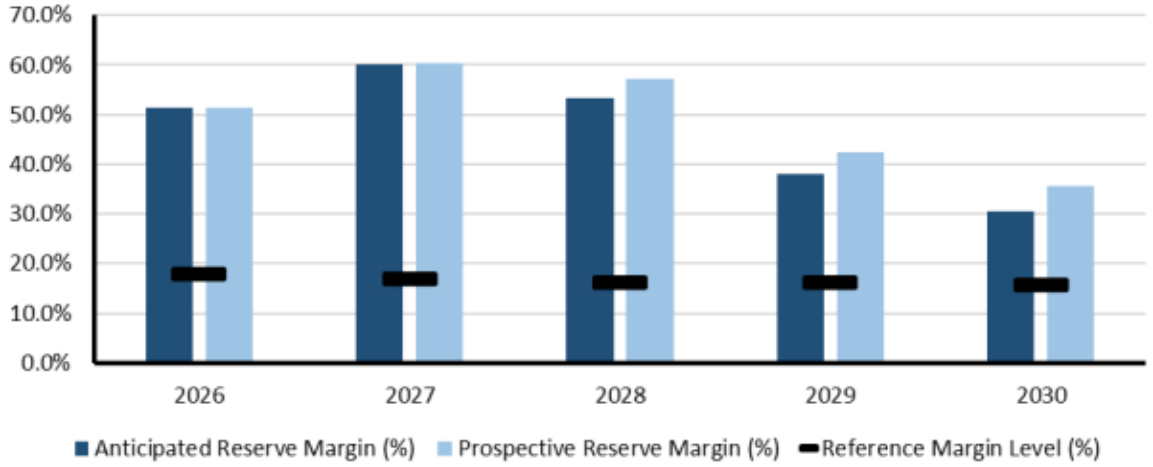
In a single sentence, the Order claims that Colorado Public Utilities Commissioners "have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads." Order at 4–5. The Order references Commissioner discussions of only a single utility in Colorado, Xcel, not multiple utilities, as the Order suggests.

Moreover, the Department has once again mischaracterized the contents of a document as providing evidence that an actual emergency exists. The Commissioners did not state that Xcel has a near-term or long-term shortfall of electricity or generating supplies, or that Xcel's plans will in fact be insufficient to address any shortfall (even if such a shortfall were to exist). Furthermore, the Commissioners' statements and deliberations underscore that the Colorado Commission is diligently

monitoring Xcel's resource adequacy situation and that the existing regulatory process in Colorado is sufficient to ensure resource adequacy for Xcel (and other utilities in Colorado).

There are additional aspects of the sources cited by the Order that undermine the claimed near-term emergency. For example, the Order cites both the 2025 Long-Term Reliability Assessment and the WECC's 2025 Western Assessment of Resource Adequacy. Both of those studies deem the Rocky Mountain region to be at "normal" risk in 2026. Ex. 2-178 at 7, 159–62 (NERC 2025 Long-Term Reliability Assessment); Ex. 2-183 at PDF 3 (2025 Western Assessment of Resource Adequacy). As noted above in Figure 11, *supra* sec. V.A.2.ii, the probabilistic modeling in the 2025 Long-Term Reliability Assessment did not include 2026, but for the years it analyzed, 2027 and 2029, the study found 0 MWh of expected unserved energy, 0 ppm of normalized unserved energy, and 0 hours of lost load risk. Ex. 2-178 at 161 (NERC 2025 Long-Term Reliability Assessment). Moreover, the 2025 Long-Term Reliability Assessment projected that in 2026, the Rocky Mountain region would have enough generating resources to meet demand. *Id.* at 159. Indeed, it projects that the Rocky Mountain region's reserve margin will be nearly three times the reference margin level in 2026. *Id.* It also projects that the Rocky Mountain region will have sufficient resources to meet the reference margin level through 2030, as shown in Figure 15 below.

Figure 15: 2025 Long-Term Reliability Assessment Planning Reserve Margins



Source: Ex. 2-178 at 159 (NERC 2025 Long-Term Reliability Assessment).

Similarly, the 2024 Long-Term Reliability Assessment does not provide evidence of an emergency in 2026 in the Rocky Mountain region. It projects no unserved energy or loss-of-load hours in the "WECC-NW" region (which formerly included the Rocky Mountain region), and projects that the on-peak reserve margin in that region exceeds the target reserve margin. Ex. 2-07 at 129 (NERC 2024 Long-Term Reliability Assessment). This is shown in Figure 16 below.

Figure 16: 2024 Long-Term Reliability Assessment Findings of "Negligible" Expected Unserved Energy and Loss of Load Hours Risk

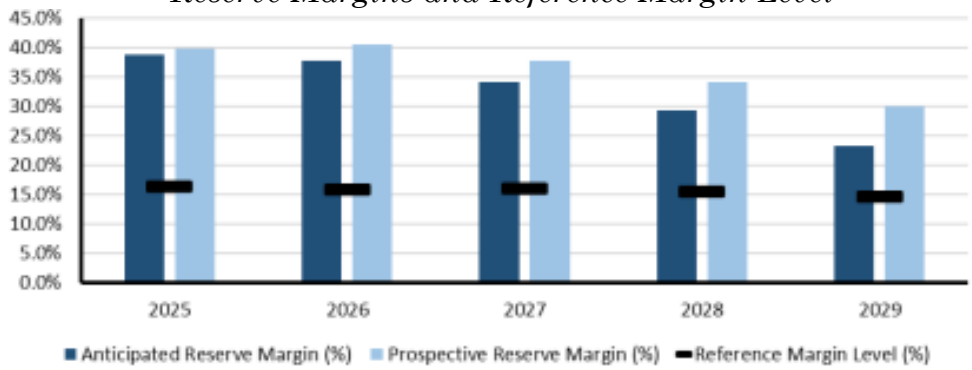
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* Provides the 2022 ProbA Results for Comparison

Source: Ex. 2-07 at 129 (NERC 2024 Long-Term Reliability Assessment).

As for capacity, the 2024 Long-Term Reliability Assessment estimates that the region that formerly encompassed the Rocky Mountain region would have enough capacity to meet target reserve margins in 2026 (and in subsequent years). *Id.* at 127. This is shown in Figure 17 below:

Figure 17: 2024 Long-Term Reliability Assessment Depiction of Reserve Margins and Reference Margin Level



Source: Ex. 2-07 at 127 (NERC 2024 Long-Term Reliability Assessment).

Thus, the 2024 Long-Term Reliability Assessment does not support the Order's determination of a near-term emergency. Instead, the assessment reaches the contrary conclusion: there is sufficient energy and capacity in the studied "WECC-NW" region in 2026 (and in the following years). *See id.* at 127–29; Ex. 2-01 at 13–14 (Current Energy Group January Report); Ex. 2-02 at 7–8 (Grid Strategies Resource Adequacy Report).

The 2024 Western Assessment of Resource Adequacy also includes additional information undermining the Order's claimed near-term emergency. Most glaringly, the study finds *no demand at risk hours in 2026 and almost none in 2027* in the three subregions that subsume (and extend beyond) the claimed emergency footprint. *See* Ex. 2-01 at 10–11 (Current Energy Group January Report). This is shown in Figure 18 below.

Figure 18: Summary of Demand-at-Risk Hours Identified in 2024 Western Assessment of Resource Adequacy

Subregion	2026 Demand-at-Risk Hours in Most Extreme Scenario	2027 Demand-at-Risk Hours in Most Extreme Scenario
NW Central	0	0
NW Northeast	0	0
NW Northwest	0	~7

Source: Ex. 2-01 at 11 (Current Energy Group January Report).

The Order also fails to come to grips with the 2024 Western Assessment of Resource Adequacy's anticipation of 10 GW of new generation in 2026, of which more than 4 GW is firm capacity, and the support for this anticipation in recent data from the Energy Information Administration. *Id.* at 11; *see also* Ex. 2-29 at 27–29 (FERC Staff Winter Reliability Assessment) (explaining that in the WECC region, 14.1 GW of nameplate capacity additions are completed or expected from March 2025 through February 2026, including roughly 7 GW of additions expected between October 2025 and February 2026). In addition, utilities have accounted for peak demand, including the possibility of increases in peak demand, and concluded in their electric resource planning that they will not have an energy or capacity shortfall in the absence of Craig being available. *See* Ex. 2-02 at 2–5, 8–9 (Grid Strategies Resource Adequacy Report).

Regardless of the exact modeling software and reliability metrics used, standard approaches to assessing the probability of energy shortfalls consist of modeling utilities' available generating and storage resources in light of expected customer demand. *See, e.g.*, Ex. 2-01 at 3–8 (Current Energy Group January Report). This typically includes a "de-rate" of resources based on the likelihood that a generator will be unavailable or produce less than its maximum potential output (*i.e.*, less than its "nameplate capacity") during a peak demand period, a computation whose result is known as "accredited capacity." *Id.* at 5. The Department does not attempt, on its own or based on the cited sources, to assess for Colorado or any other region the probability of shortfalls or the available resources in light of expected demand. Instead, the Department simply tallies retirements of certain types of resources, which logically and analytically cannot answer the question of whether the resources that actually exist today are adequate to serve electricity needs in 2026.

While the Department has failed to conduct any methodologically sound analysis of whether an energy shortfall exists in Colorado, Colorado's electric utilities have done such analyses. As further discussed in secs. V.A.2.ii and V.A.5, Tri-State's analyses conducted in 2025 concluded that it would have no unserved energy and no loss of load hours in 2026, even without the availability of Craig, and Platte River reached a similar conclusion in 2024.

In addition, the Department's July 2025 report does not address whether an energy emergency exists prior to 2030, much less in the first three months of 2026. Thus, the report does not support the claimed near-term emergency either.

The Order's reliance on NERC's 2026 Summer Reliability Assessment also does not establish any short-term emergency. As with the 2025 Long-Term Reliability Assessment and the 2025 Western Assessment of Resource Adequacy, NERC's 2026 Summer Reliability Assessment found "normal" risk, the lowest risk designation under the NERC assessment regime, for the Rocky Mountain region. The Order's selective quote that wildfires and extreme heat conditions "pose the greatest reliability risk scenario" in the region does not change NERC's conclusion that the region does not face any heightened risk. Order at 4–5. In the rest of the document, NERC is clear that "[e]xpected resources meet operating reserve requirements for assessed scenarios" and even "[a]bove-normal summer peak load combined with low resource conditions" only "*could* result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs [(energy emergency alerts)]." Ex. 3-07 at 16 (2026 Summer Reliability Assessment) (emphasis added). The mere *possibility* of employing mitigation measures in above-normal conditions does not constitute an emergency.

Finally, the Order states in footnote 6 that "[i]t likely would be difficult for the coal-fired unit to resume operations once retired." Order at 1, n. 6. In support of this sweeping assertion, the Order makes a series of generalized statements that do not reflect consideration of Craig Unit 1 and the Craig Station specifically. For example, the Order speculates about what would happen "if the co-owners were to begin disassembling the unit or other related facilities," but presents no evidence that the co-owners of Craig Unit 1 had plans to begin decommissioning or disassembling the unit shortly after December 31, 2025. The Order also fails to consider that Craig Units 2 and 3 continue to operate, Order at 1, and share common facilities with Craig Unit 1, thus making it impossible for the co-owners to decommission and disassemble common facilities that remain in use by Craig Units 2 and 3.

The Order cites only a single document in support of footnote 6, but that document directly contradicts the substance of the footnote by finding that "95%" of retired coal plants are "unremediated and unrepurposed" and "may remain structurally intact" and "have no announced plans to decommission the site." Ex. 3-03 at 5 (Business Models for Coal Plant Decommissioning).

Moreover, the Order fails to reflect the Department's consideration of evidence that undermines the assertion that a coal-fired unit cannot resume operations after it retires. For example, the Department recently announced that it has awarded funding to restart the Warrior Run coal plant in Maryland "that ceased operations in 2024." Ex. 3-04 at 2 (June 2026 Coal Recommissioning and Modernization Announcement).

The Department's decision to award federal funding to restart a retired coal unit is at odds with its statement here that it would be difficult to resume operations after Craig Unit 1 retired.

5. Many Sources Not Cited in the Order Undercut the Claimed Near-Term and Long-Term Emergency.

The Department also fails to consider many sources undercutting the claimed near-term and long-term emergency. These include planning by the Craig Co-Owners and their state regulators and boards. The Order is, consequently, unreasoned and not based on substantial evidence.

In 2016, the Craig Co-Owners announced that Craig would close by December 31, 2025.[8] 83 Fed. Reg. 31332 (July 5, 2018) (approving Colorado's Clean Air Act State Implementation Plan revision establishing Craig's closure date); Ex. 2-65 at 183 at § F.VI.D.1 (CDPHE Regulation No. 3) (Colorado Regulation No. 3 provision regarding Craig's closure, which EPA approved). As discussed below, in the decade since they made that announcement, the Craig Co-Owners have built and contracted for new generation, storage, and transmission resources to replace Craig Unit 1. Three of the Craig Co-Owners (PacifiCorp, Tri-State, and Xcel) are regulated by state public utility commissions, while the remaining two (Platte River and Salt River Project) are governed by their respective boards. But regardless of the governance structure and regulatory status of the utility, each co-owner's regulator or board has approved resource plans that include retiring Craig by December 31, 2025.

In addition, utilities have multiple ways to acquire additional supply-side generating resources quickly. Reserve sharing arrangements are in place that allow utilities to call on resources on a short-term basis. Utilities participating in the two energy imbalance markets operating in the West can use those markets to purchase any resources needed on an intra-hour basis. *See* Ex. 2-131 at 7–8 (FERC Western Energy Markets Explainer). As of April 1, 2026, many utilities in the Rocky Mountain assessment area are now participants in SPP West, and thus have expanded access to resources in the SPP footprint. Utilities also have a suite of demand-response programs, including from interruptible service contracts with large commercial customers that allow the utility to interrupt service to large customers under specific conditions, and comparable programs with individual residential customers allowing

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[8] The Craig Co-Owners reached a settlement agreement, which was incorporated into Colorado's regional haze SIP and approved by EPA, in which they agreed to either close Craig Unit 1 by December 32, 2025 or cease burning coal at Craig Unit 1 by August 31, 2021 (with an option to convert the unit to burn natural gas by August 31, 2023). Of these two compliance pathways, the Co-Owners elected to close Craig Unit by December 31, 2025.

the utility to, for example, reduce demand from air-conditioning during summer peak hours. *See generally* Ex. 2-94 at 101, 135, 182–83 (Xcel 2024 JTS, Volume 2 Technical Appendix) (explaining how Xcel relies on demand response programs, including interruptible loads).

Tri-State

For Tri-State, the Colorado Commission has approved two electric resource plans that include retiring Craig by December 31, 2025. The Colorado Commission provided its final approval of Tri-State's 2020 resource plan in 2023, Ex. 2-85 at 34 (Colorado Commission Decision C23-0437), and the plan assumed that Craig would retire by the end of 2025, Ex. 2-86 at 20, 31, 43, 53, 64 (Tri-State 150-Day Implementation Report) (showing that in all portfolios, Craig ceases to generate electricity after 2025). Tri-State concluded in its 2020 resource plan that it could reliably operate its system after 2025 without Craig. *See id.*

Tri-State reached the same conclusion—that it does not need Craig for reliability purposes—in its 2023 resource plan. Each portfolio that Tri-State modeled in its 2023 resource plan was required to meet strict reliability criteria, including during extreme weather events, and every portfolio assumed that Craig retires at the end of 2025. Ex. 2-87 at 21–22, 31–32, 42–43, 54–55, 64–65, 75–76 (Tri-State 2023 ERP 120-Day Implementation Report) (showing that in all portfolios, Craig retires at the end of 2025). After assuming that Craig would not provide any energy or capacity after 2025, Tri-State found that each portfolio would be reliable because each portfolio met Tri-State's reliability and resource adequacy requirements. *Id.* at 95 ("Each of the portfolios met Level 1 and 2 Reliability Metrics.").

Tri-State does not have either a near-term or intermediate-term need for additional capacity or energy sources after 2025. Specifically, Tri-State concluded in 2025 that it does not have a need for additional capacity until 2035, even assuming that Craig retires on December 31, 2025: "Tri-State stated within Phase I of the 2023 ERP that it did not forecast a capacity shortfall until 2029. With the updated load forecast, shown above, utilized in Phase II and Phase II preferred portfolio resources, a capacity shortfall is not forecasted to occur until 2035." Ex. 2-89 at 8 (Tri-State 2025 Annual Progress Report). The loads and resources table in Tri-State's 2025 Annual Progress Report shows that Tri-State will have surplus capacity from 2026 through 2034, even without Craig. *Id.* at 10. Note that the surplus is calculated relative to the total amount of resources needed to both meet peak demand and have planning and operating reserves. *See id.* Thus, the surplus shows Tri-State has sufficient capacity to meet its peak demand, plus additional capacity in the form of planning and operating reserves, and then has even more capacity beyond what is needed to meet peak demand and reserves. Furthermore, the loads and resources table in which Tri-State estimates a capacity surplus through 2034, *id.*, assumes that Tri-State makes no market purchases and instead is based solely on Tri-State's owned and contracted

resources, *see id.* In addition, Tri-State conducted reliability analyses in 2025 to stress-test its system under extreme winter and summer weather (including by making multiple worst-case scenario assumptions related to reduced availability of resources during extreme weather events, length of extreme weather events, reduced availability of imports, etc.) and concluded that it has sufficient capacity for 2026 and beyond even under extreme winter and summer weather events. *See* Ex. 2-86 at 6–8, 14–15, 28, 40, 51 (Tri-State 150-Day Implementation Report); Ex. 2-168 at 1–4 (Tri-State Extreme Weather Event Modeling Assumptions) (listing all of the modeling assumptions that are a part of Tri-State's analysis of its system under extreme weather events).

Tri-State's 2026 Resource Adequacy Report reaches similar conclusions as its 2025 Report. In its 2026 Report, Tri-State concludes that it has a capacity surplus in each year of the analysis period, which extends through 2035. Ex. 2-172 at 2-3 (Tri-State 2026 Annual Resource Adequacy Report) (showing that Tri-State has a capacity surplus for each year from 2026 through 2035).

The Colorado Commission approved Tri-State's 2020 and 2023 electric resource plans, which both included retiring Craig by December 31, 2025. Ex. 2-90 at 41 (Colorado Commission Decision No. C25-0612). In its August 2025 decision approving Tri-State's current resource plan, the Colorado Commission expressly found that Tri-State does not need Craig after 2025 to maintain a reliable electric system:

> Craig is not required for reliability or resource adequacy purposes based on the record in this ERP. Every portfolio that Tri-State modeled assumes that Craig retires at the end of 2025 and does not provide any energy or capacity after 2025. At the same time, Tri-State convincingly concludes that every portfolio meets all reliability metrics and is reliable.

Id. at 40.

Since 2016, Tri-State has acquired and/or built new generating, storage, transmission, and demand-response resources, and Tri-State's member cooperatives have also added their own resources. (Tri-State allows member cooperatives to self-supply some of their electricity and procure the remainder from Tri-State.) Ex. 2-89 at 12, fig. 4 (Tri-State 2025 ERP Annual Progress Report) (showing that, since 2016, Tri-State has added more than 600 MW of utility-scale and small-scale hydropower, wind, and solar); *id.* at 10–11 (stating that, as of December 2025, Tri-State had signed contracts for 500 MW of new storage resources and 200 MW of new wind resources, and is continuing contract discussions for additional resources).

Platte River

Platte River prepared a resource plan in 2020 that modeled several portfolios, each of which assumed that Craig would retire by December 31, 2025. Ex. 2-91 at 20, 26, 67, 87–90 (Platte River 2020 IRP). Platte River's Board then voted to approve a portfolio that included retiring Craig by December 31, 2025.

Platte River's current resource plan was developed in 2024. Like the 2020 plan, the 2024 plan included retiring Craig by December 31, 2025. Ex. 2-92 at 30, 106, 179 (Platte River 2024 IRP). Platte River's Board then voted to approve a portfolio from the 2024 resource plan that included retiring Craig by December 31, 2025. *Id.*, Appendix C at PDF 211–215.

Both the 2020 and 2024 plans contained action plans to procure additional generating and storage resources to meet electricity demand in Platte River's service territory. *Id.* at 176–79.

Platte River's 2020 and 2024 resource plans followed similar methodologies. *Compare* Ex. 2-92 at *passim* (Platte River 2024 IRP), *with* Ex. 2-91 at *passim* (Platte River 2020 IRP). Platte River's 2024 plan, for instance, contained forecasts of Platte River's expected load, including in 2026 and beyond, based on expected load growth in Platte River's service territory. Ex. 2-92 at 57–96 (Platte River 2024 IRP). Historically, Platte River has experienced its peak electricity demand in the summer, and it forecasts demand in summer to remain significantly higher than in winter through 2050. *Id.* at 61.

The 2024 plan analyzed reliability and resource adequacy using several metrics and by stress testing the portfolios under extreme weather scenarios. *Id.* at 120–31. In all of its modeling, Platte River concluded that it could maintain a reliable system after Craig closes at the end of 2025. *Id.* at 145–55. Platte River's electric resource plans indicate that Platte River does not have a near-term need for additional capacity or energy in the near-term or in the intermediate term.

Since 2016, Platte River has contracted for and/or built new generating, storage, transmission, and demand-response resources. Platte River added 30.5 MW of new solar in 2016, 225 MW of new wind resources in 2020, 22 MW of new solar in 2020, 1 MW of new storage in 2020, and 150 MW of new solar in 2025; and it plans on adding 150 MW of new solar and 25 MW of 4-hour storage in 2026. Ex. 2-92 at 106–08 (Platte River 2024 IRP). The 2024 IRP also calls for additional acquisitions from 2024 onward, including procuring up to 200 MW of additional thermal generation, additional storage capacity, and additional virtual power plants. *Id.* at 176–79.

Public Service Company of Colorado (Xcel)

In the years since 2016, Xcel has contracted for and/or built new generating, storage, transmission, and demand-response resources. In the 2016 electric resource

plan, the Colorado Commission approved Xcel acquiring the following new resources: 1,100 MW of wind; up to 700 MW of solar; up to 275 MW of storage; and 383 MW of gas. Ex. 2-101 at PDF 1 (Xcel Information Sheet on Colorado Energy Plan).

Xcel filed its most recent regular electric resource plan in 2021 and has pending resource procurements underway currently. In all portfolios that it presented to the Colorado Commission for selection, Xcel's 2021 resource plan assumed that Craig would retire by the end of 2025; and in that proceeding, the Colorado Commission approved two portfolios that assumed that Craig would retire by the end of 2025. Ex. 2-164 at 125 (Colorado Commission Decision No. C24-0052); Ex. 2-165 at 70 (Colorado Commission Decision No. C25-0024).

In the 2021 electric resource plan, the Commission's Phase II decision approved the "Alternative Portfolio," consisting of 5,854 MW of new generating and storage resources (which included 669 MW of new gas). Ex. 2-102 at 92, 101 (Colorado Commission Decision No. C24-0052). The Company is on track to procure the new resources approved in its 2021 resource plan. Ex. 2-103 at 14–17 (2025 Xcel ERP Annual Progress Report). As noted above, Xcel also has two resource acquisitions pending in the Near Term Procurement and the Just Transition Solicitation.

Currently, Xcel has two resource procurement dockets pending for its electric system. In the Near Term Procurement Report, Xcel proposed to acquire approximately 4,900 MW of new resources that would come online between 2027 through 2030. Ex. 2-93 at 4 (Xcel 2025 Near Term Procurement Report). In August 2025, Xcel issued a request for proposals for new generating and storage resources. In March 2026, the Colorado Commission approved Xcel acquiring up to 4,100 MW of new resources, including new wind, solar, battery storage, and gas resources. Ex. 2-169 at 1 (Colorado PUC Press Release, Feb. 18, 2026); Ex. 2-170 at 9–15 (Colorado PUC Feb. 2026 Decision).

The load forecast for the Near Term Procurement Report assumes the retirement of Craig at the end of 2025. Xcel states in the report that it has executed short-term contracts for resources for 2026 to ensure that Xcel can meet peak load in 2026. *Id.* at 29. In combination with its owned and contracted resources, these short-term purchases will ensure that Xcel has sufficient resources to reliably serve load in 2026.

Xcel is also undertaking another procurement called the "Just Transition Solicitation" in which Xcel is separately seeking supply-side resources with in-service dates between now and the end of 2031. In March 2026, the Colorado Commission issued an order marking the end of Phase I of Xcel's Just Transition Solicitation, Ex. 2-171 (Colorado PUC March 31, 2026 Decision); as a result, Xcel will soon issue Requests for Proposals for additional resources that can come online by the end of 2031.

In all of the modeling undertaken for the Just Transition Solicitation, Xcel assumed that Craig would retire by the end of 2025. Ex. 2-94 at 85 (Xcel 2024 JTS, Volume 2 Technical Appendix). In that proceeding, Xcel included multiple load forecasts, each of which accounted for expected load growth, including from large commercial customers such as data centers. Currently, Xcel's peak electricity demand occurs in summer. *Id.* at 52, 58. Xcel forecasts that its system will remain summer peaking through at least 2030. *See id.* Xcel found that all of the generic portfolios modeled in Phase I would be reliable, *see id.* at 121 (noting that "system reliability is factored into the development of portfolios in an iterative process that involves inputting various reliability requirements upfront into the EnCompass modeling process" to ensure that the portfolios are reliable), and all of these portfolios included retiring Craig by the end of 2025.

On August 12, 2025, the largest coal unit on Xcel's system, Comanche Unit 3, went out of service as a result of a forced outage. In November 2025, Xcel petitioned the Colorado Commission for a one-year variance from the requirement to retire Comanche Unit 2 by the end of 2025. The Colorado Commission granted the variance solely because of the outage at Comanche Unit 3 (Comanche Unit 3's approved retirement date is January 1, 2031). Ex. 2-95 at 25–26 (Colorado Commission Decision No. C25-0892). The Colorado Commission did not indicate there is a need to extend the life of any unit other than Comanche 2. *See id.* And the Petition did not request a variance from any retirement deadline other than a one-year extension for Comanche 2. *See* Ex. 2-96 (Comanche Unit 2 Variance Petition).

For the years after 2026, Xcel has a series of resource procurements through which it will meet any resource needs after 2026. Specifically, the Colorado Commission has scheduled the following procurements: the base solicitation in the Just Transition Solicitation in 2026; the supplemental solicitation in the Just Transition Solicitation in 2027; and Phase I of the electric resource plan in 2028. Ex. 2-97 at 50 (Colorado Commission Decision No. C25-0747).Thus, even if Xcel were to have any resource needs after 2026, the Colorado Commission has approved a schedule of procurements to fill any resource needs after 2026. Moreover, the Company regularly acquires short-term resources between scheduled procurements through short-term capacity purchases, as noted in the December 5, 2025 Near Term Procurement Report, and the Commission also approved an Incremental Need Pool process by which the Company can procure resources in-between scheduled procurements. *Id.* at 39–40, 44–45.

PacifiCorp

PacifiCorp prepares IRPs roughly every two years. For the 2023 IRP Update, PacifiCorp assumed that Craig retires at the end of 2025 in all portfolios. Ex. 2-98 at 13, 88, 115 (PacifiCorp 2023 IRP Update). PacifiCorp prepared load forecasts covering the years 2026 and beyond that reflected anticipated load growth across its service territory. *Id.* at 39–51. PacifiCorp conducted extensive modeling of reliability and

resource adequacy. In the 2023 IRP, PacifiCorp adopted a preferred portfolio that included retiring Craig at the end of 2025. PacifiCorp found that this portfolio would be consistent with maintaining the reliability of its system.

While PacifiCorp made certain methodological changes in its 2025 IRP and used different values for certain inputs, PacifiCorp's 2025 IRP was similar to its 2023 IRP in several important respects. The 2025 IRP contained forecasts of demand—which include forecasts of expected load growth—throughout PacifiCorp's service territory for the years 2026 and beyond. Ex. 2-99 at 114–40 (PacifiCorp 2025 IRP). On the supply side, PacifiCorp assumed that Craig would close at the end of 2025 and thus not provide any capacity or energy to PacifiCorp's system after 2025. *Id.* at 13, 51, 287, 294. PacifiCorp evaluated reliability and resource adequacy using a variety of metrics, which included considering the impact of extreme weather events. *Id.* at 99–113, 192.

In its 2025 IRP, PacifiCorp reaffirmed its intent to close Craig by the end of 2025 and adopted a preferred portfolio that includes closing Craig by the end of 2025. PacifiCorp adopted its preferred portfolio in part because PacifiCorp found that the portfolio would ensure system reliability, finding that it had enough capacity to meet summer and winter peak demand in 2026 and 2027 without adding new resources. *Id.* at 136–39, *See also* Ex. 2-98 at 49–50 (PacifiCorp 2023 IRP Update). PacifiCorp's system currently has lower electricity demand in the winter than in summer, and experiences peak demand in the summer months; PacifiCorp forecasts that its system will remain summer peaking through 2045. Ex. 2-99 at 74, 106, 114, 132–35 (PacifiCorp 2025 IRP).

PacifiCorp's 2023 and 2025 IRPs each included an action plan that included building and procuring new generation and storage resources and transmission lines. *Id.* at 289–90. Since 2016, PacifiCorp has contracted for and/or built new generating, storage, transmission, and demand-response resources. In its 2015 IRP Update, PacifiCorp reported that for the year 2016, it would have a total of 10,131 MW of resources (both supply- and demand-side resources) across its entire system. Ex. 2-104 at 31 (PacifiCorp 2015 IRP Update). As of its most recent IRP, PacifiCorp reports that for the year 2026, it will have 11,859 MW of existing resources (owned by PacifiCorp or contracted to PacifiCorp) available to meet load in the summer, plus 3,103 MW of available market purchases. Ex. 2-105 at 132 (PacifiCorp 2025 IRP).

None of the state commissions that regulate PacifiCorp objected to PacifiCorp's decision to close Craig by the end of 2025. The most recent PacifiCorp IRP for which state commissions have issued final decisions after proceedings to review the resource plan is PacifiCorp's 2023 IRP. State commissions took various actions on PacifiCorp's 2023 IRP, but no commission expressed concern about retiring Craig by the end of 2025. *See* Ex. 2-128 at 5, 7 (Order No. 24-073_OR PUC on Pac 2023 IRP) (Oregon PUC issues a final order in PacifiCorp's 2023 IRP docket acknowledging PacifiCorp's plan to retire Craig Unit 1 by the end of 2025); Ex. 2-129 (Utah PSC on Pac 2023 IRP)

(Utah PSC issues a final order in PacifiCorp's 2023 IRP, but does not mention any concerns with PacifiCorp's proposal to retire Craig Unit 1 by the end of 2025); Ex. 2-130 at 3 (Idaho PUC on Pac 2023 IRP) (Idaho PUC issues a final order finding that PacifiCorp's 2023 IRP, which proposed to retire Craig Unit 1 by the end of 2025, satisfies Idaho's IRP requirements and the PUC acknowledges the IRP).

Thus, PacifiCorp does not need additional capacity and energy in the near term and has established processes in place for filling any longer-term resource need.

Colorado Generally

Within Colorado, the Energy Information Administration reports that the State's electric utilities added more than 3,000 MW of net summer capacity between 2019 and the end of 2024. *Compare* Ex. 2-106 at PDF 78 (Table 4.7.A) (EIA Annual 2024), *with* Ex. 2-107 at PDF 75 (Table 4.7.A) (EIA Annual 2019). This is shown in Figure 19 below.

Figure 19: Energy Information Administration Data on Colorado's Increases in Net Summer Capacity, 2019–2024

Net Summer Capacity, 2019 (MW)	**Net Summer Capacity, 2024 (MW)**	**Differential, 2019–2024 (MW)**
16,592	19,817	3,224

Sources: Ex. 2-106 at PDF 78 (Table 4.7.A) (EIA Annual 2024); Ex. 2-107 at PDF 75 (Table 4.7.A) (EIA Annual 2019). MW values rounded to the nearest integer.

The values in Figure 19 do not account for the new resources that came online in 2025 or are planned to come online in 2026 and in future years. As explained in the attached Grid Strategies Report, there are at least 5,800 MW of resource additions planned for future years, through 2029, in Colorado. *See* Ex. 2-02 at 8–9 (Grid Strategies Resource Adequacy Report).

B. The Order Fails to Best Meet the Claimed Emergency and Serve the Public Interest.

The Order requires SPP and the Craig Co-Owners to ensure Craig is available to operate and requires SPP to "take every step to employ economic dispatch of [Craig]" to best meet the claimed emergency and serve the public interest. Order at 7. But the Order provides no rational basis for those requirements. There are at least three types of problems with the Order. First, the Order is unreasoned in requiring SPP to employ economic dispatch to meet the claimed emergency. The requirement is unreasoned because it provides for Craig to generate electric energy for reasons untethered to the claimed emergency. Second, the Order does not address Craig's shortcomings. These shortcomings include Craig's unreliability and technical capabilities. The Order does not explain how, considering the plant's unreliability and technical capabilities, Craig could meet the claimed emergency. Third, the Order does not discuss any alternatives to Craig for meeting the claimed emergency and ignores

readily available and obvious alternatives that better address the claimed emergency. As a result, the Order is unreasoned and not based on substantial evidence.

1. Legal Framework: Section 202(c)(1) Authorizes the Department to Require Only Generation that Best Meets the Emergency and Serves the Public Interest.

Section 202(c)(1) authorizes the Department to impose only those requirements that (i) "best" (ii) "meet the emergency and" (iii) "serve the public interest." 16 U.S.C. § 824a(c)(1).

The term "best" demands a comparative judgment that there are no better alternatives. The word "best" is inherently a comparative term and means "that which is 'most advantageous.'" *Entergy Corp. v. Riverkeeper, Inc.*, 556 U.S. 208, 218 (2009) (*quoting* Webster's New International Dictionary 258 (2d ed.1953)); *cf. Sierra Club v. Env't. Prot. Agency*, 353 F.3d 976, 980, 983–84 (D.C. Cir. 2004) (explaining that statutory "best available control technology" requirement demands sources in a category clean up emissions to the level that peers have shown can be achieved). Consequently, the Department must, at minimum, consider alternatives and evaluate whether and to what extent a given alternative addresses the emergency and serves the public interest, including deficiencies associated with the alternative.[9]

The Department's obligation to exercise reasoned decision-making further requires consideration of alternatives. The Department need not consider every conceivable alternative, but it must consider alternatives within the ambit of the regulatory context as well as alternatives that are significant and viable or obvious. *See Dep't of Homeland Sec. v. Regents of the Univ. of Calif.*, 591 U.S. 1, 30 (2020); *Motor Vehicle Manufs. Ass'n of the U.S. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 51 (1983); *Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 215 (D.C. Cir. 2013). Intervenors and the public may also introduce information that requires the Department to evaluate alternatives and reconsider its decision to impose or maintain a requirement. *See, e.g.*, *Chamber of Com. of the U.S. v. Secs. & Exch. Comm'n*, 412 F.3d 133, 144 (D.C. Cir. 2005) (evaluating agency failure to consider alternative raised by dissenting Commissioners and introduced by commenters); *cf.* 10 C.F.R. § 205.370 (stating ability to cancel, modify, or otherwise change an order).

The Department's regulations and practice identify relevant alternatives for its consideration. The regulations specify information the Department shall consider in deciding to issue an order under Section 202(c), and require an applicant for a 202(c) order to provide the information. 10 C.F.R. § 205.373. The specified information

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[9] To be sure, the nature and extent to which the Department must consider alternatives depends on the emergency. An emergency that truly requires the Department to act within hours, for instance, permits a more abbreviated consideration than an emergency for which the Department has days to decide.

includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions." *Id*. § 205.373(f)–(h); Ex. 2-13 at 4 (DOE Order No. 202-22-4).

The Department may then choose only the best alternative. The best alternative is the one that is most advantageous for meeting the stated emergency and serving the public interest.

The statutory command to take only measures that serve the public interest, including with respect to environmental considerations, further constrains the Department's authority. The public interest element demands that the Department advance, or at least consider, the various policies of the Federal Power Act. *Cf. Wabash Valley Power Ass'n*, 268 F.3d at 1115 (interpreting the "consistent with the public interest" standard in Section 203 of the Federal Power Act); *see Gulf States Utils. Co. v. Fed. Power Comm'n*, 411 U.S. 747, 759 (1973); *California v. Fed. Power Comm'n*, 369 U.S. 482, 484–86, 488 (1962). Primary policies of the Federal Power Act include protecting consumers against excessive prices; maintaining competition to the maximum extent possible consistent with the public interest; and encouraging the orderly development of plentiful supplies of electricity at reasonable prices. *NAACP v. Fed. Power Comm'n*, 425 U.S. 662, 670 (1976) (orderly development); *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973) (maintaining competition); *Pa. Water & Power Co. v. Fed. Power Comm'n*, 343 U.S. 414, 418 (1952) (excessive prices). And because Section 202(c) expressly protects environmental considerations, these are part of the public interest element too. See *NAACP*, 425 U.S. at 669 ("[T]he words 'public interest' . . . take meaning from the purposes of the regulatory legislation.").

2. The Order Fails to Provide a Reasoned Basis for Requiring Economic Dispatch to Meet the Emergency.

The Order claims an emergency in the WECC Rocky Mountain assessment area. Order at 1. The emergency, according to the Department, is the potential "loss of power to homes and businesses in the areas that may be affected by curtailments or power outages." *Id.* at 6. The Rocky Mountain assessment area includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. Ex. 2-178 at 159 (NERC 2025 Long-Term Reliability Assessment). The area is shown in Figure 20 below (which is identical to Figure 7 and included here for ease of reference).

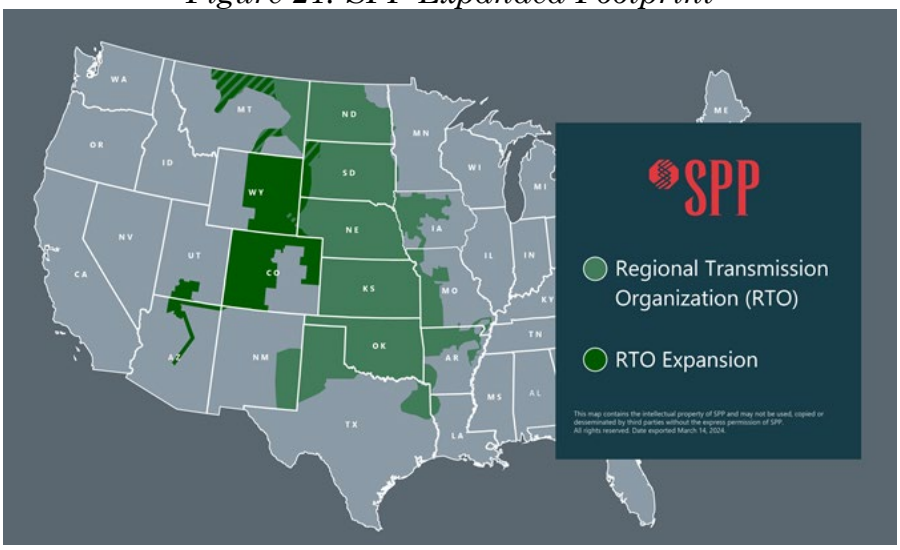
Figure 20: Boundary Areas of WECC Subregions



Source: Ex. 2-01 at app'x A at 1 (Current Energy Group January Report).

To meet that claimed emergency, the Order requires SPP to employ economic dispatch of Craig. Order at 7. SPP's economic dispatch is based on conditions across the entire SPP RTO footprint, as the SPP market determines a single optimized solution to effectuate one integrated market across the RTO footprint. *See Southwest Power Pool, Inc.*, 190 FERC ¶ 61,169, at PP 9, 40–43 (2025); Ex. 2-179 at 10–11 (SPP Deficiency Response). The market thus determines whether and to what extent to dispatch a given generator (such as Craig) to economically meet obligations across the entire SPP RTO. *See Southwest Power Pool, Inc.*, 190 FERC ¶ 61,169, at PP 9, 40–43; Ex. 2-179 at 10–11 (SPP Deficiency Response). The SPP RTO footprint includes a wide swath of the country not part of the Rocky Mountain assessment area, and at the same time does not include parts of the Rocky Mountain assessment area. See Figure 21 below (which is identical to Figure 2 and included here for ease of reference).

Figure 21: SPP Expanded Footprint



Source: Ex. 2-180 at PDF 1 (SPP RTO Expansion).

As such, the Order's economic dispatch requirement is unreasoned. The requirement is unreasoned because it provides for Craig to generate electric energy for reasons untethered to the claimed emergency, including economic conditions and conditions in a geographic footprint that is both overinclusive and underinclusive to meet the claimed emergency. (Additionally, as discussed *infra* sec. V.D.3, the Order's economic dispatch requirement is unlawful and unreasoned for additional reasons.)

3. The Order Fails to Address Craig's Shortcomings.

The Order fails to address the reasons that Craig is a poor fit to meet the claimed emergency. Craig is unreliable, and that unreliability hinders the plant from addressing the claimed emergency and actually poses risks to the grid. Moreover, Craig's technical capabilities are a mismatch to meet the claimed emergency.

The Order recognizes—without offering any evidence—significant shortcomings and weaknesses of "coal-fired unit[s]." Order at 1 n.6. But the Order then stops short. It fails to engage in reasoned decision-making regarding how, given these shortcomings and weaknesses, the Department views Craig to be the best means to meet the claimed emergency.

At the time of issuing the December Order, Craig had a forced outage due to a mechanical failure. Ex. 2-06 (Tri-State December 2025 Press Release). Bringing Craig back into service took more than four weeks and required significant repairs and physical infrastructure changes to the plant. Ex. 2-166 at 1 (Tri-State January 2026 Press Release); Ex. 2-175 at 9, 16-17 (Tri-State and Platte River January Rehearing Request). The notion that a plant that experiences persistent and prolonged availability challenges best meets the claimed emergency is facially unreasoned, and the Order presents no supporting rationale.

Craig's unavailability is part of an alarming trend. From 2016 to 2020, Craig's forced outage rate was below 6%. Ex. 2-03 at 8 (Powers Decl.). Then, between 2022 and 2023, Craig's forced outage rate jumped from 1.75% to 9.53%. *Id.* A 9.53% forced outage rate translates to 835 hours that Craig could not operate in 2023. That means Craig was unavailable for approximately five weeks of the year, on top of any non-forced outages (such as planned outages taken for servicing the plant). *See id.*

Craig's unavailability and unreliability are likely to worsen in 2026 and beyond. Tri-State—Craig's operator—has slowed capital expenditures and maintenance at Craig. *See supra* sec. IV.B.3. Tri-State "proactively works to reduce and eliminate capital expenses" for retiring plants. Ex. 2-03 at 6 (Powers Decl.) (discussing Ex. 2-51 at 187 (Tri-State 2020 ERP)). Tri-State's filings with the Colorado Commission memorialize this approach for Craig. In 2023, Tri-State witness Insgold testified that its "investments in [the Craig Plant] are being appropriately limited to only actions necessary for ensuring safe operations and regulatory compliance, given the impending retirement of these units." Ex. 2-50 at 10 (Insgold 2023 ERP Direct Testimony). Mr. Insgold's testimony reflects Tri-State's consistent and strategic decision to decrease capital expenditures and maintenance at retiring coal plants like Craig. *Id.* As a result, Tri-State did not undertake projects that it likely believed were necessary for reliable operation past the planned retirement date. Ex. 2-03 at 6–7 (Powers Decl.). Consequently, it is unlikely that Craig can be depended upon to operate reliably beyond December 2025. *Id.* at 5–6, 8 (Powers Decl.). "Craig 1 will be especially unreliable if the plant is required to run for extended periods of time, is required to stop and start numerous times, or attempts to start up at an accelerated rate in response to extreme demand conditions." *Id.* at 5; *see also* Ex. 2-26 at 59 (NERC 2024 Reliability Report) ("[R]educed investment in maintenance and abnormal cycling that are being adopted primarily in response to rapid changes in the resource mix are negatively impacting baseload coal unit performance.").

The Order also fails to address the dangers to grid reliability that it creates. An unreliable coal plant like Craig is likely to cause grid disturbances and the "loss of power to homes and businesses in the areas that may be affected by curtailments or power outages." Order at 6. As Tri-State and Platte River themselves have explained, "[k]eeping Craig Unit 1 online now simply does not meet the terms of an emergency predicated on potential resource adequacy issues eight or more years in the future, particularly given that as Craig Unit 1's operations are further extended past its intended lifespan, it is likely to experience more and longer periods of outage." Ex. 3-06 at 32 (Tri-State and Platte River April Rehearing Request).

> Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of

> current performance trends. If a large coal plant trips offline while supporting a cluster of data centers, the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

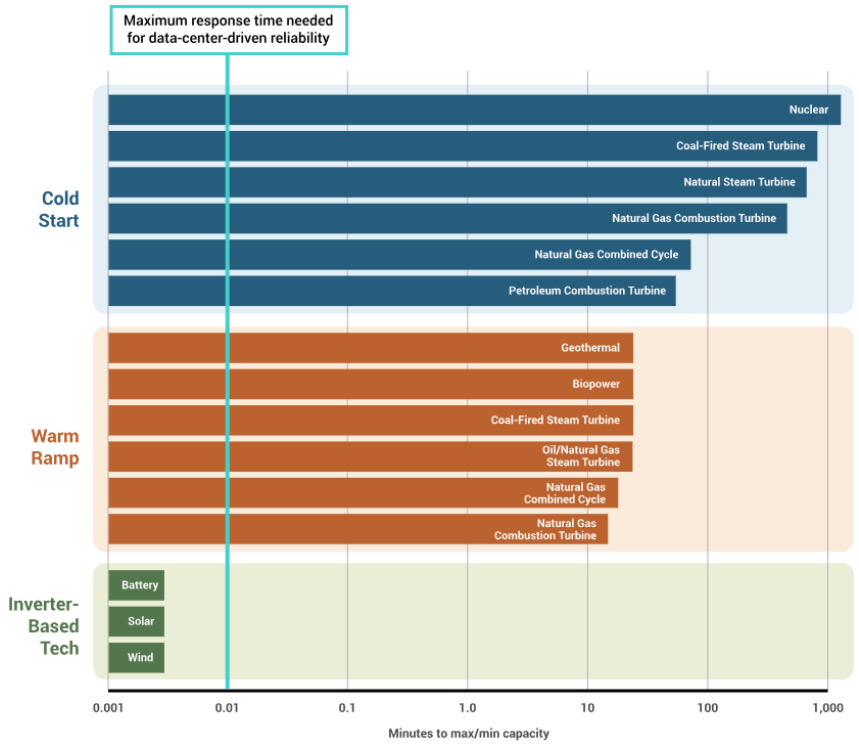
Ex. 2-44 at PDF 2–3 (RMI Analysis of Coal Plants' Threats to Reliability).

The Department avers that it is concerned with reliability, *see* Order at *passim*, yet puts forward no analysis to address the likelihood that it is actually creating the (otherwise unproven) problem it is supposedly trying to address. This ostrich-like approach to record evidence and public evidence is not reasoned decision-making. *Butte Cnty.*, 613 F.3d at 194; *cf. Ky. Mun. Energy Agency v. FERC*, 45 F.4th 162, 177 (D.C. Cir. 2022) (rejecting "ostrich-like approach" to agency decision-making).

Additionally, the Order provides no reasoned basis to conclude that Craig can meet the emergency given its technical capabilities. Craig is not designed to turn on quickly in response to times of extreme demand. Coal units like Craig usually require at least 12 hours to reach full load operation from a cold condition. Ex. 2-03 at 8–9 (Powers Decl.); Ex. 2-33 at 26 (IEA Flexibility Report); Ex. 2-44 (RMI Analysis of Coal Plants' Threats to Reliability); *see also supra* sec. IV.B.3. Meanwhile, "utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds." Ex. 2-03 at 9 (Powers Decl.).

The Order suggests that projections of demand growth, including from "data centers driving artificial intelligence," justify the continued operation of Craig. Order at 6. Even assuming *arguendo* the Department has authority under Section 202(c) to address that claimed circumstance (it does not), coal plants' "always-on nature" and "rigidity" are "a poor match for the dynamic and often unpredictable nature of data center demand." Ex. 2-44 at PDF 3 (RMI Analysis of Coal Plants' Threats to Reliability); *see also* Ex. 2-45 at 3 (Energy Innovation Report) (explaining that data center loads "are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place"); *see also* Ex. 2-32 at 16 (NARUC Coal Report) (discussing typical coal plants' startup and cycling costs); Ex. 2-33 at 26 (IEA Flexibility Report) (discussing coal plant start-ups). "[L]arge, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online." Ex. 2-44 at PDF 3 (RMI Analysis of Coal Plants' Threats to Reliability) (relying on NERC).

Figure 22: Minutes Needed for a Power Plant to Reach Max/Min Capacity



Source: Ex. 2-44 at PDF 3 (RMI Analysis of Coal Plants' Threats to Reliability).

In short, the Order fails to examine the inherent mismatch between the problem it diagnoses and the mandate it imposes. Thus, the Order does not reflect reasoned decision-making.

Additionally, the Order provides no reasoned basis for determining that Craig best meets the claimed emergency that may arise years into the future (which, again, the Department does not have authority to address under section 202(c)). Transmission and myriad other facilities are available alternatives over the multi-year span addressed by the Order. And the Order fails to identify a resource shortfall that is imminent and specific enough to identify any best-placed resource; the Order is unreasoned in failing to address how Craig is capable of meeting the generalized, uncertain claimed emergency. *See, e.g.*, *supra* sec. V.A.3; Ex. 2-02 at 10 (Grid Strategies Resource Adequacy Report). Additionally, the Order, like the Department's Section 202(c) orders to other plants, causes economic damage by, *inter alia*, crowding out otherwise competitive resources, disrupting planning, and creating policy-driven uncertainty. *See* Ex. 2-46 at PDF 2–3 (R Street Institute Commentary: *DOE "Zombies" Are Eating Competitive Power Markets*); Ex. 2-01 at 4 (Current Energy Group January Report) ("The [reviewed] studies do not support a proposition that extraordinary federal interventions into established processes are necessary to address the challenges in the latter part of the decade. Rather, federal intervention

sends mixed and counterproductive signals to the market that undermine existing planning and procurement practices."); Ex. 2-175 at 31 (Tri-State and Platte River January Rehearing Request) (stating that "Craig Unit 1's continued operation interferes with [Tri-State and Platte River's] ability to invest in other generation capacity" and that, due to transmission constraints, "Craig Unit 1's continued operation could interfere with the ability of new alternatives like Axial Basin to provide economic power to the grid"). Additionally, Craig's operations cause significant environmental harm, a factor the Department does not evaluate in reflexively selecting Craig to meet its (unproven) emergency. For all these reasons, too, the Order is without support in the record and unreasoned.

4. The Order Fails to Address or Reflect Consideration of Alternatives.

Other alternatives are available that meet the claimed emergency. The Department's failure to consider these alternatives is unreasoned and further shows that the Order is based on insubstantial evidence.

Hydropower, battery storage, demand response, and combustion gas turbines are all better suited to addressing rapidly varying, peak demand conditions. Ex. 2-03 at 9, 15 (Powers Decl.). As previously explained, *supra* secs. V.A.2, V.A.5, Colorado utilities have collectively built thousands of megawatts of new resources that are now online and provide generating capacity. For example, in 2026, Tri-State will have at its disposal a total of 717 MW of gas and oil-fired generation, 516 MW of hydropower, and 134 MW of demand response to address fast-changing demand on its system. Ex. 2-89 at 10 (Tri-State 2025 ERP Annual Progress Report). Further, Tri-State will have surplus capacity from 2026 through 2034, even without Craig. *Id.* But the Order fails to address—or even mention—these other readily available alternatives.

The Order also fails to address imports to the Rocky Mountain assessment area as an alternative to Craig to meet the purported emergency. Section 202(c) specifically identifies "delivery, interchange, or transmission of electric energy" as among the alternatives available to meet a claimed emergency. 16 U.S.C. § 824a(c)(1). And the Department's regulations provide for consideration of available resources, including power transfers. 10 C.F.R. §§ 205.373(f), 205.375. The Department has long recognized that power pools and utility coordination "are a basic element in resolving electric energy shortages." *Emergency Interconnection of Elec. Facilities and the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power,* 46 Fed. Reg. 39984, 39984–86 (Aug. 6, 1981). Recent history demonstrates the important role of transmission connectivity along with imports and exports. *See, e.g.*, Ex. 2-30 at 64 (Winter Storm Elliott System Operations Inquiry) ("Despite tightening conditions on the MISO system . . . MISO maintained steadily increasing exports to TVA throughout the day."); Ex. 2-31 at 43, 83–84 (PJM Elliott Report) (describing PJM exports); *see also* Ex. 2-15 at PDF 2 (DOE Order No. 202-02-1) (providing for usage of interregional transmission). According to NERC, starting in summer 2029, "imports

may be necessary if new resources were to be significantly delayed." Ex. 2-07 at 128 (NERC 2024 Long-Term Reliability Assessment).

Here, the Department does not discuss a notable change between the Order and the December Order issued for Craig Unit 1: that SPP West became operational on April 1, 2026. As noted previously, several large utilities in the Rocky Mountain region became participants in SPP West effective April 1, including Tri-State. The Order does not evaluate alternatives to meet the claimed emergency due to this change.

The Department offers no reasonable basis to question the availability of resources from neighboring regions. But even if there were barriers to transmission from those regions, the Department has not (and likely could not) explain why the Order provides a better means of ensuring resource sufficiency than addressing those barriers directly through its power to require "interchange" and "transmission" of electric energy from those neighboring regions. 16 U.S.C. § 824a(c)(1).[10]

In fact, the successful operation of the grid during the December Order's duration prove that other alternatives can meet the (unreasoned, unsubstantial, and unlawful) claimed emergency. Craig broke and went out of service on December 19, 2025, almost two weeks before the December Order issued, and stayed that way until January 20, 2026. *See* Ex. 2-166 at 1 (Tri-State January 2026 Press Release); Ex. 2-06 (Tri-State December 2025 Press Release). Even after it was repaired, Craig was never called upon to operate before the December Order expired. Ex. 2-177 at 2 (March 30, 2026 Colorado Sun Article). There is no evidence of an increase in adverse resource adequacy or reliability events during that time period. Supply and demand were balanced by alternatives to Craig. The Department must consider the proven alternatives to reach a reasoned decision based on substantial evidence.

Lastly, in response to the Public Interest Organizations' rehearing request of the December Order, Ex. 3-01 at 7 (Department Order No. 202-25-14B, "December Rehearing Order"), the Department cited a study showing that the amount of "[a]ctive capacity in [interconnection] queues (~2,290 GW) is nearly twice the installed capacity of U.S. power plant fleet (~1,320 GW); greater than peak load and installed capacity in most regions," Ex. 3-02 at 17 (Queued Up: 2025 Edition), and that "[a]ctive queue capacity is highest in the West (584 GW)," *id.* at 16. Despite being issued after

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[10] The Department must also incorporate demand-side resources as a condition precedent to, or an alternative to, circumstances calling for generation by a polluting resource like Craig (and in determining whether an emergency exists), a requirement consistent with Departmental practice. *See* 16 U.S.C. § 824a(c)(1)–(2); 10 C.F.R. § 205.375; *e.g.*, Ex. 2-16 at 3 (DOE Order No. 202-20-2); Ex. 2-17 at 4–5 (DOE Order No. 202-22-2); Ex. 2-18 at 2–3 (DOE Order No. 202-281).

the December Rehearing Order, the Order at issue here does not reflect any consideration of the alternative of using authorities that may be available to the Department to speed up the interconnection of these generating resources.

C. The Order Exceeds Other Limits on the Department's Authority.

1. The Department Lacks Jurisdiction to Impose the Availability Requirements.

In directing the Craig Co-Owners to take "all measures" to ensure that Craig is "available to operate," Order at 7, the Department exceeds its authority under Section 202(c) of the Federal Power Act and impermissibly intrudes on the authority over generating facilities that Section 201(b) of the statute reserves to the states, 16 U.S.C. §§ 824(b)(1), 824a(c)(1). The sweeping language in the Department's Order would encompass physical and all other changes necessary to revive a generating plant undergoing closure pursuant to a state-approved retirement process. The Federal Power Act's language, structure, legislative history, and interpretation by the courts all confirm that the Department's Order is unlawful.

The structure and language of the Federal Power Act reflect Congress's deliberate choices to preserve the states' traditional authority over generating facilities and to circumscribe the Department's emergency authority in light of the states' role. The first sentence of the Federal Power Act declares that federal regulation extends "only to those matters which are not subject to regulation by the States." *Id.* § 824(a). Section 201(b)(1) states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy." *Id.* § 824(b)(1). The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities, *see, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 155 (2016), including the authority to order their closure, *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009) (explaining that under Section 201(b), states retain the right "to require the retirement of existing generators" or to take any other action in their "role as regulators of generation facilities"). Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes." 16 U.S.C. § 824a(b).

There is a clear distinction between authority to regulate generation facilities and the Department's authority under Section 202(c) to require generation of electric energy. Electric energy is an electromagnetic wave, and its "generation, delivery, interchange, and transmission" is the creation and propagation of that wave. *See* Brief *Amicus Curiae* of Electrical Engineers, Energy Economists and Physicists in Support of Respondents at 2, *New York v. FERC*, 535 U.S. 1 (2002); *see also* Edison Electric Institute Glossary of Electric Utility Terms (1991 ed.) (defining electric generation as "the act or process of transforming other forms of energy into electric energy"). Section 202(c)(1), like the rest of the Federal Power Act, is written "in the

technical language of the electric art" and federal jurisdiction generally "follow[s] the flow of electric energy, an engineering and scientific, rather than a legalistic or governmental test." *Conn. Light & Power v. Fed. Power Comm'n*, 324 U.S. 515, 529 (1945); *see also Fed. Power Comm'n v. Fla. Power & Light Co.*, 404 U.S. 453, 454, 467 (1972).

The scope of the Department's emergency power under Section 202(c) is bounded both by the provision's specific language and Congress's clear intention and repeated direction in the Federal Power Act to respect the states' authority over generating facilities. When an actual emergency exists, Section 202(c)(1) authorizes the Department to order only two specific things: (1) "temporary connections of facilities" and (2) "generation, delivery, interchange, or transmission of electric energy." *Id.* § 824a(c)(1). The only reference to "facilities" in the authorizing provision of Section 202(c)(1) appears in the clause relating to temporary connections, not in the clause pertaining to "generation" of electric energy. And that clause only authorizes connections "of" facilities; it does not provide authority to regulate the facilities. The differences in Congress's word choice in these clauses—referencing "facilities" in one authorizing provision but not the other—must be given effect. *See, e.g.*, *Gallardo v. Marstiller*, 596 U.S. 420, 430 (2022); *Gomez-Perez v. Potter*, 553 U.S. 474, 486 (2008).

Given Congress's use of the term "generating facilities" elsewhere in the statute, if it had intended to give the Department authority over generating facilities in Section 202(c)(1), it would have done so explicitly. Instead, the provision conspicuously excludes authority to manage the physical characteristics of power plants. Congress purposely limited and particularized the Department's emergency powers, carefully avoiding intrusion on the states' authority over generating facilities recognized in Section 201(b)(1). *See* S. Rep. No. 74-621, at 19 (explaining that the emergency powers in Section 202(c)(1) "which were indefinite in the original bill have been spelled out with particularity"); *compare* S. 1725, Cong. Tit. II § 203(a) (providing in original, unenacted bill that control of the production and transmission of electric energy "except in time of war or other emergency declared to exist by proclamation of the President, shall, as far as practicable, be by voluntary coordination"), *with* 16 U.S.C. § 824a(c)(1) (providing particularized, specific authorities and circumstances in which the authorities may be exercised).

In certain circumstances, the Department may require generation of electric power, and a utility may properly take steps at the facility to produce the power. It is commonplace in the electric sector for the federal regulator properly acting within its authority to cause effects in a state regulator's jurisdictional sphere, and vice versa. *See Elec. Power Supply Ass'n*, 577 U.S. at 281. But the federal regulator may neither directly regulate generation facilities nor impose requirements aimed at the facilities, even if nominally regulating within its sphere. *See id.* at 281–82; see also *Hughes*, 578 U.S. at 164–65. Such encroachment is impermissible, even in a real emergency or in a wrongly claimed one. *See Conn. Light & Power*, 324 U.S. at 530 ("Congress is acutely aware of the existence and vitality of these state governments. It sometimes

is moved to respect state rights and local institutions even when some degree of efficiency of a federal plan is thereby sacrificed."). Thus, the Department may not require generation that necessitates the utility taking steps reserved to state authority, such as building a new generating unit or refurbishing a broken one.

The Federal Power Act does not give the Department sweeping authority to order "all measures" needed to make a generation facility "available to operate." 16 U.S.C. § 824a(c)(1). Nowhere does the statute empower the Department to order "all" steps that may be needed to ensure Craig's availability, which could include repairs or modifications to physical facilities and other measures going far beyond electric power generation. Because the plant is at the end of its useful life, with years of forgone maintenance and capital expenditures, rendering it capable of meeting a short-term supply shortfall could essentially require rebuilding significant parts of the plant. *See* Ex. 2-175 at 13 (Tri-State and Platte River January Rehearing Request) (stating that the Craig Co-Owners have had to make "material physical changes to the plant, including repairing out-of-service equipment"). On its face, the Department's Order is *ultra vires*. The Order also contravenes the Federal Power Act's repeated direction to respect the states' authority over generating facilities, which includes the authority that Colorado exercised in providing and planning for Craig's closure. *See, e.g.,* COLO. REV. STAT. §§ 40-2-125.5 (requiring retail utilities to submit joint electric resource and clean energy plans for Colorado Commission approval), 40-2-137 (allowing investor-owned utilities to submit resource portfolios that retire existing electric generating facilities), 40-2-134 (requiring wholesale electric cooperatives to submit electric resource plans for Colorado Commission approval); *see also* 4 COLO. CODE REGULS. 723–3:3600–723–3:3619; 40 C.F.R. § 51.308 (providing states' requirements and authority under the regional haze program). The Order, therefore, is unlawful and should be withdrawn.[11]

2. The Department Lacks Jurisdiction to Disallow Treatment of Craig as a Capacity Resource.

The Order also includes an explicit instruction that "[b]ecause this order is predicated on the shortage of facilities for generation of electric energy and other causes, Craig Unit 1 shall not be considered a capacity resource." Order at 7. This instruction serves only to increase costs to customers, who will be required to procure duplicative capacity as a result. It is also illegal.

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[11] A utility that takes steps outside of what section 202(c) authorizes—"temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy," 16 U.S.C. § 824a(c)(1)—cannot point to a Section 202(c) order as the basis for a right to recover those costs. *See id.* (providing for compensation or reimbursement to be paid based on just and reasonable terms for carrying out an authorized order).

Section 202(c) authorizes the Commission to "require by order . . . temporary connections of facilities and . . . generation, delivery, interchange, or transmission of electric energy," and then shields facilities who operate pursuant to a Section 202(c) order from liability for unavoidable violations of federal, state, or local environmental laws or regulations. 16 U.S.C. § 824a(c)(1), (3). Nowhere does the Act suggest that the Department may predetermine or override the reasoned decisions of FERC in its determination of whether just and reasonable wholesale rates require an operating resource to be considered a capacity resource. Indeed, the very nature of 202(c) orders, which are limited to emergencies involving extant resource shortfalls (in which, by definition, there are no alternative capacity resources that might be displaced by the ordered generation) suggests that capacity resource treatment is well outside the Department's 202(c) authority. There is simply no rational connection between the Order's instruction and the Department's limited authority to "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." 16 U.S.C. § 824a(c)(1).

The impropriety of this instruction is exacerbated by the Order's failure to tie it to any discernible purpose that would alleviate the purported emergency underlying the Order. The only explanation the Order offers for the instruction—essentially that Craig cannot be a capacity resource because the order does not deem it a capacity resource—is clearly circular. As a result, the true reasoning behind this instruction remains unclear—but one clear effect, particularly now that two of the Craig co-owners have joined SPP, is to prevent SPP from considering the continued existence of Craig as it works to ensure resource adequacy across its footprint. SPP's tariff requires that Load Responsible Entities in its region maintain adequate capacity to meet their Resource Adequacy Requirement, which is calculated by multiplying each entity's peak load projection by an SPP-determined Planning Reserve Margin.[12] The tariff also establishes clear procedures for calculating capacity contribution from all resources. Thus, the Order's elimination of capacity treatment for Craig prevents SPP from following its own tariff in the wake of Craig's continued operation.

The Department does not have authority under Section 202(c) to govern ratemaking matters. The Department of Energy Organization Act transferred only partial authorities of the Federal Power Commission to the Department, and transferred to the Federal Energy Regulatory Commission "the establishment, review, and enforcement of rates and charges for the transmission or sale of electric energy." 42 U.S.C. § 7172(a); *see* 42 U.S.C. subchapter IV, 42 U.S.C. § 7151(b).

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[12] SPP Open Access Transmission Tariff, Att. AA, https://www.spp.org/spp-documents-filings/?id=18162.

The Order thus represents a significant and improper intrusion into FERC's authority to ensure that RTOs like SPP justly and reasonably ensure resource adequacy in their footprints. In particular, the Order undermines years of FERC's regulatory oversight of SPP's resource adequacy construct, as codified in SPP's FERC-approved tariff. It is within FERC's purview under Section 205 of the Federal Power Act to provide that oversight, 16 U.S.C. § 824d, and it is within SPP's purview to apply its own tariff in the first instance and decide whether Craig should be able to provide capacity to meet Resource Adequacy Requirements within SPP's FERC-approved resource adequacy construct, 18 C.F.R. § 35.1(e) ("No public utility shall . . . impose any classification, practice, rule, [or] regulation . . . which is different from that provided in a rate schedule required to be on file with this Commission unless otherwise specifically provided by order of the Commission for good cause shown.").

The Department's intrusion into the oversight relationship between FERC and the RTOs also runs afoul of the filed-rate doctrine, which holds that "no change shall be made [in] any [approved] . . . rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission and to the public" in another filing with FERC. 16 U.S.C. § 824d(d); *Okla. Gas & Elec. Co. v. FERC*, 11 F.4th 821, 829 (D.C. Cir. 2021). Interference in SPP's capacity accreditation procedures effectuates a de facto change to its tariff, without the legally required notice. And more generally, "Congress rejected a pervasive regulatory scheme for controlling the interstate distribution of power in favor of voluntary commercial relationships. . . . governed in the first instance by business judgment and not regulatory coercion." *Otter Tail Power*, 410 U.S. at 374. The Department's interference here in the core operational procedures of SPP's resource adequacy construct improperly upends that relationship.

The impact of the instruction on the Craig Co-owners that have not joined SPP is no more proper. Utilities that are not RTO members are still subject to FERC oversight, as are their resource adequacy determinations. Intruding into those utilities' efforts to follow FERC-approved processes to ensure resource adequacy similarly intrudes on FERC's authority. Additionally, to the extent the decree is directed to state and local officials who also regulate those utilities and provide oversight over their resource adequacy constructs, the Order violates the Tenth Amendment by commandeering state and local officials to implement a federal program. *See, e.g.*, *Printz v. United States*, 521 U.S. 898, 933 (1997).

More broadly, the Department's instruction disallowing SPP from including Craig in its resource adequacy planning suggests that it does not trust SPP and the Craig Co-Owners to accurately assess resource adequacy—the instruction would otherwise be unnecessary to maintain grid security, and therefore outside the Department's Section 202(c) authority. But the Order provides no evidence that either SPP or the non-SPP Craig Co-Owners cannot be trusted to ensure resource adequacy, so a

Department determination that they cannot be trusted would be arbitrary and capricious.

If left unchecked, this provision could impose completely avoidable cost increases on Colorado and SPP ratepayers, by forcing them to pay not only for the resources necessary to meet their own resource adequacy goals, but also for an additional resource, Craig, that the Department is forbidding from contributing to those resource adequacy goals. Even were there a valid emergency justifying the Order, this instruction induces wasteful and unnecessary investments and should be rescinded.

In short, including this instruction is yet another way in which the Department has misapplied the statute: its inclusion only further ensures that Craig's principal impact will not be to plug a gap but rather to sabotage the resource planning of the Craig Co-Owners and heighten cost burdens in a manner that does not serve the public interest.

D. The Order Fails to Provide the Conditions Required Under Section 202(c) to Lessen Conflicts with Environmental Standards and Minimize Environmental Harm.

Where an order "may result in a conflict with a requirement of any Federal, State, or local environmental law or regulation," Section 202(c) imposes several requirements. 16 U.S.C. § 824a(c). The Department must "ensure" that the order "requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest." *Id.* The Department must also "ensure," "to the maximum extent practicable," that the order "is consistent with any applicable Federal, State or local environmental law or regulation." *Id.* Additionally, the Department must ensure that the order minimizes any adverse environmental impacts, regardless of the facility's compliance (or non-compliance) with environmental standards. *See id.*

1. Legal Framework: Section 202(c) Further Limits the Department's Authority and Mandates Affirmative Steps to Maximize Environmental Compliance and Minimize Environmental Harm Where the Order "May Result in a Conflict" with a Federal, State, or Local Environmental Law or Regulation.

The Federal Power Act obligates the Department to include precautions in a Section 202(c) Order where the order "may result in a conflict" with environmental laws or regulations. This is a forward-looking inquiry with a low threshold.[13]

[13] If actual noncompliance with environmental laws and regulations occurs to carry out the order, the statute provides a safe harbor. 16 U.S.C. § 824a(c)(3).

The word "may" in this context denotes a mere possibility, not a certainty. This is especially apparent when matched against the term "shall" used in Section 202(c)(2) and the other provisions added to Section 202(c) at the same time. *See* Fixing America's Surface Transportation Act of 2015, Pub. L. No. 114-94, 129 Stat. 1312 § 61002 (codified at 16 U.S.C. § 824a). Congress' use of the two disparate terms must be given effect. *See, e.g.*, *Kingdomware Techs., Inc. v. United States*, 579 U.S. 162, 172 (2016) (discussing significance of the words "may" and "shall" in the same statutory provision).

Moreover, the consequences need not be "noncompliance" or "violation" of environmental law, both of which are terms Congress also used in 2015 when adding other provisions to Section 202(c). A potential "conflict" suffices. *Cf. Crosby v. Nat'l Foreign Trade Council*, 530 U.S. 363, 372–73 (2000) (explaining that courts find "conflict" in the preemption context where, for instance, a law or order "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress"). Taken together, anytime a Department order creates circumstances that might obstruct the accomplishment or execution of environmental laws or regulations, Section 202(c)(2) imposes duties on the Department to maximize compliance with the law and minimize adverse environmental effects.

Congress adopted the requirements of Section 202(c)(2) to address environmental issues arising in response to emergencies on the grid. Congress was well aware of environmental issues stemming from 202(c) orders when it imposed the requirements in Section 202(c)(2). *See, e.g.*, Rolsma, 57 Conn. L. Rev. at 807–09 (discussing prior incidents of tension between environmental requirements and responses to emergencies on the grid, and congressional hearings addressing the matter as part of the passage of Section 202(c)(2)). Congress struck a reasonable balance requiring that environmental concerns not be left by the wayside while the Department responds to actual emergencies. Rather than requiring the Department to engage in a probing review of environmental laws and permits at all levels of our federalist system before acting, Congress set a low threshold for imposition of the mandatory Section 202(c)(2) duties to minimize conflicts with state environmental laws and environmental harms flowing from a Section 202(c) order.

2. The Order May Result in a Conflict with a Federal, State, or Local Environmental Law or Regulation.

Here, the Department implicitly acknowledges the possible conflict. The Order is limited to a 90-day duration. Order at 8. That temporal limitation exists for a Section 202(c) order that may result in a conflict with environmental requirements. 16 U.S.C. § 824a(c)(4).

The evidence shows that the Order results in an actual conflict with state and federal environmental regulations: the provision in Colorado's federally-approved Clean Air Act State Implementation Plan ("SIP") that requires Craig to close on or

before December 31, 2025. 83 Fed. Reg. 31332 (July 5, 2018) (approving Colorado's SIP revision establishing Craig's closure date); Ex. 2-65 at 183 at § F.VI.D.1 (CDPHE Regulation No. 3) (Colorado Regulation No. 3 provision regarding Craig's closure, which EPA approved). This SIP provision addresses Colorado's legal obligations under the Clean Air Act's regional haze program, which Congress created to combat the negative effects of air pollution on visibility and treasured scenic vistas in federal "Class I" areas (i.e., listed national parks and wilderness areas). *See generally* 42 U.S.C. § 7491. Congress determined that these areas should enjoy the highest level of air quality and set a national goal of eliminating all human-caused visibility impairment. *Id.* §§ 7491(a)(1); 7472(a). Under the Clean Air Act and EPA's Regional Haze Rule, states must periodically revise their SIPs to continue making progress toward Congress's national visibility goal. *Id.* § 7491(b)(2); 40 C.F.R. § 51.308(b), (f), (g). Once EPA approves a state's SIP, it becomes enforceable under federal law. 42 U.S.C. § 7413(a)(1)–(2).

In developing its SIP for the regional haze first implementation period, Colorado determined that air pollution from the Craig Plant contributes to visibility impairment in several Colorado Class I areas, including (among others) Rocky Mountain National Park, Flat Tops Wilderness Area, Eagles Nest Wilderness Area, Mount Zirkel Wilderness Area, and Rawah Wilderness Area. Ex. 2-03 at 11 (Powers Decl.); Ex. 2-71 at 47–48 (BART CALPUFF). These areas are shown in Figure 23 below.

Figure 23: Map of Colorado Class I Areas Affected by Visibility Impairment



Source: Google Earth.

Colorado revised its air pollution control regulations and submitted a SIP revision to EPA in 2017, which established two compliance pathways for Craig: (1) closure by December 31, 2025; or (2) conversion to natural gas-firing by August 31, 2023, coupled with more stringent NO_x emission limits. 83 Fed. Reg. 31332. EPA approved the SIP revision, thereby incorporating by reference the compliance requirements for Craig into the Code of Federal Regulations. *Id.* at 31333. The owners of Craig elected to

close the facility by December 31, 2025, and have not converted it to natural gas-firing. The closure deadline is also contained in Craig's air permit. Ex. 2-73 at 23 (Craig Station Operating Permit) (condition 1.10.1 of Craig air permit). Therefore, the Order's mandate for Craig to be available for operation through June 28, 2026 directly conflicts with state and federal environmental regulations.

In addition to flouting Craig's enforceable closure deadline, the Order may result in a conflict with other environmental requirements. Craig's air permit contains emission limits for NO_x, PM, and SO_2, pollutants that harm human health and contribute to haze formation. Ex. 2-03 at 11 (Powers Decl.); Ex. 2-73 (Craig Station Operating Permit) (sec. II of Craig air permit). The facility operates pollution control equipment to achieve compliance with those limits: ultra-low NO_x burners with overfire air for NO_x control; wet limestone scrubbers for SO_2 control; and pulse jet fabric filters (baghouse) for PM control. Ex. 2-03 at 11 (Powers Decl.). The air permit requires the facility to properly maintain and operate pollution control equipment to achieve compliance with emission limits and to minimize air pollution from the facility. *Id.* at 13. Failure to install, maintain, and operate these air pollution controls in a satisfactory manner can increase emissions, creating a risk that the facility will violate its emission limits. *Id.* at 9, 13–14. For example, over time, fly ash erodes and plugs the bags used in pulse jet fabric filters, causing the bags to degrade and potentially to rupture. *Id.* at 14. Regular bag replacement is necessary for satisfactory performance. *Id.* Similarly, wet limestone scrubbers often suffer from scale formation, poor utilization of reagent, and inadequate spray nozzle efficiency. *Id.* And ultra-low NO_x burners can be degraded by erosion at the burner tip and wear in the coal pulverizers, requiring regular maintenance to minimize NO_x in the boiler. *Id.* There is no information in the public record indicating that the pollution control equipment at Craig has been maintained in a manner that would support operational integrity and adequate emissions control performance beyond the facility's planned closure date. *Id.* at 14–15. Therefore, it cannot be assumed that Craig's pollution control equipment is in good working order and will operate reliably to control the facility's air emissions. *Id.* at 15.

3. The Order Lacks the Conditions Required by Section 202(c).

i. The Order Fails to Require Generation Only During Hours Necessary to Meet the Purported Emergency.

The Order directly contradicts the Department's obligation to require generation "only during hours necessary to meet the emergency." 16 U.S.C. § 824a(c)(2). The Order instead states: "For the duration of this Order, SPP is directed to take every step to employ *economic dispatch* of Craig Unit 1 to *minimize costs* to ratepayers." Order at 7 (emphasis added). The "emergency" nominally described by the Order is the potential "loss of power to homes and businesses in the areas that may be affected by curtailments or power outages." *Id.* at 6. Even if the Department had substantiated that emergency (which it has not), the Act would allow the Department

to compel generation only when such losses would occur absent Craig's operation. 16 U.S.C. § 824a(c)(2).[14] "Economic dispatch," in sharp contrast, requires "the lowest-cost resources [to] run first," in pursuit of "the lowest-cost energy available." *City of New Orleans v. FERC,* 67 F.3d 947, 948–49 (D.C. Cir. 1995)*; see also Fla. Power & Light Co. v. FERC,* 88 F.3d 1239, 1241 (D.C. Cir. 1996) (noting distinction between economic dispatch and reserve capacity rules).

By instructing SPP to pursue economic dispatch, the Order's terms permit (indeed, direct) operation of Craig even when other—albeit potentially higher cost—resources are available that would prevent any "curtailments or outages"—that is, the claimed emergency. The Order's further instructions—limiting "operation of Craig Unit 1 to the times and within the parameters established in paragraph A," Order at 7—do not provide the necessary limitation either; they simply repeat that initial instruction without any further limitation.[15]

Moreover, a Department allowance for Craig to offer into SPP on a must run basis, *see generally* DOE Order No. 202-25-7B at P 59, also violates the Department's obligations under Section 202(c)(2). Such allowance fails to ensure generation only during hours needed to meet the claimed emergency. Even Secretary Wright has recognized the waste and cost associated with such an approach:

> [W]hen I hear politicians say we just need more electrons on the grid, no we don't. No we don't. It's the middle of the day and the weather is mild. . . . It just means we send subsidy checks to those generators and we tell the other generators turn down because we're mailing subsidy

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[14] *See, e.g.*, Ex. 2-14 at 9 (DOE Order No. 202-17-4 Summary of Findings) ("authorizing operation of" units subject to emergency order "only when called upon . . . for reliability purposes," according to "dispatch methodology" approved by the Department); *see also* Ex. 2-21 at 7 (Department Order No. 202-26-01) (authorizing specified entities "to direct [certain] backup generation resources . . . to operate as a last resort before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load interruption) or during an EEA 3"); Ex. 2-22 at 7 (Department Order No. 202-26-01A) (authorizing specified entities "to direct [certain] backup generation resources . . . to operate after ERCOT deploys all available market services, except for frequency responsive services, before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load interruption) or during an EEA 3"); *cf.* Ex. 2-23 at 3 (Department Order No. 202-26-03) ("In the event that ISO-NE determines that generation from the Specified Resources is necessary to meet the electricity demand that ISO-NE anticipates in its service territory, I direct ISO-NE to dispatch such unit or units and to order their operation only as needed to maintain reliability.").

[15] That direction further fails to conform to the statute's command to compel only the generation that will "best meet the emergency." 16 U.S.C. § 824(c)(1).

> checks to these generators. . . . Giving me extra electricity when I don't need it is just an extra cost.

Secretary Wright Remarks on Affordability and Reliability of Electricity Grid, YouTube, timestamps at 4:30 and 15:00 (Feb. 6, 2026), https://www.youtube.com/watch?v=pRi38SJkHPQ.

ii. The Order Fails to Ensure Maximum Practicable Consistency with Environmental Rules and to Minimize Adverse Environmental Impacts.

The Order further fails to "ensure" that Craig operates "to the maximum extent practicable" consistent with applicable environmental rules. Order at 7; 16 U.S.C. § 824a(c)(2). The Order paraphrases the statutory text—that "operations of Craig Unit 1 must comply with applicable environmental requirements . . . to the maximum extent feasible," but fails to specify *who* bears that responsibility or *what* such operation entails. Order at 7. It imposes no further conditions beyond stating that the Order provides no relief from any obligation to "pay fees, or purchase offsets or allowances for emissions." *Id*. The direction to "comply . . . to the maximum extent feasible" is, as a result, wholly unenforceable; the Order provides no basis for the Department, or anyone else, to determine whether the plant is in fact complying or who might face the consequences of any failure to do so. *Cf.* Ex. 2-13 at 5–7 (DOE Order No. 202-22-4) (requiring, *inter alia,* reporting of "number and actual hours each day" of operation "in excess of permit limits or conditions," and information describing how generators met requirement to comply with environmental requirements to maximum extent feasible). As such, the Order does not meet the Department's statutory obligation to "*ensure*" the maximum feasible consistency with applicable environmental standards—an obligation that requires the Department to offer some discrete direction as to the plant's operations, rather than merely parroting the statutory text. 16 U.S.C. § 824a(c)(2) (emphasis added).

The most definitive way to maximize consistency with state and federal environmental laws and regulations would be to limit Craig's generation to only the hours necessary to address a "loss of power to homes and businesses" that would occur absent Craig's generation. That limitation would reduce air pollution that contributes to, among other things, visibility impairment in Colorado Class I areas, a problem the closure of Craig was intended to address pursuant to the Clean Air Act's regional haze requirements.

In addition, the Order fails to "minimize[] any adverse environmental impacts." 16 U.S.C. § 824a(c)(2). That mandate is textually and substantively distinct from the Department's (also unfulfilled) obligation to ensure maximum practicable compliance with environmental standards. *Id.*

The Order claims to minimize impacts by "limit[ing] operation of Craig Unit 1 to the times and within the parameters established in paragraph A." Order at 7. But Paragraph A states only that the Craig Co-Owners shall "take all measures necessary

to ensure that Craig Unit 1 is available to operate" at the direction of SPP, that SPP must "take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers," and that the Co-Owners shall "comply with all orders from SPP related to the availability and dispatch of Craig Unit 1." *Id.* at 7.[16] Instructions demanding availability and economic dispatch have no rational relationship to a requirement to minimize environmental harm. And the Order includes no measures that would mitigate impacts when compliance with environmental standards proves impracticable—measures that have been routinely included in past orders. *See, e.g.*, Ex. 2-14 at 9 (DOE Order No. 202-17-4 Summary of Findings) (permitting non-compliant operation only during specified hours, and requiring exhaustion of "all reasonably and practically available resources," including demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions); Ex. 2-13 at 7 (DOE Order No. 202-22-4) (requiring "reasonable measures to inform affected communities" of non-compliant operations).

The Order makes no attempt to minimize adverse environmental impacts. As stated above, the clearest way to minimize adverse environmental impacts would be to limit Craig's generation to only during hours necessary to address a "loss of power to homes and businesses" that would occur absent Craig's generation. Without that limitation, the Order allows Craig to emit air pollution during operations that are not needed to meet the Department's claimed (and unsupported) emergency. Craig is a significant emitter of NO_x, PM, SO_2, and CO_2. Ex. 2-03 at 11–13 (Powers Decl.). That air pollution is likely to harm human health and the environment and to adversely affect air quality in the state's widely visited national parks and wilderness areas. At a minimum, minimizing adverse environmental impacts would require verification of the good working order of Craig's pollution control equipment, given Tri-State's lack of investment in the unit in preparation for its intended closure. *Id.* at 13-15.

Moreover, the statute requires the Department to include sufficiently detailed reporting obligations to ascertain what impacts result from emergency operations; without such reporting, the Department has no ability to "ensure" that adverse impacts are minimized. *See, e.g.*, Ex. 2-24 at 5 (DOE Order No. 202-24-1) (requiring detailed data on emissions of pollutants). The Order here instead only requires "such additional information" as the Department, in the future, may (or may not) "request[] . . . from time to time." Order at 7. That possibility of future, unspecified

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[16] To the extent the Order allows SPP to independently devise conditions limiting environmental impacts, that mere possibility, first, cannot satisfy the Department's own statutory obligation to "ensure" that its "order" minimizes environmental impacts (and limits hours to those necessary to meet the emergency, and mandates the maximum practicable compliance). 16 U.S.C. § 824a(c)(2). And even if it could, the Order requires Tri-State and the Co-Owners to "ensure that Craig Unit 1 is available to operate," Order at 7, a direction that is inconsistent with the statute's requirements to minimize the plant's adverse environmental impacts.

inquiry cannot satisfy the statute's demand that the Department "ensure" that its Order minimizes environmental impacts. 16 U.S.C. § 824a(c)(2).

iii. There Is No Indication that the Department Has Conducted the Consultation Required by Section 202(c)(4)(B) or Adopted Conditions Resulting from Consultation.

Finally, there is no indication in the Order or otherwise that the Department has, as Section 202(c)(4)(B) requires, "consult[ed] with the primary Federal agency with expertise in the environmental interest protected" by the laws with which the Order may conflict. 16 U.S.C. § 824a(c)(4)(B); *see* Order at 6–7. The Order serves as a renewal or re-issuance of the March Order; it claims an emergency exists in the Rocky Mountain assessment area and that "[t]he emergency conditions that necessitated the issuance of Order Nos. 202-25-14 and 202-26-21 continue." Order at 1, 3. But the Department has provided no evidence of consultation with any federal agency having expertise in the environmental interest protected by the laws and regulations with which the Order may conflict. *Cf.* Ex. 2-187 at 2 (Department Order No. 202-22-2 Amendment No. 1) (stating that "the Department consulted with EPA . . . and EPA did not request any additional conditions"); Ex. 2-188 at 2 (Department Order No. 202-22-1 Amendment No. 2) (same); Ex. 2-14 at 9–10 (Department Order No. 202-17-4 Summary of Findings) (including EPA consultation in public record). Nor is there any evidence of "[t]he conditions, if any, submitted" by EPA (or any other agency) following consultation, or "an explanation of [the Department's] determination" that such conditions "would prevent the [Order] from adequately addressing the emergency"—material that Section 202(c)(4)(B) requires the Department to make "available to the public." 16 U.S.C. § 824a(c)(4)(B); *see* Ex. 2-189 at 1 (Starfield Email to Hoffman) (made public by Department). If the Department has failed to consult and procure the required conditions, the Order is contrary to law. 16 U.S.C. § 824a(c)(4)(B). If the Department has received and declined conditions, but refused to disclose them or an explanation of why the Department does not believe any such conditions are necessary, that too is contrary to law. *Id.*

VI. REQUEST FOR STAY

Public Interest Organizations further move the Department for a stay of the Order until the conclusion of judicial review. 18 C.F.R. § 385.212.[17] The Department has the authority to issue such a stay under the Administrative Procedure Act and should do so where "justice so requires." 5 U.S.C. § 705. In deciding whether to grant a request for stay, agencies consider (1) whether the party requesting the stay will suffer irreparable injury without a stay; (2) whether issuing a stay may substantially harm

[17] Pursuant to Federal Power Act Section 313(c) and Rule 713(e) of the applicable rules, the filing of a request for rehearing does not automatically stay a Department Order. 16 U.S.C. § 825*l*(c); 18 C.F.R. § 385.713(e).

other parties; and (3) whether a stay is in the public interest. *Nken v. Holder*, 556 U.S. 418, 434, 436 (2010); *Ohio v. EPA*, 603 U.S. 279, 291 (2024); *see, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.,* 184 FERC ¶ 61,020, at P 41 (2023); *ISO Eng. Inc.*, 178 FERC ¶ 61,063, at P 13 (2022), *rev'd on other grounds sub nom. In re NTE Conn., LLC*, 26 F.4th 980, 987–88 (D.C. Cir. 2022).

Injuries under this standard must be actual, certain, imminent, and beyond remediation. *Mexichem Specialty Resins, Inc. v. EPA*, 787 F.3d 544, 555 (D.C. Cir. 2015); *Wis. Gas Co. v. FERC*, 758 F.2d 669, 674 (D.C. Cir. 1985); *ANR Pipeline Co.*, 91 FERC ¶ 61,252, at 61,887 (2000); *City of Tacoma*, 89 FERC ¶ 61,273, at 61,795 (1999) (recognizing that, absent a stay, options for "meaningful judicial review would be effectively foreclosed"). Financial injury is only irreparable where no "adequate compensatory or other corrective relief will be available at a later date, in the ordinary course of litigation." *Wis. Gas Co.*, 758 F.2d at 674 (*quoting Va. Petroleum Jobbers Ass'n v. Fed. Power Comm'n*, 259 F.2d 921, 925 (D.C. Cir. 1958)); *see also In re NTE Conn., LLC*, 26 F.4th 980, 991 (D.C. Cir. 2022). Environmental injury, however, "can seldom be adequately remedied by money damages and is often permanent or at least of long duration, *i.e.*, irreparable. If such injury is sufficiently likely, therefore, the balance of harms will usually favor the issuance of an injunction to protect the environment." *Amoco Prod. Co. v. Vill. of Gambell*, 480 U.S. 531, 545 (1987).

Under those standards, a stay of the Order is appropriate.

A. Intervenors Will Suffer Irreparable Harm Without a Stay of the Order.

A stay is necessary to protect Public Interest Organizations, their members, and the public from harm from continued coal-fired power operations at Craig caused by the Department's Order. As noted *supra* sec. IV.B.3, Craig emits health- and environment-harming air pollutants like NO_x, PM, SO_2, and VOCs. In just three months, Craig could emit over one million pounds of NO_x, hundreds of thousands of pounds of SO_2, and thousands of pounds of PM. Ex. 2-03 at 12–13 (Powers Decl.). Air pollution from Craig is harmful to human health, and these harms would not occur if the plant shut down. *Id.* These air pollutants also contribute to visibility impairment at several national parks and wilderness areas in Colorado, including Rocky Mountain National Park, Flat Tops Wilderness Area, Eagles Nest Wilderness Area, Mount Zirkel Wilderness Area, and Rawah Wilderness Area. *See supra* sec. V.D.2. The health and environmental harms from this pollution flow directly from the Department's Order and are actual, specific, and imminent, and can be deadly. *See, e.g.*, Ex. 2-121 at 2–3 (Mercury Mortality Risks of Coal); Ex. 2-123 at PDF 5–6 (EPA COBRA Health Effects Estimate); Ex. 2-160 at PDF 2–3 (Clean Air Task Force Toll from Coal).

Additionally, without a stay, the Order creates other injuries, too. It needlessly forces the Craig Co-Owners to divert attention and investment dollars away from

their electric resource and clean energy plans, thereby denying Public Interest Organizations' members the benefits of Colorado and other state energy policies designed to benefit them and the public. *See supra* secs. V.A.2, V.A.5. In addition, in forcing ratepayers to pay for the availability and generation of a coal-burning facility that the State, stakeholders, and operator want to close, the Department's Order jeopardizes the diversification of generating resources that the Department itself has said increases grid reliability and will also inherently and unjustifiably add to ratepayer costs. Ex. 2-122 at PDF 2–3 (*Energy Reliability and Resilience*); Ex. 2-175 at 31 (Tri-State and Platte River January Rehearing Request) (explaining how "the Order fails to consider how mandating Craig Unit 1's continued operation interferes with [Tri-State and Platte River's] ability to invest in other generation capacity" and stating that, due to transmission constraints, "Craig Unit 1's continued operation could interfere with the ability of new alternatives like Axial Basin to provide economic power to the grid"). As ratepayers, Public Interest Organizations and their members will ultimately bear the costs of keeping this unnecessary coal plant online. Ex. 2-175 at 2 (Tri-State and Platte River January Rehearing Request) (describing the costs to Tri-State's members and Platte River's communities); Ex. 3-06 at 14, 16-17, 20, 22 (Tri-State and Platte River April Rehearing Request) (same); Ex. 2-176 at 4–5 (Xcel Motion to Intervene in Petition for Rehearing) (stating that the co-owners have incurred "substantial additional operations, maintenance, and fuel costs," that Xcel's share of those costs was approximately $100,000 as of April 2026, and that Xcel intends to seek cost recovery).

B. A Stay Would Not Result in Harm to Any Other Interested Parties.

No other interested parties would be harmed by a stay. The issuance of a stay would not harm end-use electricity consumers because the lack of an actual emergency means that a stay would not disrupt the provision of electricity. *See, e.g.*, *supra* sec. V.A. Furthermore, because the Craig Co-Owners have already planned for the plant's closure and continue to plan for resource adequacy, *see supra* secs. V.A.2, V.A.5, a stay would only have the effect of relieving them of the administrative, compliance, and planning burdens imposed by the Order. On the balancing of equities, there is therefore no meaningful countervailing harm that would follow from a stay.

C. A Stay Is in the Public Interest Given the Significant Evidence Demonstrating There Is No Factual or Legal Support for the Order and Given the Harm It Produces to the Broader Public.

There is no public interest served by the Order, and a stay will only benefit the public. First, the Order exceeds the Department's authority; it has provided no reasonable grounds to substantiate any near-term or imminent shortfall in electricity supply that would justify Craig's continued operation. *See League of Women Voters v. Newby*, 838 F.3d 1, 12 (D.C. Cir. 2016) (noting "there is a substantial public interest 'in having governmental agencies abide by the federal laws that govern their

existence and operations'") (quoting *Washington v. Reno*, 35 F.3d 1093, 1103 (6th Cir. 1994)). Second, the Order overrides Colorado's exercise of its "authority to choose [its] preferred mix of energy generation resources." *Citizens Action*, 125 F.4th at 239. By doing so, it unlawfully intrudes into states' reserved authority over in-state "facilities used for the generation of electric energy." 16 U.S.C. § 824(b)(1); *see Pac. Gas & Elec.*, 461 U. S. at 205 ("Need for new power facilities, their economic feasibility, and rates and services, are areas that have been characteristically governed by the States."); *see also Hughes*, 578 U.S. at 154 (cleaned up) ("Under the [Federal Power Act], FERC has exclusive authority to regulate the sale of electric energy at wholesale in interstate commerce. . . . But the law places beyond FERC's power, and leaves to the States alone, the regulation of any other sale—most notably, any retail sale—of electricity."). And third, a stay would protect the broader public—beyond Public Interest Organizations and their members—from the onerous costs and dangerous pollution produced by Craig's unnecessary operation and availability.

VII. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department grant intervention in the proceedings over the Order; stay the Order; grant rehearing of the Order; rescind the Order (and any renewals of the Order); and allow Craig to retire.

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Attachments:
Glossary of Terms
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GLOSSARY OF TERMS

Shortened Term	Long Description
Department	Department of Energy or DOE
Order	Department of Energy Order No. 202-26-31
December Order	Department of Energy Order No. 202-25-14
March Order	Department of Energy Order No. 202-26-21
Colorado Commission	Colorado Public Utilities Commission
Craig	Craig Unit 1
Craig Co-Owners	The five co-owners of Craig Unit 1
Craig Plant	The entire Craig facility
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Corporation
Platte River	Platte River Power Authority
RTO	Regional Transmission Organization
SIP	Clean Air Act State Implementation Plan
SPP	Southwest Power Pool
Tri-State	Tri-State Generation and Transmission Association
WECC	Western Electricity Coordinating Council
Xcel	Public Service Company of Colorado or Xcel Energy

INDEX OF EXHIBITS

No.	Exhibit Name	Document Name	URL and Notes
2-01	Current Energy Group January Report	Current Energy Group Report, *Resource Adequacy in the Mountain West* (Jan. 2026)	
2-02	Grid Strategies Resource Adequacy Report	Michael Goggins, Grid Strategies, *Craig Unit 1 is Not Needed for Electric Reliability* (Jan. 2026)	
2-03	Powers Decl.	Declaration of Bill Powers (Jan. 24, 2026)	Exhibits identified in Mr. Powers' declaration with a "1-" prefix are numbered here with a "2-" prefix. For instance, Exhibit 1-50 identified in Mr. Powers' declaration is numbered here as Exhibit 2-50.
2-04	Grid Strategies Costs Report	Michael Goggins, Grid Strategies, *The Economic Cost of a DOE Mandate for the Craig Unit 1 Coal-Burning Generator to Continue Operating* (Dec. 2025)	
2-05	Telos Resource Adequacy Report	Telos Energy, *Resource Adequacy Planning in Colorado* (2025)	
2-06	Tri-State December 2025 Press Release	Tri-State, *U.S. DOE Orders Tri-State to keep Craig Generating Station Unit Operating for Next 90 days* (Dec. 31, 2025)	https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days

No.	Exhibit Name	Document Name	URL and Notes
2-07	NERC 2024 Long-Term Reliability Assessment	N. Am. Electric Reliability Corp., *2024 Long-Term Reliability Assessment* (July 11, 2025)	
2-08	NERC 2025-26 Winter Assessment	North American Electric Reliability Corp., *2025-2026 Winter Reliability Assessment* (Nov. 2025)	https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf
2-09	2024 Western Assessment of Resource Adequacy	WECC, *2024 Western Assessment of Resource Adequacy* (last visited April 21, 2026)	https://feature.wecc.org/wara/
2-10	Cooke Email to Alle-Murphy	Email from Lot Cooke, DOE to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (Dec. 30, 2005)	https://www.energy.gov/oe/articles/question-and-answer-procedural-questions-application-rehearing-order-no-202-05-02?nrg_redirect=397676
2-11	DOE Rehearing Procedures	U.S. Dep't of Energy, *DOE 202(c) Order Rehearing Procedures* (last visited June 17, 2025)	https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures
2-12	Department 202(c) Webpage	U.S. Dep't of Energy, *DOE's Use of Federal Power Act Emergency Authority* (last visited April 27, 2026)	https://www.energy.gov/ceser/does-use-federal-power-act-emergency-authority
2-13	Department Order No. 202-22-4	U.S. Dep't of Energy, Order No. 202-22-4 (Dec. 24, 2022)	https://www.energy.gov/sites/default/files/2022-12/PJM%20202%28c%29%20Order.pdf
2-14	Department Order No. 202-17-4 Summary of Findings	U.S. Dep't of Energy, Summary of Findings DOE Order No. 202-17-4 (Sept. 14, 2017)	https://www.energy.gov/sites/default/files/2017/09/f36/Order%20202-17-4%20Summary%20of%20Findings.pdf

No.	Exhibit Name	Document Name	URL and Notes
2-15	Department Order No. 202-02-1	U.S. Dep't of Energy, Order No. 202-02-1 (Aug. 16, 2002)	https://www.energy.gov/sites/default/files/202%28c%29%20order%20202-02-1%20August%2016%2C%202002%20-%20CSC.pdf
2-16	Department Order No. 202-20-2	U.S. Dep't of Energy, Order No. 202-20-2 (Sept. 6. 2020)	https://www.energy.gov/oe/articles/federal-power-act-section-202c-caiso-september-2020?nrg_redirect=454296
2-17	Department Order No. 202-22-2	U.S. Dep't of Energy, Order No. 202-22-2 (Sept. 4, 2022)	https://www.energy.gov/ceser/federal-power-act-section-202c-banc-september-2022
2-18	Department Order No. 202-21-1	U.S. Dep't of Energy, Order No. 202-21-1 (Feb. 14, 2021)	https://www.energy.gov/oe/articles/federal-power-act-section-202c-ercot-february-2021?nrg_redirect=364318
2-19	FERC Energy Primer	FERC, *Energy Primer: A Handbook of Energy Market Basics* (Dec. 2023) (excerpt)	https://www.ferc.gov/media/energy-primer-handbook-energy-market-basics
2-20	Department Order No. 202-08-1	U.S. Dep't of Energy, Order No. 202-08-1 (Sept. 14, 2008)	https://www.energy.gov/sites/prod/files/202%28c%29%20order%20202-08-1%20September%2014%2C%202008%20-%20CenterPoint%20Energy.pdf
2-21	Department Order No. 202-26-01	U.S. Dep't of Energy, Order No. 202-26-01 (Jan. 24, 2026)	https://www.energy.gov/documents/order-no-202-26-01-ercot
2-22	Department Order No. 202-26-01A	U.S. Dep't of Energy, Order No. 202-26-01A (Jan. 25, 2026)	https://www.energy.gov/documents/amended-order-no-202-26-01a
2-23	Department Order No. 202-26-03	U.S. Dep't of Energy, Order No. 202-26-03 (Jan. 25, 2026)	https://www.energy.gov/documents/order-no-202-26-03-iso-ne

No.	Exhibit Name	Document Name	URL and Notes
2-24	Department Order No. 202-24-1	U.S. Dep't of Energy, Order No. 202-24-1 (Oct. 9, 2024)	https://www.energy.gov/sites/default/files/2024-10/Duke%20202%28c%29%20Order_100924%20FINAL_JMG%20signed.pdf
2-25	Omitted		
2-26	NERC 2024 Reliability Report	NERC, *2024 State of Reliability* (June 2024)	
2-27	NERC 2025 Summer Reliability Assessment	NERC, *2025 Summer Reliability Assessment* (May 2025)	https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2025.pdf
2-28a	2019–24 NERC Summer Reliability Assessments	NERC, *Summer Reliability Assessments for 2019-2025* (compiled)	2019 Reliability Assessment: https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2019.pdf 2020 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf 2021 Reliability Assessment: https://nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf 2022 Reliability Assessment: n/a 2023 Reliability Assessment: https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2023.pdf 2024 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf

No.	Exhibit Name	Document Name	URL and Notes
2-28b	2019–24 NERC Summer Reliability Assessments	NERC, *Summer Reliability Assessments for 2019-2025* (compiled)	2019 Reliability Assessment: https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2019.pdf 2020 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf 2021 Reliability Assessment: https://nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf 2022 Reliability Assessment: n/a 2023 Reliability Assessment: https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2023.pdf 2024 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf
2-28c	2019–24 NERC Summer Reliability Assessments	NERC, *Summer Reliability Assessments for 2019-2025* (compiled)	2019 Reliability Assessment: https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2019.pdf 2020 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf 2021 Reliability Assessment: https://nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20SRA%202021.pdf 2022 Reliability Assessment: n/a 2023 Reliability Assessment: https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2023.pdf 2024 Reliability Assessment: https://www.nerc.com/pa/RAPA/ra/

No.	Exhibit Name	Document Name	URL and Notes
			Reliability%20Assessments%20DL/NERC_SRA_2024.pdf
2-29	Omitted		
2-30	Winter Storm Elliott System Operations Inquiry	FERC, NERC, and Regional Entity Staff Report, *Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott* (Oct. 2023)	https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022#
2-31	PJM Elliott Report	PJM, *Winter Storm Elliott: Event Analysis and Recommendation Report* (July 17, 2023)	https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf?ref=blog.gridstatus.io
2-32	NARUC Coal Report	Phillip Graeter & Seth Schwartz, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices*, Nat'l Assoc. of Regulatory Util. Commissioners (Jan. 2020) (excerpt)	https://www.osti.gov/servlets/purl/1869928
2-33	IEA Flexibility Report	Colin Henderson, *Increasing the Flexibility of Coal-Fired Power Plants*, International Energy Agency Clean Coal Centre (Sept. 2014) (excerpt)	https://usea.org/sites/default/files/092014_Increasing%20the%20flexibility%20of%20coal-fired%20power%20plants_ccc242.pdf

No.	Exhibit Name	Document Name	URL and Notes
2-34	Secretary Wright's West Virginia Remarks	Charles Young, *Energy Secretary Chris Wright: Future of U.S. Coal is 'long and bright'*, West Virginia News (July 5, 2025)	https://www.wvnews.com/news/wvnews/energy-secretary-chris-wright-future-of-u-s-coal-is-long-and-bright/article_948eb88e-2509-42a3-b985-07c47f1ee151.html
2-35	July Resource Adequacy Report	U.S. Dep't of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Grid* (July 2025)	https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf
2-36	Energy Emergency EO	Exec. Order No. 14,156, 90 Fed. Reg. 8433, Declaring a National Energy Emergency (Jan. 29, 2025)	https://www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency
2-37	Grid EO	Exec. Order No. 14,262, 90 Fed. Reg. 15521, Strengthening the Reliability and Security of the U.S. Electric Grid (Apr. 14, 2025)	https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid
2-38	NY Times Coal Article	Brad Plumer & Mira Rojanasakul, *Trump Signs Orders Aimed at Reviving a Struggling Coal Industry*, NY Times (Sept. 3, 2025)	https://www.nytimes.com/2025/04/08/climate/trump-order-coal-mining.html
2-39	DOE July 7 Press Release	U.S. Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025)	https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security

No.	Exhibit Name	Document Name	URL and Notes
2-40	PIOs' RFR of July Resource Adequacy Report	*Motion to Intervene and Request for Rehearing of Nat. Res. Def. Council, the Ecology Ctr., Envtl. Def. Fund, Envtl. Law and Pol'y Ctr., Pub. Citizen, Sierra Club, and Vote Solar*, U.S. Dep't of Energy Resource Adequacy Report (Aug. 8, 2025)	https://sustainableferc.org/wp-content/uploads/2025/08/2025-08-06_NRDC-et-al-Request-for-Rehearing-DOE-Resource-Adequacy-Report.pdf
2-40a	Department's Response to PIOs' RFR of July Resource Adequacy Report	Letter from Tina Francone, Acting Director, Grid Deployment Office, Dep't of Energy, to Caroline Reiser et al., Nat. Res. Def. Council, RE: August 8, 2025 Submission (Sept. 5, 2025)	
2-41	Inst. Pol'y Integrity Report	Jennifer Danis, Christopher Graf & Matthew Lifson, *Enough Energy: A Review of DOE's Resource Adequacy Methodology*, Inst. Pol'y Integrity (July 2025)	https://policyintegrity.org/files/publications/IPI_EnoughEnergy_FinalReport.pdf
2-42	GridLab Report	Ric Oconnell, *GridLab Analysis: Department of Energy Resource Adequacy Report*, GridLab (July 11, 2025)	https://gridlab.org/gridlab-analysis-department-of-energy-resource-adequacy-report/
2-43	Duke University Rethinking Load Growth Study	Tyler H. Norris et al., *Rethinking Load Growth: Assessing the Potential for Integration of Large*	https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf

No.	Exhibit Name	Document Name	URL and Notes
		Flexible Loads in US Power Systems, Duke University Nicholas Institute for Energy, Environment & Sustainability (2025)	
2-44	RMI Analysis of Coal Plants' Threats to Reliability	Gabriella Tosado, Ashtin Massie & Joe Daniel, RMI, *Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants* (Aug. 12, 2025)	https://rmi.org/reality-check-we-have-whats-needed-to-reliably-power-the-data-center-boom-and-its-not-coal-plants/
2-45	Energy Innovation Report	Eric G. Gimon, *Dodging the Firm Fixation for Data Centers and the Grid*, Energy Innovation (Nov. 2025)	https://energyinnovation.org/wp-content/uploads/Dodging-the-Firm-Fixation-for-Data-Centers-and-the-Grid.pdf
2-46	R Street Institute Commentary: DOE "Zombies" Are Eating Competitive Power Markets	Michael Giberson, *Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets*, R Street (Nov. 13, 2025)	https://www.rstreet.org/commentary/low-energy-fridays-doe-zombies-are-eating-competitive-power-markets/
2-47	Palgrave Handbook	Manfred Hafner & Giacomo Luciana, *Palgrave Handbook of International Economics*, Palgrave Macmillan (2022) (excerpt)	https://link.springer.com/book/10.1007/978-3-030-86884-0
2-48	IEA Report	International Energy Agency, *The role of CCUS in low-carbon power systems* (July 17, 2020) (excerpt)	https://www.iea.org/reports/the-role-of-ccus-in-low-carbon-power-systems

No.	Exhibit Name	Document Name	URL and Notes
2-49	Tri-State Revised 2020 ERP Assessment of Existing Resources	Tri-State, *ERP Assessment of Existing Resources* (Aug. 3, 2020)	
2-50	Insgold 2023 ERP Direct Testimony	Barry Insgold, *Direct Test., Rev. 1* (Dec. 1, 2023)	
2-51	Tri-State 2020 ERP	Tri-State, *2020 ERP* (Dec. 1, 2020)	
2-52	2023 Colorado Water Plan	Colo. Water Conservation Bd., *Colorado Water Plan* (2023)	
2-53	Colorado Sun Article	Brittany Peterson and Jennifer McDermott, *In Colorado town built on coal, some families are moving on, even as Trump tries to boost industry* (Dec. 8, 2025)	https://coloradosun.com/2025/12/08/colorado-coal-transition-jobs/
2-54	PacifiCorp FERC Form 1	PacifiCorp, *FERC Form 1* (April 14, 2025)	
2-55	Platte River Power Authority Coal Energy	Platte River Power Authority, *Coal Energy*	https://prpa.org/generation/coal/
2-56	Xcel FERC Form 1	Public Service Company of Colorado, *FERC Form 1* (April 4, 2025)	
2-57	2018 SIP Element Adopted	Docket No. EPA-R08-OAR-2018-0015, Environmental Protection Agency, *SIP Element Adopted* (April 26, 2018)	

No.	Exhibit Name	Document Name	URL and Notes
2-58	Lisa Tiffin 2020 ERP Direct Testimony	Colorado PUC Proceeding No. 20A-0528E, *Lisa Tiffin Direct Testimony* (December 1, 2020)	
2-59	Intertek Reliability Study	Intertek, *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators* (May 12, 2020)	https://web.archive.org/web/20240620151239/https://www.wecc.org/Reliability/1r10726%20WECC%20Update%20of%20Reliability%20and%20Cost%20Impacts%20of%20Flexible%20Generation%20on%20Fossil.pdf
2-60	SRP Power Generation Sources	Salt River Project, *SRP Power Generation Sources*, (last visited Jan. 27, 2026)	https://www.srpnet.com/grid-water-management/grid-management/power-generation-stations
2-61	2023 ERP Phase II Modeling Assumptions	Colorado PUC Proceeding No. 23A-0585E, Phase II Implementation Report, Attachment B, *Modeling Assumptions* (April 11, 2025)	
2-62	NERC Electrochemical Storage Study	NERC, *Energy Storage: Overview of Electrochemical Storage* (February 2021)	
2-63	GE LM6000 Information	General Electric, *Get to know the LM6000* (last visited Jan. 27, 2026)	https://www.gevernova.com/gas-power/products/gas-turbines/lm6000
2-64	Tri-State SPP West Press Release	Tri-State, *Benefits of SPP RTO West participation highlighted in filing with Colorado PUC* (June 17, 2025)	https://tristate.coop/benefits-spp-rto-west-participation-highlighted-filing-colorado-puc

No.	Exhibit Name	Document Name	URL and Notes
2-65	CDPHE Regulation No. 3	Colorado Department of Public Health and Environment, Colorado APCD, *Regulation No. 3, Part F, Sec. VI.D* (adopted December 15, 2016)	
2-66	Omitted		
2-67	EPA NO_2 Information	U.S. EPA, *Basic Information about NO_2* (last visited Jan. 27, 2026)	https://www.epa.gov/no2-pollution/basic-information-about-no2
2-68	EPA Sulfur Dioxide Information	U.S. EPA, *Sulfur Dioxide Basics* (last visited Jan. 27, 2026)	https://www.epa.gov/so2-pollution/sulfur-dioxide-basics
2-69	EPA PM Information	U.S. EPA, *Health and Environmental Effects of Particulate Matter (PM)* (last visited Jan. 27, 2026)	https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm
2-70	2018 BART	Docket No. EPA-R08-OAR-2018-0015, Colorado APCD, *Best Available Retrofit Technology (BART) Analysis – Tri-State Craig Station Units 1 and 2* (April 26, 2018)	
2-71	BART CALPUFF	Colorado Department of Public Health and Environment, *BART CALPUFF Class I Federal Area Individual Source Attribution Visibility Impairment Modeling Analysis for Tri-State Generation &*	

No.	Exhibit Name	Document Name	URL and Notes
		Transmission Association Craig Station Units 1 and 2 (Revised) (Mar. 3, 2006)	
2-72	EPA Carbon Dioxide Information	U.S. EPA, *Carbon Dioxide Emissions* (last visited Jan. 27, 2026).	https://www.epa.gov/ghgemissions/carbon-dioxide-emissions
2-73	Craig Station Operating Permit	Colorado Department of Public Health and Environment, *Craig Station Operating Permit* (July 1, 2021)	
2-74	March 2025 Field Inspection Report	Colorado APCD, *Field Inspection Report – Craig Generating Station* (March 25, 2025)	
2-75	Tri-State 2023 ERP Phase I Report	Colorado PUC Proceeding No. 23A-0585E, Hearing Exhibit 101, Attachment LKT-1, *Tri-State 2023 Electric Resource Plan Phase I* (April 22, 2024)	
2-76	Power Engineering Fabric Filters Article	Power Engineering, *Real World Performance Results of Fabric Filters on Utility Coal-Fired Boilers* (August 1, 2012)	https://www.power-eng.com/environmental-emissions/real-world-performance-results/
2-77	Power Engineering Wet-Limestone Scrubbing Article	Power Engineering, *Wet-Limestone Scrubbing Fundamentals* (August 1, 2006)	https://www.power-eng.com/operations-maintenance/wet-limestone-scrubbing-fundamentals/

No.	Exhibit Name	Document Name	URL and Notes
2-78	Power Magazine Pulverizers Article	Power Magazine, *To optimize performance, begin at the pulverizers* (February 2007)	https://www.powermag.com/to-optimize-performance-begin-at-the-pulverizers/
2-79	Riley Power Low NOx Burner Performance Article	Riley Power, *Advanced Erosion Protection Technology Provides Sustained Low NOx Burner Performance* (April 2024)	
2-80	Neundorfer Fabric *Filter Design*	Neundorfer, *Lesson 5 - Fabric Filter Design Review* (April 2016)	
2-81	Norman Kapala 2021 Consumers IRP Direct Testimony	Michigan PSC Case No. U-21090, *Revised Direct Testimony* of Norman J. Kapala (October 2021)	
2-82	2011 BART	Docket No. EPA-R08-OAR-2011-0770, Colorado Department of Public Health and Environment, Air Pollution Control Division, *Best Available Retrofit Technology (BART) Analysis – Tri-State Craig Station Units 1&2* (March 26, 2012)	
2-83	2025 EIA Form 923	U.S. Department of Energy, *EIA Form 923, Page 4 Generator Data* (2025)	
2-84	2024 EIA Form 923	U.S. Department of Energy, *EIA Form 923, Page 4 Generator Data* (2024)	

No.	Exhibit Name	Document Name	URL and Notes
2-85	Colorado Commission Decision No. C23-0437	Colorado PUC Proceeding No. 20A-0528E, *Decision No. C23-0437* (June 30, 2023)	
2-86	Tri-State 150-Day Implementation Report	Colorado PUC Proceeding No. 20A-0528E, *Tri-State's 150-Day Implementation Report* (2023)	
2-87	Tri-State 2023 ERP 120 Day Implementation Report	Colorado PUC Proceeding No. 23A-0585E, *Tri-State's 120-Day Implementation Report* (2025)	
2-88	Tri-State 2023 ERP Modeling Assumptions	Colorado PUC Proceeding No. 23A-0585E, Tri-State's Hearing Exhibit 101 LKT-1 - Attachment B - Public - *Modeling Assumptions* (2023)	
2-89	Tri-State 2025 ERP Annual Progress Report	Colorado PUC Proceeding No. 23A-0585E, *Tri-State's 2025 Annual Progress Report* (Dec. 1, 2025)	
2-90	Colorado Commission Decision No. C25-0612	Colorado PUC Proceeding No. 23A-0585E, *Decision No. C25-0612* (August 26, 2025)	
2-91	Platte River 2020 IRP	Platte River Power Authority*, 2020 Integrated Resource Plan* (2020)	

No.	Exhibit Name	Document Name	URL and Notes
2-92	Platte River 2024 IRP	Platte River Power Authority, *2024 Integrated Resource Plan* (2024)	
2-93	Xcel 2025 Near Term Procurement Report	Public Service Company of Colorado, *Near Term Procurement Report* (2025)	
2-94	Xcel 2024 JTS, Volume 2 Technical Appendix	Colorado PUC Proceeding No. 24A-0442E, Hearing Exhibit 101, Attachment JWI-2, *Volume 2 - Technical Appendix, Rev. 2* (Oct. 15, 2024)	
2-95	Colorado Commission Decision No. C25-0892	Colorado PUC Proceeding No. 25V-0480E, *Decision No. C25-0892* (Dec. 10, 2025)	
2-96	Comanche Unit 2 Variance Petition	Colorado PUC Proceeding No. 25V-0480E, *Joint Petition* (2025)	
2-97	Colorado Commission Decision No. C25-0747	Colorado PUC Proceeding No. 24A-0442E, Decision No. C25-0747 (November 6, 2025)	
2-98	PacifiCorp 2023 IRP Update	PacifiCorp, *2023 Integrated Resource Plan Update* (2024)	
2-99	PacifiCorp 2025 IRP	PacifiCorp, *2025 Integrated Resource Plan, Volume I* (Mar. 31, 2025)	

No.	Exhibit Name	Document Name	URL and Notes
2-100a	Salt River Project 2023 IRP	Salt River Project, *Integrated System Plan* (2023)	
2-100b	Salt River Project 2023 IRP	Salt River Project, *Integrated System Plan* (2023)	
2-101	Xcel Information Sheet on Colorado Energy Plan	Xcel, *Information Sheet on Colorado Energy Plan* (2019)	
2-102	Colorado Commission Decision No. C24-0052	Colorado PUC Proceeding No.21A-0141E, *Decision No. C24-0052* (Jan. 23, 2024)	
2-103	2025 Xcel ERP Annual Progress Report	Xcel, Colorado PUC Proceeding No. 21A-0141E, *2021 Electric Resource Plan & Clean Energy Plan Annual Progress Report* (Mar. 31, 2025)	
2-104	PacifiCorp 2015 IRP Update	PacifiCorp, *Integrated Resource Plan Update* (2015)	
2-105	PacifiCorp 2025 IRP	PacifiCorp, *Integrated Resource Plan* (2025)	
2-106	EIA Annual 2024	EIA, *2024 EIA Annual* (2025)	

No.	Exhibit Name	Document Name	URL and Notes
2-107	EIA Annual 2019	EIA, *2019 EIA Annual* (2021)	
2-108	UT Austin Article	University of Texas at Austin Energy Institute, *The History and Evolution of the US Electricity Industry* (2016)	https://energy.utexas.edu/sites/default/files/UTAustin_FCe_History_2016.pdf
2-109	PacifiCorp 2025 Oregon RFP	Oregon PUC Docket UM 2383, *PacifiCorp, PacifiCorp's Informational Filing* (2025)	
2-110	PacifiCorp 2024 URC RFP	PacifiCorp, *2024 Utah Renewable Communities Request for Proposals, "2024 URC RFP"* (2025)	
2-111	Western Energy Imbalance Market Webpage	CAISO, *Western Energy Markets, Western Energy Imbalance Market*, (last visited Jan. 27, 2026)	https://www.westernenergymarkets.com/western-energy-imbalance-market-weim
2-112	WEIS Southwest Power Pool	SPP, *Western Energy Imbalance Service Market*, (last visited Jan. 27, 2026)	https://spp.org/western-services/weis/
2-113	Craig Station, AMD data 2020 through 2025	EPA, Enforcement and Compliance History Online, *Air Pollutant Report*, (last visited April 21, 2026)	https://echo.epa.gov/air-pollutant-report?fid=110041086393
2-114	Tri-State Members	Tri-State Gen. & Transm. Ass'n, Inc., *What It Means To Be a Member* (last visited Jan. 19, 2026)	https://tristate.coop/members

No.	Exhibit Name	Document Name	URL and Notes
2-115	Department Explainer on Balancing Authorities	Dep't of Energy, *How It Works: The Role of a Balancing Authority* (2022)	https://www.energy.gov/sites/default/files/2023-08/Balancing%20Authority%20Backgrounder_2022-Formatted_041723_508.pdf
2-116	EIA Explainer on Balancing Authorities	Sara Hoff, U.S. Energy Info. Admin., U.S. Dep't of Energy, *U.S. Electric System Is Made up of Interconnections and Balancing Authorities* (July 20, 2016)	https://www.eia.gov/todayinenergy/detail.php?id=27152
2-117	NERC Emergency Operations	N. Am. Elec. Reliab. Corp., *EOP-011-4 Emergency Operations* (last visited Jan. 19, 2026)	https://www.nerc.com/globalassets/standards/reliability-standards/eop/eop-011-4.pdf
2-118	Department Press Release on Centralia Order	U.S. Dep't of Energy, *Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter* (Dec. 17, 2025)	https://www.energy.gov/articles/energy-secretary-ensures-washington-coal-plant-remains-open-ensure-affordable-reliable-and
2-119	2001 National Energy Policy	Nat'l Energy Pol'y Dev. Grp., *Reliable, Affordable, and Environmentally Sound Energy for America's Future* (May 16, 2001)	https://www.nrc.gov/docs/ml0428/ml042800056.pdf
2-120	Department Export Authorization EA-365-C (Oct. 21, 2025)	Research Power Corp., *Order No. EA-365-C* (Oct. 21, 2025)	https://www.energy.gov/gdo/ea-365-c-research-power-corporation

No.	Exhibit Name	Document Name	URL and Notes
2-121	Mercury Mortality Risks of Coal	*Particulate Pollution from Coal Associated with Double the Risk of Mortality than PM2.5 from Other Sources*, Harvard T.H. Chan Sch. of Pub. Health (Nov. 23, 2023)	https://hsph.harvard.edu/news/particulate-pollution-from-coal-associated-with-double-the-risk-of-mortality-than-pm2-5-from-other-sources/
2-122	Energy Reliability and Resilience	U.S. Dep't of Energy, *Energy Reliability and Resilience* (webpage as of Oct. 21, 2025)	https://web.archive.org/web/20251021071021/https:/www.energy.gov/eere/energy-reliability-and-resilience
2-123	EPA COBRA Health Effects Estimate	Envtl. Prot. Agency, *COBRA Web Edition* (last visited Jan. 22, 2025)	Go to https://cobra.epa.gov/. In Step 1.A, select Colorado and "Moffat" county. In Step 1.B, select "Fuel Combustion: Industrial." In Step 1.C, input reduce SO2 by 335.43 tons and reduce NOx by 2,211.57 tons (based on Craig-specific data for annual emissions from 2024, available at https://campd.epa.gov/data/custom-data-download). In Step 1.C, also input reduce PM2.5 by 13 tons (based on Craig-specific 2020 National Emissions Inventory ("NEI") data for annual PM2.5 Filterable emissions, scaled by the ratio of Craig's 2024 SO2 and NOx emissions to their 2020 NEI SO2 and NOx emissions. NEI 2020 data is available at https://www.epa.gov/air-emissions-inventories/2020-national-emissions-inventory-nei-data). Use a 2% discount rate and run scenario.

No.	Exhibit Name	Document Name	URL and Notes
2-124	2025 PacifiCorp Fact Sheet	PacifiCorp, "Just the Facts" (2025)	https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/about/PacifiCorp_Fact_Sheet.pdf
2-125	Service Area and Territory (Electric Power and Water) SRP	SRP, "Service Territory" (2025)	https://www.srpnet.com/about/service-area-territory
2-126	Xcel, List of Towns Receiving Electric Service in Colorado	Xcel, *Colorado Communities Served by Xcel Energy* (2024)	https://xcelnew.my.salesforce.com/sfc/p/#1U0000011ttV/a/8b000002Y8vy/cDTZ25fPv.NuR_sx_peANfpfaxL47xQXr7fhoTJZoOw
2-127	Who we serve - Platte River Power Authority	Platte River Power Authority, *Who We Serve* (last visited Jan. 26, 2026)	https://prpa.org/about-prpa/who-we-serve/
2-128	Order No. 24-073_OR PUC on Pac 2023 IRP	Oregon PUC Docket LC 82, Order No. 24-073 (Mar. 19, 2024)	
2-129	Utah PSC on Pac 2023 IRP	Utah PUC Docket No. 23-035-10, Order (April 17, 2024)	
2-130	Idaho PUC on Pac 2023 IRP	Idaho PUC Docket PAC-E-23-10, Order No. 35977 (Oct. 31, 2023)	
2-131	FERC Western Energy Markets Explainer	Office of Public Participation, FERC, *Western Energy Markets Explainer* (last visited Jan. 2, 2026)	https://ferc.gov/OPP/western-markets-explainer

No.	Exhibit Name	Document Name	URL and Notes
2-132 through 2-144	Omitted		
2-145	Western Pool Reserve Sharing Program	Western Power Pool, *Northwest Power Pool Reserve Sharing Program Documentation* (effective Oct. 1, 2025)	https://www.westernpowerpool.org/private-media/documents/NWPP_RSG_Program_Doc_-_RSGC_Approved_effective_10.1.2025.pdf
2-146	Western Frequency Response Sharing Group	Western Power Pool, Western *Frequency Response Sharing Group* (last visited Jan. 2, 2026)	https://www.westernpowerpool.org/about/programs/western-frequency-response-sharing-group
2-147	WRAP Tariff	Western Power Pool, *Western Resource Adequacy Program Tariff* (effective Mar. 16, 2025)	https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_3.16.25.pdf
2-148	WRAP Notice	Rebecca Sexton, *WPP Notice to WRAP Resource Adequacy Participants Committee*, Western Power Pool (last modified Oct. 31, 2025)	https://www.westernpowerpool.org/news/wpp-notice-to-wrap-resource-adequacy-participants
2-149	"About WECC" Webpage	Western Elec. Coordinating Council, *About WECC* (last visited Jan. 2, 2026)	https://www.wecc.org/about/about-wecc
2-150	NERC Rules of Procedure	N. Am. Elec. Reliab. Corp., *Rules of Procedure* (effective Nov. 28, 2023)	https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/nerc-rop-effective-20231128_with-appendicies.pdf
2-151	WECC Contingency Reserve Whitepaper	Western Elec. Coordinating Council, *WECC-0142 BAL-002-WECC-3 Contingency*	https://www.nerc.com/globalassets/standards/approved-standards/bal/bal-002-wecc-3-cont.-rev.---req.-to-retire---white-paper---final_09162025.pdf

No.	Exhibit Name	Document Name	URL and Notes
		Reserve Request to Retire (Jan. 21, 2025)	
2-152	WECC Risk Factor Criteria	Western Elec. Coordinating Council, *WECC Risk Factor Criteria for Inherent Risk Assessment* (effective March 22, 2021)	https://www.wecc.org/sites/default/files/documents/program/2024/WECC%20Risk%20Factor%20Criteria%20for%20IRA.pdf
2-153	WECC Reliability Assessment Webpage	Western Elec. Coordinating Council, *Reliability Assessments* (last visited Jan. 2, 2026)	https://www.wecc.org/program-areas/reliability-planning-performance-analysis/reliability-assessments
2-154 through 2-158	Omitted		
2-159	Email Correspondence with E3	Email Thread Between Arne Olson, Energy and Envtl. Economics, Inc., and Brad Cebulko, Current Energy Group, Re: E3 NW RA study and Centralia (Dec. 31, 2025 to Jan. 9, 2026)	
2-159a	E3's Attachment to Email Correspondence with E3	E3's Attachment (in PDF form) to Email Thread in Ex. 1-159	
2-159b	E3's Attachment to Email Correspondence with E3 (as	E3's Attachment (as transmitted in Excel form) to Email Thread in Ex. 1-159	

No.	Exhibit Name	Document Name	URL and Notes
	transmitted in Excel form)		
2-160	Clean Air Task Force Toll from Coal	Clean Air Task Force, *Toll from Coal* (last visited Jan. 23, 2025)	https://www.tollfromcoal.org/#/map/(title:6021//detail:6021//map:6021/CO)
2-161	SPP West Press Release	*Southwest Power Pool First RTO to Operate in Both Interconnections with Tariff Approval* (Mar. 20, 2025)	https://www.spp.org/news-list/spp-first-rto-to-operate-in-both-interconnections-with-tariff-approval/
2-162	EIA Generating Unit Annual Capital and Life Extension Costs Analysis	EIA, Generating Unit *Annual Capital and Life Extension Costs Analysis* (2019)	https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf
2-163	Trump Advisor Says Electricity Customers Pay for 202(c) Orders	Laura Sanicola, Barrons, *Who's Paying to Keep Coal Plant Alive? All Electricity Customers, Trump Advisor Says* (Jan. 14, 2026)	https://www.msn.com/en-us/money/markets/who-s-paying-to-keep-coal-plant-alive-all-electricity-customers-trump-advisor-says/ar-AA1UdRHI
2-164	Colorado Commission Decision No. C24-0052	Colorado PUC Proceeding No. 21A-0141E, *Decision No. C24-0052* (2024)	
2-165	Colorado Commission Decision No. C25-0024	Colorado PUC Proceeding No. 21A-0141E, *Decision No. C25-0024* (2025)	

No.	Exhibit Name	Document Name	URL and Notes
2-166	Tri-State January 2026 Press Release	Tri-State, *Tri-State Makes Craig Generating Station Unit 1 Available to Operate in Compliance with DOE Emergency Order* (Jan. 23, 2026)	https://tristate.coop/tri-state-makes-craig-generating-station-unit-1-available-operate-compliance-doe-emergency-order
2-167	SPP Markets+ Website	SPP, *Markets+* (last visited Jan. 27, 2026)	https://www.spp.org/marketsplus
2-168	Tri-State Extreme Weather Event Modeling Assumptions	Colorado PUC Proceeding No. 23A-0585E, 2023 ERP Phase II Implementation Report, Attach. B-5, *Extreme Weather Event Modeling Assumptions*	
2-169	Colorado PUC Press Release, Feb. 18, 2026	Colorado PUC, "Colorado Public Utilities Commission Approves New Energy Resources for Xcel Energy" (Feb. 18, 2026)	https://puc.colorado.gov/press-release/colorado-public-utilities-commission-approves-new-energy-resources-for-xcel-energy
2-170	Colorado PUC Feb. 2026 Decision	Colorado PUC Proceeding No. 21A-0141E, Decision No. C26-0117 (Feb. 23, 2026)	
2-171	Colorado PUC March 31, 2026 Decision	Colorado PUC Proceeding No. 24A-0442E, Decision No. C26-0200 (Mar. 31, 2026)	

No.	Exhibit Name	Document Name	URL and Notes
2-172	Tri-State 2026 Annual Resource Adequacy Report	Colorado PUC Proceeding No. 26M-0028E, TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.'S NOTICE OF 2026 RESOURCE ADEQUACY ANNUAL REPORT (Mar. 17, 2026)	
2-173	2024 NREL Lessons from Renewable Integration Studies	National Renewable Energy Laboratory, Maintaining Grid Reliability – Lessons from Renewable Integration Studies (Apr. 2024)	https://docs.nlr.gov/docs/fy24osti/89166.pdf
2-174	2021 NREL North American Renewable Integration Study	National Renewable Energy Laboratory, The North American Renewable Integration Study: A U.S. Perspective (June 2021)	https://docs.nrel.gov/docs/fy21osti/79224.pdf
2-175	Tri-State and Platte River Request for Rehearing	Request for Clarification and for Rehearing of Tri-State Generation and Transmission Authority and Platte River Power Authority, *In re Craig Order No. 202-25-14*	https://tristate.coop/sites/default/files/PDF/Order%20No.%20202-24-14%20-%20Petition%20for%20Rehearing%20of%20Tri-State%20Generation%20and%20Platte%20River%20-%20FINAL%20COMBINED.pdf
2-176	Xcel Motion to Intervene in Petition for Rehearing	Motion for Leave to Intervene of Public Service Company of Colorado, Case Nos. 26-1059, 26-1060 (D.C. Cir.)	

No.	Exhibit Name	Document Name	URL and Notes
2-177	March 30, 2026 Colorado Sun Article	Michael Booth, *Life of coal burning Craig Unit 1 extended again by Trump administration* (Mar. 30, 2026)	https://coloradosun.com/2026/03/30/craig-coal-power-trump-administration-extension/
2-178	NERC 2025 Long-Term Reliability Assessment	N. Am. Elec. Reliab. Corp., *2025 Long-Term Reliability Assessment* (Jan. 2026)	https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf
2-179	SPP Deficiency Response	SPP, Deficiency Response, FERC Docket No. ER24-2184-001 (Nov. 4, 2024), Accession No. 20241104-5148	https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20241104-5148&optimized=false&sid=dde6f58b-8031-46cf-8518-471a0e9356a3
2-180	SPP RTO Expansion	SPP, *RTO Expansion* (last visited Apr. 17, 2026)	https://www.spp.org/western-services/rto-expansion/
2-181	Department Press Release on March Centralia Order	U.S. Dep't of Energy, *Trump Administration Keeps Coal Plant Open to Ensure Affordable, Reliable and Secure Power in the Northwest* (Mar. 16, 2026)	https://www.energy.gov/articles/trump-administration-keeps-coal-plant-open-ensure-affordable-reliable-and-secure-power
2-182	Grid Strategies Analysis of NERC LTRA	Adria E. Brooke, Michael Goggin & John D. Wilson, *Review of NERC's 2025 Long-Term Reliability Assessment*, Grid Strategies (Mar. 5, 2026)	https://gridstrategiesllc.com/wp-content/uploads/FINAL-2025-LTRA-Review.pdf

No.	Exhibit Name	Document Name	URL and Notes
2-183	2025 Western Assessment of Resource Adequacy	WECC, *2025 Western Assessment of Resource Adequacy* (last visited Apr. 20, 2026).	https://feature.wecc.org/2025wara/index.html
2-184	2025 WARA Supplemental Information	WECC, *2025 Western Assessment Supplemental Information* (last visited Apr. 20, 2026)	https://feature.wecc.org/warasupplemental/index.html
2-185	Current Energy Group April Report	Current Energy Group Report, *Resource Adequacy in the Mountain West: Addendum* (Apr. 2026)	
2-186	Public Interest Organizations' January 2026 Rehearing Request	Sierra Club et al., *Motion to Intervene, Motion for Clarification and Request for Rehearing and Stay* (Jan. 28, 2026)	https://www.energy.gov/documents/motion-intervene-motion-clarification-and-request-rehearing-and-stay-sierra-club
2-187	Department Order No. 202-22-2 Amendment No. 1		https://www.energy.gov/sites/default/files/2022-09/Amendment%20No.%201%20to%20Order%20202-22-2%20sb%20A_S3%20Hogan.pdf
2-188	Department Order No. 202-22-1 Amendment No. 2		https://www.energy.gov/sites/default/files/2022-09/Amendment%202%20to%20Order%20202-22-1_FINAL_9.8.2022%20sb%20A_S3%20Hogan.pdf
2-189	Starfield email to Hoffman	Email from Lawrence Starfield, EPA to Patricia Hoffman, DOE Re: DOE section202(c) order (Sept. 11, 2017)	https://www.energy.gov/sites/default/files/2017/09/f36/2017-9-11%20EPA%20consultation%20renewal.pdf

No.	Exhibit Name	Document Name	URL and Notes
3-01	Department Order No. 202-25-14B		https://www.energy.gov/documents/order-addressing-arguments-raised-rehearing-202-25-14b
3-02	Queued Up: 2025 Edition	Rand, Joseph et al, Lawrence Berkeley National Laboratory, "Queued Up: 2025 Edition" (Dec. 2025)	https://eta-publications.lbl.gov/sites/default/files/2025-12/queued_up_2025_edition_12.15.2025.pdf
3-03	Business Models for Coal Plant Decommissioning	Lessick, Jennifer et al, Pacific Northwest National Laboratory, "Business Models for Coal Plant Decommissioning" (Aug. 2021)	https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf
3-04	June 2026 Coal Recommissioning and Modernization Announcement	DOE, "Project Selections for Broad Agency Announcement DE-FOA-0003605, Restoring Reliability: Coal Recommissioning and Modernization (Topic 1)" (June 4, 2026)	https://www.energy.gov/hgeo/project-selections-broad-agency-announcement-de-foa-0003605-restoring-reliability-coal-0
3-05	Public Interest Organizations' April 2026 Rehearing Request	Sierra Club et al., *Motion to Intervene, Motion for Clarification and Request for Rehearing and Stay* (Apr. 28, 2026)	https://www.energy.gov/documents/motion-intervene-motion-clarification-and-request-rehearing-and-stay-public-interest-11
3-06	Tri-State and Platte River April	Request for Rehearing of Tri-State Generation and Transmission Association and Platte	https://www.energy.gov/documents/request-rehearing-tri-state-generation-and-transmission-association-and-platte-river

No.	Exhibit Name	Document Name	URL and Notes
	Rehearing Request	River Power Authority, *In re Craig Order No. 202-26-21*	
3-07	NERC 2026 Summer Reliability Assessment	North American Electric Reliability Corp., *2026 Summer Reliability Assessment* (May 2025)	https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4-02
NERC 2026 State of Reliability Technical Assessment

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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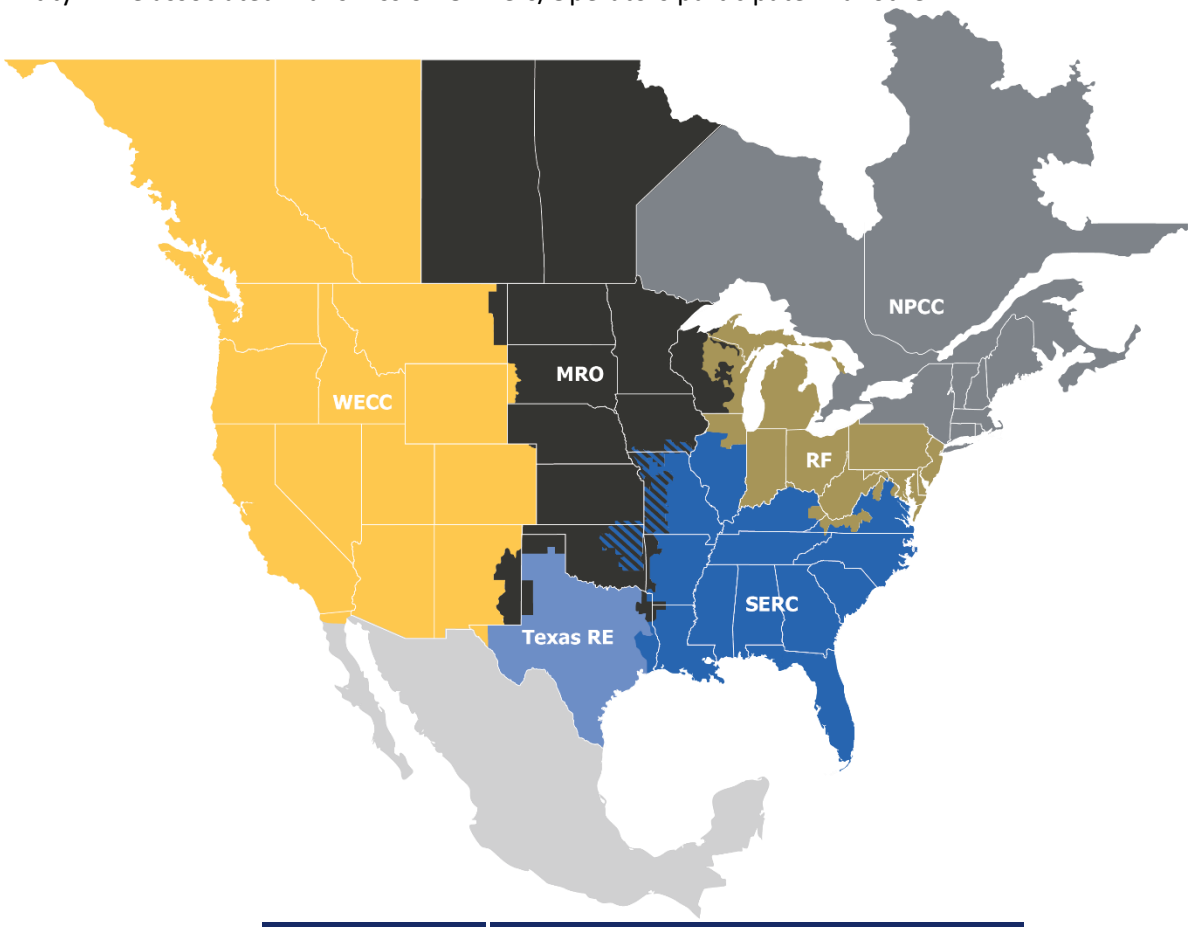
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Preface

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.

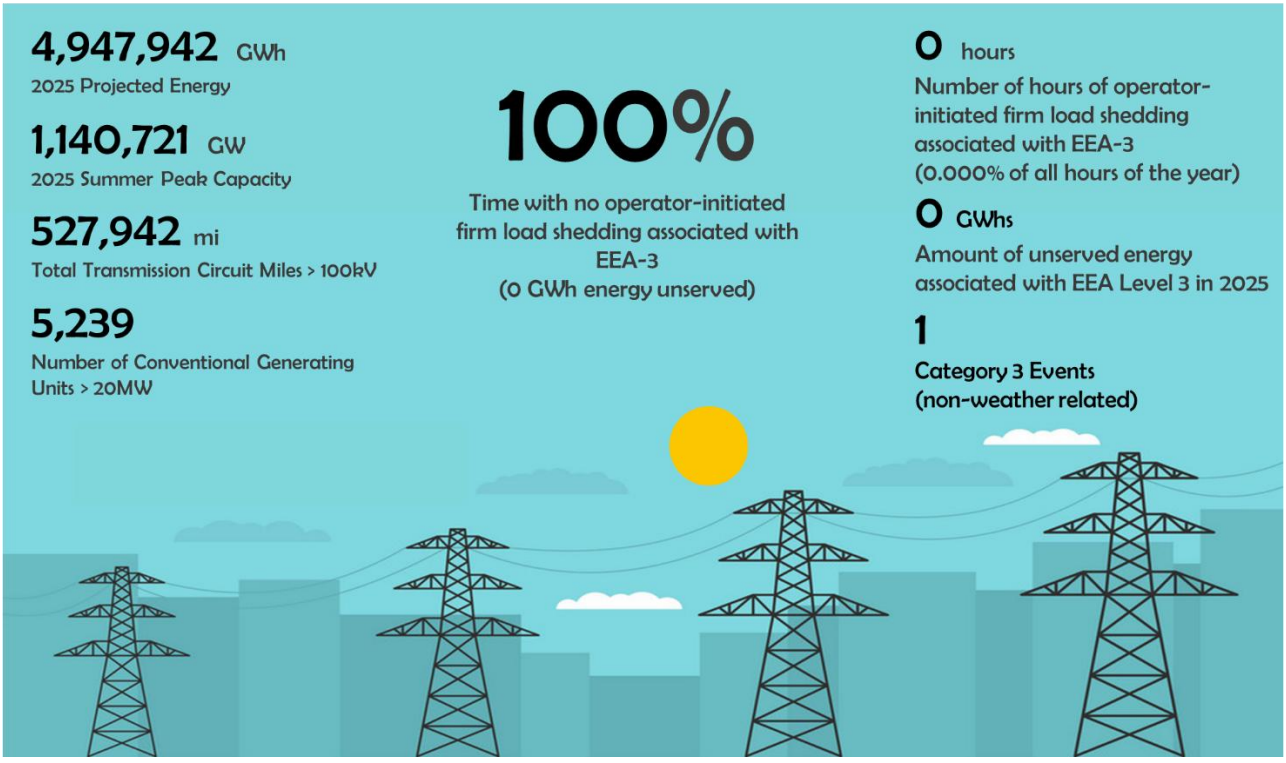


Figure 1.1: 2025 BPS Inventory and Performance Statistics

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.

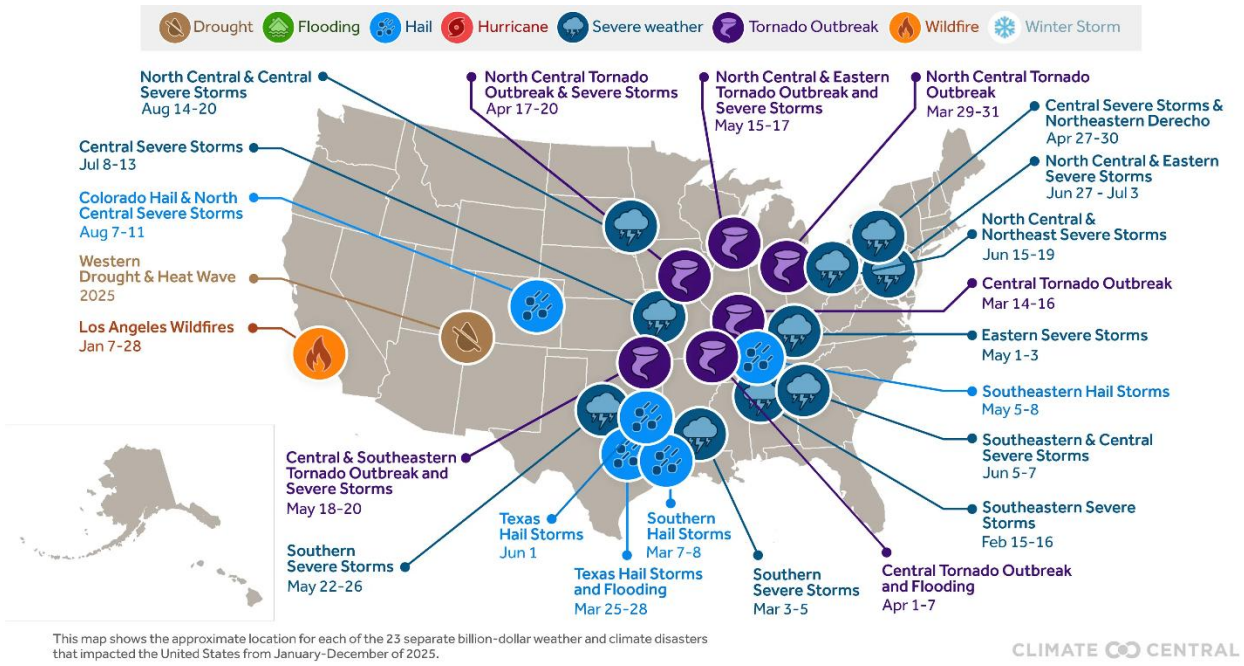


Figure 1.2: 2025 U.S. Billion-Dollar Weather and Climate Disasters[10]



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.

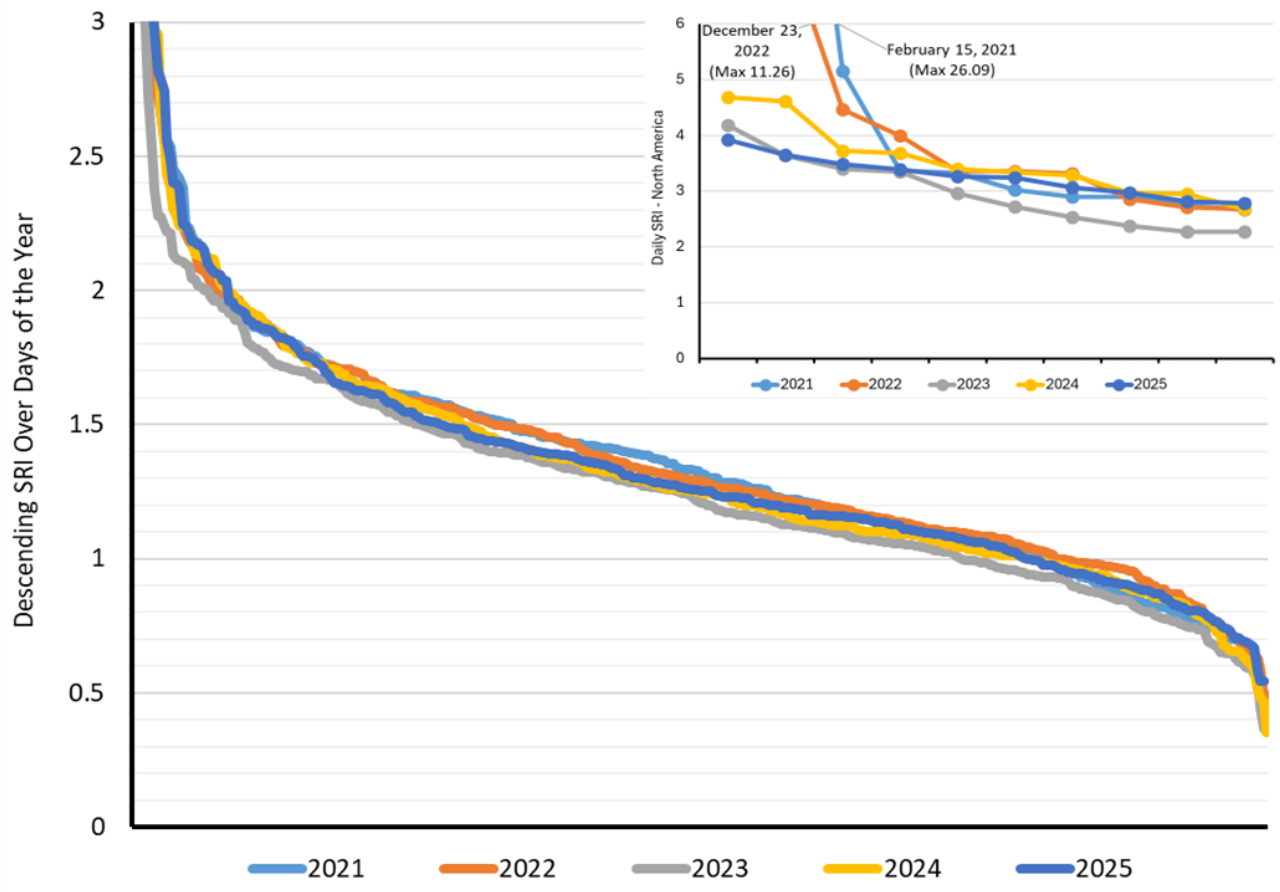


Figure 2.1: NERC Descending SRI by Day of the Year

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.

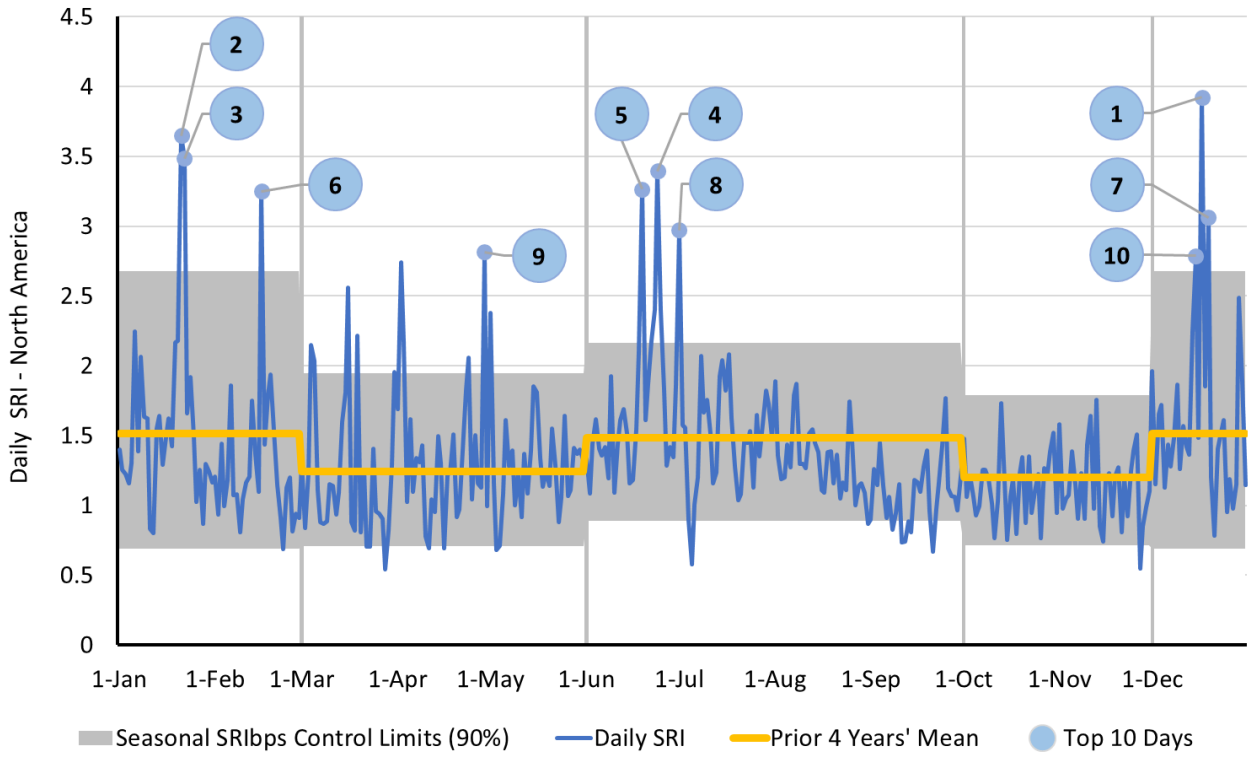


Figure 2.2: 2025 Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

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**.

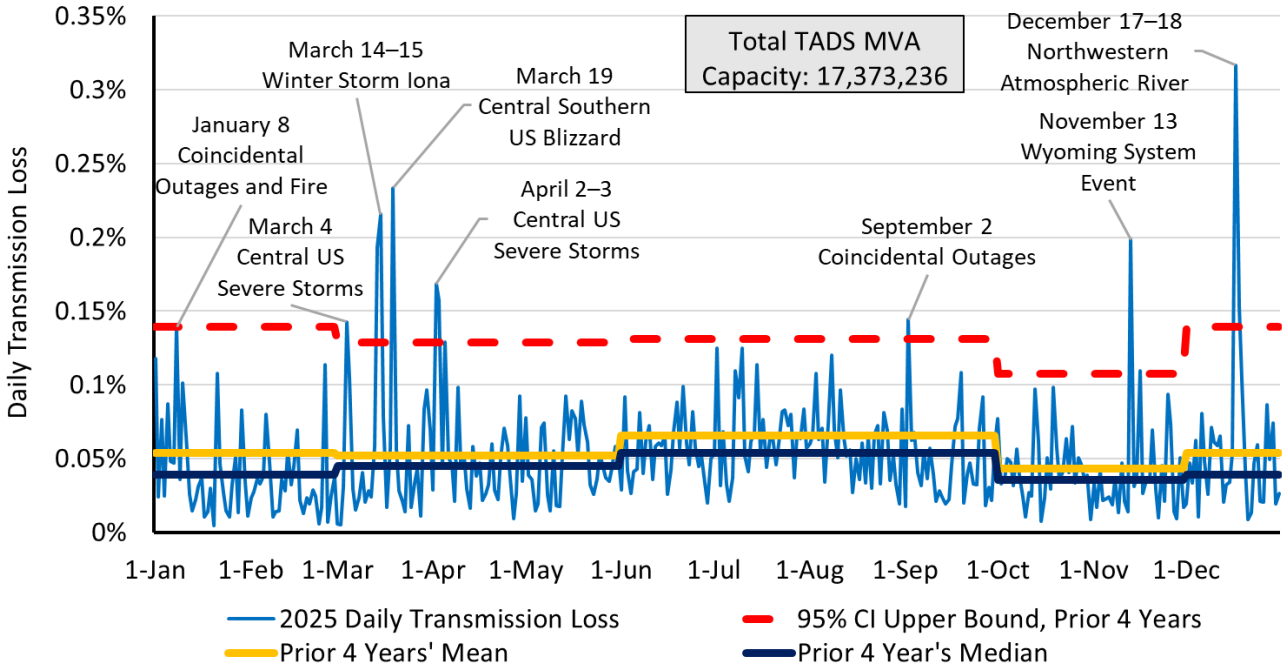


Figure 2.3: 2025 Sustained Transmission Outages During Extreme Days

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.

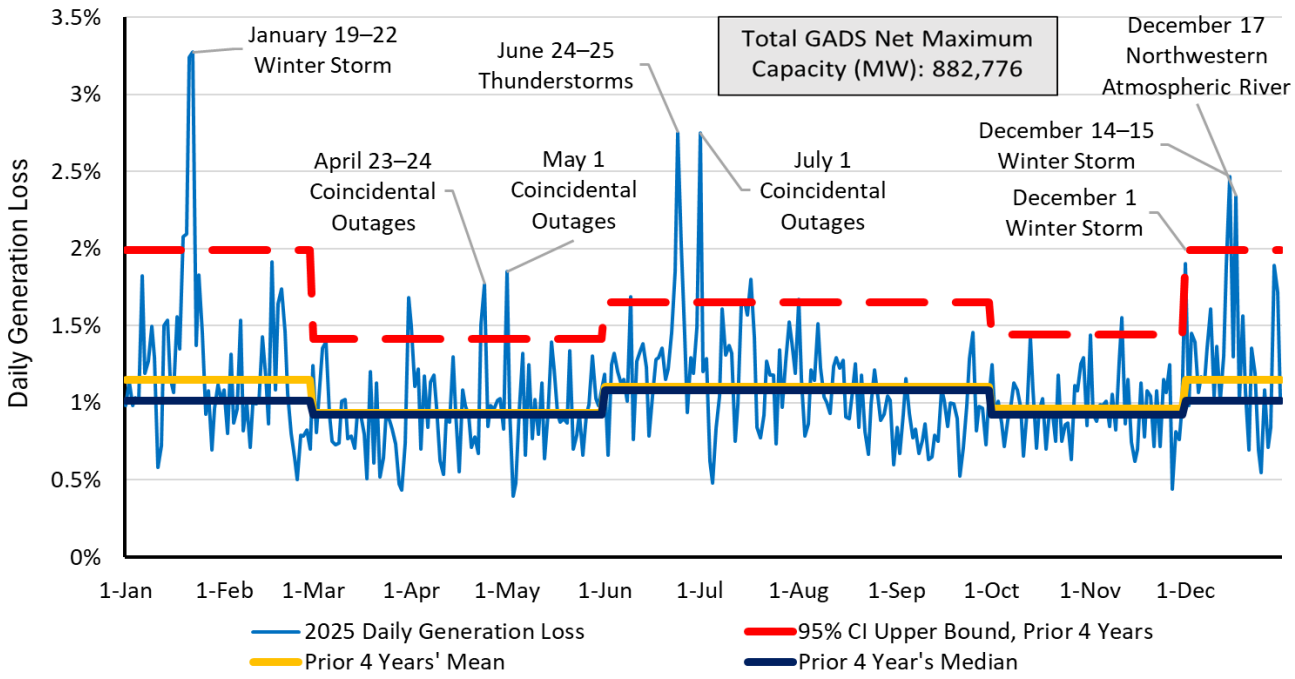


Figure 2.4: 2025 Generation Impacted During Extreme Days

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.

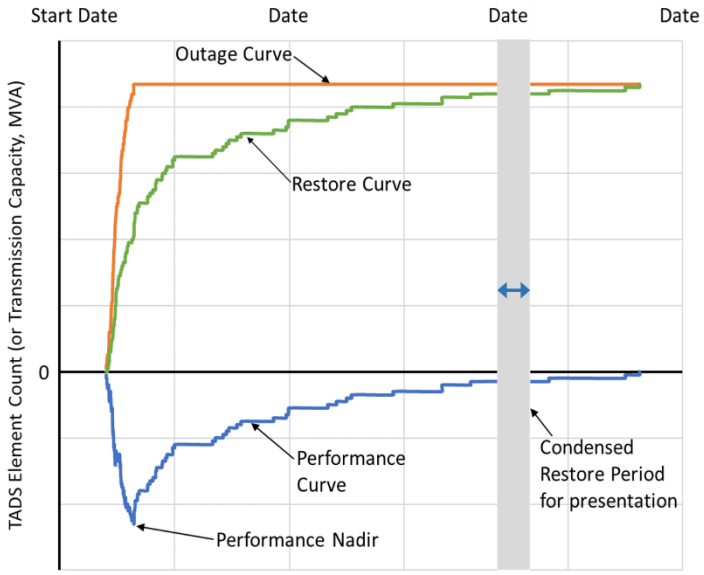


Figure 2.5: Example of Outage, Restore, and Performance Curves for a Large Transmission Outage Event

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.

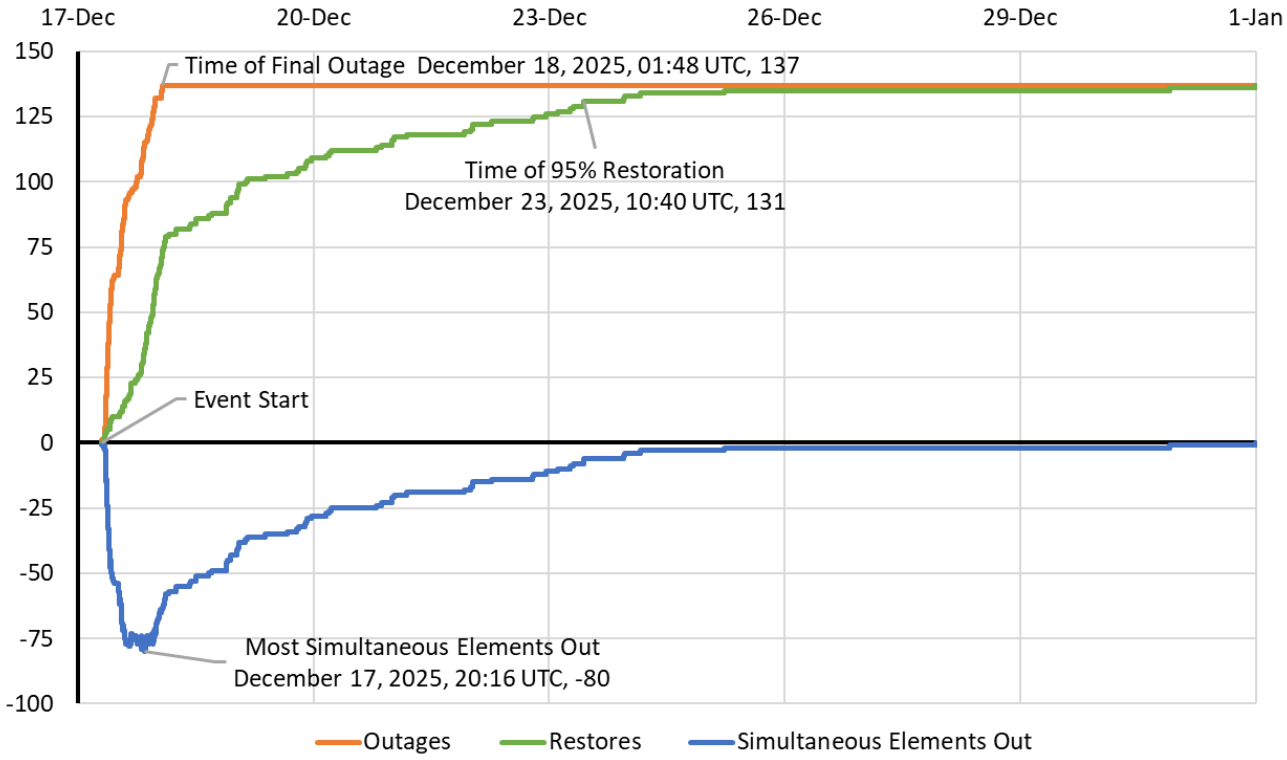


Figure 2.6: Transmission Element Outage, Restore, and Performance Curves for Atmospheric River Event in the Western Interconnection, December 17, 2025–January 22, 2026

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

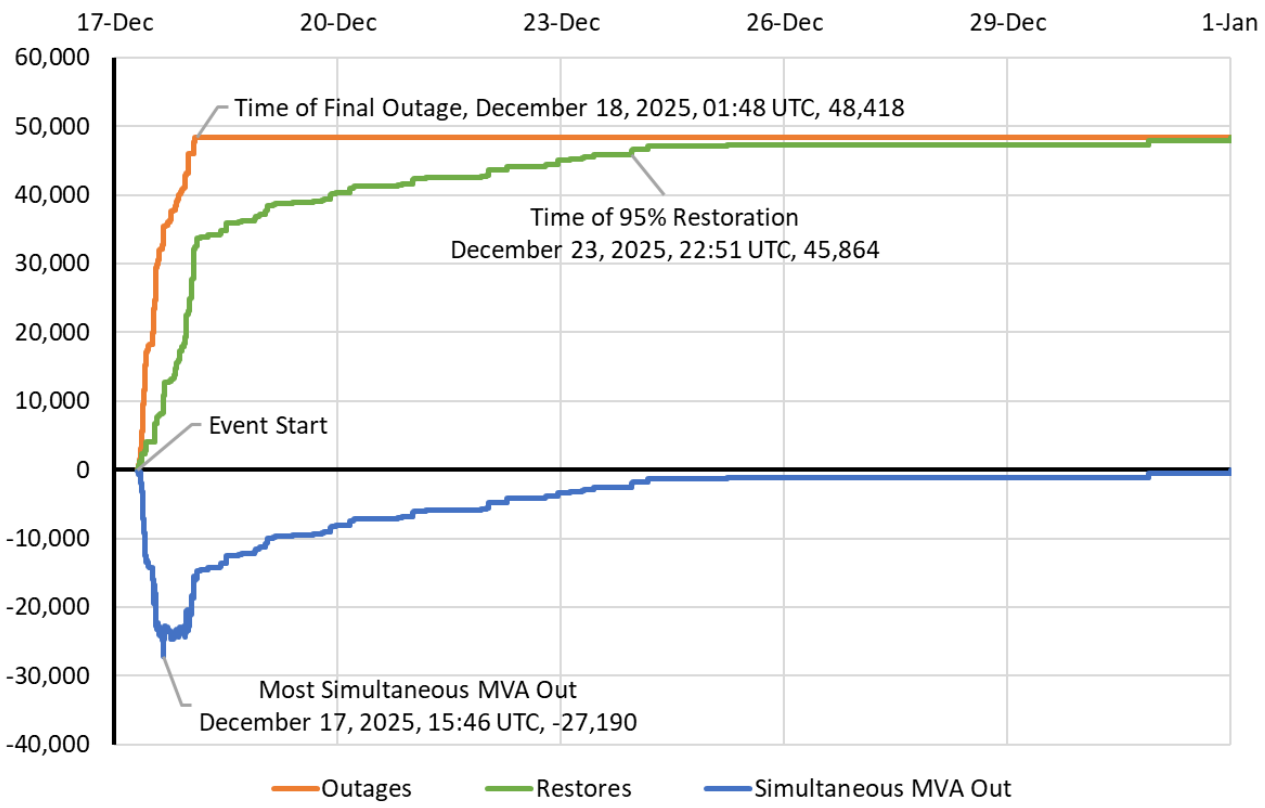


Figure 2.7: Transmission Capacity (MVA-Based) Outage, Restore, and Performance Curves for Atmospheric River Event in the Western Interconnection, December 17, 2025–January 22, 2026

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.

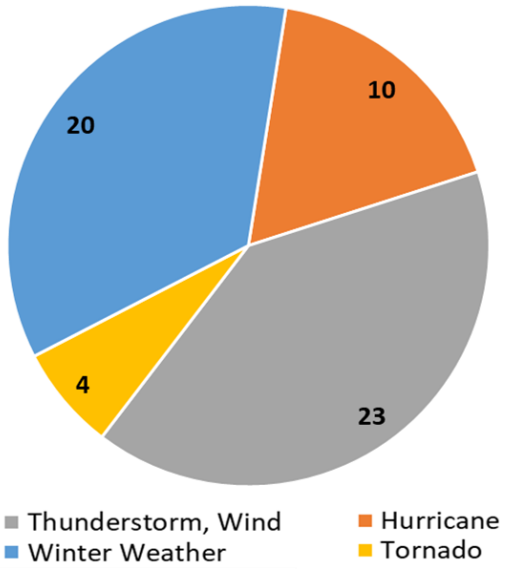


Figure 2.8: Weather Types of Large Transmission Events, 2021–2025

[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.

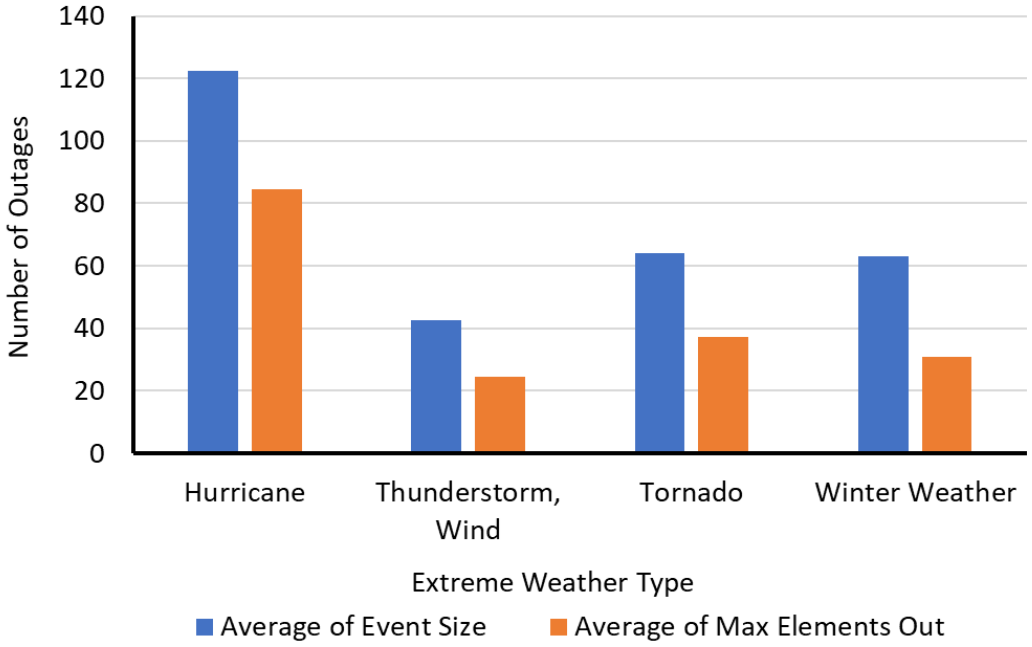


Figure 2.9: Resilience Statistics for 2021–2025 Large Weather-Related Events

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

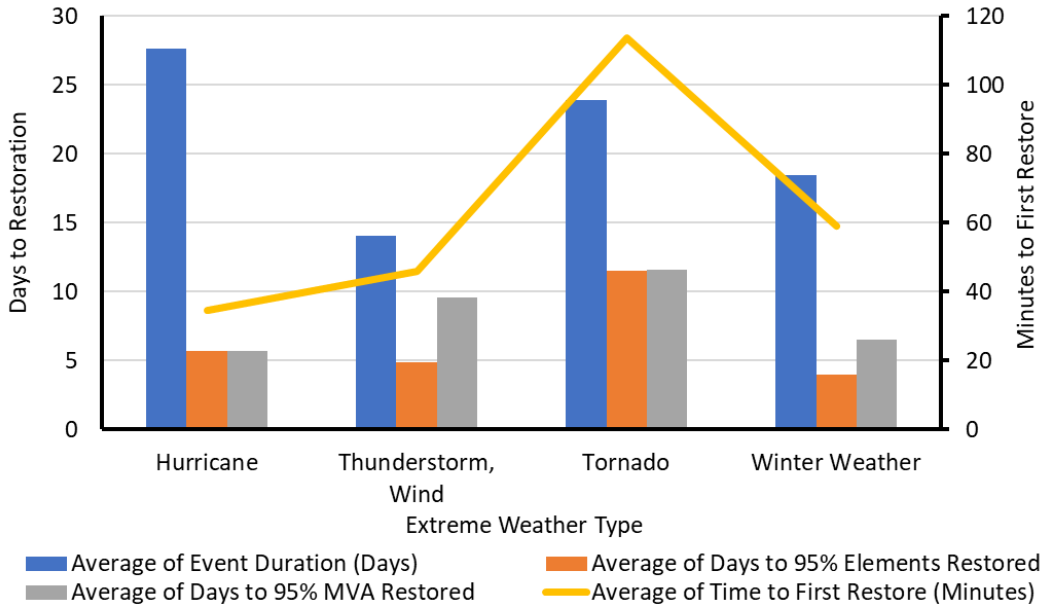


Figure 2.10: Average Event Duration vs. Average Sustained Restoration Duration

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.

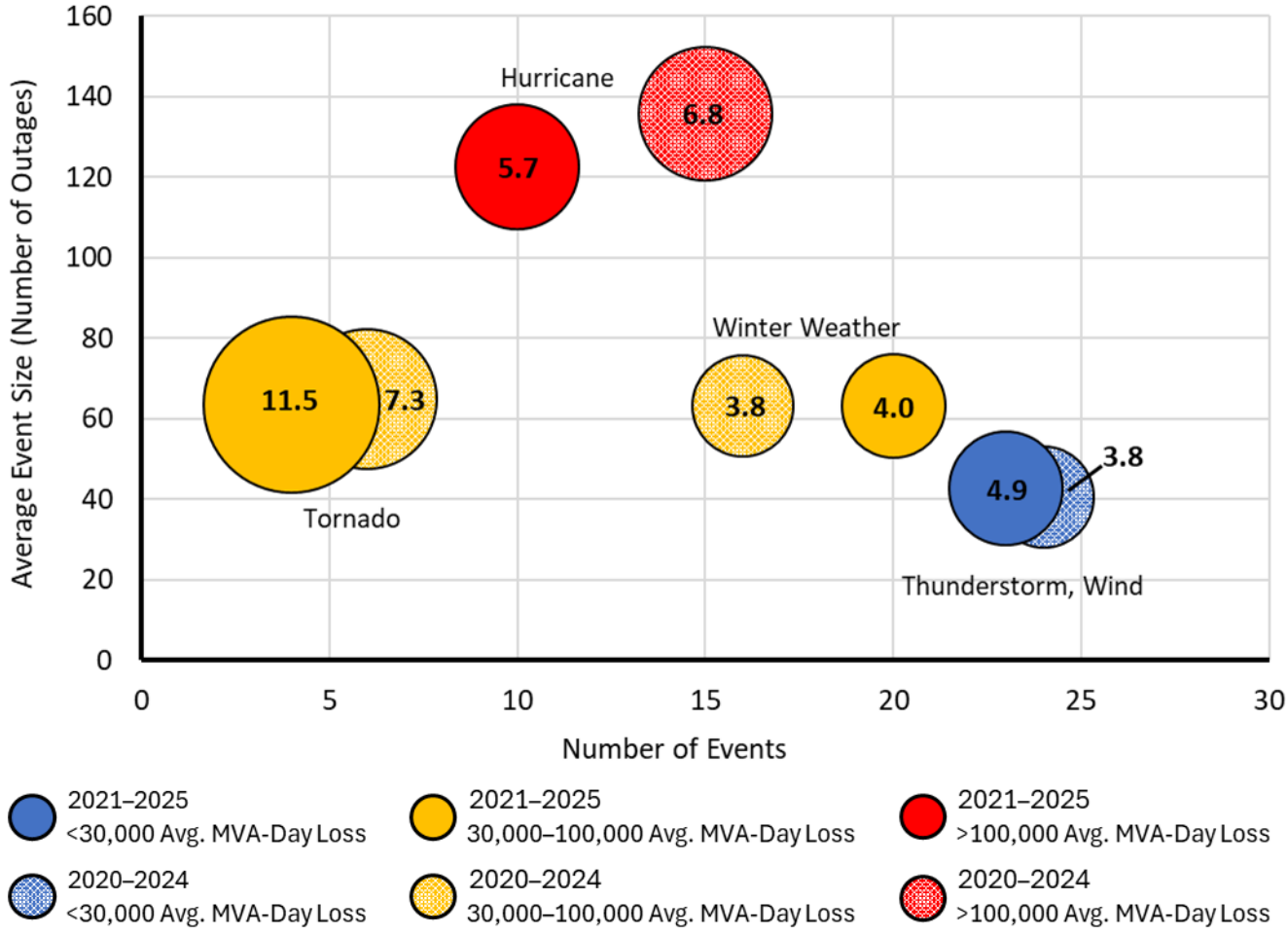


Figure 2.11: Statistics for Large Transmission Events by Weather Type for 2020–2024 vs. 2021–2025

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

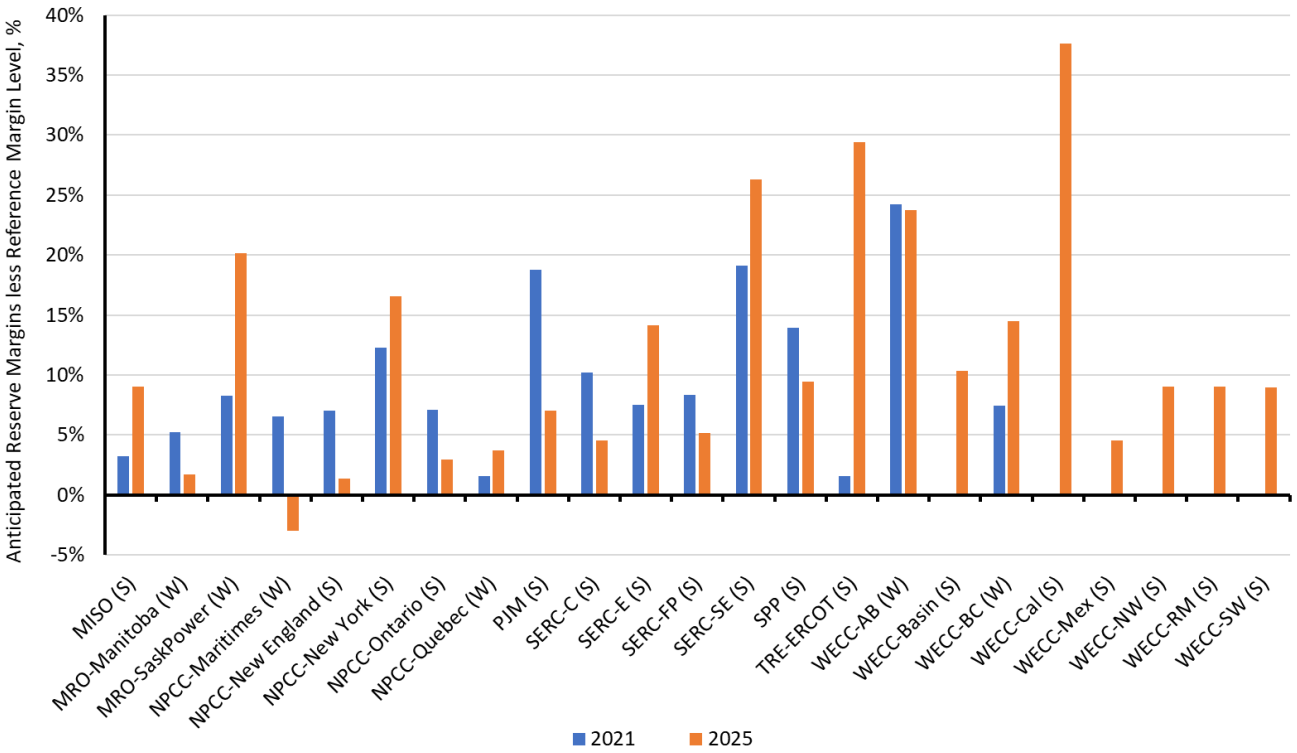


Figure 3.1: 2021 and 2025 Peak Season Planning Reserve Margins Less Reference Margin Levels[33]

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.

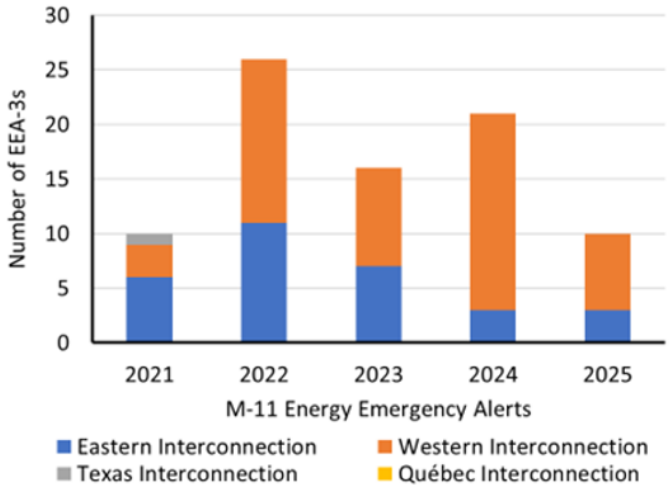


Figure 3.2: EEA 3 by Year and Interconnection

[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

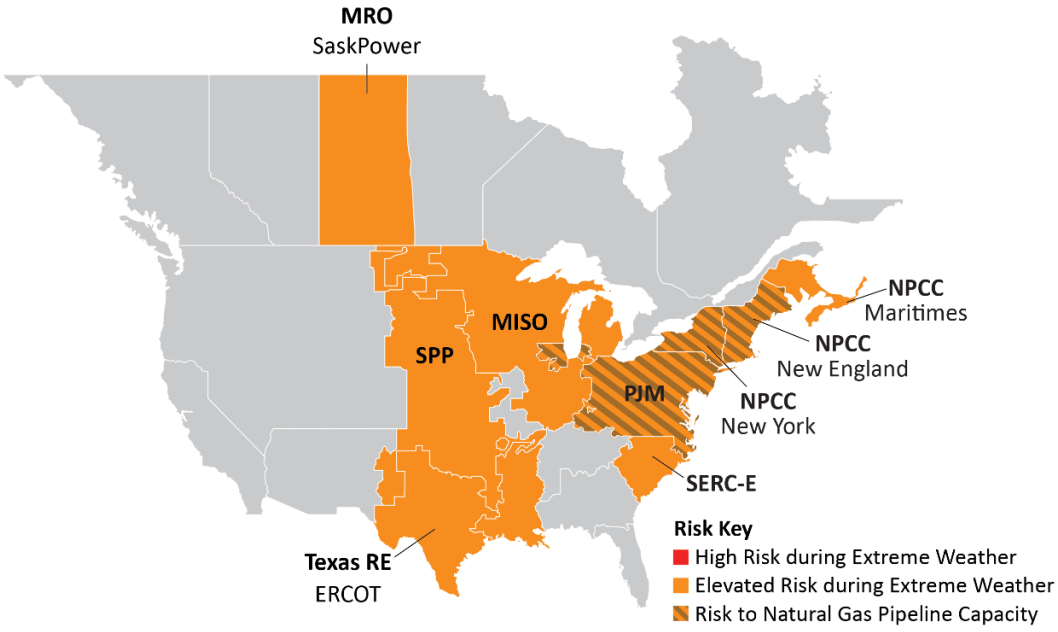


Figure 3.3: 2024–2025 Winter Reliability Assessment Risk Area Map

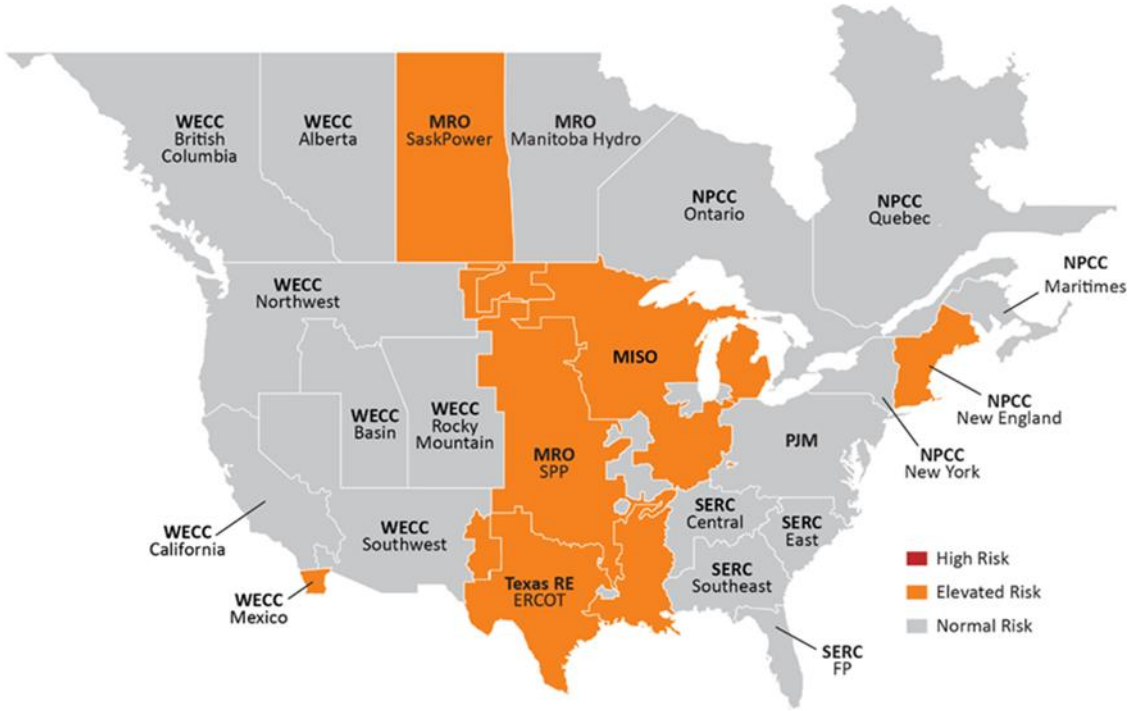


Figure 3.4: 2025 Summer Reliability Assessment Risk Area Map

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

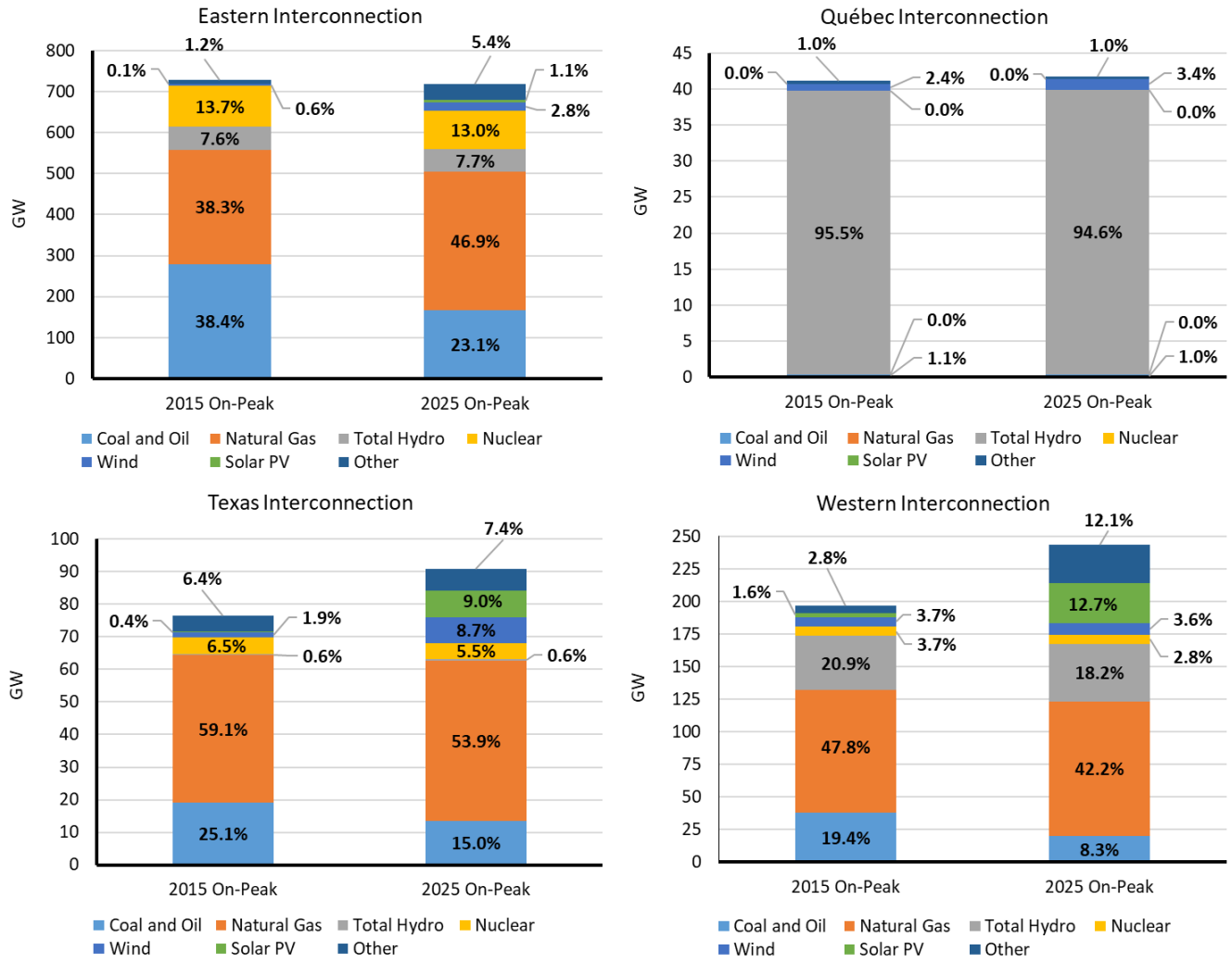


Figure 3.5: 2015 and 2025 Capacity Resource Mix by Interconnection

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

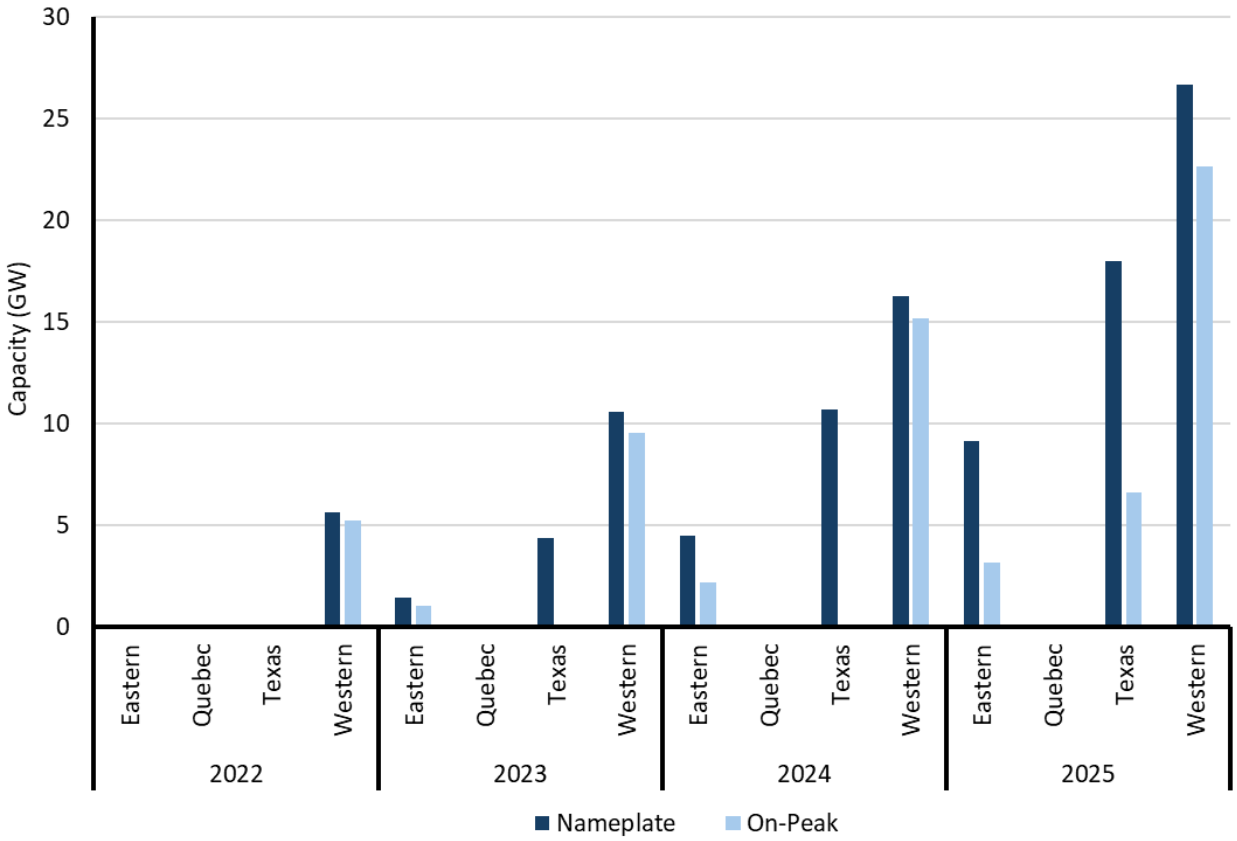
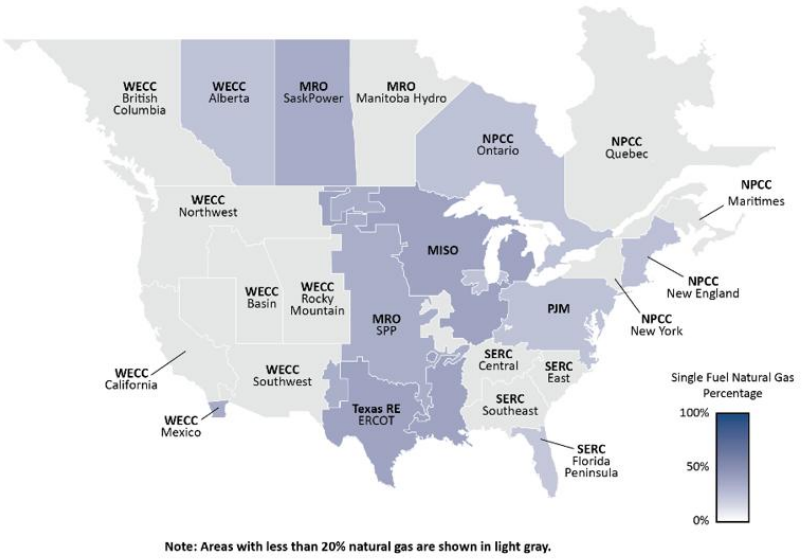


Figure 3.6: 2022–2025 Battery and Hybrid Capacity by Interconnection[48]

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**).

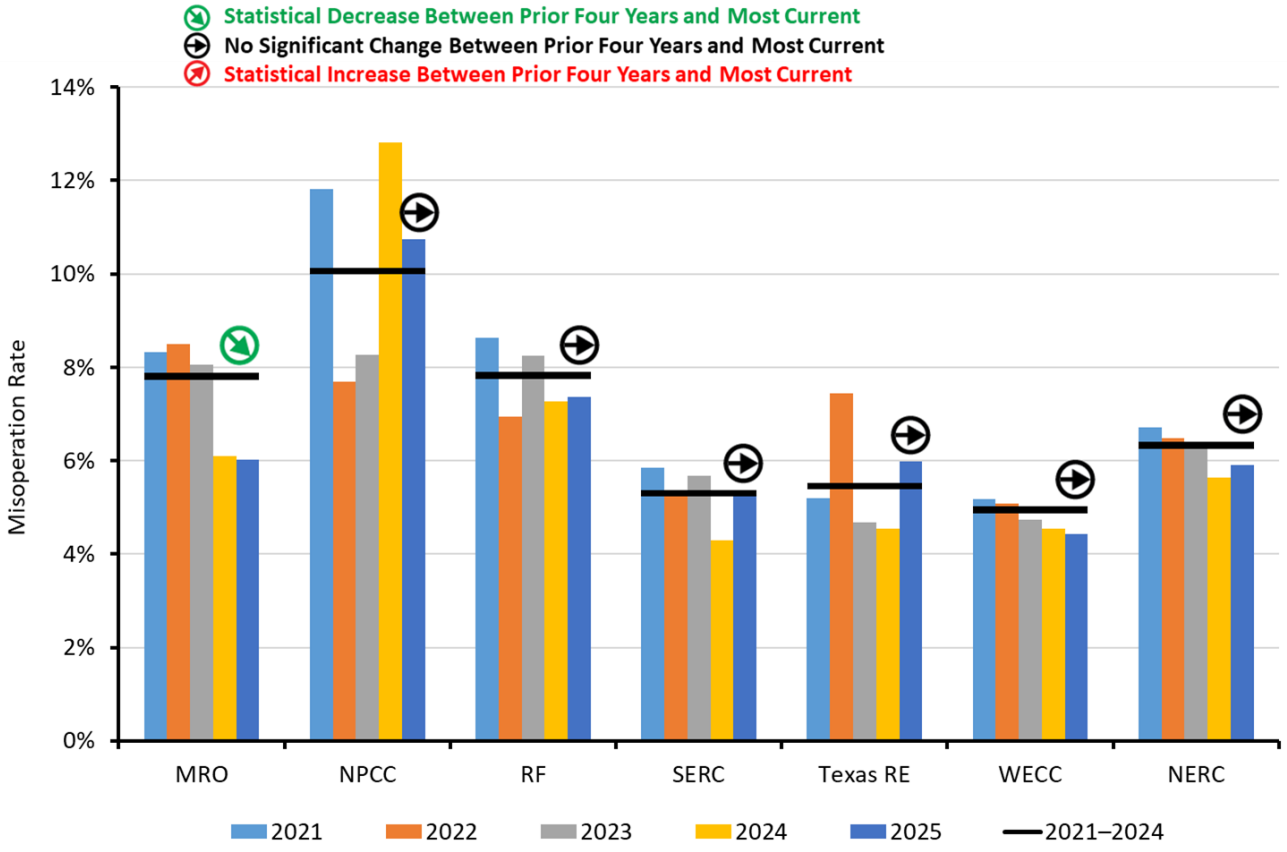


Figure 3.8: Changes and Trends in the Annual Misoperations Rate by Regional Entity[54]

[54] M-9, Protection System Misoperations Rate

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.

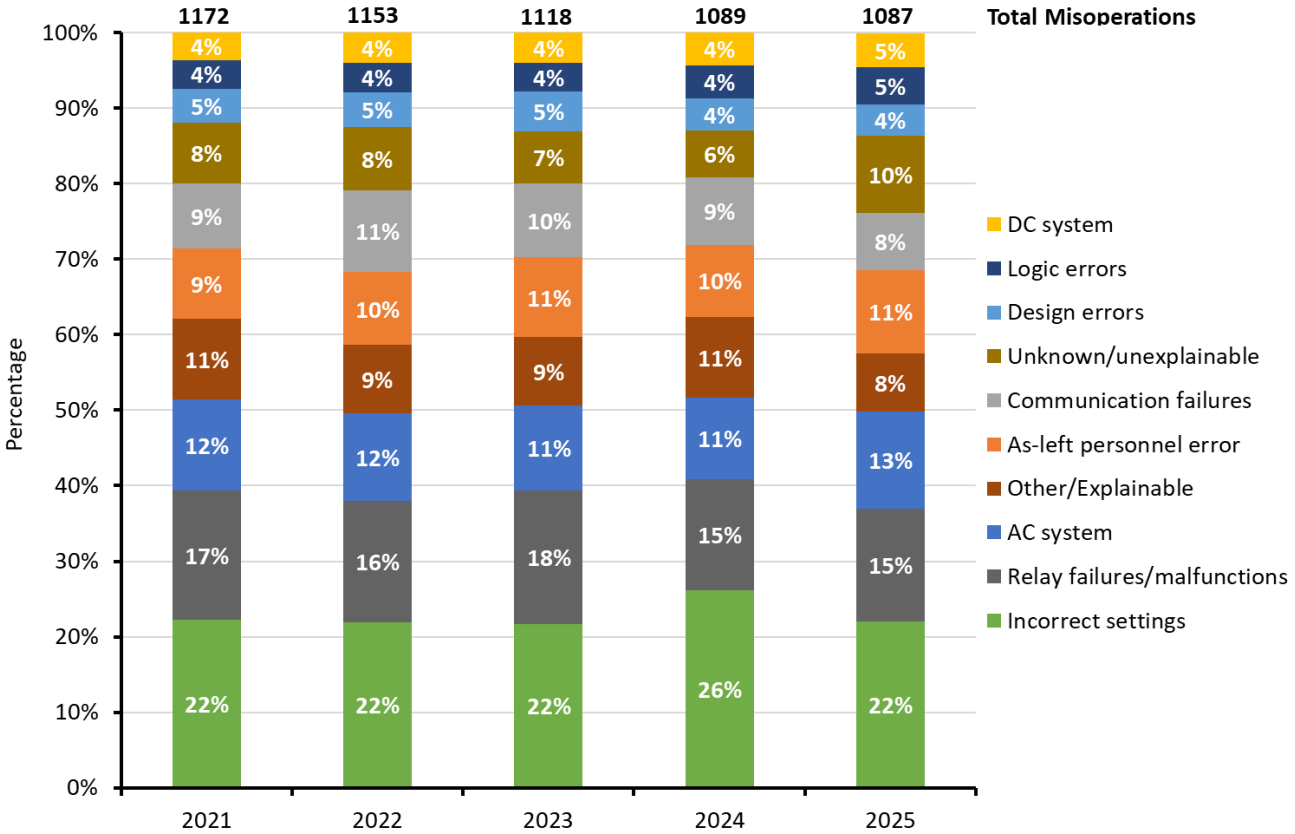


Figure 3.9: Percentage of Misoperations by Cause Code (2021–2025)

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.

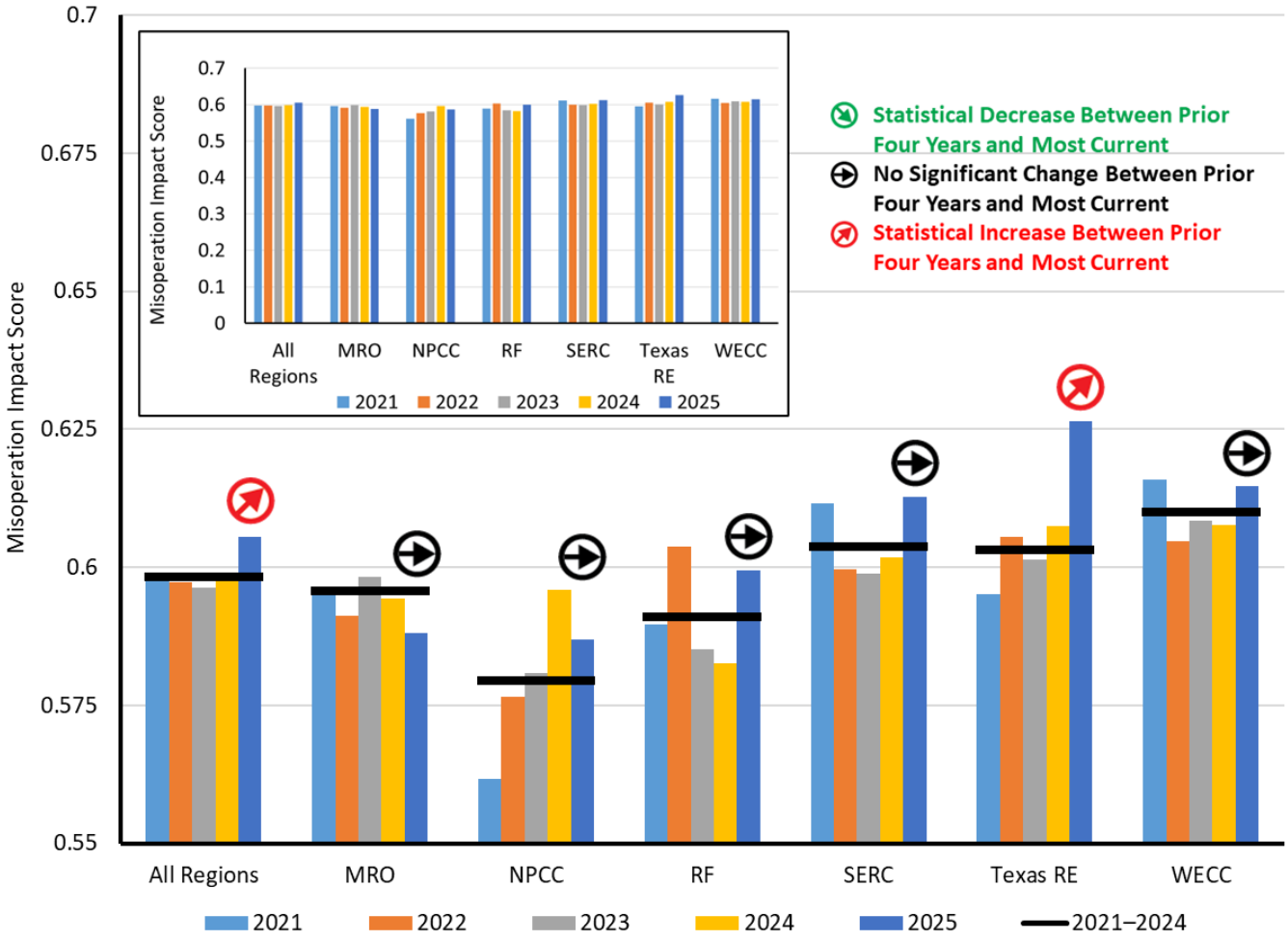


Figure 3.10: Misoperation Impact Score

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

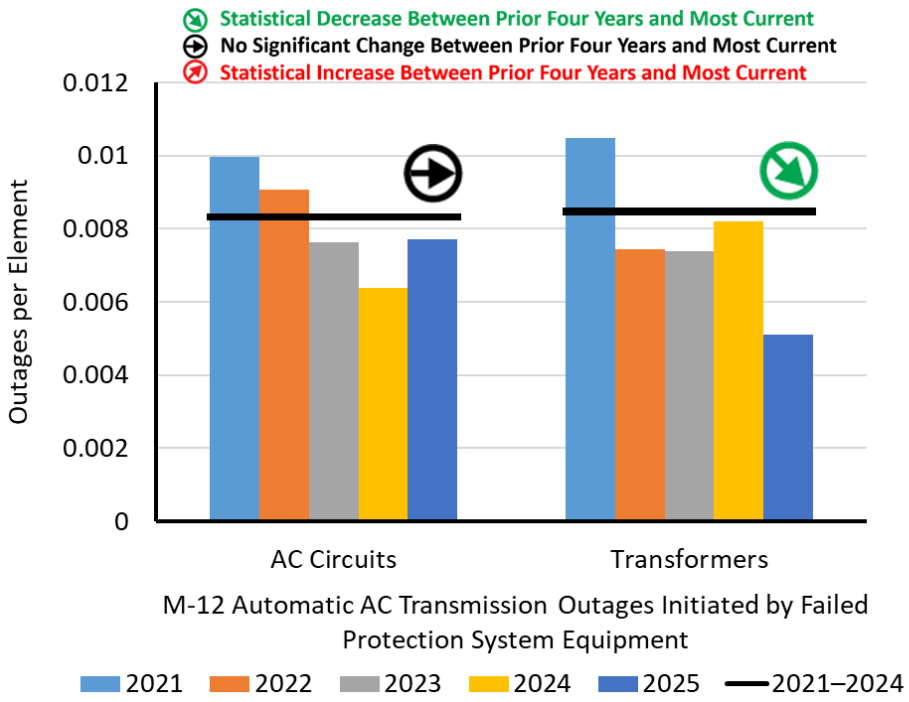


Figure 3.11: Failed Protection System Equipment Outages[56]

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)

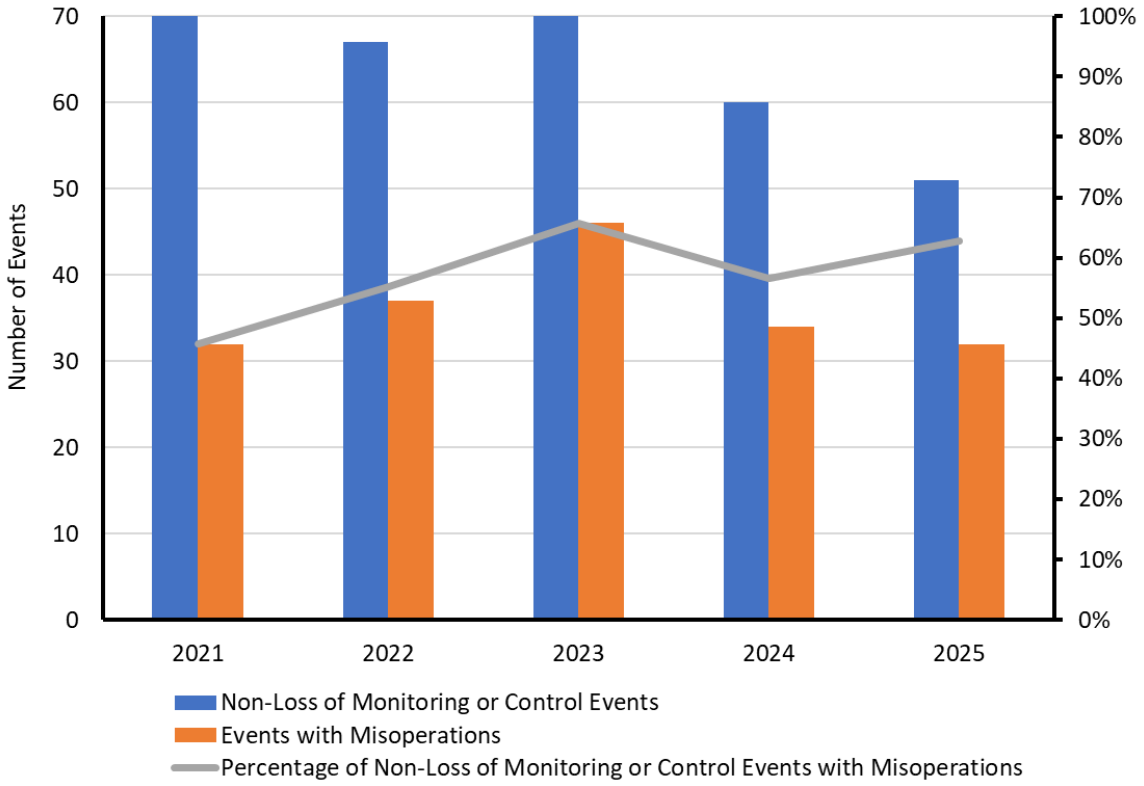


Figure 3.12: Events with Misoperations

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.

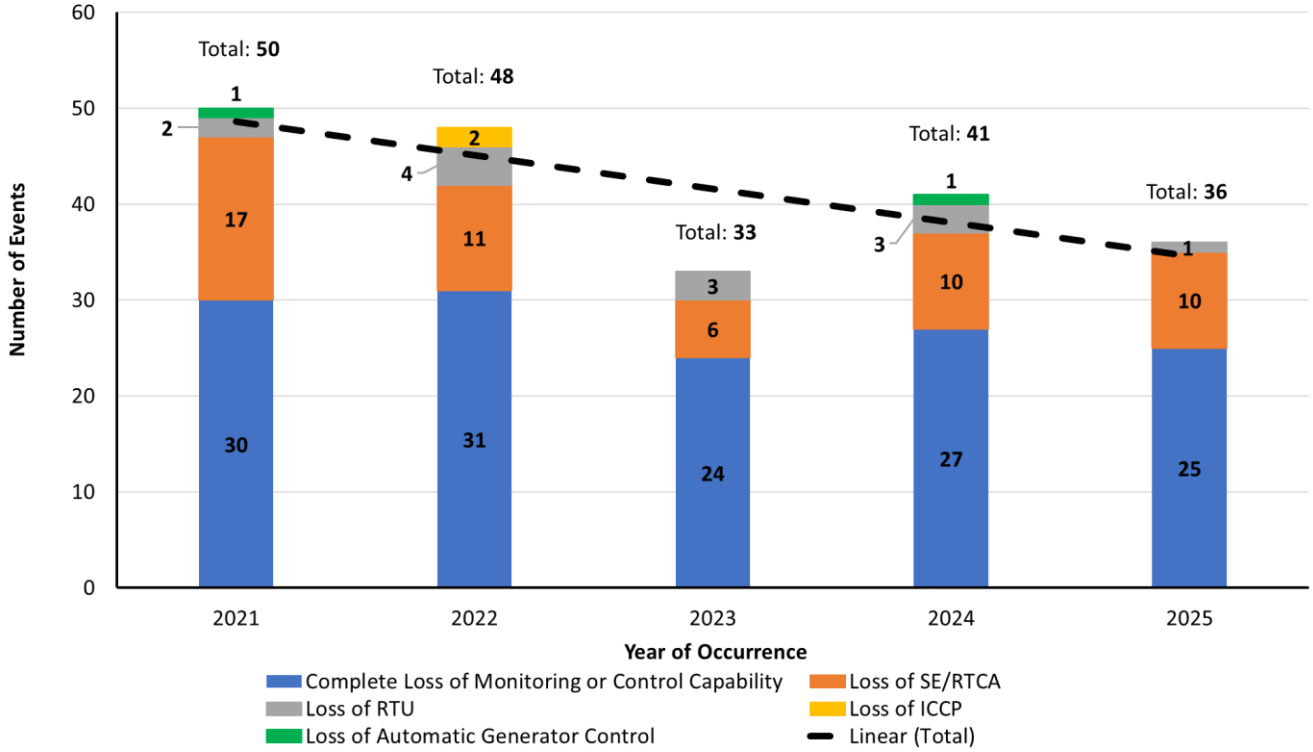


Figure 3.13: Number of EMS-Related Events (2021–2025)

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.

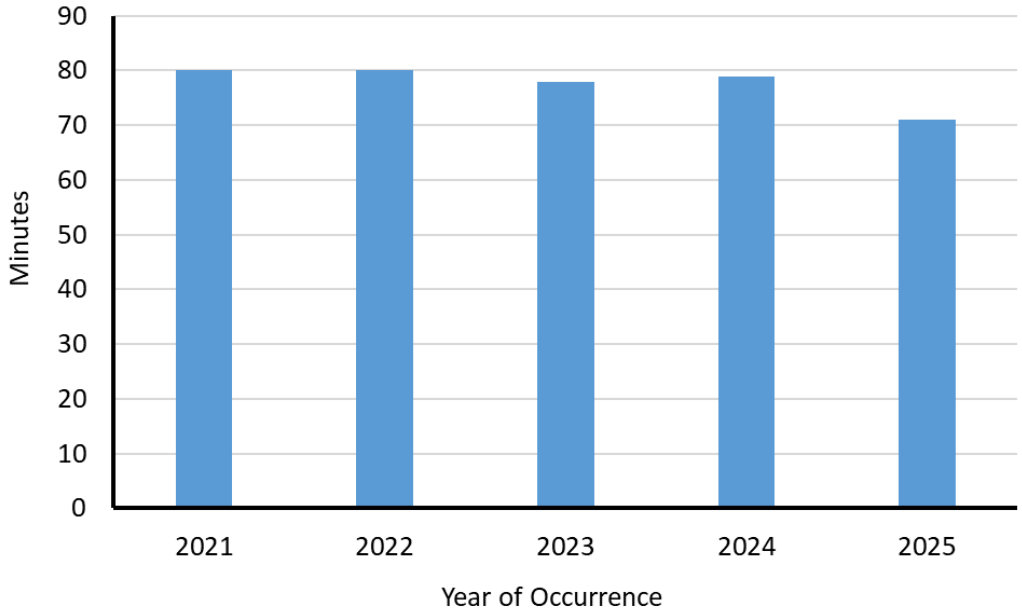


Figure 3.14: Average EMS Outage Time (2021–2025)

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.

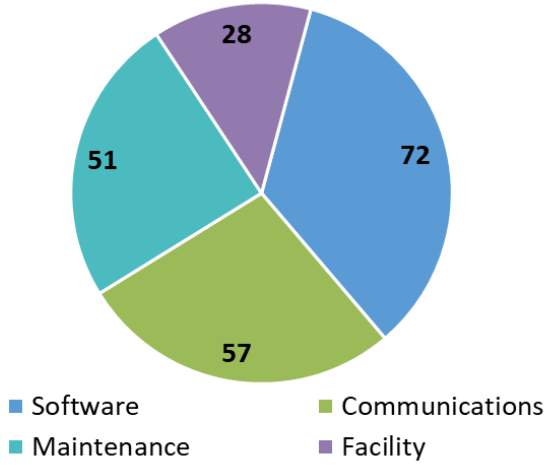


Figure 3.15: Overview of Contributors to Loss of EMS Functions (2021–2025)

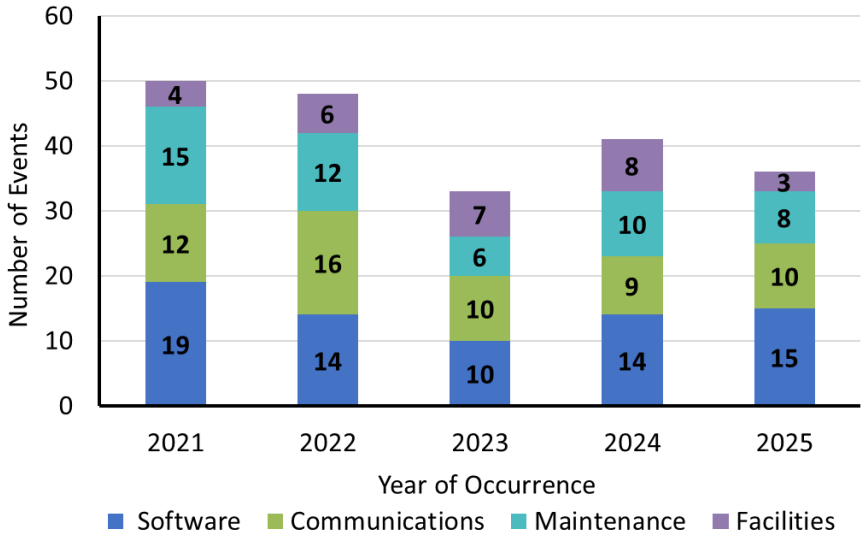


Figure 3.16: Trend of Contributors to Loss of EMS Functions (2021–2025)

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.

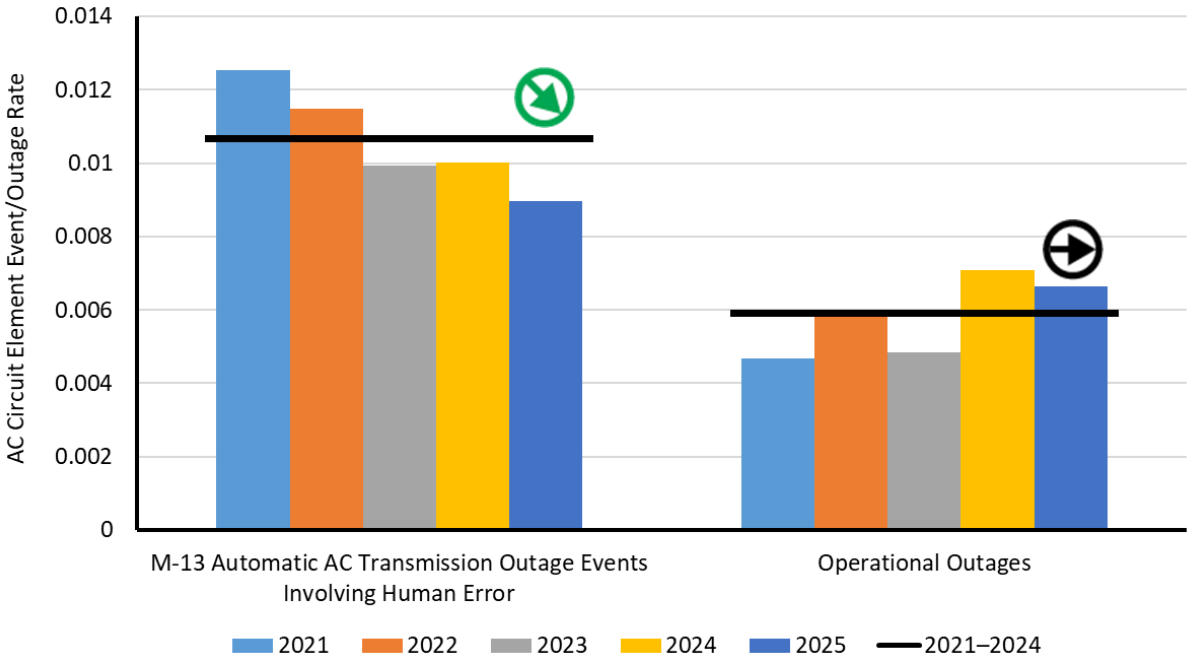


Figure 3.17: Automatic AC Transmission Outage Events and Operational Outages Involving Human Error[64]

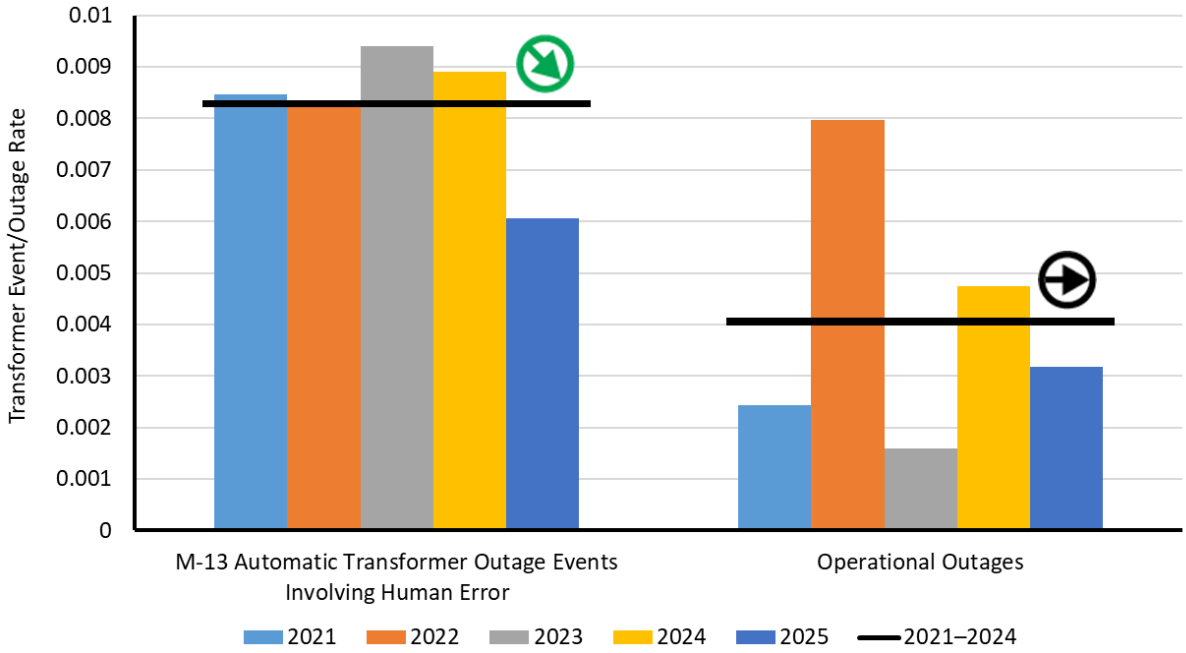


Figure 3.18: Automatic Transformer Outage Events and Operational Outages Involving Human Error[65]

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.

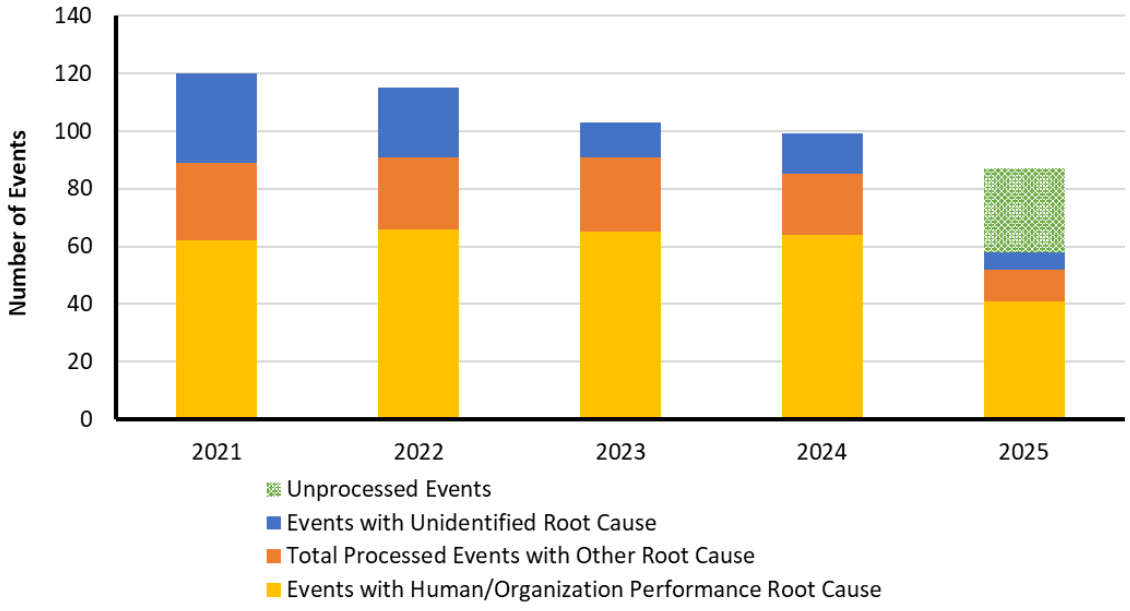


Figure 3.19: ERO EAP Organization/Human Performance Root Cause Identification by Year

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.

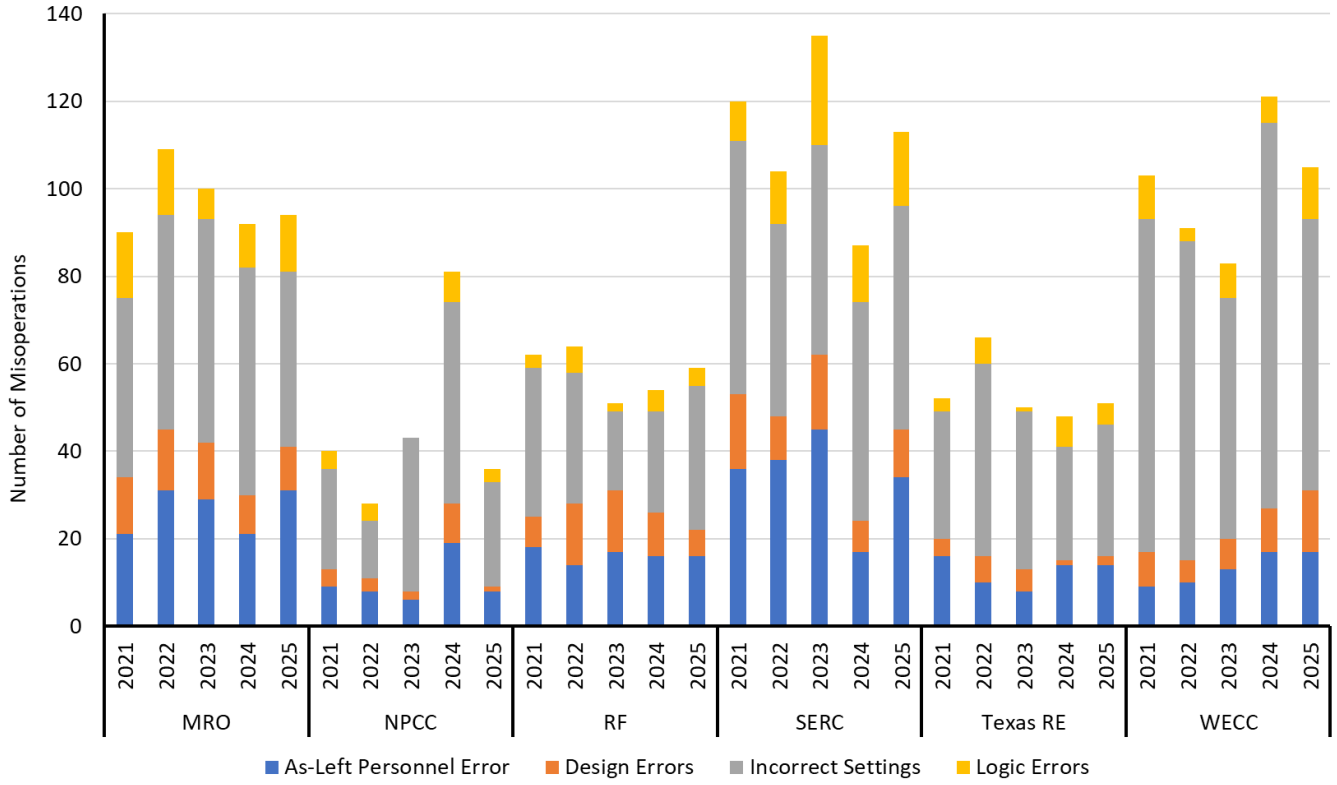


Figure 3.20: MIDAS Protection System Misoperations Due to Human Error by Regional Entity

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.

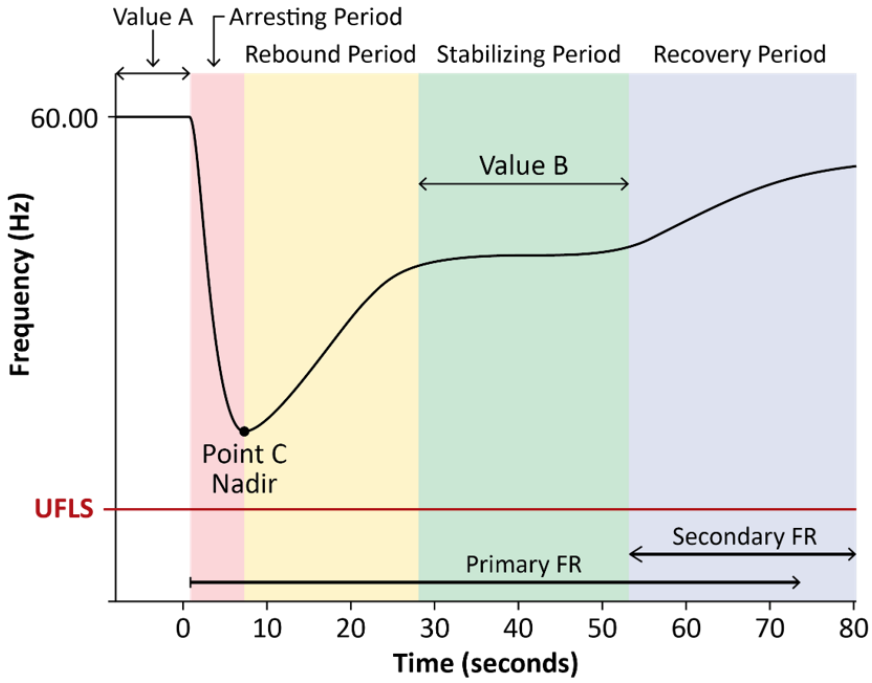


Figure 4.1: Frequency Response Methodology

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.

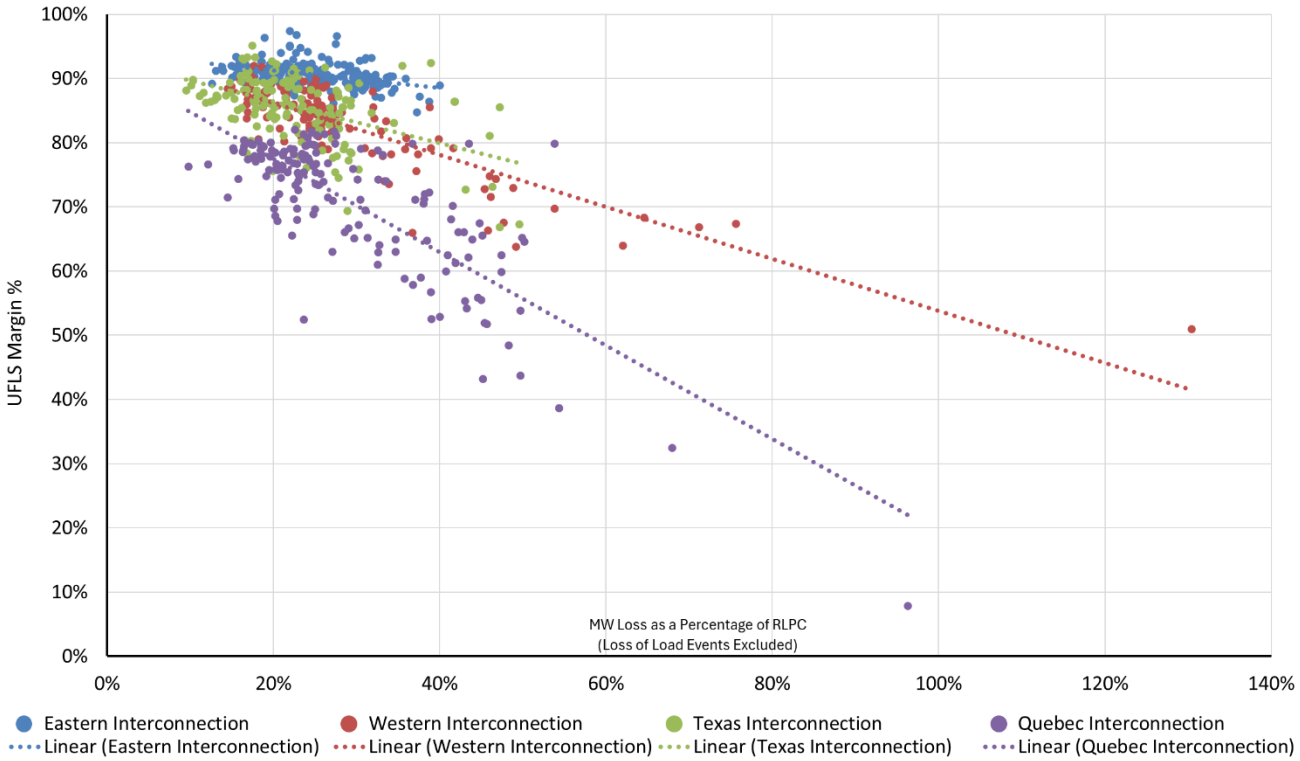


Figure 4.2: Operating Year 2021–2025 Qualified Frequency Disturbances and Remaining UFLS Margin

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

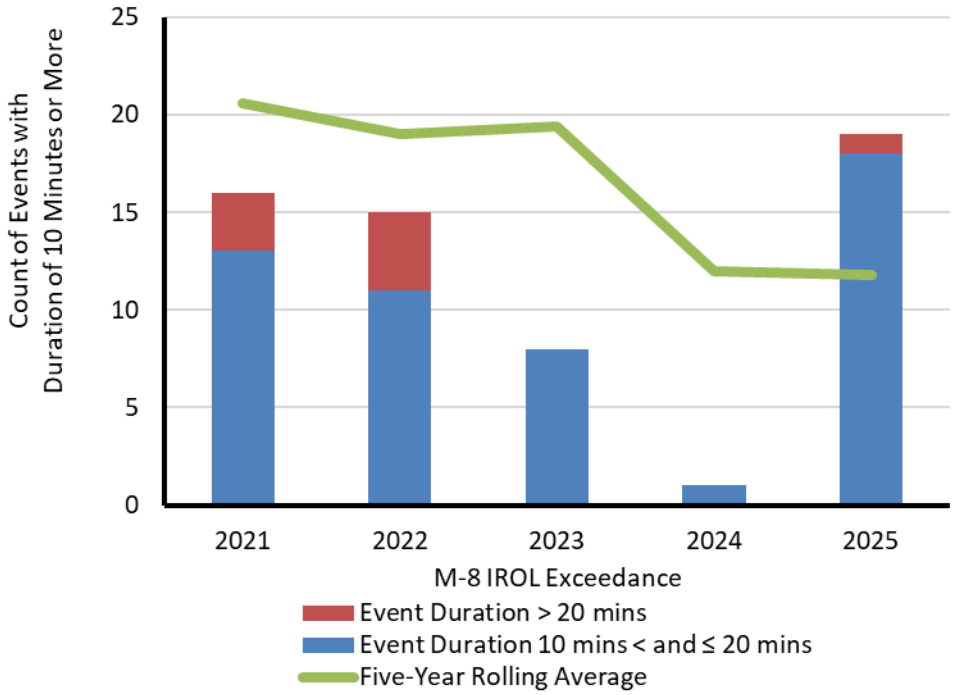


Figure 4.3: IROL Exceedance Counts

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.

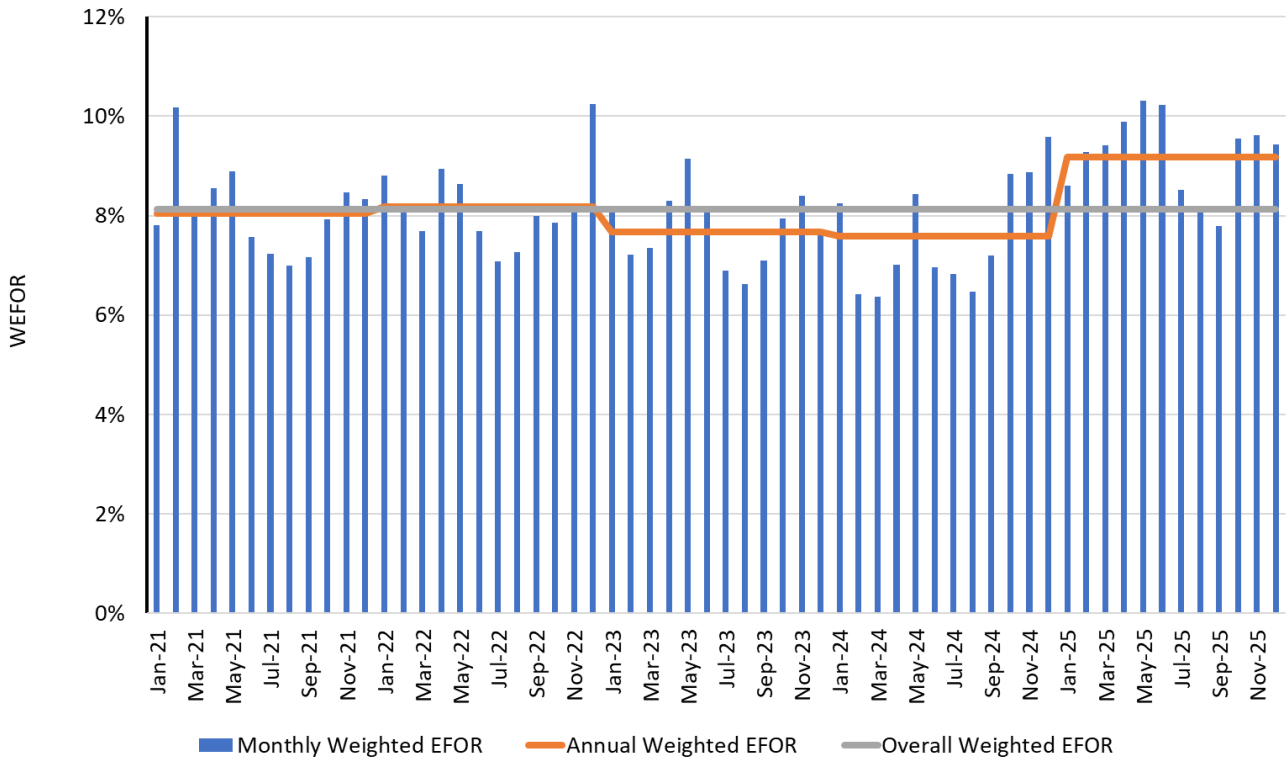


Figure 4.4: Monthly, Annual, and Five-Year WEFOR

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**).

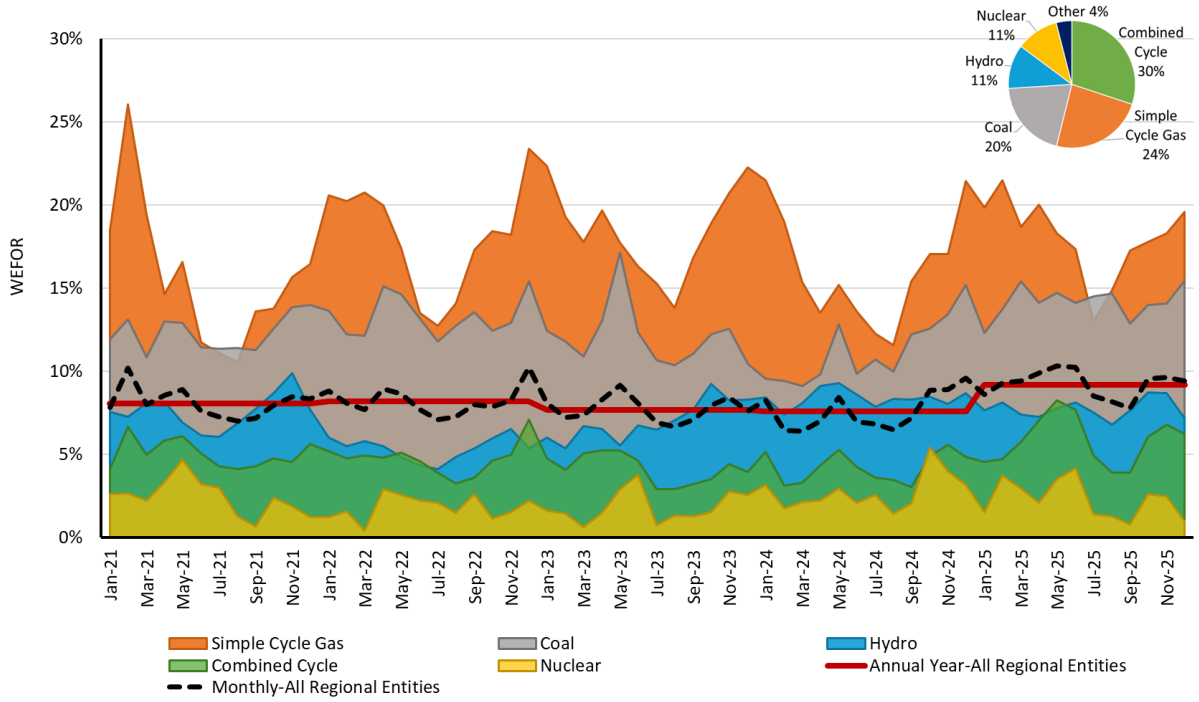


Figure 4.5: Five-Year WEFOR by Fuel Type and 2025 Resource Mix by Net Maximum Capacity

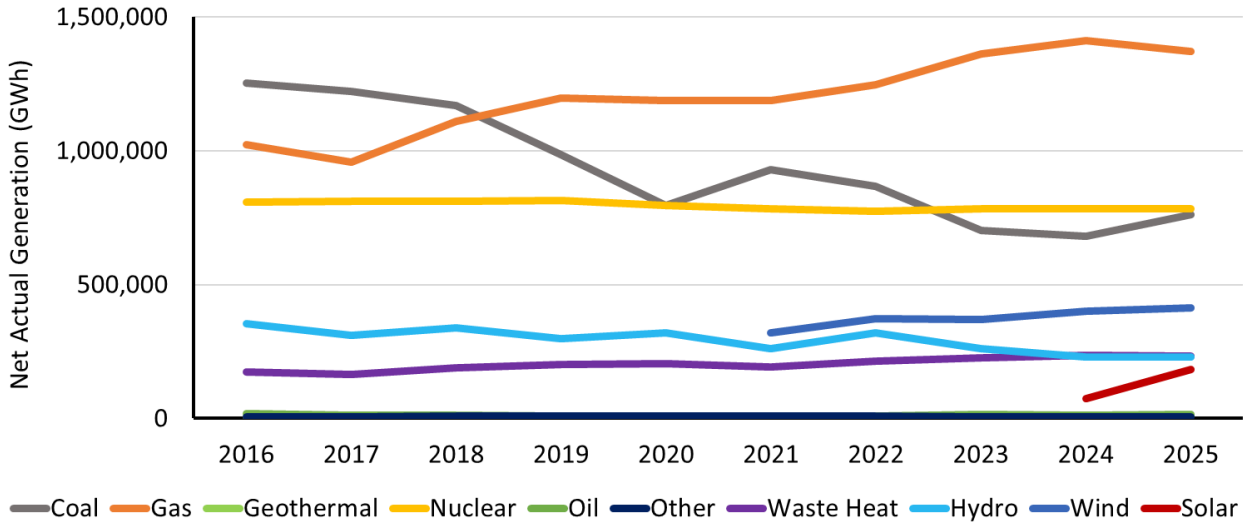


Figure 4.6: 10-Year Annual Net Actual Generation (GWh) by Fuel Type

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

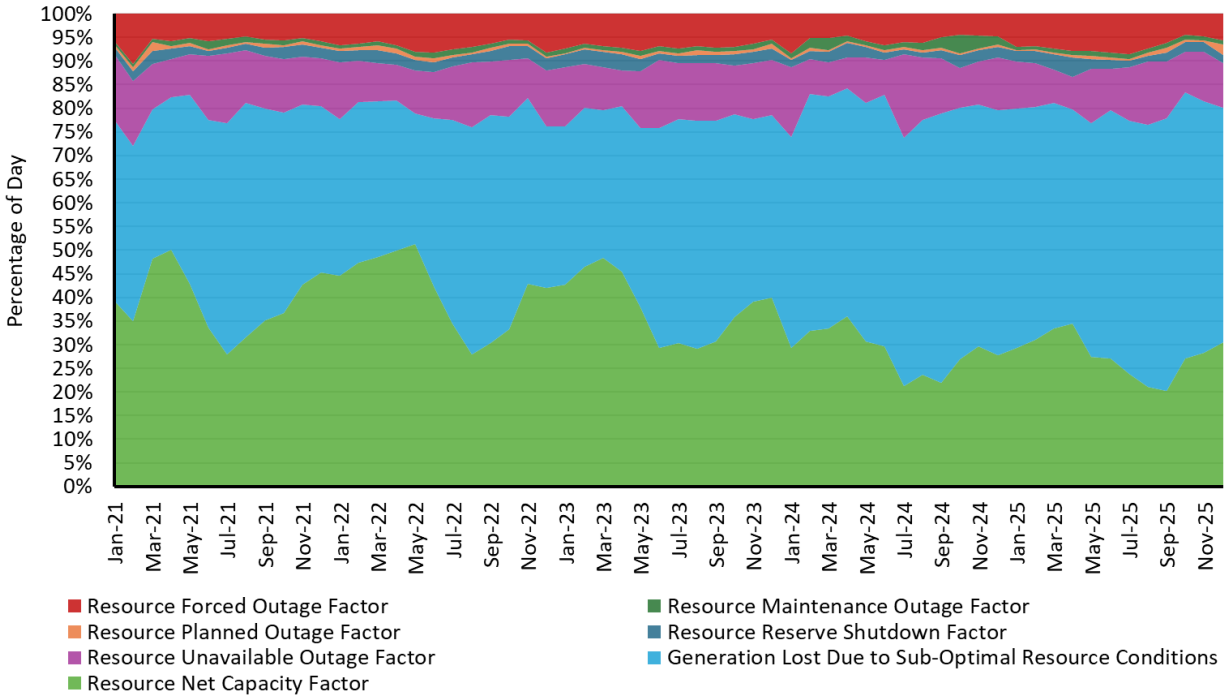


Figure 4.7: Monthly Net Output Factor and Weighted Resource Forced Outage Rate (WRFOR) Wind Plant Reporting Group 200 MW+

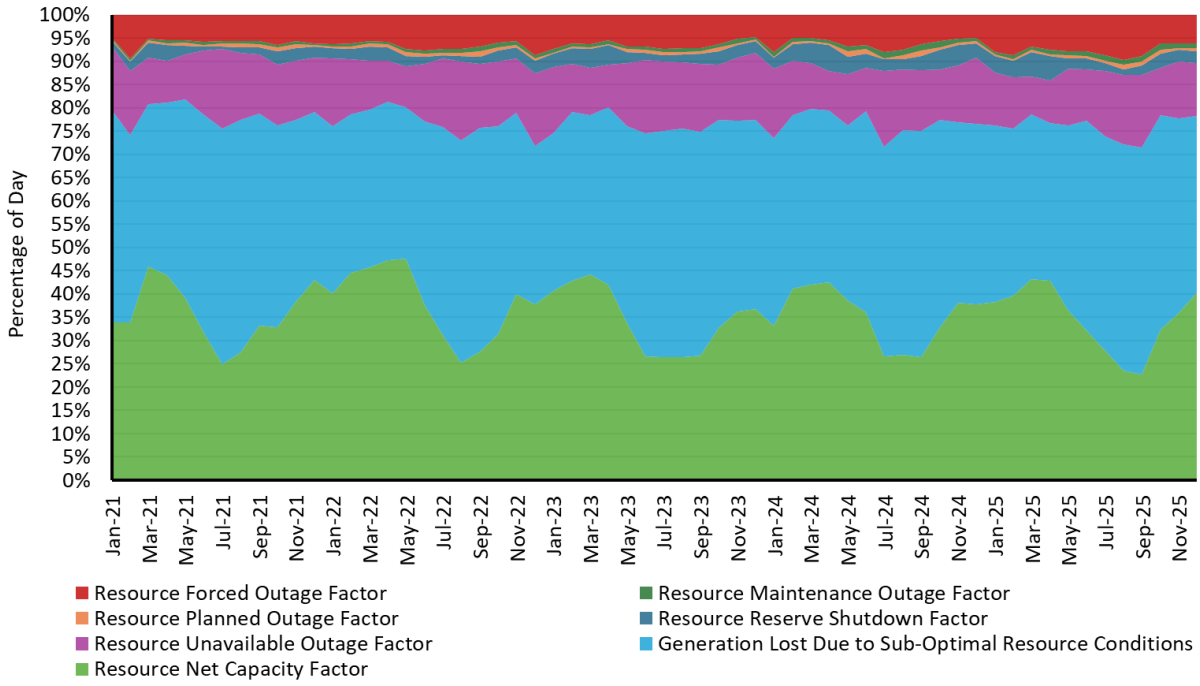


Figure 4.8: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 100–199 MW

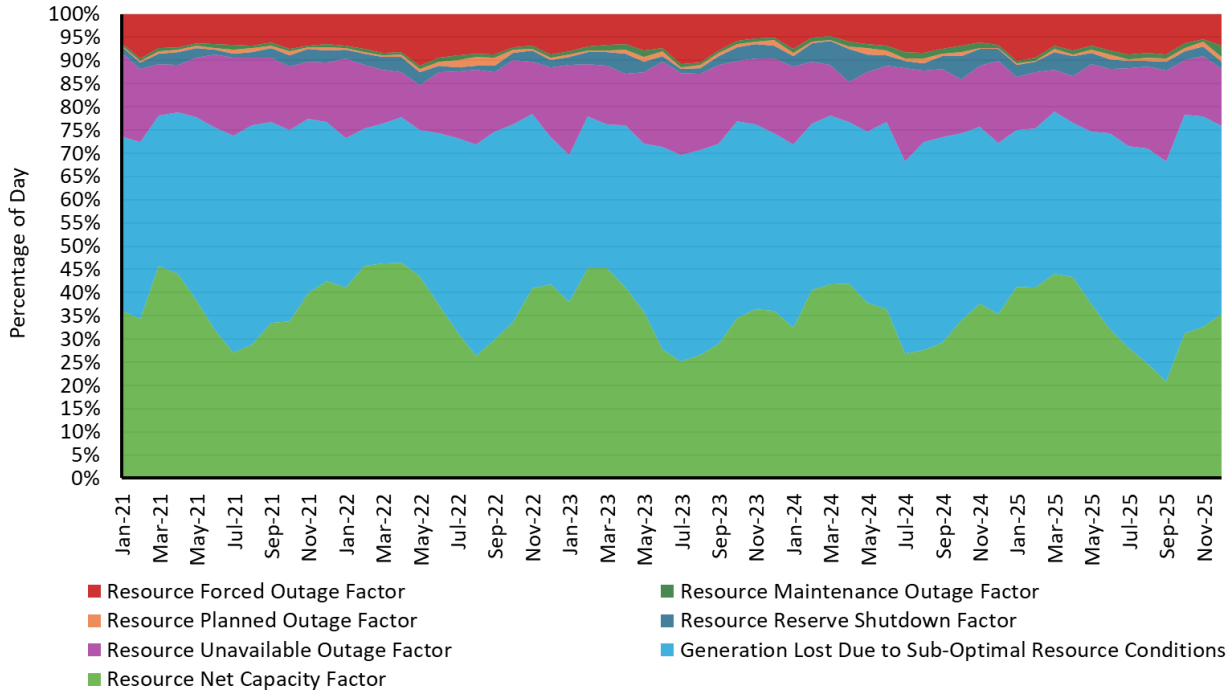


Figure 4.9: Monthly Net Output Factor and WRFOR Wind Plant Reporting Group 75–99 MW

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.

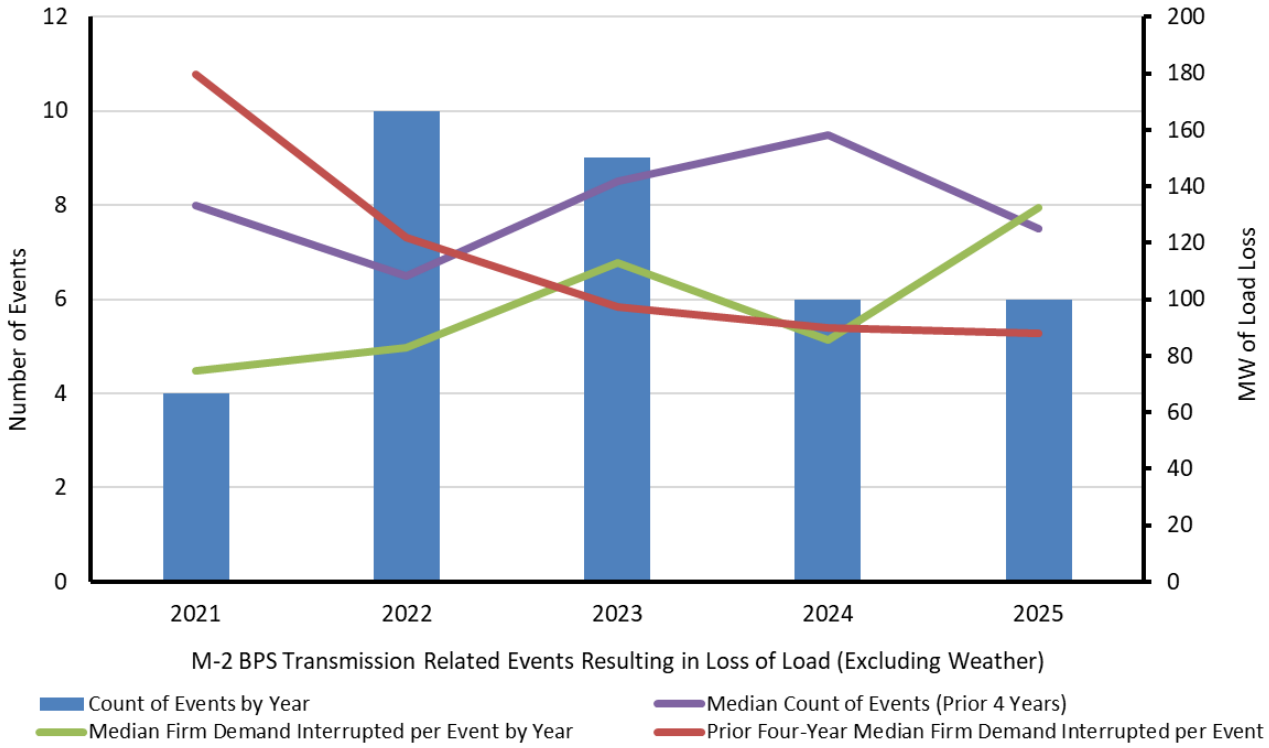


Figure 4.10: Transmission-Related Events Resulting in Loss of Firm Load and Median Amount of Firm Load Loss Excluding Weather-Related Events[80]

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

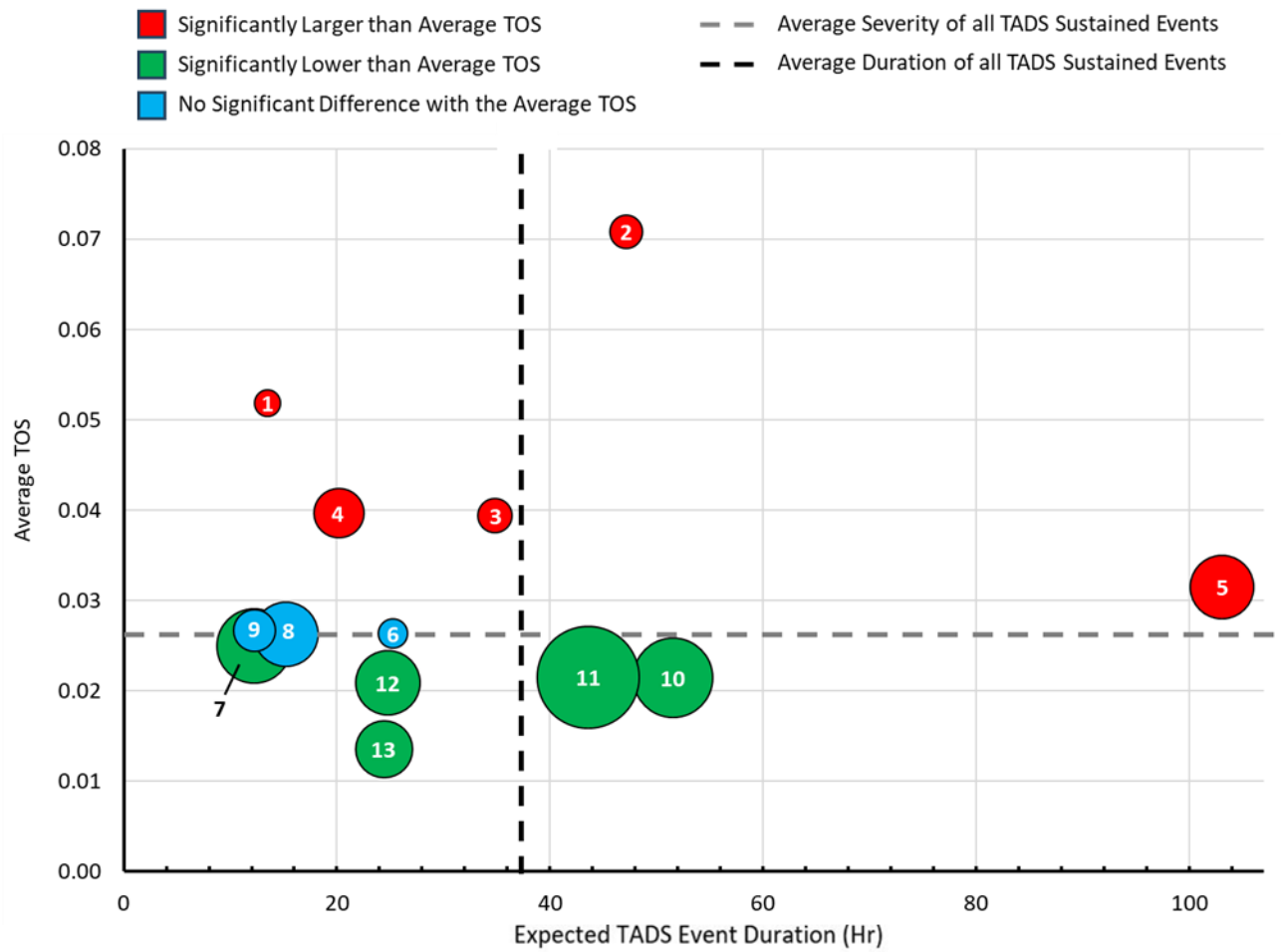
The impact of a TADS event on BPS reliability is called the transmission outage severity (TOS) of the event, which is defined by the number of sustained outages in the event and by the type and voltage class of transmission elements involved in the event. TADS events are categorized by initiating cause 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.

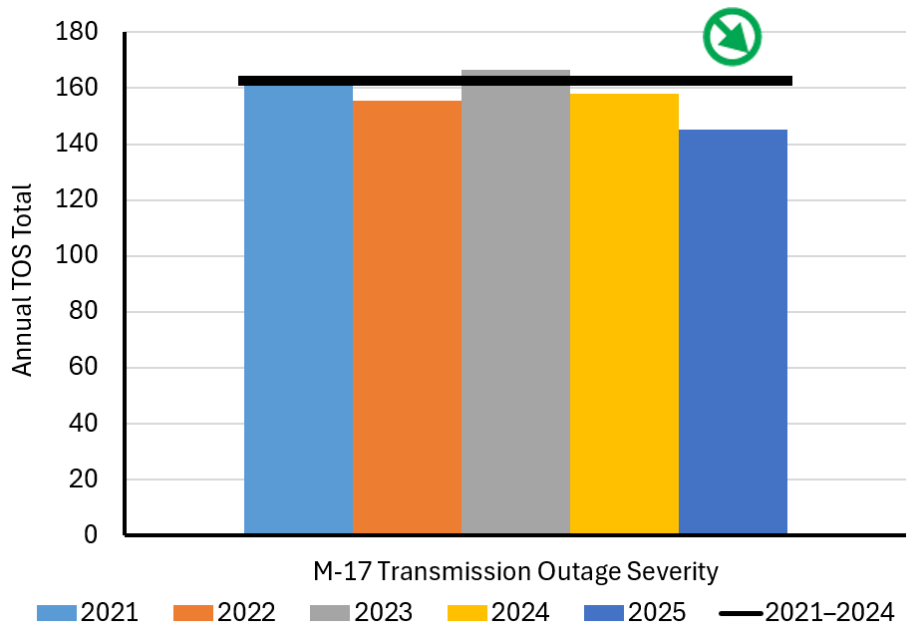


Figure 4.12: TOS of TADS Sustained Events of 100 kV+ AC Circuits and Transformers by Year[81]

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**).

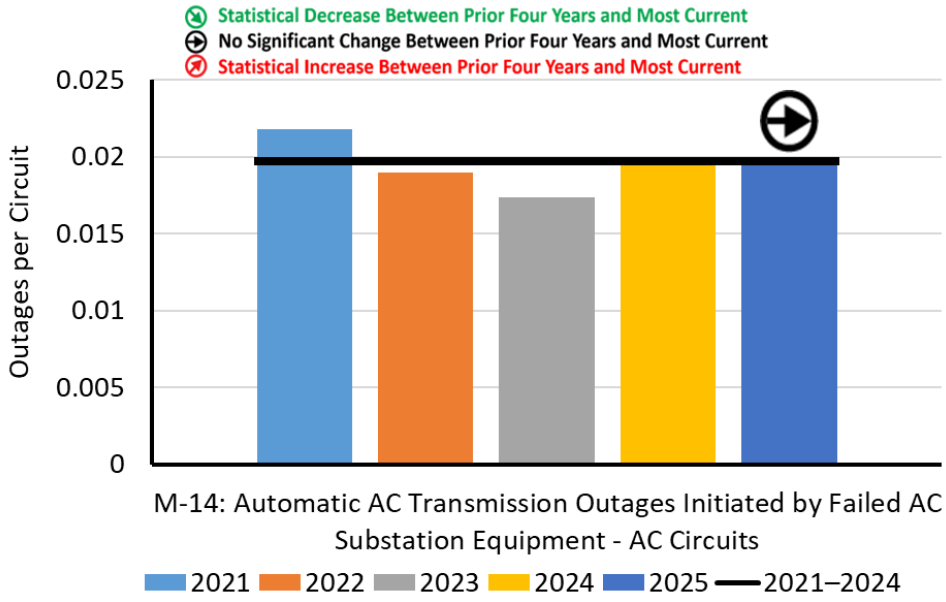


Figure 4.13: Number of Outages Per AC Circuit Due to Failed AC Substation Equipment[82]

[81] M-17, Transmission Outage Severity
[82] M-14, Automatic AC Transmission Outages Initiated by Failed AC Substation Equipment

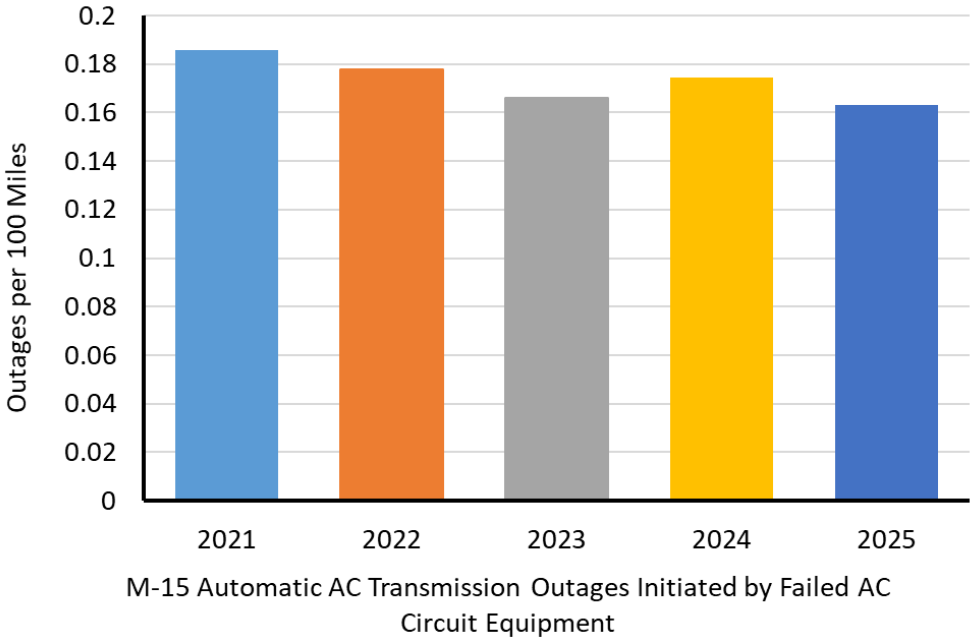


Figure 4.14: Number of Outages Per 100 Miles Due to Failed AC Circuit Equipment[83]

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.

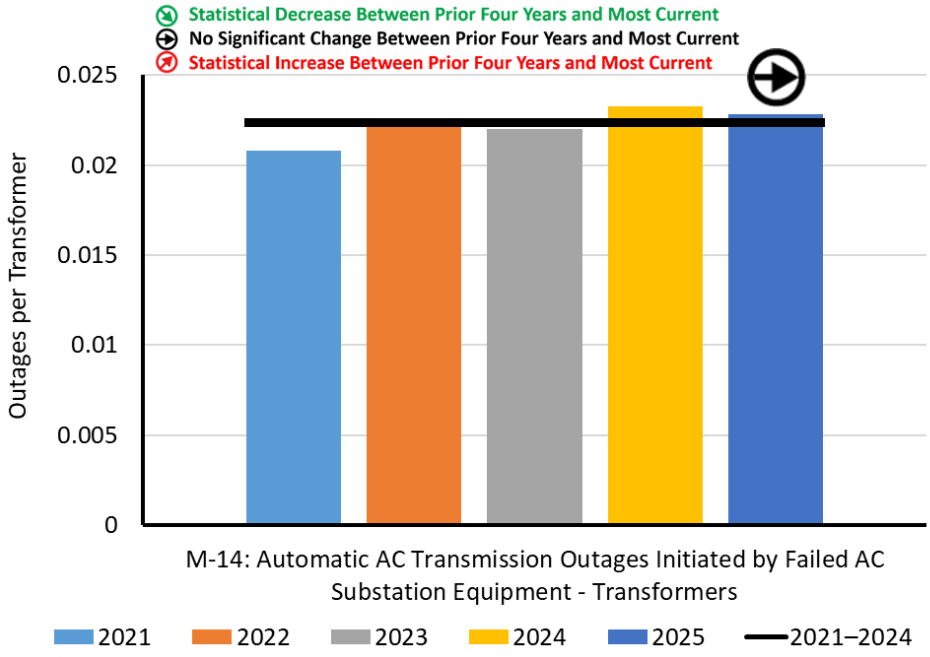


Figure 4.15: Number of Outages Per Transformer Due to Failed AC Substation Equipment[84]

[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.

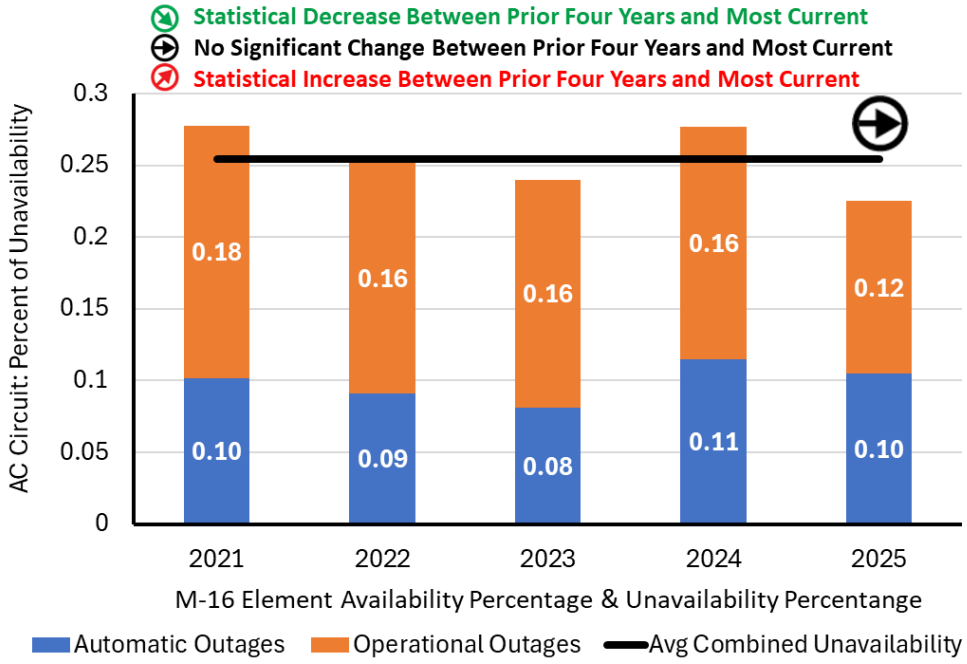


Figure 4.16: AC Circuit Unavailability >200 kV[85]

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

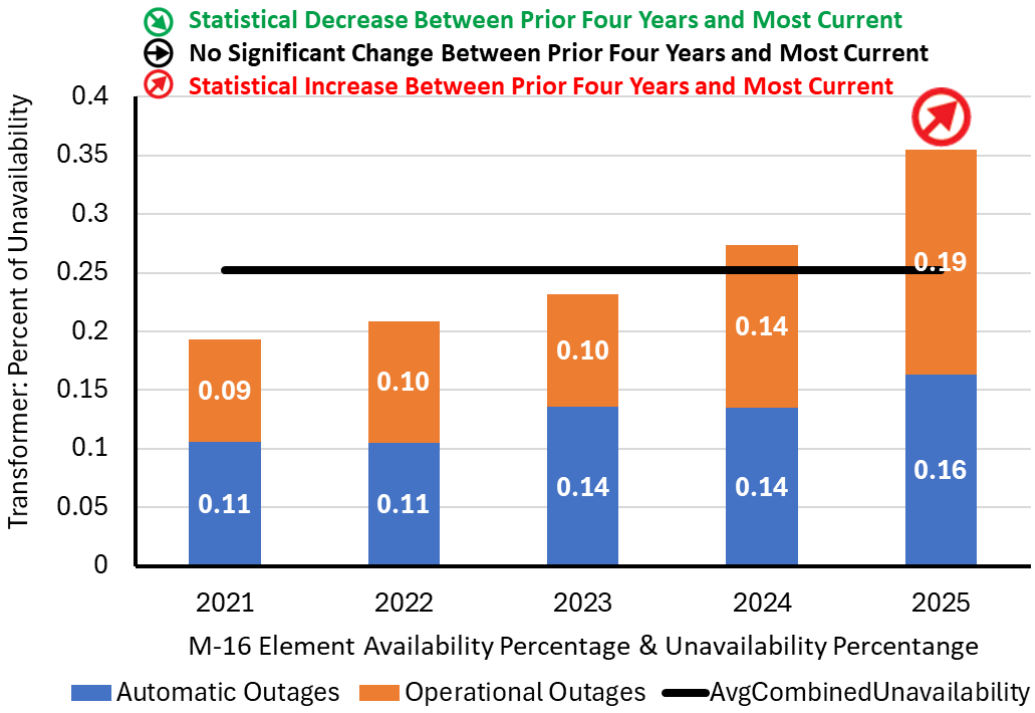


Figure 4.17: Transformer Unavailability >200 kV [86]

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

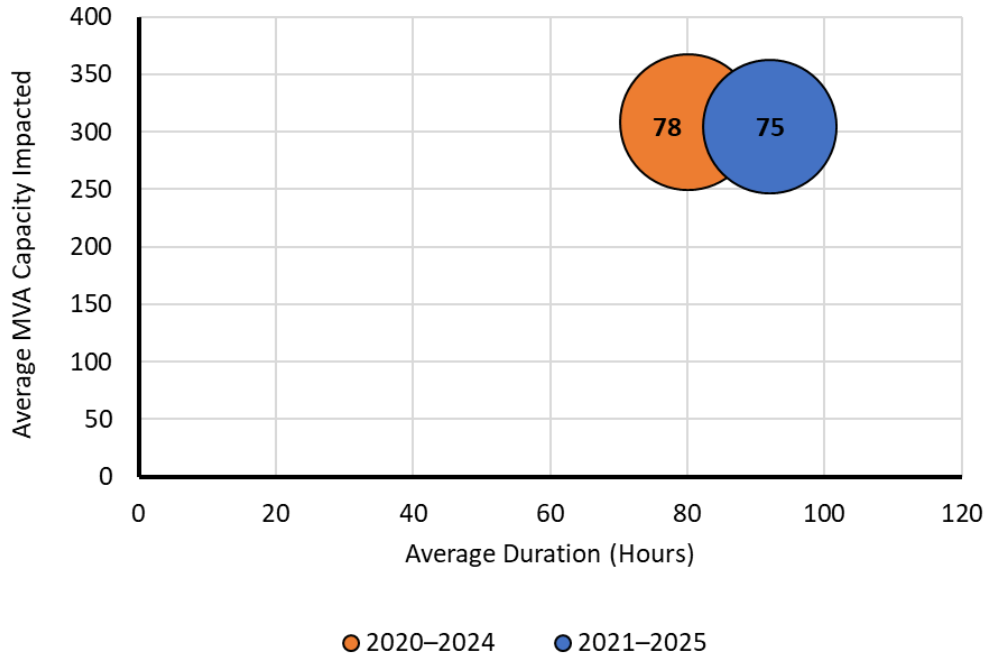


Figure 4.18: Comparison of TADS Physical Security Metric for 2020–2024 vs. 2021–2025[87]

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.

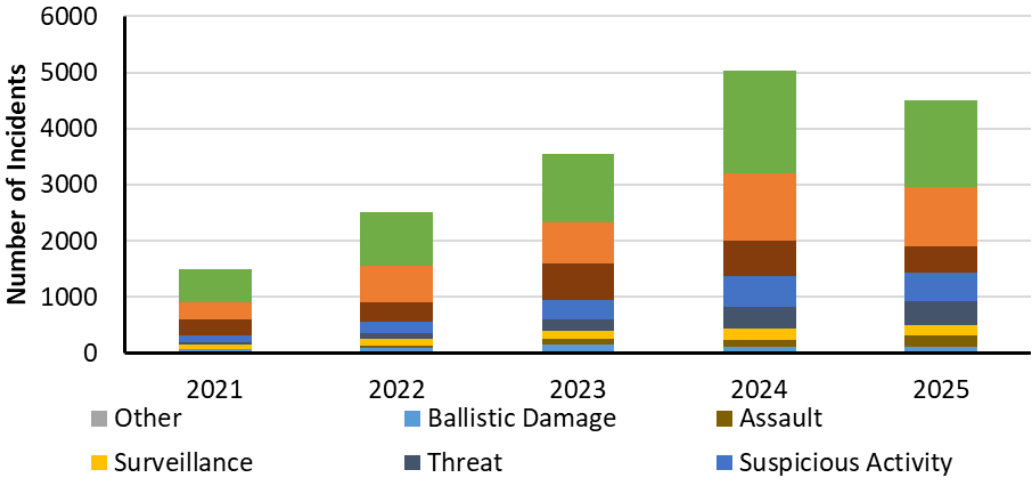


Figure 4.19: Incidents Resulting in Operational Impacts (Severity Level 2 and Level 3) by Tactic (2021–2025)

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.

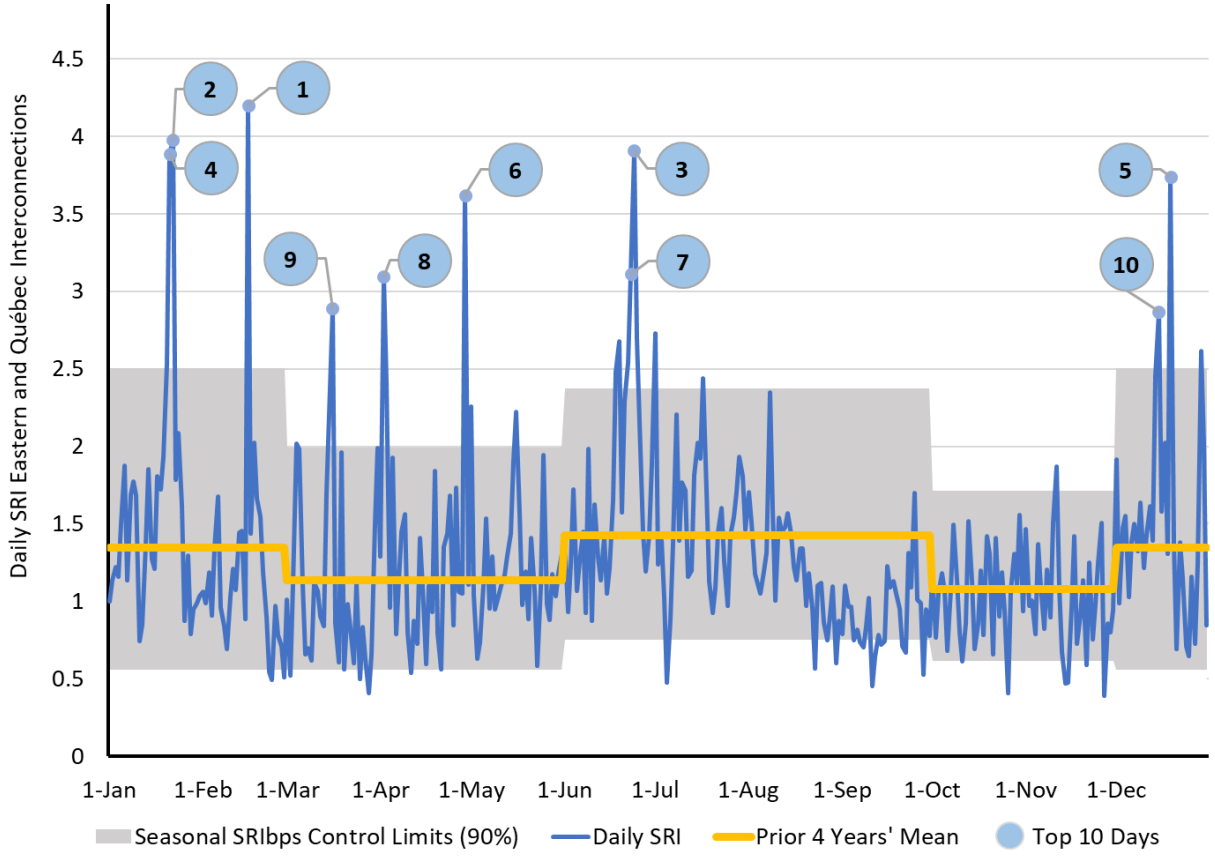


Figure A.1: 2025 Eastern and Québec Interconnections Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

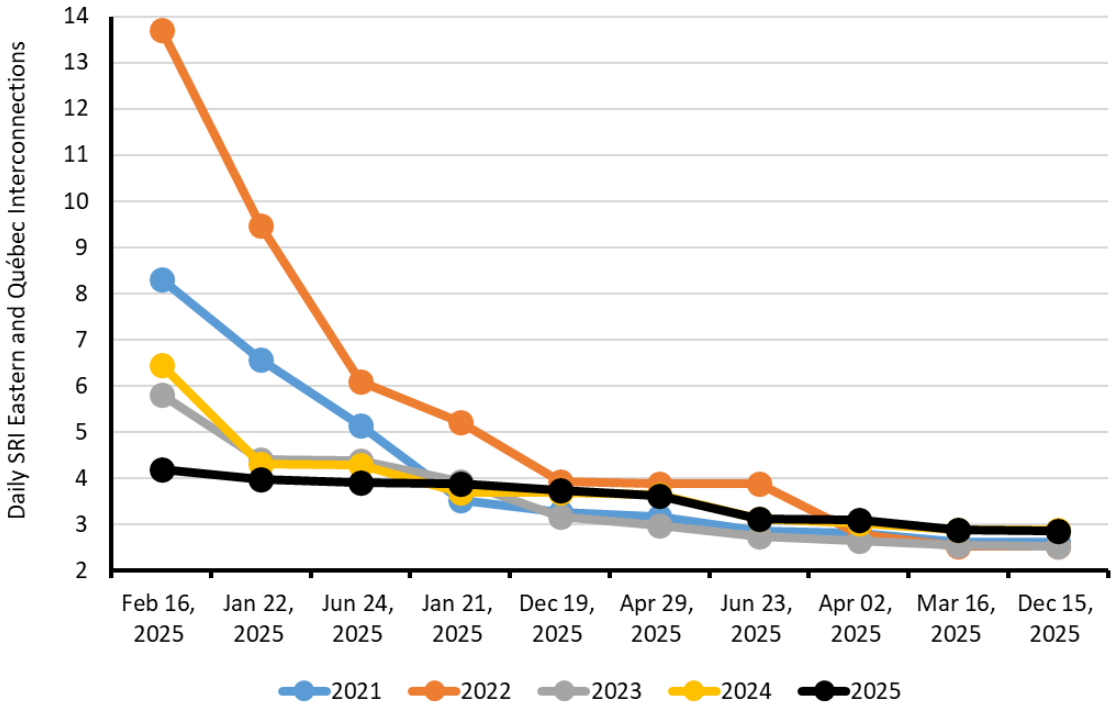


Figure A.2: Eastern and Québec Interconnections Top Annual Daily SRI Days, Sorted Descending

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.

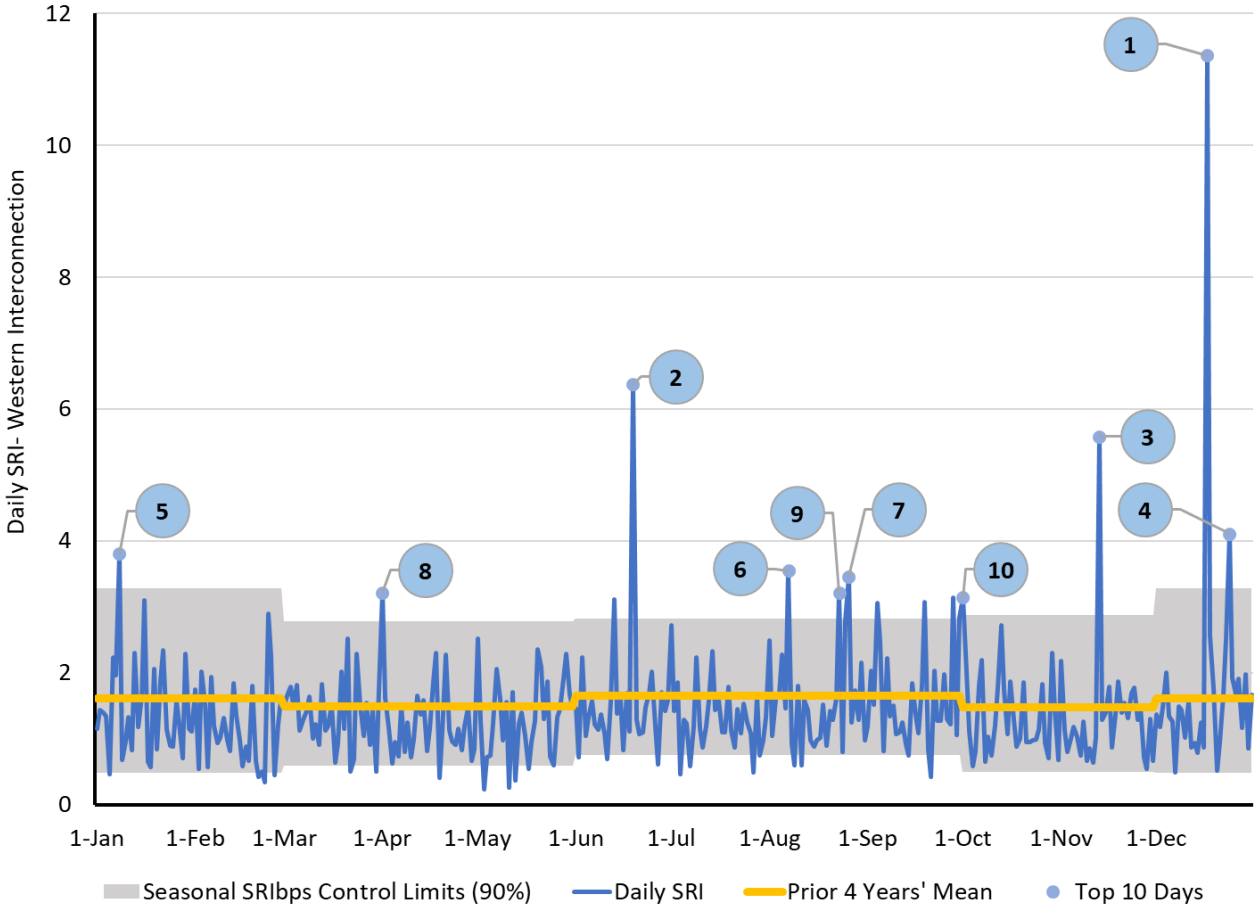


Figure A.3: 2025 Western Interconnection Daily SRI with Top 10 Days Labeled, 90% Confidence Interval

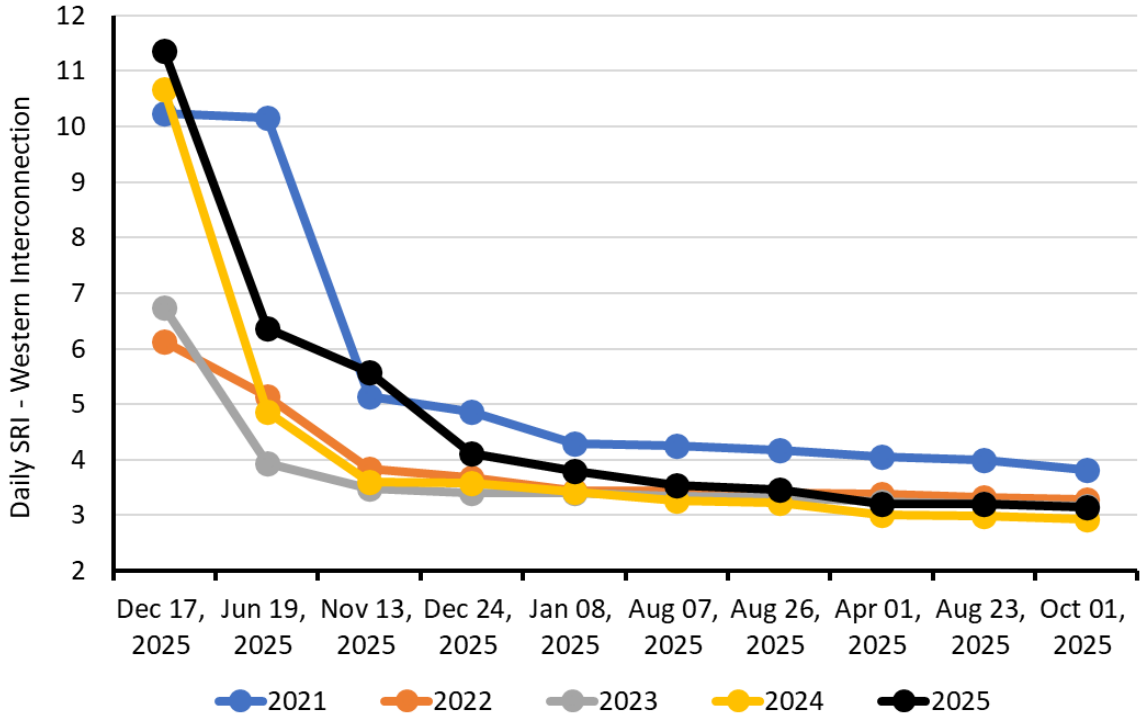


Figure A.4: Western Interconnection Top Annual Daily SRI Days Sorted Descending

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.

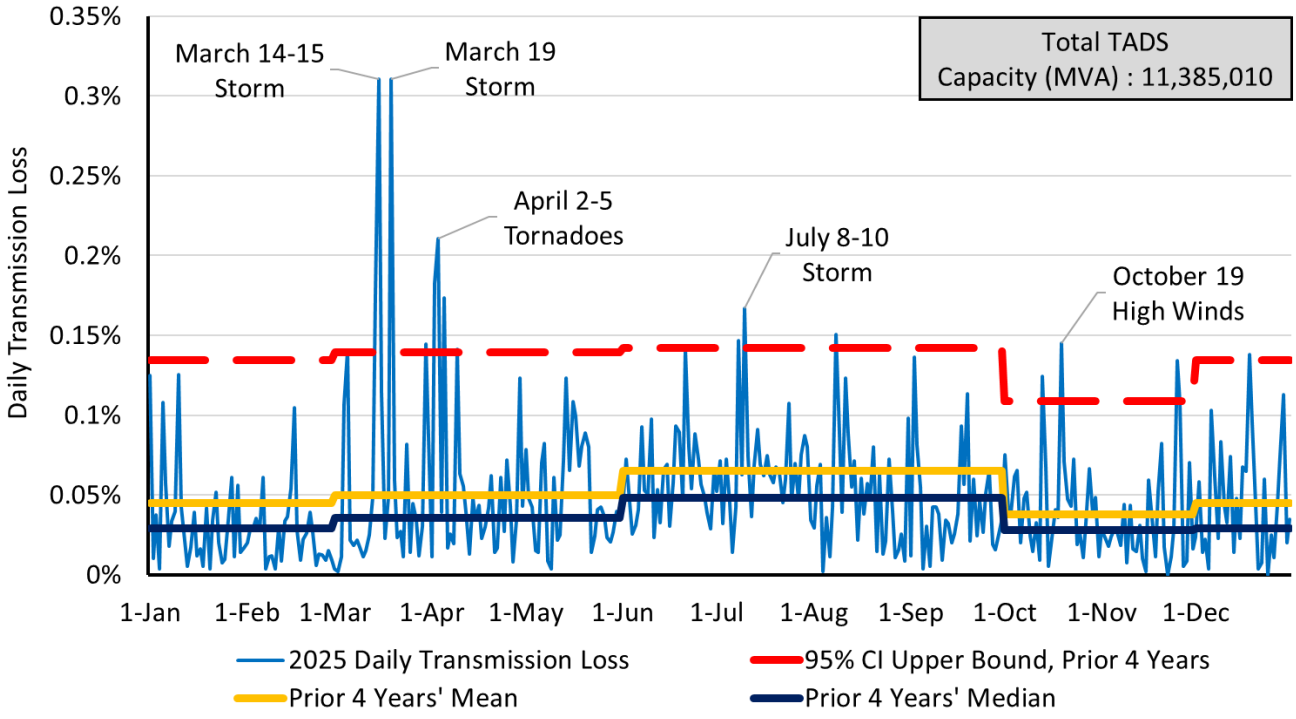


Figure A.5: Eastern and Québec Interconnections—Transmission Impacts During Extreme Days of 2025

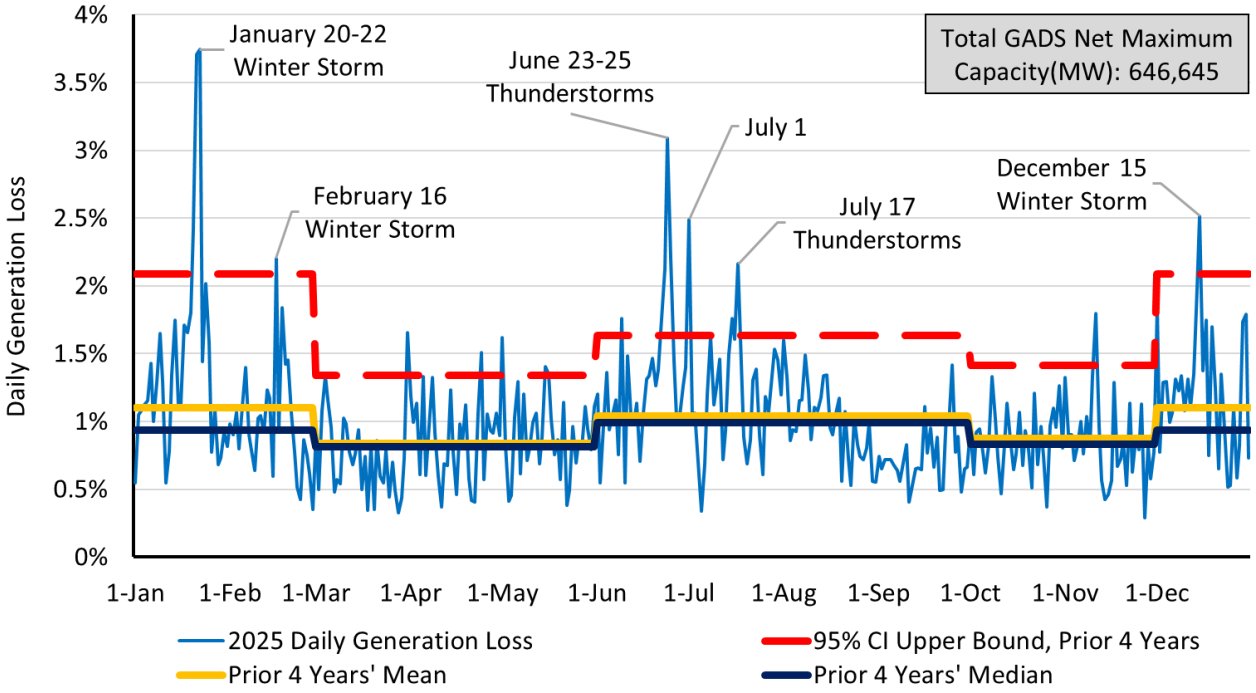


Figure A.6: Eastern and Québec Interconnections—Generation Impacts During Extreme Days of 2025

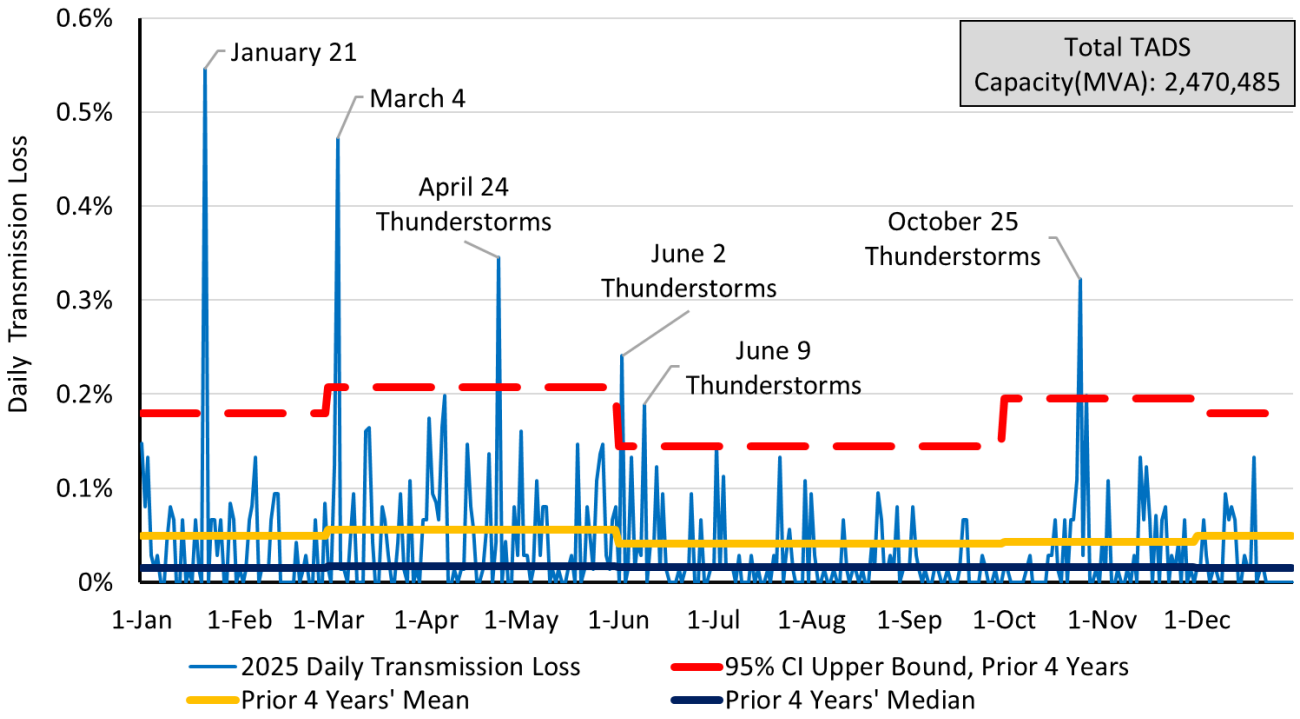


Figure A.7: Texas Interconnection—Transmission Impacts During Extreme Days of 2025

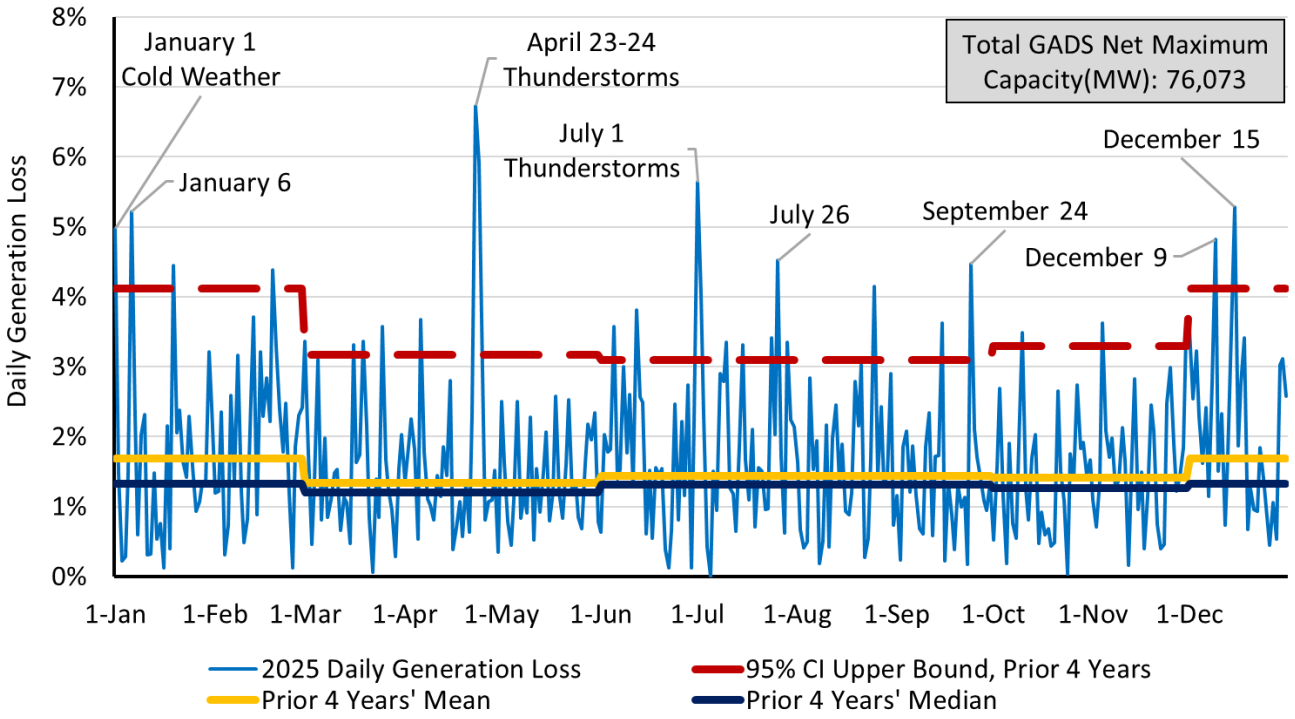


Figure A.8: Texas Interconnection—Generation Impacts During Extreme Days of 2025

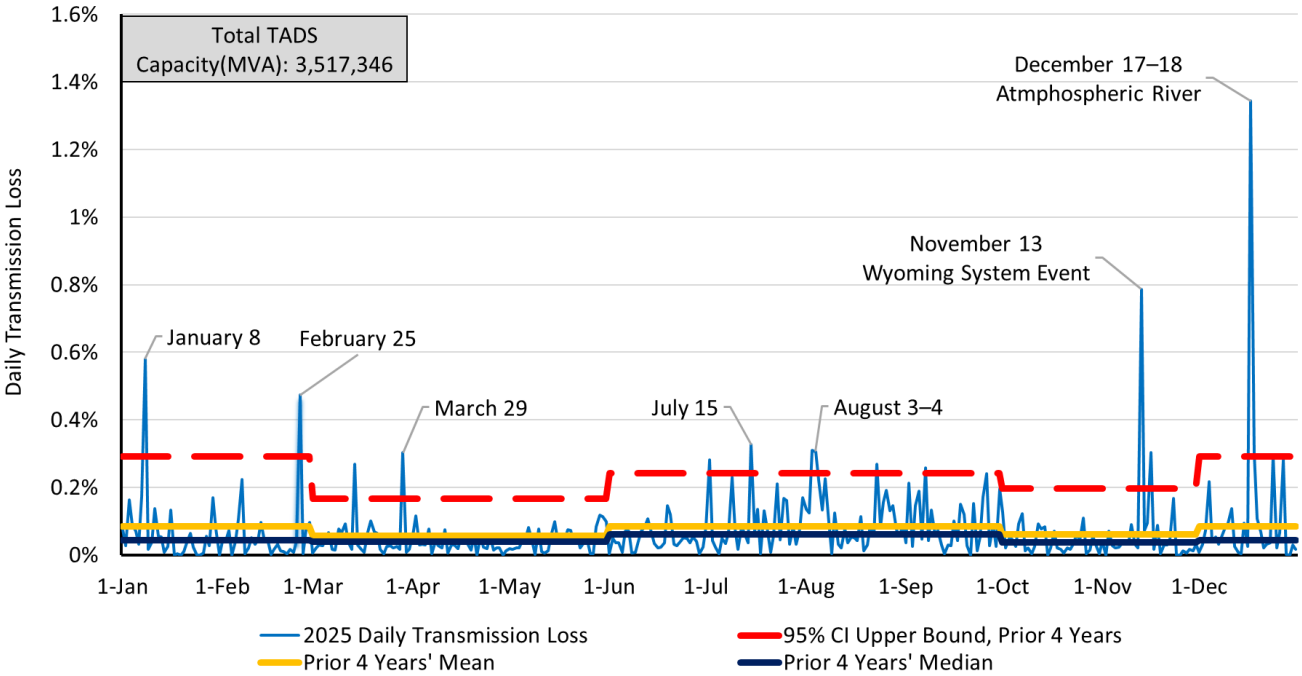


Figure A.9: Western Interconnection—Transmission Impacts During Extreme Days of 2025

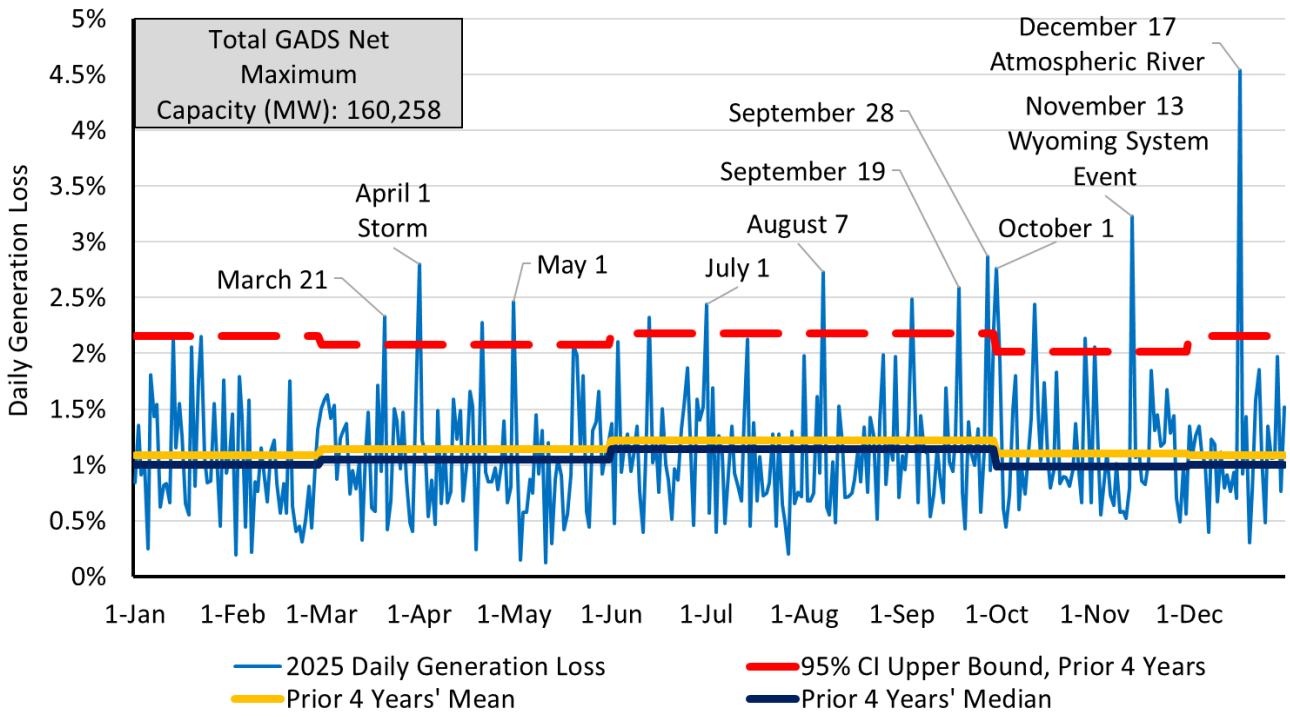


Figure A.10: Western Interconnection—Generation Impacts During Extreme Weather Days

Appendix B: Acknowledgements

NERC Industry Group Acknowledgements	
Group	**Officers**
Reliability and Security Technical Committee	Chair: John Stephens, City Utilities of Springfield Vice Chair: Srinivas Kappagantula, Arevon Energy
Performance Analysis Subcommittee	RSTC Sponsor: Brett Kruse, Calpine Corporation Chair: Heide Caswell, Oregon Public Utilities Commission Vice Chair: Peter Ashcroft, WECC
Transmission Availability Data System User Group	Chair: Nick DePompei, SERC Vice Chair: Rodolfo Lozano, ITC Transmission
Generation Availability Data System User Group	Chair: Danny Small, Missouri Public Utility Alliance Vice Chair: Ken Sabourin, Sunflower Energy
Events Analysis Subcommittee	Chair: James Hanson, WECC Vice Chair: Cindy Robert, Hydro- Québec
Reliability Assessment Subcommittee	Chair: Amanda Sargent, WECC Vice Chair: Evan Shuvo, Texas RE
Resources Subcommittee	Chair: Daniel Baker, Southwest Power Pool Vice Chair: Jose Luis Hinojosa, ERCOT
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Frequency Working Group	Chair: Joseph Marcrum, Southern Company
Inverter-Based Resources Performance Subcommittee	Chair: Julia Matevosyan, Entergy Vice Chair: Rajat Majumder, Invenergy
Large Loads Working Group	Chair: Eric Meier, ERCOT Vice Chair: Sudip Manandhar, Southern Company
Real-Time Operating Subcommittee	Chair: Derek Hawkins, Southwest Power Pool Vice Chair: Raja Thappetaobula, CAISO
System Planning Impacts from Distributed Energy Resources Working Group	Chair: Shayan Rizvi, NPCC Vice Chair: John Schmall, ERCOT
System Protection and Control Working Group	Chair: Lynn Schroeder, Sunflower Vice Chair: Manish Patel, Silicon Ranch Corporation

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Robert Tallman	Senior Engineer, Reliability Assessments
Lee Thaubald	Senior Application Specialist, Performance Analysis
Aung Thant	Principal Engineer, Engineering & Security Integration
Sofia Weir	Senior Physical Security Analyst, E-ISAC Security Operations

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4-03
NERC Incident Review

Incident Review

Load-Pocket Shoulder Season Challenges

Primary Takeaways

In recent years, shoulder seasons have become increasingly challenging for bulk power system (BPS) operators to manage. This review details 4 of 6 incidents over a 13-month period that resulted in pre-contingent load shedding. All these load-shed incidents had similar contributing circumstances: All incidents occurred during what is commonly known as the "shoulder seasons" and had unavailable generation that was either planned or unplanned, unavailable transmission that was either planned or unplanned, and more load than forecasted. Load was shed in all instances because of real-time contingency analysis (RTCA) results that indicated significant issues related to the next loss of a transmission element. These issues would have involved either significant overloads that could lead to cascading or significantly low voltages bordering on voltage instability.

During RTCA, which is important for operating the power system, analysis is performed on the system's current operating state. This differs from operational planning analysis (OPA), which studies the system for forecasted operating conditions. Very often, the real-time operating conditions are different than the forecasted operating conditions.

RTCA is the safety net used to ensure that the system is operating in a secure state in its current configuration and loading levels. Planned and unplanned outages, variable energy resources (VER), and variable weather conditions leading to variations in load can drive real-time conditions that necessitate load shed to maintain BPS reliability.

Background

Shoulder seasons are the spring and fall periods that are between the summer and winter peak load periods. These seasons have historically been used for planned BPS maintenance and construction in preparation for the upcoming peak load season. For instance, generating resources require periodic maintenance to ensure their availability during peak seasons. This periodic maintenance requires an outage of the generating facility. Market rules and other economic incentives have caused generation planned maintenance outages to be concentrated into the shoulder seasons, leading to increasing numbers of generators being out for maintenance simultaneously. Additionally, transmission lines require periodic maintenance, such as insulator, crossarm, or structure replacement, leading to planned outages during shoulder seasons.

Furthermore, the BPS is in a cycle of growth and transition, and significant new transmission development is occurring. To facilitate the construction of new transmission facilities, outages on existing BPS transmission facilities are required. This work is also concentrated in the shoulder seasons.

Historically, BPS reserve margins have been sufficient for the shoulder seasons to accommodate these outages without much difficulty, but reserve margins have shrunk in recent years. In its *2024–2025 Winter Reliability Assessment*,[1] NERC identified significant reductions in thermal generation from the previous winter. In many instances, this thermal generation has been replaced by VERs, such as wind and solar. However, VERs present

[1] https://www.nerc.com/globalassets/programs/rapa/ra/nerc_wra_2024.pdf

challenges and uncertainties for system operators in combination with facility outages during the shoulder seasons.

Another factor is load magnitude, of which temperature was historically the major driver with the largest percentage of load being residential and commercial building cooling and heating. Cold temperatures in the winter and hot temperatures in the summer caused loads to peak in those seasons, with lower loads in the shoulder seasons. However, loads that have a flat demand curve regardless of temperature have recently grown significantly, causing the delta between peak and shoulder seasons to shrink. Temperatures in the shoulder seasons were also historically temperate, meaning that operators could count on temperature-sensitive load to not be high in magnitude. In recent years, shoulder season temperatures have varied more significantly than historical norms. Compounding the challenges, especially in spring, thunderstorms and tornadoes create unplanned (forced) equipment outages.

All these factors must be considered when determining whether to grant equipment outage requests. The outages are typically planned weeks, if not months, in advance, as operators must forecast system conditions to determine whether the outage request is feasible. If conditions are much different than those predicted weeks or months earlier, load shed may be required to maintain a secure operating state, which is what occurred in the incidents described in this incident review.

Summary of the Incidents

This incident review summarizes four shoulder season load-shed incidents. Each is unique, but all share some of the aforementioned common difficulties. These incidents all occurred in a smaller area within a Balancing Authority (BA) area footprint, referred to as a load pocket.[2] Load pockets have varying degrees of transmission lines that connect the pockets to the larger grid. Energy imports on these transmission lines, along with the generation internal to the load pocket, serve as the energy source for load within the pocket. The magnitude of the load within the pocket, offset by the internal generation, determines the import capability that is needed to serve the load pocket. The needed import capability determines the required number or total capacity of the connecting transmission lines. Entities will sometimes create a transmission "ring" around the load pocket. Conceptual diagrams of simple and complex load pockets are depicted in **Figure 1** and **Figure 2**.

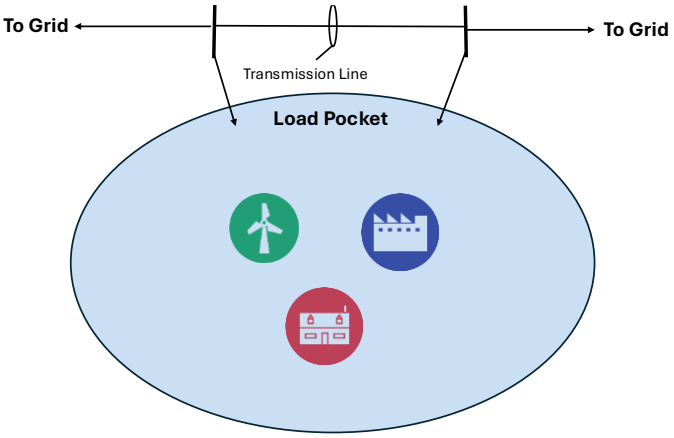


Figure 1: Simple Load Pocket

[2] A "load pocket" is a concentrated area of load that typically contains some generation.

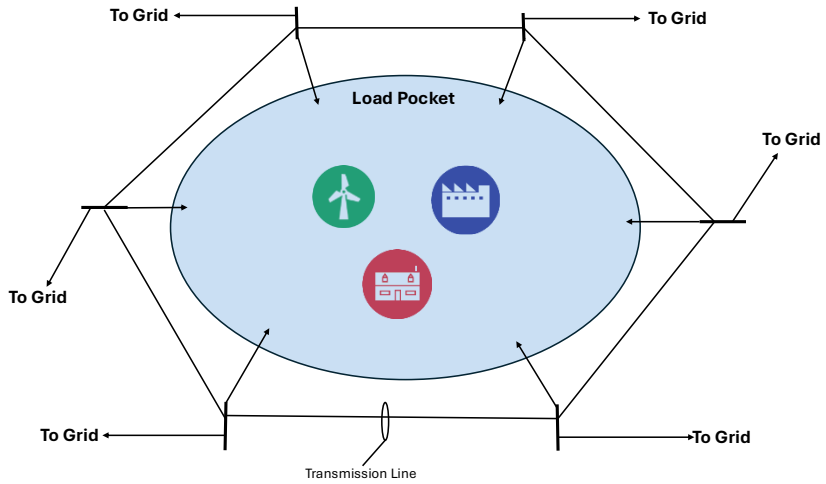


Figure 2: Complex Load Pocket

Incident Details

Entity A Incidents

Entity A experienced three load-shed incidents in the same load pocket in 2024 and 2025. Details are included for two of those incidents. This load pocket has seen rapid and significant load growth in the past few years, driving increased reliability risk in the shoulder season. Transmission projects are planned to increase the capacity into the load pocket but are still a few years from being in service. Consequently, the capacity margin for this load pocket, which contains a substantial amount of VERs consisting of wind and solar facilities, has been reduced from previous levels.

Each of the three incidents contained a combination of the following contributing factors:

- Unavailable Generation
  - Planned Maintenance Outages
  - Unplanned/Forced Outages
  - Low Wind Generation Output
  - Solar Generation Evening Ramp Down
  - Emission Constraints

  Planned and unplanned generation outages or derates within the load pocket contributed to these incidents. Unavailable generation internal to the load pocket places an increased need for capacity on the transmission lines that connect the load pocket to the rest of the electric grid.

- **Load Forecast Error**
  In each incident, there was a significant difference between actual and forecast load, with a significant portion of this extra load attributable to line losses on the transmission system. These increased losses

resulted from increased power flow on the transmission system due to reduced generation output internal to the load pocket.

- **Transmission Outages**
  - Planned Outages
  - Unplanned/Forced Outages

  In both the load-shed incidents being examined, unplanned/forced outages of 345 kV transmission lines due to faults contributed significantly to the potential voltage instability.

- **Solar Generation Evening Ramp Off**
  Evening solar generation ramp down presents a significant challenge for grid operators, as, in the shoulder seasons, it coincides with the daily peak load. In one of Entity A's incidents, the solar generation ramp down from 200 MW at 18:30 to 25 MW at 19:30 was coincident with the entity's daily peak load and coincided with minimum wind generation internal to the load pocket.

- **Low Wind Generation Output**
  This load pocket contains a significant amount of wind generation, but during one of the load-shed incidents, the wind generation was approximately 2% of nameplate.

Incident 1

In this April event, a 345 kV transmission line was forced out of service due to a sustained fault. This outage, coupled with a planned maintenance outage on another 345 kV line, resulted in an increased dependence on generation internal to the load pocket due to decreased transmission import capability. Low wind speeds that day resulted in only 100 MW of wind generation internal to the load pocket, compared to 4,700 MW of nameplate capacity. As peak load was approaching later in the day, a generator inside the load pocket that was planned to help meet the daily peak load failed to start. At very close to the same time, the solar evening ramp off also began with solar ramping down from 200 MW to 25 MW in one hour, coincident with load ***increasing*** to its daily peak value. RTCA, when accounting for these transmission and generator outages/unavailability, indicated that voltage instability would occur with the next contingency, requiring the operators to shed load pre-contingency. To return the system to a secure operating state as soon as possible, the operators shed approximately 150 MW of load.

Incident 2

In this March event, the load pocket experienced a significant internal unforecasted wind generation reduction that led to increased flows on the transmission system, resulting in increased line losses. At the time of the unexpected wind generation reduction, there were extensive planned and unplanned/forced outages of flexible/dispatchable generation, which is a key element to respond to unplanned/unforecasted generation shortages. Additionally, a key 345 kV transmission line was out of service for planned maintenance.

The generation reduction, increased flows, and resulting increased line losses on the transmission system led the RTCA to indicate voltage instability in the pocket for the next contingency. This circumstance required the operator to shed load pre-contingency—specifically shedding 122 MW of load to return the system to a secure operating state as quickly as possible.

Entity B Incidents

Entity B experienced two load-shed events in the same load pocket in April 2025. Both incidents were prompted by RTCA analysis indicating voltage instability—severe enough to require pre-contingent load shedding—for a next contingency loss. These incidents resulted in load sheds of 115 MW and 140 MW, respectively, to maintain reliability of the BPS. This load pocket has experienced significant generation retirements during the last 10 years, resulting in less reserve margin within the load pocket and leading to less flexibility for operators to respond to unanticipated conditions.

Contributing Factors for the April 26 Incident[3]

Generation planned maintenance outages contributed significantly to this incident, as 3,000 MW of generation was unavailable due to planned maintenance outages inside the load pocket. At the time of the outage requests months earlier, analysis did not reveal any issues with the outages based on the forecasted assumptions.

A 345 kV line and a dc tie transmission line were out of service on the day of the incident, significantly reducing the import capacity into the load pocket.

Grid operators perform OPA studies to identify any potential issues for the next-day operating conditions. This gives the grid operator time to develop mitigations for any identified issues. This analysis must use forecasted conditions, such as load, generation, and network topology. Differences between the actual real-time conditions and those forecasted in the OPA could result in unanticipated challenges. In this instance, a few real-time differences arose, as follows:

- The load pocket experienced a high temperature exceeding the daily forecast by approximately 5 degrees, resulting in a load 300 MW over the forecasted load.
- A 185 MW natural-gas-fired unit was off-line in real time.
- The network power flow differed significantly from the flow predicated in the OPA, which anticipated a north to south power flow. The actual flow in real time during the incident was south to north.

In addition to the grid operator performing day-ahead reliability planning studies, the market function performs day-ahead market analysis to determine the generation plan for the next day. As the market analysis determined that a 348 MW natural gas generator internal to the load pocket was not needed for economic or reliability purposes, the unit was placed in reserve shutdown mode.

Entity C Incident

In this May incident, a combination of extensive planned and unplanned generation outages, higher-than-forecasted load, and a critical 500 kV transmission line outage led to a transmission system emergency resulting in a need to shed 600 MW of load to maintain reliable operations.

Both planned and unplanned generation outages internal to the load pocket contributed significantly to this incident; 74% of the generation internal to the load pocket was unavailable on that day, and a 500 kV transmission line had previously been forced out of service due to structure failures caused by severe weather.

[3] 4-26-2025 Load Shed Event

These factors led to a 1,732 MW decrease in transmission capacity into the load pocket. In total, the load pocket's available capacity was reduced by 9,332 MW.

Table 1: Load Pocket Capacity Reductions	
Load-Pocket Unavailable Generation	**Reduction (MW)**
Planned Outages	2,600
Unplanned Outages	3,900
Derates	1,100
Total	7,600
Unavailable 500 kV line Capacity	1,732
Total Unavailable Capacity Into Load Pocket	9,332

Additionally, the temperature in the load pocket on that day was 92 degrees, approximately 5 degrees hotter than normal, resulting in a substantial increase in load and causing the actual load to exceed the forecasted load level.

The day prior to the load-shed incident, operators identified that a 230 kV line would overload if the loss of a 500 kV line occurred. The day-ahead analysis did not indicate an overload greater than 125%, and a plan was formulated to initiate post-contingent load shed to alleviate the overload should the 500 kV line be lost.

On the day of the load shed, the increased transmission line loading resulted in the need to adjust the system to address other transmission lines exceeding their rating. These adjustments, in addition to the increased loading, resulted in the RTCA indicating that the overload on the 230 kV line was greater than 125% for the next worse contingency: the loss of the 500 kV line.

The entity's operating procedure states that contingent overloads greater than 125% require further analysis to assess the potential for cascading. If this analysis identifies a load loss of 1,000 MW or more when removing elements loaded greater than 125%, a temporary interconnection reliability limit (TIROL) is identified and pre-contingent load shed is required, as happened on this day for the entity. After the TIROL was identified, the entity declared a transmission system emergency and initiated 600 MW of load shed to alleviate the TIROL.

Future Considerations

All these incidents occurred in shoulder seasons. Each incident had significant amounts of planned and unplanned outages, higher-than-forecasted temperatures, and RTCA results for a next contingency that required pre-contingent load shedding.

As 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
- 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.)

For more information, please contact:
NERC – Event Analysis

Date of Publication: March 4, 2026

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4-04
NERC 2026 State of Reliability Overview

NERC

2026 State of Reliability

Assessment Overview of 2025 Bulk Power System Performance

June 24, 2026

2026 SOR Snapshot

2026 SOR Technical Assessment

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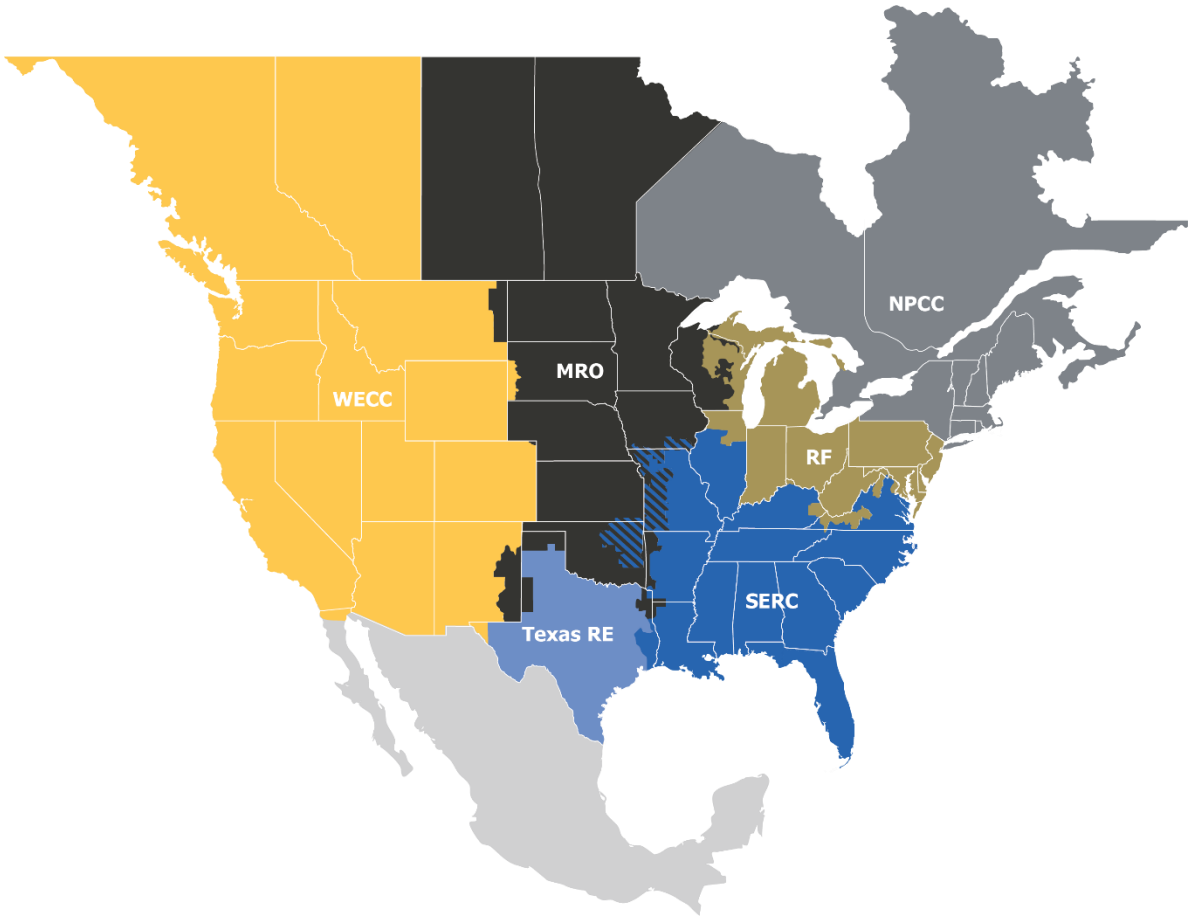
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Preface

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 Overview

NERC delivers the *State of Reliability* (SOR) as a two-part report that consists of the *2026 SOR Overview* and the *2026 SOR Technical Assessment*.[1] The *2026 SOR Overview* serves as a high-level summary of the most important and actionable topics impacting the BPS and how they are being addressed, while the *2026 SOR Technical Assessment* provides NERC's comprehensive annual analytical review of BPS reliability for the 2025 calendar year. The analysis within the SOR report fulfills a key role in NERC's mission by providing an unbiased, data-driven look at the BPS's reliability, identifying ongoing challenges, and informing future-looking assessments. This overview seeks to inform regulators, policymakers, and industry leaders of the most significant reliability risks facing the BPS and describes the actions that the ERO Enterprise has taken, and will take, to address them.

Development Process

ERO staff developed this overview and the corresponding *2026 SOR Technical Assessment* with support from the Performance Analysis Subcommittee (PAS). Both documents draw conclusions from an established set of reliability indicators and mandatory information reported by industry to 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, the Institute of Electrical and Electronics Engineers (IEEE) Distribution Reliability Working Group, and other sources as available.

Considerations

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

[1] NERC SOR 2026 Technical Assessment

Executive Summary

The North American BPS continues to deliver reliable electric service under increasingly challenging conditions. Key performance indicators remain stable overall even as the system experiences rising demand growth, more frequent extreme weather events, and significantly higher penetrations of inverter-based resources (IBR).

At the same time, the report highlights a critical shift in the nature of reliability risk. Many of the emerging concerns facing the system are no longer driven by single contingencies or localized disturbances but by correlated and system-wide stresses, including energy limitations, operational challenges associated with maintaining reliability in lower-inertia systems, and declining availability of aging combustion generation. Although fuel supply uncertainty and extreme weather exposure were not major drivers in this year's assessment, they remain subject to ongoing monitoring given their continuing potential to affect reliability. The findings emphasize that continued reliability success will depend not only on maintaining infrastructure and resource adequacy but also on improving industry's ability to anticipate, model, and manage these evolving risks before they manifest as reliability events.

While the SOR focuses on historical occurrences in the past year, it is also important to recognize future resource adequacy concerns. NERC's forward-looking *Long-Term Reliability Assessment*[2] and related non-NERC reports[3] continue to highlight that generation development has not and is not expected to keep pace with needs as new projects face delays and cancellations due to supply chain constraints, changing economies, and increasing grid upgrade costs. Similarly, while existing transmission performance continues to improve, its development, particularly of major interstate lines, is not advancing at a pace that can adequately support future reliability needs.

Reliability Indicators

Table 1 provides an overview of key performance measures of the BPS that compares 2025 performance to the previous four years. The results show that while a majority of these measures continue to improve or remain stable, several indicators are identified for monitoring or further attention, highlighting areas that warrant industry focus. The table is intended to contextualize known and emerging trends and areas of operational focus to help stakeholders understand where reliability risks may be evolving or re-emerging as the grid continues to transform.

[2] Long-Term Reliability Assessments
[3] MISO *2026 Reliability Imperative Report*

Table 1: Reliability Indicators[4]			
Improving	**Stable**	**Monitor**	**Actionable**
Frequency Response: Eastern, Texas, and Western Interconnections	**Frequency Response:** Québec Interconnection	**Winter Reserve Margin:** NPCC Maritimes	**Inertia and Rate-of-Change-of-Frequency:** Québec Interconnection[5]
Inertia and Rate-of-Change-of-Frequency: Eastern, Texas, and Western Interconnections	**Protection System Misoperations Rate**	**Transmission-Related Events Resulting in Loss of Load:** Supported by Event Analysis Data	
Energy Emergency Alerts	**Transmission Outages Caused by Failed Protection System Equipment:** AC Circuits	**Interconnection Reliability Operating Limit (IROL) Exceedance**	
Transmission Outages Caused by Failed Protection System Equipment: Transformers	**Automatic AC Transmission Outages Caused by Failed AC Substation Equipment:** AC Circuits	**Transmission Outages Caused by Failed AC Substation Equipment:** Transformers	
Automatic Transmission Outage Events Involving Human Error: AC Circuits and Transformers	**Transmission Element Availability:** AC Circuits	**Transmission Element Availability:** Transformers	
Transmission Outages Caused by Failed AC Circuit Equipment	**Transmission Outage Severity**		
	Transmission Physical Security Metric		

Emerging Trends

While the BPS remains reliable and continues to perform well operationally, underlying reliability risk is increasing and changing in nature; the margin for error continues to decrease while dependence on operational mitigations increases.

NERC's analysis in the SOR report also identifies several important emerging trends:

1. **Conventional generation forced outage rates are up.**
   The report identifies a meaningful increase in conventional generator forced outage rates in 2025, with annual weighted equivalent forced outage rates (WEFOR) increasing to 9.2% compared to historical norms rarely exceeding 8%. Coal and combined-cycle units were the primary drivers of this increase with an increase of over 39.8 TWh and 19.1 TWh of unavailable energy year over year, respectively. In contrast to recent years' generation challenges, operational performance during the

[4] Some metrics are evaluated for multiple sub-topics. These metrics are either listed multiple times, with the different sub-topics beneath the bolded metric name (e.g. different interconnections for Frequency Response), or the criteria driving the overall status is listed (e.g. NPCC Maritimes causing Winter Reserve Margin to have the Monitor status).

[5] The Québec Interconnection 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 Interconnection, particularly under summer light-load conditions, leading to lower system inertia during this period. These conditions have been cyclical historically and are expected to improve in the coming years.

most challenging winter week of 2025[6] improved as industry winterization efforts continued. Instead, the reduction in availability was distributed throughout the year, suggesting a broader baseline degradation in much of the coal and combined-cycle fleets' performance.

2. **Demand growth and large load integration continue challenging operators.**
   Projected annual energy demand rose to nearly 4.95 million GWh in 2025, while actual summer peak demand in several areas approached or exceeded the normal forecast. Data center and computational loads continued emerging as a major reliability consideration due to their scale, speed of development, and unique operational characteristics. In 2025, two instances of data center customer-initiated load reduction (CILR) exceeded 1,000 MWs, with many more exceeding 100 MWs. NERC continued to work with the electric and data center industries to issue new alerts, host technical conferences, perform standards work, and offer large load guidance activities, reflecting the growing importance of load modeling, operational coordination, and frequency response impacts associated with these rapidly growing loads.

3. **Resource mix transformation is fundamentally changing system operations and reliability management.**
   Solar, wind, and battery energy storage systems (BESS), all IBRs, continued to expand rapidly in 2025, with BESS growth approximately matching solar growth. In several peak demand periods, solar and/or wind production materially exceeded planning assumptions and supported system operations during stressed conditions. Additionally, BESS continued to demonstrate the capability to provide rapid frequency response. At the same time, IBRs are increasing operational complexity associated with inertia, protection systems, dynamic performance, and disturbance response. NERC continued extensive IBR mitigation work in 2025 and early 2026, including new technical requirements related to IBR performance, ride-through capability, and model validation.

4. **Industry mitigation actions are tracking well in many foundational reliability areas.**
   The *2026 SOR Technical Assessment* also documents continued improvement in several important controllable reliability metrics, including overall transmission system outage severity, protection system misoperations, failed protection-system-related outages, and transmission-related loss-of-load events.

[6] Comparisons across winter storm events should be interpreted with caution, as outage risk remains elevated and storm impacts vary significantly by the area impacted, duration, system condition, and event severity.

Conventional Generation Forced Outage Rates Up

Forced outage performance is a foundational indicator of BPS reliability because it illustrates the ability of generating resources to perform daily as well as when they are most needed, during periods of high demand, stressed system conditions, and extreme weather. While reserve margins and accredited capacity metrics provide a static view of resource sufficiency, an analysis of year-over-year forced outage rate changes provides insights into the availability of the conventional resource fleet, revealing trends in outage behavior and emerging reliability vulnerabilities.

Analysis of 2025 Weighted Equivalent Forced Outage Rate

Our 2025 analysis of the conventional GADS[7] revealed an increase in reported units' annual WEFOR[8] to 9.2%, which is higher than the historical norms of 7–8% (see **Figure 2**). This increase was not the result of any particular event but an increase distributed across most months throughout the year, with three months' WEFORs being comparable to the months when winter storms Elliott and Uri occurred. The lack of specific major events is indicative of a more subtle baseline increase in conventional forced outage rates. This, combined with tightening reserve margins[9] in some areas that have continued into 2025 from prior years—as well as performance improvements during the most challenging winter week of the year (January 19–25), highlighted by NERC, the Federal Energy Regulatory Commission (FERC), and industry—emphasizes the overall operational improvements while underscoring the increasingly precarious position of the BPS. As WEFOR increases, planning reserve margins may also increase at a higher rate to accommodate the associated uncertainty[10] (see **Figure 1**).[11]

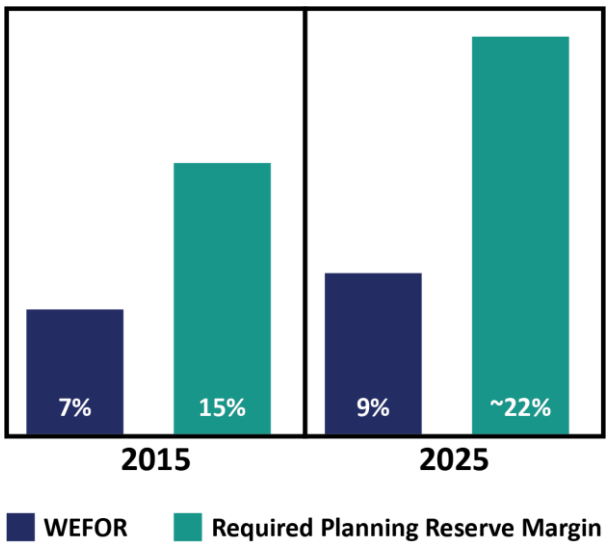


Figure 1: Conceptual Example of Forced Outage Rates Impacting Reserves

[7] GADS reporting is mandatory for units with a capacity >20 MW owned by NERC-registered Generator Owners (GO) per Section 1600 of NERC's Rules of Procedure. The conventional data set is separate from wind, solar, and hybrid energy storage data collection. Standalone energy storage is not currently collected by NERC under a Section 1600 data request.

[8] GADS Data Reporting Instructions - Appendix F Equations - WEFOR is an equation used throughout the electric industry to assess generator reliability by looking at how much units' time and generating capacity is reduced due to forced outages and derates relative to the amount of time they could be generating, weighting that value by each units' net maximum capacity.

[9] Reserve margins refer to the amount of excess generation an area is required to have available as a contingency for major system events to reduce the likelihood of cascading blackouts and load shedding. They are also key to NERC's Reliability Assessments' ability to forecast adequate generation.

[10] Many factors impact reserve margin calculations and vary from season to season throughout the year. Higher impact drivers include forced outage rates, planned maintenance rates, load forecasts, extreme weather outage adders, resource fleet composition, variable energy performance, and resource age.

[11] Figure is for demonstrative purposes. Proportions are not perfectly representative to actual value relations.

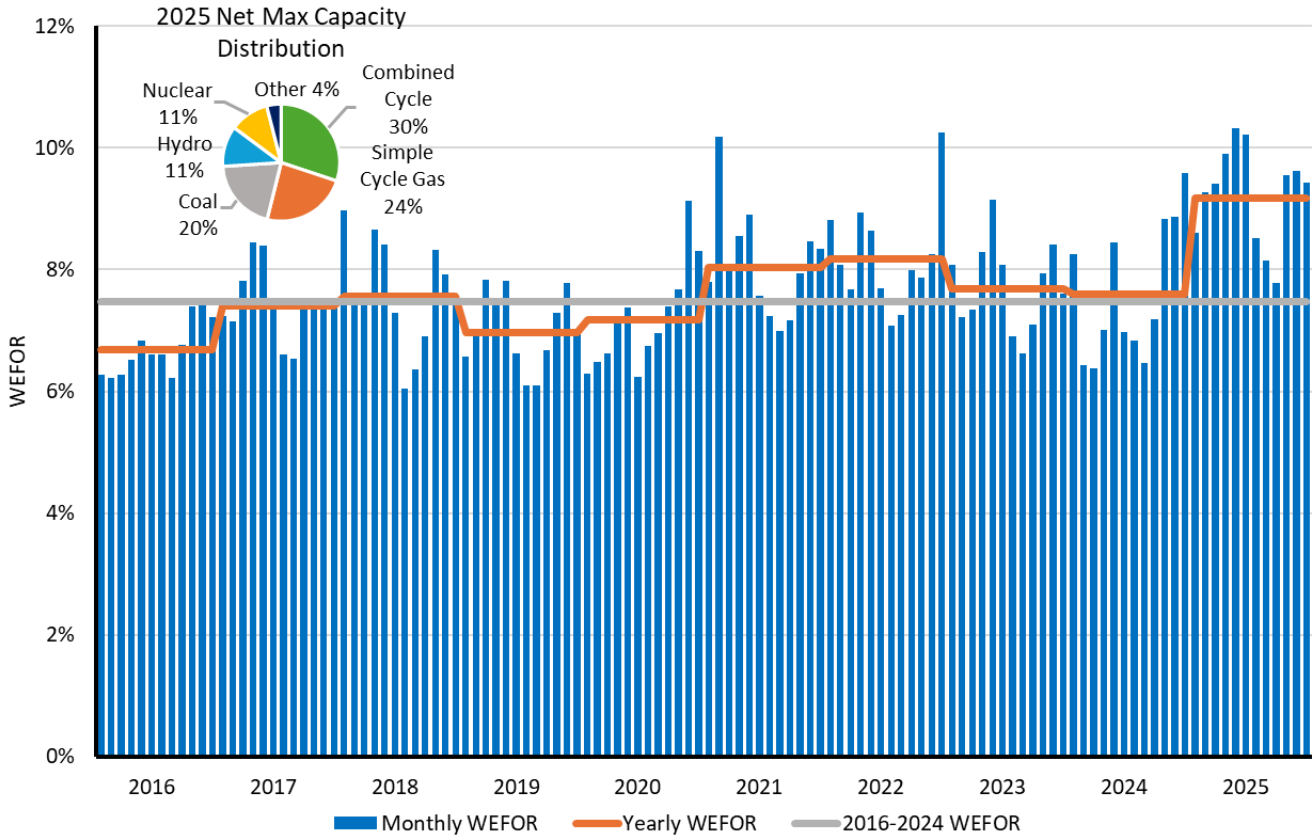


Figure 2: Monthly, Annual, and Five-Year WEFOR

Further analysis (see **Table 2**) identified that the increase in unavailability was primarily driven by a variety of combustion-based generators. The largest year-over-year increases in TWh of unavailability were observed in coal (39.8 TWh increase from 2024 to 2025) and combined-cycle units (19.1 TWh increase from 2024 to 2025). Combining this information with each type of unit's installed net maximum capacity and WEFOR identifies coal-fueled generators as being of more concern than others.

Table 2: 2024 vs. 2025 Year-Over-Year Forced Unavailability Comparison

Primary Fuel Type	Change in GWh[12]	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/Overall	68,440	7.6%	9.2%

[12] Measured by WEFOR numerator:
$\sum(([Forced\ Outage\ Hours] + [Equivalent\ Forced\ Derate\ Hours]) * [Net\ Maximum\ Capacity])$

To identify possible commonalities, the owners of 41 generators that had a year-over-year increase of at least 1 TWh[13] of unavailability were asked to voluntarily provide additional context to their 2025 GADS data by NERC and the Regional Entities. Of those contacted, responses for 26 generators were provided, which identified several key insights to drive further investigation:

- Sixteen of the units experienced equipment destruction extensive enough to significantly prolong their 2025 outage(s).
- Eight of the units indicated that supply chain constraints significantly prolonged their 2025 outage(s).
  - Constraints were all indicated as occurring at the manufacturer; however, constraints may have occurred deeper into the supply chain unknown to the Generator Owner (GO).
  - Constraints identified included being unable to obtain materials for the repairs, challenges locating part specifications, inexperienced project management, and lack of staff to perform the work.
- Six of the units indicated complete or partial turbine blade release or vibration, which, upon further inspection, would have likely resulted in eventual release.
- Multiple units[14] leveraged the forced outage downtime to perform additional maintenance and inspections. Some indicated that these actions also extended the duration of the outage(s) but resulted in future benefits by either functionally moving up scheduled outages or identifying opportunities to prevent future outages.

After entity responses were evaluated, cause code components were also evaluated by an approximated MWh of forced capacity reduction since 2016. The largest groups were then trended to identify which ones had the largest and/or most consistent increases, with the following component groups being identified:

- **Catastrophe:** Increases over prior year in 2017, 2020, and 2024
  - Largely driven by an increase in use in 2020 because of COVID-19. NERC directed reporters to utilize this code for outages relating to the pandemic at that time prior to the addition of a more appropriate cause code.
  - 2017 and 2024 increases were higher than usual but would not have warranted inclusion on their own.
- **Turbines (High, Intermediate, and Low Pressure):** Increases over prior year in 2017, 2020, 2023, and 2025
  - All three individual turbine component groups were independently identified and represent the largest, most consistently increasing group if combined.
- **Regulatory:** Increases over prior year in 2017, 2018, 2019, 2022, 2023, and 2025
  - Most consistently increasing component group.
  - Initial analysis did not indicate any alignment with a particular policy objective, with both decreases and increases throughout various governmental phases.

[13] Year-over-year variation in MWhs of unavailable generation was used intentionally used in lieu of WEFOR or a single year's MWhs of unavailable generation. This was to focus on units that experienced issues starting in or shortly before 2025 and were most impactful to the overall annual WEFOR. A cutoff was applied to limit overall industry burden and receive a processable amount of input given the timeframe while also being a large enough group to identify common issues. The exact 1 TWh amount provided a clean cut point with a sufficient population but was ultimately arbitrary.

[14] Because this specific information was not directly requested and this is a common industry practice, an exact number of units is not available.

- **Safety:** Increases over prior year in 2018, 2020, 2022, and 2025
- **Nox Reduction Systems:** Increases over prior year in 2017, 2018, 2022, and 2025
- **Boiler Fuel Supply to Bunker:** Increases over prior year in 2017, 2020, 2022, 2024, and 2025

Further data analysis of these component groups and investigation into the underlying cause codes and submitted verbal descriptions are necessary.

The results of this analysis align with, but do not prove, industry assertions concerning coal and combined-cycle units. Most large coal units are over 40 years old and are expected to be retired in the relatively near future. These large coal and combined-cycle units were not designed for regular cycling, which has become an operational requirement in some areas and a necessity to maintain economic viability in others. These factors compound to increase the likelihood of failure over time and act to reduce the incentive to prioritize expensive restoration. Recent Federal Power Act section 202(c) emergency energy orders requested through the Department of Energy (DOE) have also received mixed reception among GOs. These mandates do improve system capacity, but that capacity may not be from reliable units.

Related Actions

Recommendations

- NERC will pursue further analysis and collaborate with the GADS user group (GADSUG) to better understand the causes driving this increase in WEFOR.
- NERC will work with industry to develop specific, measurable reliability indicators for generation performance.
- NERC and the relevant stakeholders should consider adjusting or at least be prepared to adjust reserve requirements to account for lower conventional generation availability.
- GOs should consider bolstering turbine inspection procedures at required intervals. GOs should also consider performing these inspections more frequently or when other major maintenance/outages provide the opportunity.
- Regulators should consider implementing alternative operating requirements during energy emergencies to ensure that regulations do not hinder BPS reliability during critical periods.
- GOs should ensure that manufacturers have capability and plan to replace major components in the event of failure.
- Manufacturers should consider immediately increasing the number of trained technical maintenance personnel to bolster expertise due to the increasing frequency of outages involving major equipment failure and the lack of adequate or sufficiently experienced staff, which was cited multiple times.
- Manufacturers should verify material procurement and processing capabilities.

Demand Growth and Large Load Integration Challenges Continue

Recent events involving data centers and cryptocurrency mining facilities continue to demonstrate the importance of improving industry's understanding of these loads' characteristics and risks as well as the considerations and mitigations needed to reliably integrate them into the BPS.

In a February 2025 event in the Eastern Interconnection, 1,800 MW of data center CILR occurred due to a transmission fault. An additional Eastern Interconnection event in February 2025 resulted in 428 MW of data center CILR. Similar Eastern Interconnection events were observed in March 2025 (227 MW of data center CILR), May 2025 (540 MW of data center CILR), and June 2025 (1,300 MW of data center CILR). ERCOT continues to experience cryptocurrency mining facility CILR events with nine events occurring in 2025 in which at least 100 MW of CILR occurred from computational load facilities.[15] **Figure 3** provides a summary of the Eastern Interconnection and ERCOT data center and cryptocurrency mining facility events.

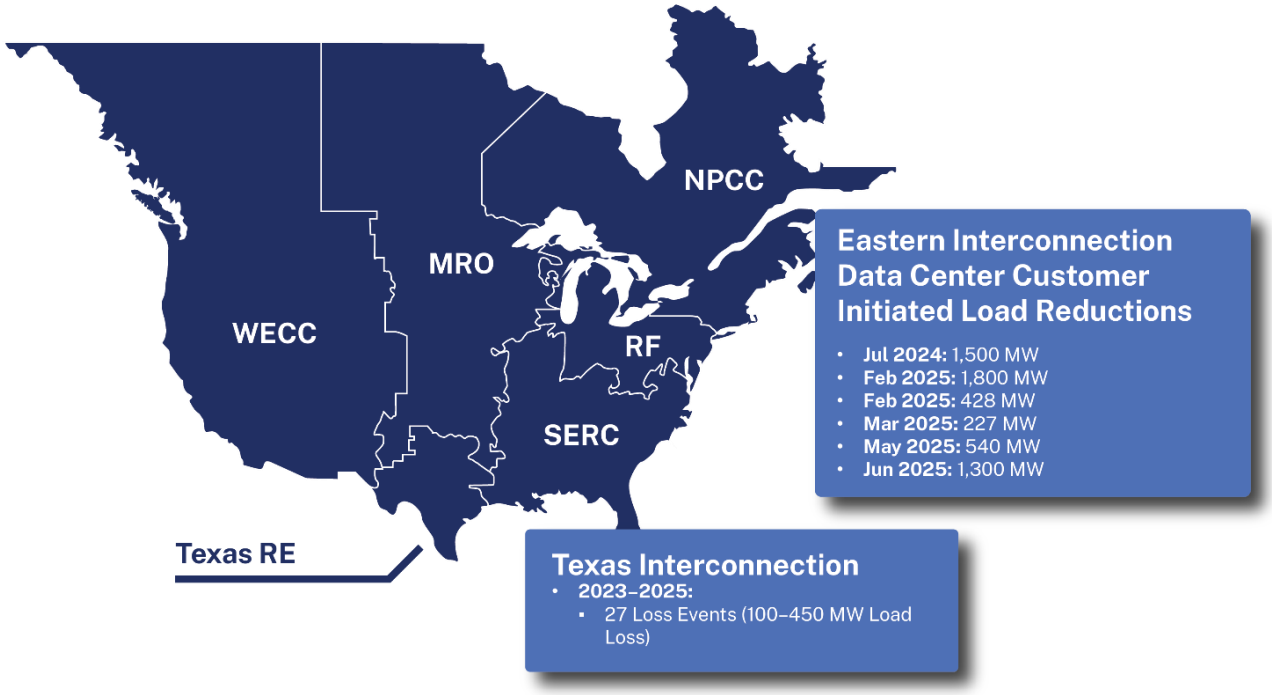


Figure 3: Customer-Initiated Load Reduction Events

Figure 4 provides a breakdown of the large CILRs tracked in ERCOT since 2023. Compared to 2023, the number of events in 2024 and 2025 increased, without indicating improvement. Most events were large computational load events; however, several non-computational load events did occur.

[15] See the Incident Review: Considering Voltage-Sensitive Crypto Load Reductions for an analysis of cryptocurrency mining facility ride-through events in ERCOT.

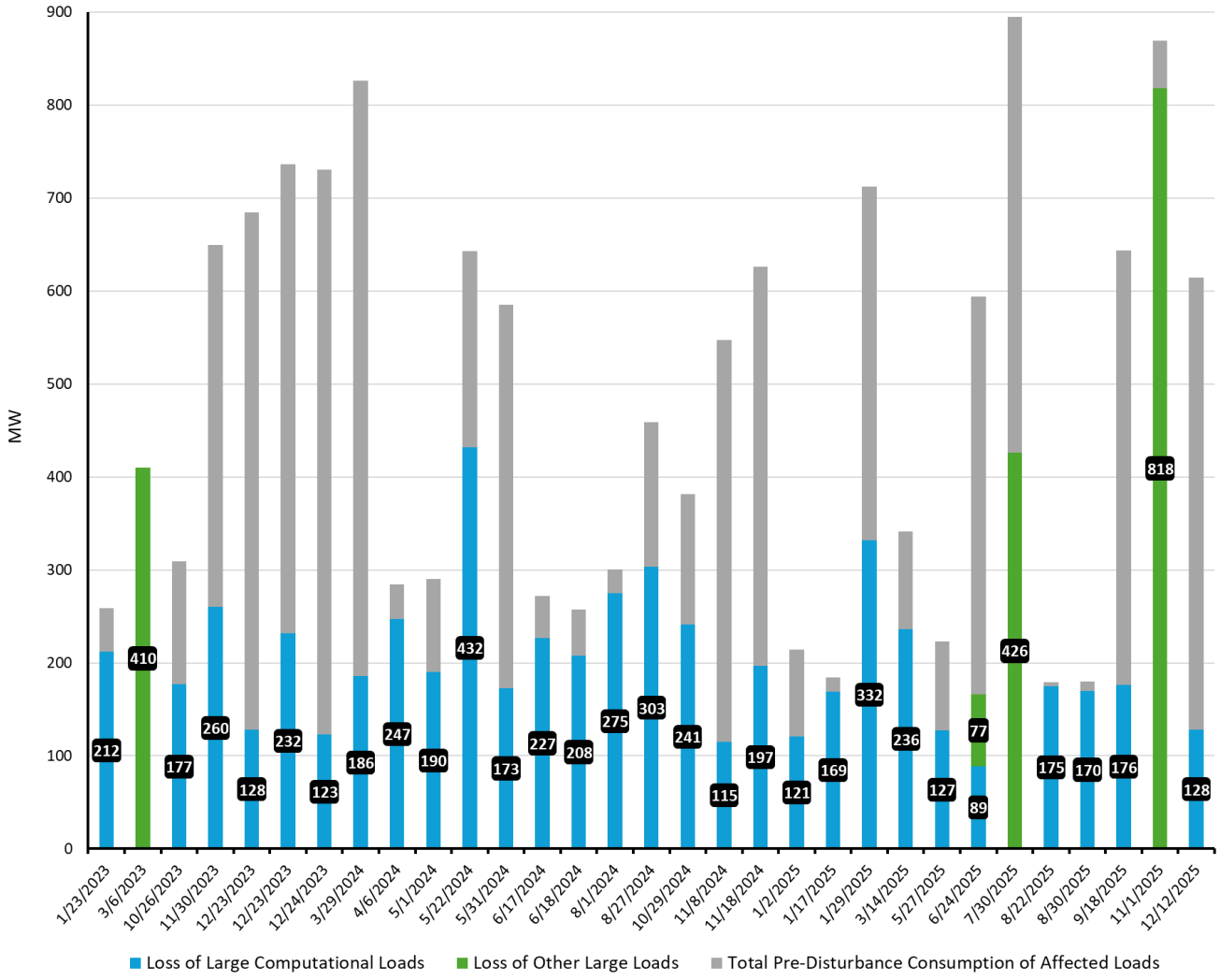


Figure 4: ERCOT Large Load Ride-Through Events

These events demonstrate that the reliability challenges from large loads will increase as these facilities become more prevalent on the grid. As the size of individual large load facilities increases and if large load facilities are located near one another, the sizes of these large load events will likely increase. This could lead to measurable frequency or voltage stability issues. It remains important for grid planners and operators to understand and study the expected performance of the large load facilities during grid disturbances. For the reliability risks to be studied and addressed, load models and study practices that reflect the behavior of the large loads and the risks to the BPS are essential. Continued collaboration between large load facility owners and operators as well as grid planners and operators is essential to ensure the reliable operation of the BPS.

Related Actions

Existing and Ongoing Efforts

- NERC developed a Large Loads Action Plan to address the BPS risks related to emerging large loads.[16]
- The Large Loads Working Group (LLWG) continues to provide technical guidance, industry collaboration, and reliability risk assessment and monitoring for the increasing integration of large loads. The LLWG has published the following white papers and reliability guideline:

[16] Large Loads Action Plan

- A white paper discussing the characteristics of emerging large loads and the risks they pose to the BPS[17]
- A white paper discussing the gaps in NERC Reliability Standards and industry practices related to emerging large loads[18]
- A reliability guideline providing industry with the best practices for mitigating BPS risks related to emerging large loads[19]

- The Load Modeling Working Group (LMWG) continues to address gaps in modeling the dynamic characteristics of the emerging large loads. The LMWG's activities include the following:
  - Developed a technical reference guide for industry on modeling data centers for transient stability studies
  - Endorsed and continues to improve a performance model called Power Electronic Reconnecting and Ceasing (PERC1) for modeling data centers in 2025
  - Continues to educate industry with workshops and by developing tools to help industry develop useful data center models, such as a data center questionnaire[20]
- NERC issued a Level 2 Industry Recommendation Alert to address risks related to large loads.[21]
- Additionally, NERC issued a Level 3 Essential Actions Alert providing specific actions deemed essential to address BPS risks posed by computational large loads,[22] including the following:
  - Transmission Planners and Planning Coordinators developing requirements for computational load modeling data, settings, and parameters
  - Transmission Planners and Planning Coordinators focusing on computational load impacts in system studies
  - Planning Coordinators updating their qualified change definition to reflect the changes that can occur to computational loads
  - Transmission Operators establishing a commissioning process that ensures operational readiness for the integration of large loads
  - Transmission Planners and Planning Coordinators implementing actions to ensure that non-consequential loss of firm computational load does not occur for typically cleared faults
  - Transmission Owners taking actions to capture and share fault recording data for computational load facilities
  - Transmission Operators, Reliability Coordinators, and Balancing Authorities establishing interpersonal communication capabilities and joint operating procedures with computational loads as well as issuing operating instructions to prevent Bulk Electric System (BES) emergencies
- NERC hosted a technical conference focused on the BPS risks posed by emerging large loads and the mitigations needed to integrate emerging large loads into the BPS.[23]

[17] Characteristics and Risks of Emerging Large Loads
[18] NERC LLWG White Paper - Assessment of Gaps
[19] Risk Mitigation for Emerging Large Loads
[20] Data Center Information Collection Questionnaire
[21] Large Load Interconnection, Study, Commissioning, and Operations
[22] Level 3 Computational Load Alert
[23] 02-24-26 Emerging Large Loads Technical Conference

- NERC posted draft updates to the NERC Rules of Procedure for establishing a new registered entity for computational load entities. Additionally, the NERC Standards Committee has launched a standards project to develop Reliability Standards that address the risks posed by computational loads.
- The frequency response metric will continue to be monitored to measure the response to frequency events during large load tripping events.

Recommendations

- The following recommendations are discussed in the LLWG white papers:[24]
  - Registered entities should coordinate with large load entities to address the risks posed by emerging large loads.
  - Relevant NERC Reliability and Security Technical Committee (RSTC) subgroups (including the LLWG, the LMWG, the Security Working Group, and the System Protection and Control Working Group) should continue to assess and address the risks posed by emerging large loads.
  - Regulators should work with utilities to address the risks posed by emerging large loads.
  - Policymakers should review interactions between interconnection requirements, existing state regulations and planning processes, and regional grid operator requirements. Additionally, policymakers should review requirements for large load customers to provide operational data and information to Transmission Owners (TO), Transmission Operators (TOP), Transmission Planners (TP), and other entities.
- NERC registered entities should implement the recommendations provided in the Level 2 Industry Recommendation Alert and the Level 3 Essential Actions Alert.[25]
- NERC will continue incident analysis and lessons learned and share findings with industry.
  - NERC will consider the necessity of mandatory data collection requirements.
- Communication and coordination with the Electric Power Research Institution (EPRI), the Energy Systems Integration Group (ESIG), large load industry groups, and the electric industry at large should be continued.

[24] Characteristics and Risks of Emerging Large Loads, NERC LLWG White Paper - Assessment of Gaps
[25] Large Load Interconnection, Study, Commissioning, and Operations, Level 3 Computational Load Alert

Resource Mix Transformation

The BPS and BES continue to experience a rapid resource mix transformation as conventional generation retirements continue to be replaced primarily by natural gas and increasing IBR penetration. This reduction in conventional resource diversity and increased reliance on variable energy resources continued to pose risks and challenge grid operations in 2025. Additionally, the magnitude of BESS helping to smooth solar generation coming on-line in the morning and going off-line in the evening has increased, with installed capacity roughly matching solar additions last year.

IBR Reliability Considerations

As detailed in NERC's *2025 SOR Overview*,[26] IBR reliability risks remain a priority as these resources continue to grow across the BPS. The primary concern is that some IBRs have unexpectedly reduced or ceased output in response to normally occurring grid disturbances, including generator faults, then rapidly resume output within minutes. These events are driven by a combination of ride-through performance limitations, inverter and plant-level controls, protection systems, and modeling quality deficiencies. Following several major IBR-driven disturbances since 2017, NERC has pursued numerous activities to mitigate related reliability concerns.[27] The *2025 SOR* identified continued unexpected IBR output reductions following normally occurring system disturbances with four events four events exceeding 500 MW reported in 2024 and 16 such events reported since 2020.

Available operational data in 2025 suggests improvements in several key areas. Industry participation in model validation and disturbance review activities increased substantially following implementation of the alert recommendations. While no major widespread disturbance events associated with previously observed common-mode IBR tripping mechanisms were identified during the assessment period, there was a loss of 1,132 MW due to sub-synchronous oscillation protection tripping generation off, a failure mode previously unobserved at this scale. Additionally, rapidly increasing IBR penetration continues to increase operational complexity, particularly in regions experiencing reduced inertia, high renewable penetration during light-load conditions, or rapidly changing power flow conditions. Throughout 2025 and the first half of 2026, several additional major efforts have been undertaken and/or completed as highlighted below.

IBR-Related Actions

Existing and Ongoing Efforts

Level 3 Alert[28]

NERC issued *Level 3 Alert: Essential Actions for Inverter-Based Resource (IBR) Performance and Modeling* to TOs, TPs, Planning Coordinators (PC), and currently registered GOs to enhance technical minimum requirements, study processes, and improve modeling to mitigate risks posed by IBR performance during system disturbances.

- **Essential Action #1**: Each TO and TP, in coordination with their PC, should enhance the existing criteria and policies in their generator interconnection and planning activities, respectively, with additional technical details and IBR-specific performance criteria. These performance-based factors help ensure uniform IBR performance both in normal and post-disturbance operations and include reactive power control, frequency response control, ride-through behavior and post-disturbance performance, and full use of reactive power capability.

[26] 2025 NERC State of Reliability - Overview
[27] Quick Reference Guide: Inverter-Based Resource Activities
[28] NERC Level 3 Alert: Essential Actions for Inverter-Based Resource (IBR) Performance and Modeling

- **Essential Action #2**: Each TP and PC should enhance their modeling and study practices to ensure that sufficient study work and model quality verification are performed and documented to reflect models that are representative of installed, or to-be installed, equipment by establishing model quality and accuracy criteria as well as model performance tests and conformity criteria and by enhancing existing criteria used throughout the generator interconnection.
- **Essential Action #3**: TOs, TPs, or PCs should perform a detailed review of currently operating IBRs on their systems to understand the extent of condition of both real-world performance and accuracy of their models.
- **Essential Action #4**: Each GO should create and implement processes to help ensure that the models used for the evaluation of their design and submitted to TPs and PCs for use in generator interconnection and planning processes are accurate and high-fidelity representations of their IBRs.

To follow up on the Level 3 Alert, the ERO has developed an outreach strategy for 2026 to gather information about why entities are not adopting essential actions or are reporting substandard performance expectations and to address legitimate challenges through clarification of essential actions or, where appropriate, through regulatory processes.

New Standards

Significant reliability gaps associated with modeling are addressed by the updated MOD standards finalized in 2025: MOD-026-2,[29] MOD-032-2,[30] and MOD-033-2.[31] Model validation and verification requirements in MOD-026-2 improve model accuracy and documentation. Enhancements in MOD-032-2 help ensure that validated and verified models are collected and used for both local reliability studies and Interconnection-wide case creation. Improvements in MOD-033-2 allow PCs to assess individual generator performance against their model behaviors as part of system model validation efforts and to remedy discrepancies through MOD-032-2 processes.

Inverter-Based Resource Subcommittee and Electromagnetic Transient Modeling Working Group

The Inverter-Based Resource Subcommittee (IRPS) and Electromagnetic Transient Modeling Working Group (EMTWG) continue to develop reliability guidelines and white papers to share best practices among industry to further reduce IBR risks associated with modeling, studies, commissioning, and testing. Many of these risks can be traced back to poor commissioning and testing of IBRs before they enter commercial operation. These gaps are addressed in the *Draft Reliability Guideline: IBR Commissioning Best Practices*[32] and an upcoming white paper, *IBR Equipment EMT Model Validation*, which aims to provide model validation acceptance criteria, thereby complementing model validation requirements in MOD-026-2 and closing risks posed by inaccurate models.

Category 2 Generator Owner Registration[33]

On May 18, 2023, FERC issued an order approving the NERC Work Plan filed on February 15, 2023, as amended on March 13, 2023, to address registration of IBRs that are connected to the BPS but not within NERC's definition of the BES (referred to hereafter as "Category 2 GO/GOP"). The ERO Enterprise has identified and communicated with 531 IBR facilities that meet the Category 2 GO/Generator Operator (GOP) registry criteria across all the Regional Entities and are, or planned to be, interconnected as of May 15, 2026.

[29] MOD-026-2
[30] MOD-032-2
[31] MOD-033-3 – Further revisions have been implemented in 2026.
[32] Draft Reliability Guideline: Commissioning Best Practices
[33] NERC Files IBR Registration Update, Marking Milestone for Grid Reliability

Beginning on May 15, 2026, entities with identified IBR facilities that meet the Category 2 GO/GOP registry criteria were registered and are now subject to compliance with applicable Reliability Standards, as required by the IBR Order. As part of the Inverter-Based Resource Registration Initiative, NERC staff developed a document identifying the finalized and pending compliance dates for the applicability and enforceability of Reliability Standards applicable to Category 2 GO and GOP registrations. As of May 15, 2026, entities registered as Category 2 GOs or Category 2 GOPs are required to comply with, as applicable, BAL-001-TRE, IRO-010-5, MOD-032-2, PRC-012-2, PRC-017-1, TOP-003-6.1, VAR-001-5, and VAR-002-4.1.

Additional technical conferences will be pursued to assist in identifying which Reliability Standards must be revised to establish applicability to Category 2 IBRs and in which order and grouping they should be developed.

The ERO Enterprise is integrating the new Category 2 GO and GOP registrants into relevant ERO Enterprise efforts, including Compliance Monitoring and Enforcement Program activities related to Reliability Standards applicable to those entities. The ERO Enterprise will continue to identify and register additional entities that meet the Category 2 GO and GOP registry criteria as additional IBR facilities are developed and connected to the BPS.

The completion of the NERC Work Plan represents the conclusion of a substantial three-year ERO Enterprise effort to address the risk to BPS reliability posed by unregistered IBR facilities.

BESS Reliability Considerations

As the BES resource mix continues to rapidly evolve, BESS penetration has rapidly increased over the past several years (see **Figure 5**) to approximately match solar growth in 2025. This growth is projected to continue, requiring observation and analysis of this resource's capabilities.

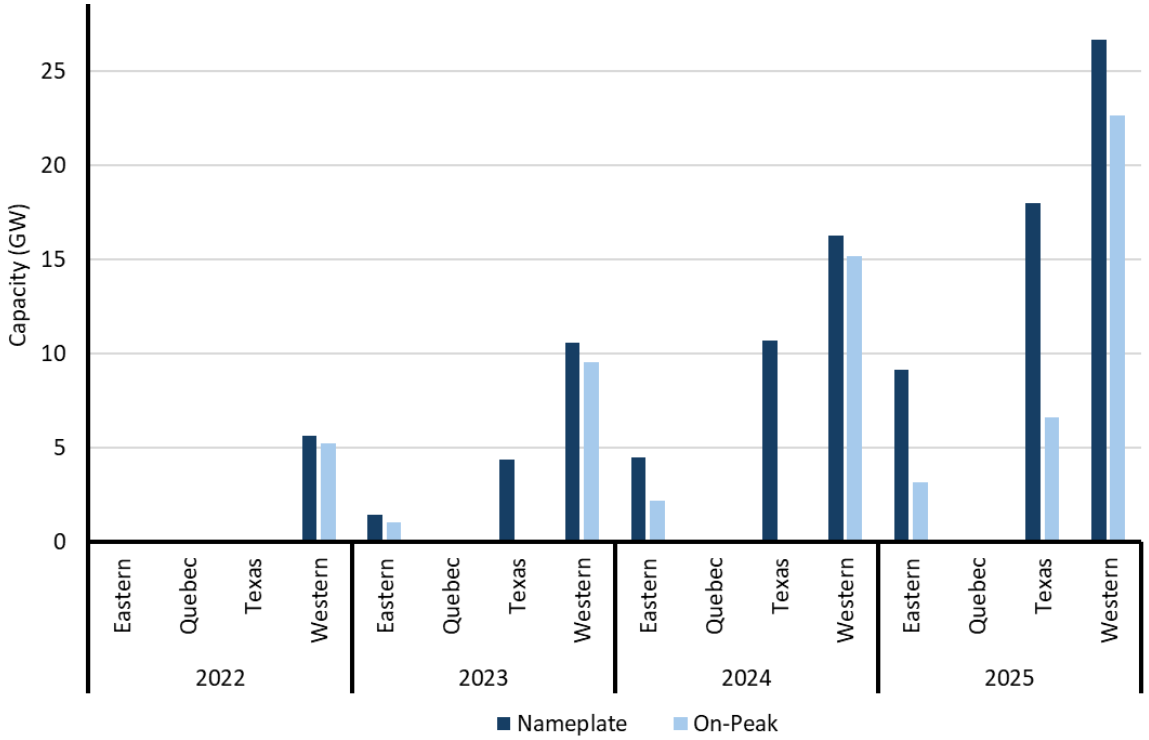


Figure 5: 2022–2025 Battery and Hybrid Capacity by Interconnection

Unique Failure Event

In January 2025, a 300 MW BESS facility experienced thermal runaway during routine testing that ultimately resulted in the functional destruction of a previous-generation warehouse-style facility.[34] While outages internal to the plant regularly occur with other generation resources of similar or greater capacities, the permanent, unplanned loss of a non-BESS facility is exceedingly rare. As such, this type of failure represents a risk consideration unique to BESS that needs to be taken into consideration as the resource continues to expand. Improvements to BESS reliability, thermal runaway mitigation, failure isolation, fire suppression, and updates to fire codes have all acted to significantly reduce the likelihood of these events occurring. NERC will continue to monitor these failure events, but they do not represent a significant concern to overall system reliability at this time.

Load Curve Smoothing

BESS is typically installed to take advantage of price differences between high-generation/low-load and low-generation/high-load conditions. As a result, it provides a smoothing effect that functionally reduces expected and unexpected variability from increasingly prevalent wind and solar generation (see **Figure 6**).

As a result, conventional generators have more time to come off-line and on-line during the most strenuous portions of the day in areas most impacted by as the period when solar resources are going off-line just before peak load conditions in the evening. Because many older, larger conventional generators were not designed to cycle on- and off-line daily, increasing the ramp period can reduce wear and tear, improving their reliability.

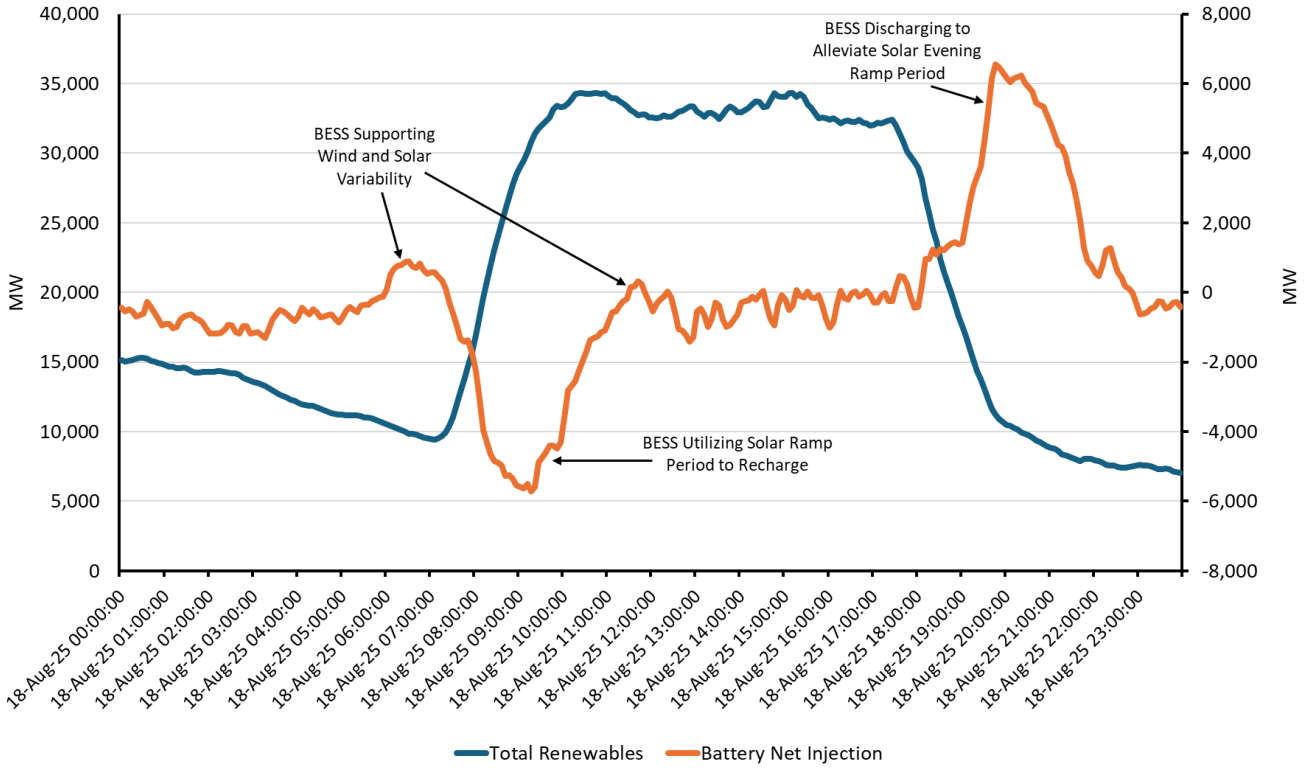


Figure 6: Total Renewables Plus Evening Solar Ramp[35]

[34] Moss Landing BESS Fire Report Final 12.22.25.pdf

[35] Secondary Y-axis has been shifted and scaled for visual clarity.

Frequency Response Impacts

As detailed earlier in the *2025 SOR Overview*,[36] BESS has demonstrated the capability to rapidly respond to frequency disturbances. In 2025, areas with sufficiently dense BESS installations and primary frequency response support initiatives continued to demonstrate the resource's ability to arrest frequency decline and restore frequency to deadband more quickly than conventional generators.

It should be noted that BESS are energy storage resources with limited capacity, typically intended to last a few hours. As a result, BESS's role in frequency disturbance events is ultimately to rapidly recover and maintain frequency until additional resources can come on-line for indefinite system support. This introduces a functional limitation during long-term widespread system degradation events, meaning that BESS is not a complete solution for events like major winter storms.

BESS-Related Actions

Recommendations

- BESS data collection and sharing value and viability are being evaluated by NERC's Performance Analysis team.
- NERC encourages BESS facilities to provide information on services that they are providing with relevant parties.
- NERC encourages policymakers to consider revisions to fire codes if they have not already.
- NERC will continue to monitor BESS performance and major events for risks.
- In November 2025, ERCOT stakeholders approved Nodal Operating Guide Revision Request 272 and Planning Guide Revision Request 121. These revisions require new BESS resources with a standard generation interconnection agreement (SGIA) date on or after April 1, 2026, to demonstrate the capability of providing advanced grid-support (grid-forming) functions as well as to provide appropriate models for these functions.

[36] 2025 NERC State of Reliability - Overview

Industry Mitigation Actions

Performance data reported to NERC enables a risk-based approach to reliability management across major emerging reliability issues prior to the creation of formal reliability indicators. Current areas of focus include severe weather, conventional generator performance, large loads, BESS, and IBRs (see **Table 3**). In response to these evolving risks, industry and the ERO Enterprise implemented a broad range of mitigation activities throughout 2025 detailed in the body of this report.

In addition to these top priorities, more cautionary mitigation activities included more conservative operating practices during stressed and cold-weather conditions, increased use of probabilistic and all-hours reliability assessments, improved model validation requirements, transmission planning resilience analysis for extreme weather events, and new planning and operational guidance associated with load-pocket reliability risks.

Table 3: Monitoring Emerging Trends and Mitigation Resolution

Monitored Reliability Challenge	Key Measures Tracked	2025 Trends	Mitigation Effectiveness Indicators	Indicators that Additional Attention is Required
Increasing Incidence of Severe Weather	Severity risk index (SRI), transmission outages, restoration duration, MVA-days lost, load loss	Worst SRI days remained within historically favorable ranges; overall weather conditions considered favorable	Reduced outage severity, faster restoration, lower cumulative SRI	Increasing high-SRI days, longer restoration times, larger correlated outages
Generator Forced Outage and Performance Trends	Annual/monthly WEFOR, fuel-specific outage rates, unavailable MWh, seasonal outage spikes	Overall WEFOR increased to 9.2%; coal 11.2% to 14.1% (39.8 TWh change), combined cycle 4.2% to 5.7% (19.1 TWh change)	Improved winter performance, reduced outage severity during extreme events	Elevated WEFOR, correlated winter outage spikes
Reliable Large Load Integration	Peak demand growth, frequency response, load forecast error, transmission constraints, CILR	Annual energy demand increased to ~4.95 million GWh; actual summer peak higher than forecast; two CILRs exceeding 1,000 MWs	Stable frequency performance, improved operational visibility	Rapid localized demand growth, frequency volatility, planning uncertainty
Reliable BESS Integration and Performance	Frequency arrest performance, recovery speed, BESS availability	BESS deployment approximately matched solar growth; improved fast frequency response performance observed when incentivized in high-BESS areas	Improved frequency recovery, successful grid-forming performance	Thermal runaway/fire events, duration limitations, unavailable BESS capacity
Reliable IBR Integration	Ride-through performance, rate-of-change-of-frequency (RoCoF), IBR trip events, model validation	Expanded IBR mitigation activities continued through 2025	Reduced disturbance-related tripping, improved model accuracy	Weak-grid instability, repeated tripping events, model-performance divergence

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4-05
SPP Operational Review

SPP
Powering Progress

OPERATIONAL REVIEW

C.J. Brown,

Vice President Operations

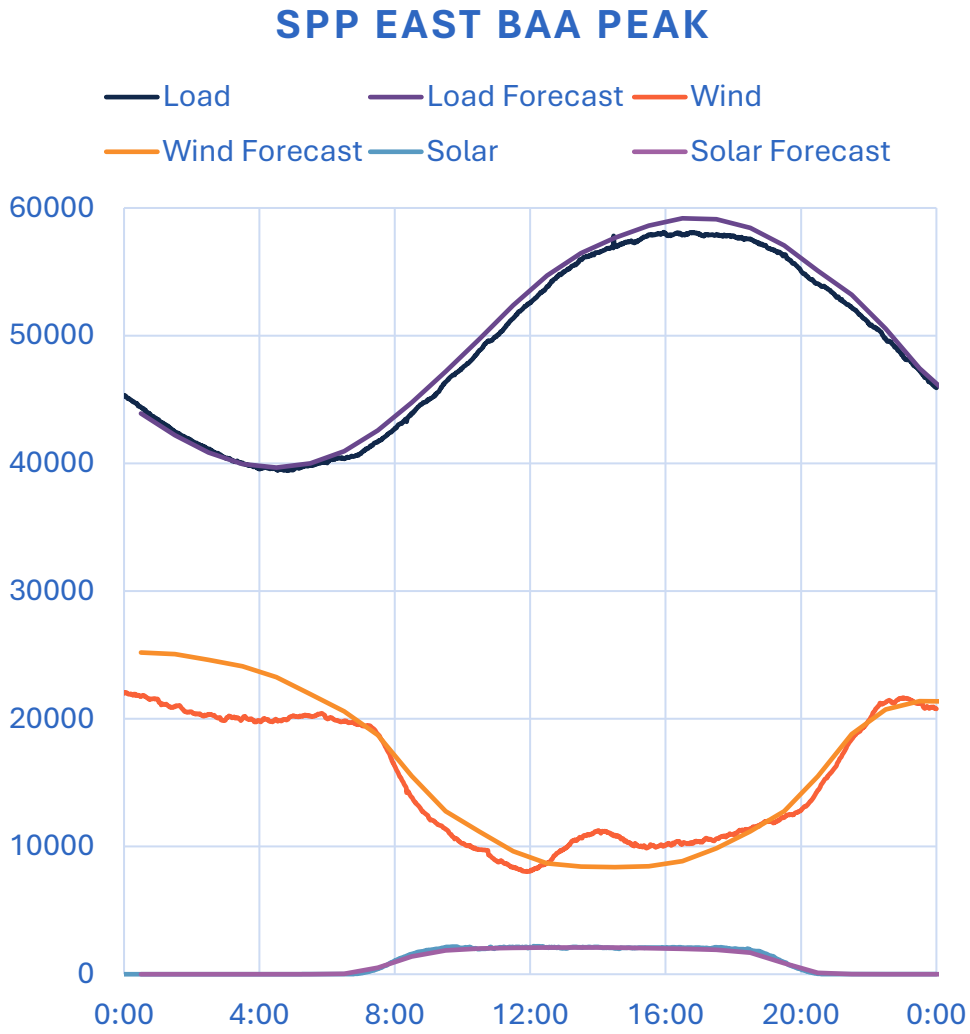
SPP
Powering Progress

EAST BAA

Setting New Peak

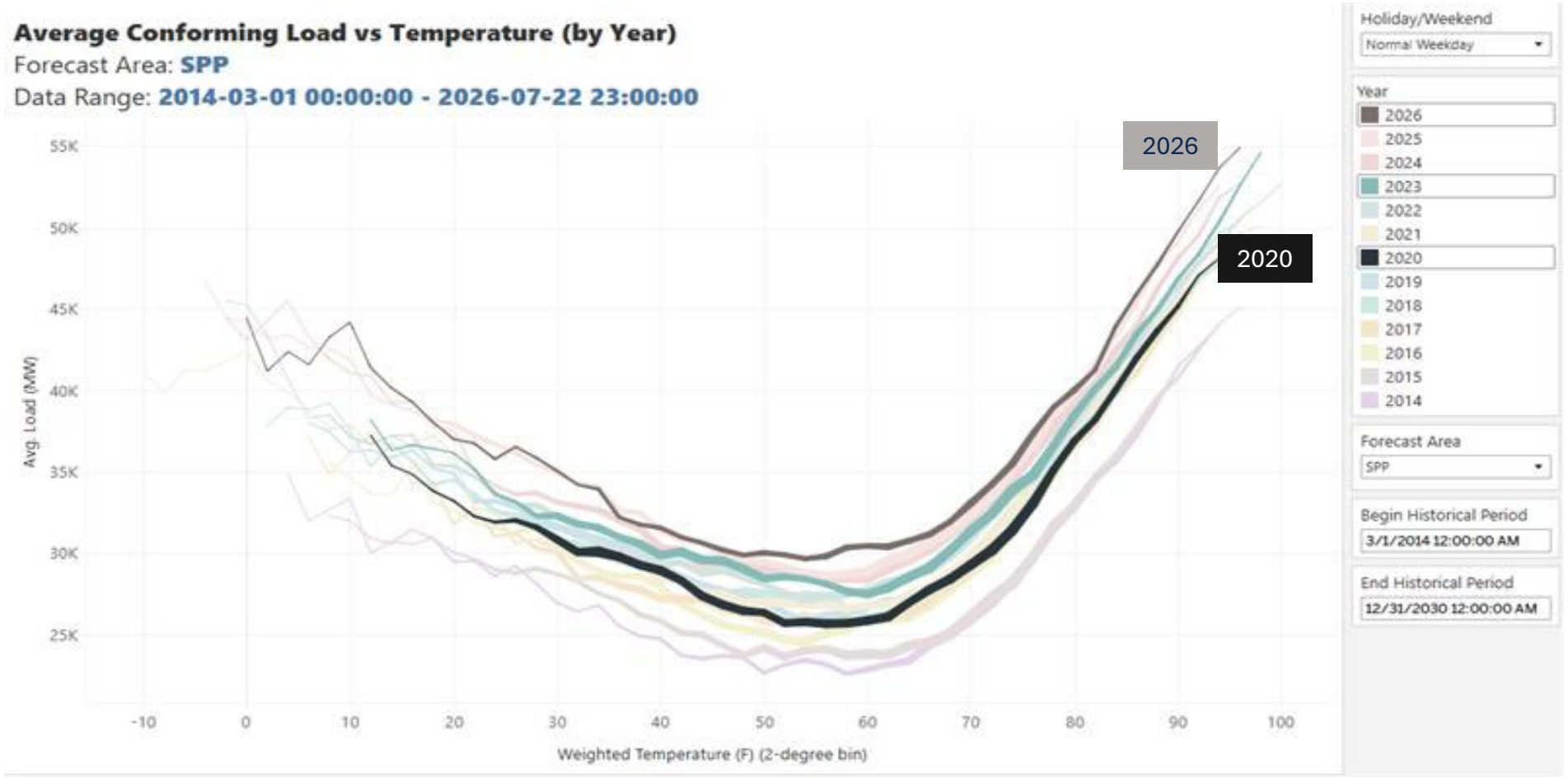
- New Peak Demand: 58,127 MW (7/27/2026)
  - 56,926 MW (07/26/2026)
  - 56,785 MW (07/20/2026)
- Previous Peak Demand: 56,184 MW (8/21/2023)
- VER Production at Peak: ~12.3 GW
- Imports at Peak: ~1.3 GW
- Wind output was above forecast through afternoon hours

- **SPP issued a Resource Advisory for its East BAA effective Saturday, July 25 at 12 p.m. through Thursday, July 30 at 7 p.m.**
- **Long-lead generation and reliability status resources committed**



An Eye on Load Growth

Load growth is showing up in the trends: At comparable temperatures, total system load is higher than prior years



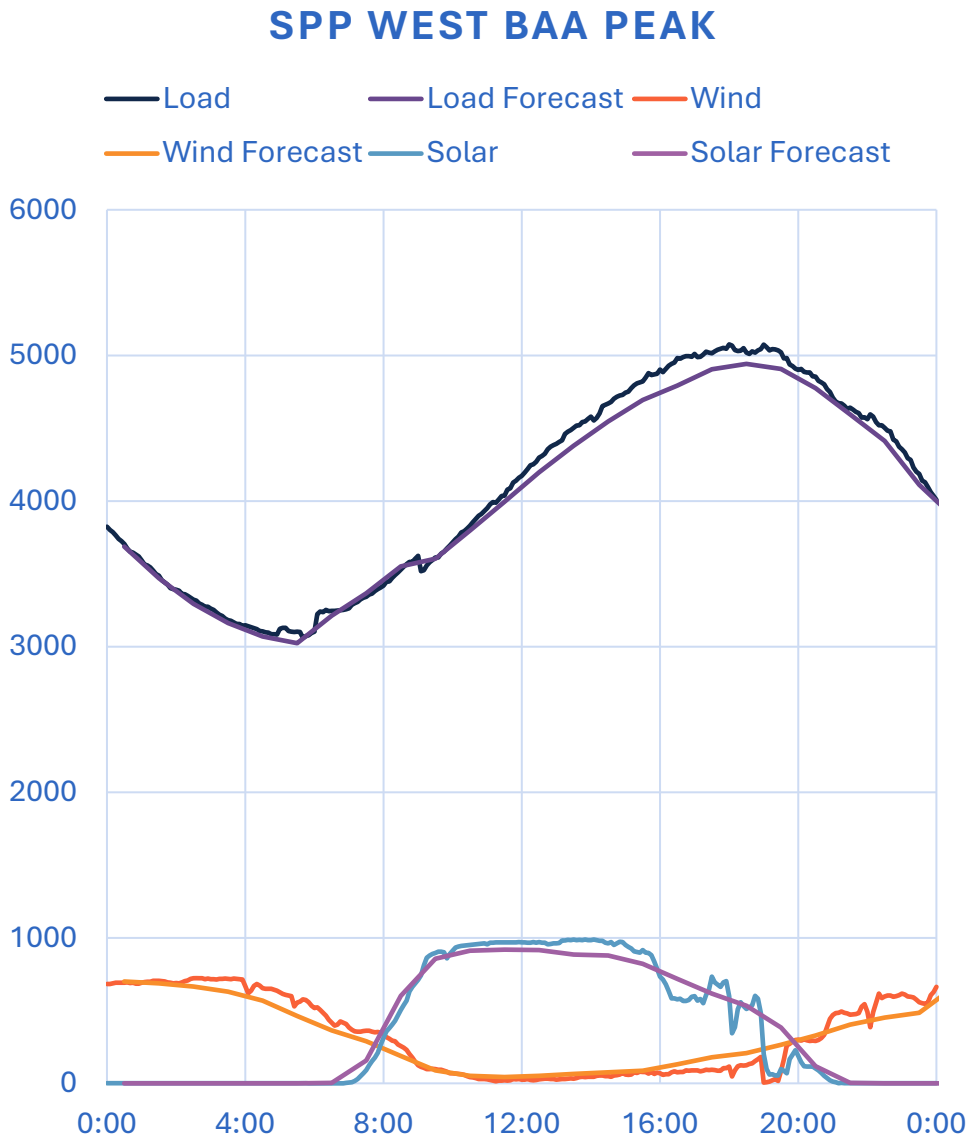
SPP
Powering Progress

WEST BAA

Setting New Peak

- New Peak Demand: 5,121MW (07/20/2026)
- VER Production at Peak: ~193MW
  - Solar: 187MW
  - Wind: 6MW
- Imports at the Peak: ~1200MW

- **SPP issued a Resource Advisory for its West BAA effective July 16, later escalating to Conservative Operations effective July 20 – August 1.**
- **Long-lead generation and reliability status resources committed**



July 15–20, 2026 – Event Overview

5 days

From risk assessment on 7/15 to emergency on 7/20

5,121 MW

Instantaneous load peaked at 19:00, and was above forecasts

EEA3

highest level reached, declared 17:09

97th–99th

percentile where the realized error landed

Takeaways

The assessment

Risk at the 7/20–21 evening peak was flagged on 7/17.

Lead time is a constraint

Long lead start time forced a commitment call 2 days prior.

What drove us to the emergency conditions

A 400 MW resource tripped, at 15:53, with the evening peak ramping in and solar drop extending the high net loads.

SWPW – West BAA Event Timeline

July 15–20, 2026 – Assessment Period and Operating Day

Before the operating day

07/15 · Resource Advisory declared

Declared due to high load, VER and outage uncertainty. It was extended to include 07/20 Operating Day on 07/18.

07/17 Long-lead resource commitment

Risk was assessed and determined that long-lead action were needed, including on Craig 1, to mitigate the exposure.

07/19 · Conservative Ops declared

Escalation for 07/20 operating day due to high persistent risk of high load, VER and outage uncertainty.

Operating day – July 20

15:53 — **Resource trips – additional risk materializes**
~200 MW output, ~427 MW capacity

Recovery Period — **Contingency Reserves Obligation (CRO) depleted**
CRO at 0 during recovery; reserve recovery at risk

16:35 — **EEA1 declared**
Determined that reserve recovery is at risk. Non-firm exports curtailed.

17:09 — **EEA3 declared**
Reserve Obligation 283 MW vs 111 MW available; Short reserves

18:00 / 18:45 — **EEA2, then EEA1**
Strong imports showed up; near ~2GW of imports

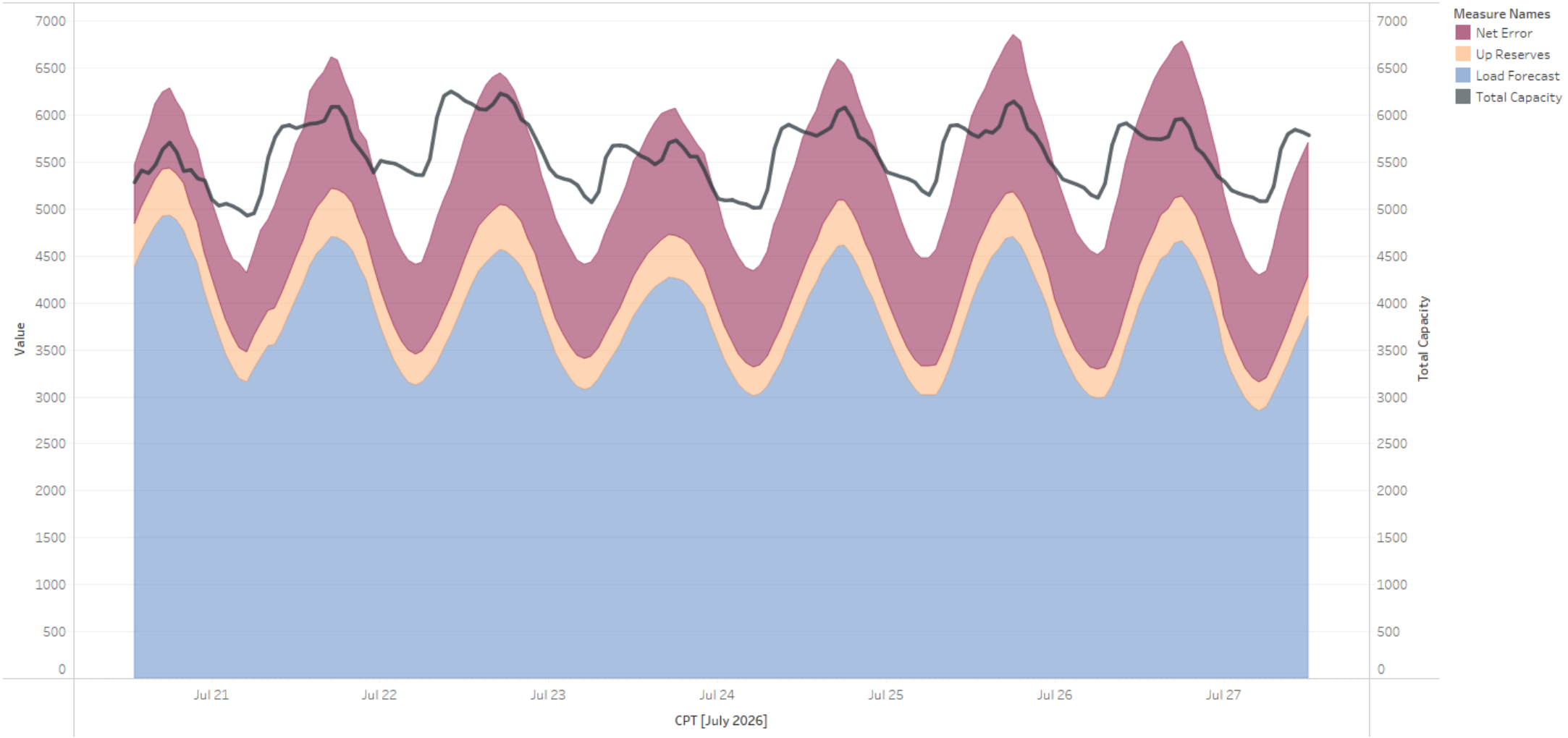
19:02 — **Transmission challenge – SW Colorado**
Concurrent congestion likely caused by the large imports , managed by RC.

21:35 — **EEA0 declared**
CRO 257 MW; 781 MW rampable capacity available

7/20/2026 12:00 **with** Import considerations

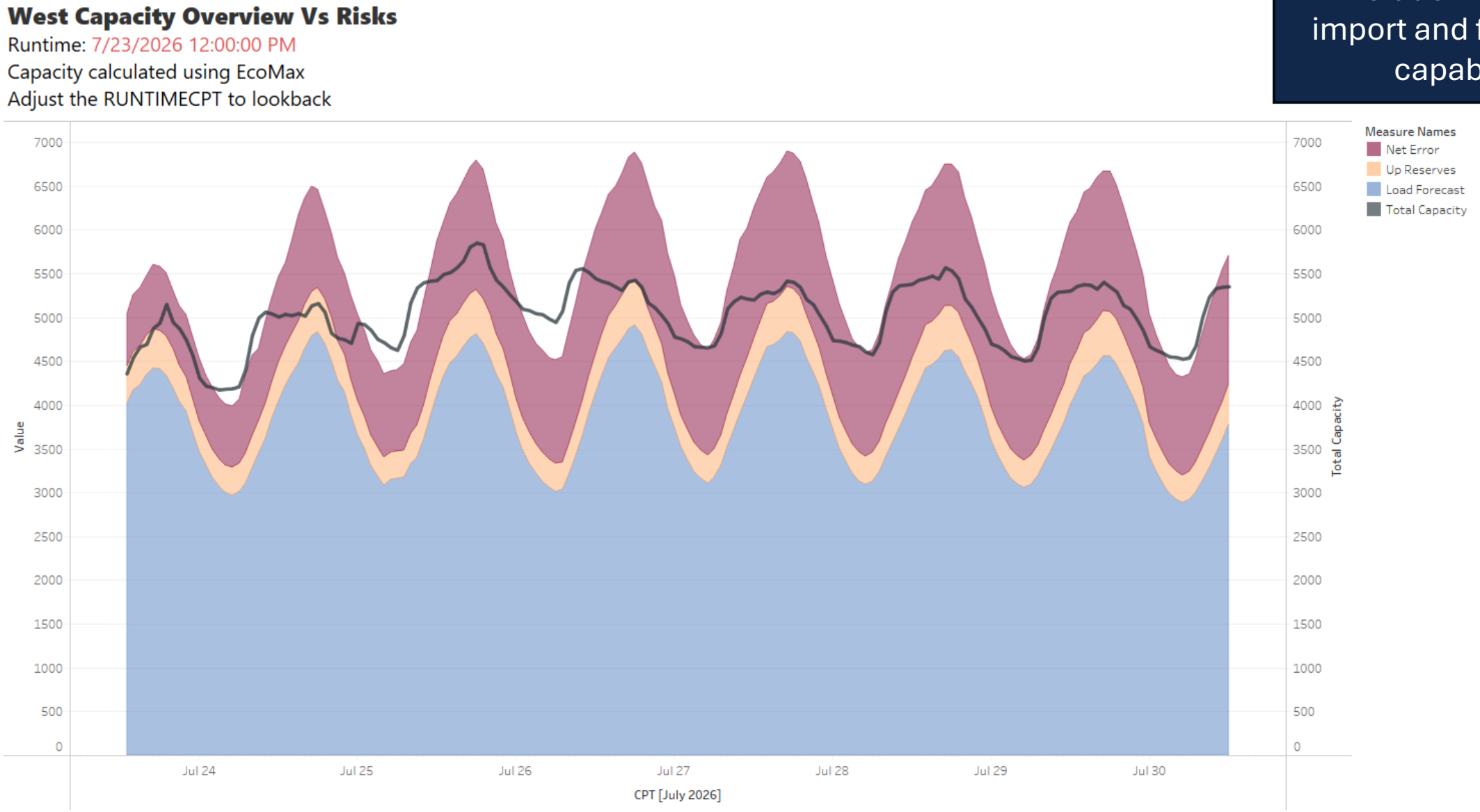
Import assumptions include MDRA AC import and full DC tie capability

West Capacity Overview Vs Risks
Runtime: 7/20/2026 12:00:00 PM
Capacity calculated using EcoMax
Adjust the RUNTIMECPT to lookback



7/23/2026 12:00 **with** Import considerations

Import assumptions include MDRA AC import and full DC tie capability



July 24, 2026 — SWPW West BAA Energy Emergency

Large import curtailment/adjustments triggered Emergency conditions in the SWPW BAA

EEA2	2h 42m	~750 MW	200 MW
Highest level reached	EEA1 to EEA0 (2h 37m in EEA2)	Imports curtailed/adjusted lower	Emergency assistance from PSCO

19:30 — **Large NSI adjustment effective top of the hour**
This was largely triggered by CAISO market adjustments

19:59 — **EEA1 declared**
29 minutes after the NSI adjustment took effect

20:04 — **EEA2 declared**
Escalated five minutes after EEA1

20:13 — **Emergency assistance received (200MW)**
100MW initially, additional 100MW next hour

20:46 — **Demand-side management requested**
Interruptible load called on

21:37 — **Interruptibles allowed to restore**
Recovering any load that was interrupted

22:26 — **Termination of emergency assistance requested**
PSCO support no longer needed

22:41 — **EEA0 declared**
Event terminated, 2h 42m after EEA1

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4-06
Exhibit A, DOE Order No. 26-202-37

Southwest Power Pool, Inc.

Order No. 202-26-37

Exhibit A

Resource Name and Location	Owner/Operator	Fuel Type	Summer Rating	Restriction (e.g., SOx, NOx, Hg, Waste Water)
CSU.SOUTHPLANT_AU1	Colorado Springs Utilities	Natural Gas	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
		Fuel Oil	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
CSU.SOUTHPLANT_AU2	Colorado Springs Utilities	Natural Gas	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
		Fuel Oil	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
CSU.SOUTHPLANT_AU3	Colorado Springs Utilities	Natural Gas	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
		Fuel Oil	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
CSU.SOUTHPLANT_AU4	Colorado Springs Utilities	Natural Gas	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
		Fuel Oil	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
CSU.SOUTHPLANT_AU5	Colorado Springs Utilities	Natural Gas	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
		Fuel Oil	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
CSU.SOUTHPLANT_AU6	Colorado Springs Utilities	Natural Gas	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
		Fuel Oil	24.83	PM, SO2, NOx, VOC, CO, fuel throughput
CSU.RD_NIXON_2	Colorado Springs Utilities	Natural Gas	28	PM, VOC, SO2, NOx, CO, Fuel throughput, unit run hours
CSU.RD_NIXON_3	Colorado Springs Utilities	Natural Gas	28	PM, VOC, SO2, NOx, CO, Fuel throughput, unit run hours
Rawhide Energy Station CT-A	PRPA	Natural Gas	63.5	NOx, CO
Rawhide Energy Station CT-B	PRPA	Natural Gas	63.5	NOx, CO
Rawhide Energy Station CT-C	PRPA	Natural Gas	63.5	NOx, CO
Rawhide Energy Station CT-D	PRPA	Natural Gas	63.5	NOx
Rawhide Energy Station CT-F	PRPA	Natural Gas	126.8	NOx
Rawhide Energy Station Unit 1	PRPA	Coal (Oil for startup fuel)	280	Opacity, SO2, CO, NOx, Hg
Burlington 1	Tri-State	Fuel Oil - Simple Cycle	50	Opacity
Burlington 2	Tri-State	Fuel Oil - Simple Cycle	50	Opacity
Craig 1	Tri-State	Coal	427	
Craig 2	Tri-State	Coal	410	PM, SO2, NOx, Opacity, Hg
Craig 3	Tri-State	Coal	448	PM, PM10, SO2, NOx, CO, Opacity, Hg
JM Shafer GT-A	Tri-State	Natural Gas - Combined Cycle	36	SO2, NOx, CO, VOC, (PM/PM10, fuel use: Annual), Wastewater discharge effluent limits

Resource Name and Location	Owner/Operator	Fuel Type	Summer Rating	Restriction (e.g., SOx, NOx, Hg, Waste Water)
JM Shafer GT-B	Tri-State	Natural Gas - Combined Cycle	36	SO2, NOx, CO, VOC, (PM/PM10, fuel use: Annual), Wastewater discharge effluent limits
JM Shafer GT-C	Tri-State	Natural Gas - Combined Cycle	36	SO2, NOx, CO, VOC, (PM/PM10, fuel use: Annual), Wastewater discharge effluent limits
JM Shafer GT-D	Tri-State	Natural Gas - Combined Cycle	36	SO2, NOx, CO, VOC, (PM/PM10, fuel use: Annual), Wastewater discharge effluent limits
JM Shafer GT-E	Tri-State	Natural Gas - Combined Cycle	36	SO2, NOx, CO, VOC, (PM/PM10, fuel use: Annual), Wastewater discharge effluent limits
JM Shafer ST-A	Tri-State	Natural Gas - Combined Cycle	52	Duct burners included with unit emissions.
JM Shafer ST-B	Tri-State	Natural Gas - Combined Cycle	52	Duct burners included with unit emissions.
Knutson 1	Tri-State	Natural Gas or Fuel Oil - Simple Cycle	65	SO2, NOx, CO, opacity (PM/PM10, VOC, fuel use: Annual)
Knutson 2	Tri-State	Natural Gas or Fuel Oil - Simple Cycle	65	SO2, NOx, CO, opacity (PM/PM10, VOC, fuel use: Annual)
Limon 1	Tri-State	Natural Gas or Fuel Oil - Simple Cycle	65	SO2, NOx, CO, opacity (PM/PM10, VOC, fuel use: Annual)
Limon 2	Tri-State	Natural Gas or Fuel Oil - Simple Cycle	65	SO2, NOx, CO, opacity (PM/PM10, VOC, fuel use: Annual)
LRS 2	Tri-State	Coal	570	
LRS 3	Tri-State	Coal	570	

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4-07
NERC EOP-011-4

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-4**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed plan(s) to mitigate operating Emergencies and that those plans are implemented and coordinated within the Reliability Coordinator Area as specified within the requirements.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

   4.1.4 Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.5 UFLS-Only Distribution Provider identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

   4.1.6 Transmission Owner identified in the Transmission Operator's Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area

5. **Effective Date:** See Implementation Plan for Project 2021-07. As provided therein, each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner that receives notification from the Transmission Operator that it is required to assist in the mitigation of operating Emergencies in the Transmission Operator Area under Requirement R7 shall become compliant with Requirement R8 within 30 calendar months of the notification.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Operator-controlled manual Load shed, undervoltage load shed (UVLS), or underfrequency load shed (UFLS) during an Emergency that accounts for each of the following:

1.2.5.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

1.2.5.2. Provisions to minimize the overlap of circuits that are designated for manual Load shed, UVLS, or UFLS and circuits that serve designated critical loads which are essential to the reliability of the BES;

1.2.5.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

1.2.5.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual Load shed to situations where warranted by system conditions;

1.2.5.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity; and

1.2.6. Provisions to determine reliability impacts of:

1.2.6.1. Cold weather conditions; and

1.2.6.2. Extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has

been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. Capability and availability;

2.2.3.2. Fuel supply and inventory concerns;

2.2.3.3. Fuel switching capabilities; and

2.2.3.4. Environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load, and demand response;

2.2.8. Provisions for excluding critical natural gas infrastructure loads which are essential to the reliability of the BES, as defined by the Applicable Entity, as Interruptible Load, curtailable Load, and demand response during extreme cold weather periods within each Balancing Authority Area;

2.2.9. Provisions for Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding in accordance with Requirement R1 Part 1.2.5; and

2.2.10. Provisions to determine reliability impacts of:

2.2.10.1. Cold weather conditions; and

2.2.10.2. Extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator;

evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated emails or other correspondences that it reviewed, Transmission Operator and Balancing Authority Operating Plans, within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator

communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

R7. Each Transmission Operator shall annually identify and notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning, Long-term Planning]*

M7. Each Transmission Operator will have documentation, such as dated emails or other correspondences that it identified and notified Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners annually in accordance with Requirement R7.

R8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area shall develop, maintain, and implement a Load shedding plan. The Load shedding plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

8.1. Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding during an Emergency that accounts for each of the following:

8.1.1. Provisions for manual Load shedding capable of being implemented in a timeframe adequate for mitigating the Emergency;

8.1.2. Provisions to minimize the overlap of circuits that are designated for manual, undervoltage, or underfrequency Load shed and circuits that serve designated critical loads which are essential to the reliability of the BES;

8.1.3. Provisions to minimize the overlap of circuits that are designated for manual Load shed and circuits that are utilized for UFLS or UVLS;

8.1.4. Provisions for limiting the utilization of UFLS or UVLS circuits for manual

Load shed to situations where warranted by system conditions; and

8.1.5. Provisions for the identification and prioritization of designated critical natural gas infrastructure loads which are essential to the reliability of the BES as defined by the Applicable Entity.

8.2. Provisions to provide the Load shedding plan to the Transmission Operator for review.

M8. Each Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner notified by a Transmission Operator per R7 to assist with the mitigation of operating Emergencies in its Transmission Operator Area will have a dated Load shedding plan(s) developed in accordance with Requirement R8 and evidence that the Load shedding plan(s) was provided to its Transmission Operator; evidence such as a review or revision history to indicate that the Load shedding plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Load shedding plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R8.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with the mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6.
- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R7.
- The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner shall retain the current Load shedding plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R8.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator- reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area, but failed to implement it.
R2	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area, but failed to implement it.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	N/A	N/A	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk, but failed to notify the Balancing Authority or Transmission Operator.
R4	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				Alert.
R7	N/A	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities more than one, but fewer than 30 days late.	The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one or more of those entities 30 days or more, but fewer than 60 days late.	The Transmission Operator did not identify or notify Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding. OR The Transmission Operator identified on an annual basis the Distribution Providers, UFLS-Only Distribution Providers and Transmission Owners, that are required to assist with the mitigation of operating Emergencies in its Transmission Operator Area through Operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding, but notified one

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
				OR more of those entities 60 days or more late.
R8	N/A	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to maintain it in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to provide it to its Transmission Operator in accordance with Requirement R8.	The applicable Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner failed to develop a Load shedding plan(s) in accordance with Requirement R8. OR The Distribution Provider, UFLS-Only Distribution Provider, and Transmission Owner developed a Load shedding plan(s), but failed to implement it in accordance with Requirement R8.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by the NERC Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.
1	November 19, 2015	FERC approved EOP-011-1. Docket Nos. RM15-7-000, RM15-12-000, and RM15-13-000. Order No. 818	
2	June 11,2021	Adopted by the NERC Board of Trustees	Revised under Project 2019-06
2	August 24,2021	FERC approved EOP-011-2. Docket Number RD21-5-000	
3	October 26, 2022	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
3	February 16, 2023	FERC approved EOP-011-3. *N. Am. Elec. Reliability Corp.*, 182 FERC 61,094	
4	October 23, 2023	Adopted by the NERC Board of Trustees	Revised under Project 2021-07
4	February 15, 2024	FERC Order issued approving EOP-011-4. Docket No. RD24-1-000	

Attachment 1-EOP-011-4
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use. Circumstances:**

   - The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
   - Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect. Circumstances:**

   - The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
   - An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress. Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre- Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

3.4.2 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4-08
Order No. 202-26-36

Department of Energy
Washington, DC 20585

Southwest Power Pool, Inc. Order No. 202-26-36
Regarding Specified and Backup Generation Resources

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) Organization Act,[2] and for the reasons set forth below, I hereby determine that a statutory emergency exists in the West Balancing Authority Area (BAA) of the Southwest Power Pool, Inc. (SPP) Region,[3] due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation and transmission of electric energy, and other causes. I direct SPP and backup generation resources defined below to comply with this Order.[4] SPP is authorized to call upon its Transmission Owners to implement this Order as needed. Issuance of this Order will meet the emergency and serve the public interest.

EMERGENCY SITUATION

On July 20, 2026, SPP issued Energy Emergency Alerts (EEA), including an EEA Level 3 for its West BAA and subsequently issued an EEA Level 2. Based on discussions with SPP leadership, SPP verbally requested an order to allow Specified Resources to exceed their Operating Limits as necessary to ensure reliability during the limited timeframe notwithstanding any applicable environmental limitations under federal, state, or local law or regulation.

SPP also requested authority to unlock and deploy backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk-power system) at data centers (including, but not limited to, hyperscaler facilities), and at other large load industrial and commercial customer sites as another tool to mitigate any undue risk to the bulk-power system. SPP expects employment of this backup generation will reduce stress on the grid and permit orderly, safe, and secure operations during the hot weather conditions and other causes, consistent

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] SPP serves as the Reliability Coordinator and Balancing Authority for its region and is, therefore, responsible for overseeing the dispatch of generation to meet system demand at all times within the limits of the transmission system.

[4] All geographical or electrical areas of the Bulk-Power System are under the oversight of one and only one Reliability Coordinator. *See North American Electric Reliability Corp.* (NERC) Rules of Procedure § 501.1.4.1. All Balancing Authorities are under the responsibility of one and only one Reliability Coordinator. *See id.* § 501.1.4.2. All load and generation is under the responsibility and control of one and only one Balancing Authority. *See id.* § 501.1.4.4.

with my letter issued on January 22, 2026, regarding the deployment of backup generation during emergency conditions.

REQUEST FOR ORDER

SPP requests that the Secretary issue an order effective upon issuance on July 20, 2026, through 11:59 PM EDT on July 21, 2026, the expected period to address stress on the grid caused by hot weather and other causes, consistent with the discussion herein.

DESCRIPTION OF MITIGATION MEASURES

In anticipation of this emergency, SPP has issued EEA Levels 3 and 2 on July 20, 2026.

APPLICATION OF EOP-011-4

Section 215 of the FPA[5] established a framework for development and implementation of mandatory and enforceable Reliability Standards that apply to Bulk-Power System owners, operators, and users, such as Reliability Coordinators and Balancing Authorities. NERC certifies Reliability Coordinators and Balancing Authorities pursuant to an Organization Certification program set forth in its Rules of Procedure,[6] because of the significant roles these two functional entity category types have in ensuring bulk-power system reliability. A Reliability Coordinator is defined as

> the entity that is the highest level of authority who is responsible for the Reliable Operation of the [Bulk Electric System (BES)], has the Wide Area view of the BES, and has the operating tools, processes, and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.[7]

A Balancing Authority is "the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing

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[5] 16 U.S.C. § 824o.

[6] *See generally* NERC Rules of Procedure, https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/nerc-rop-with-appendices-eff-20250520_signed.pdf; *see also id.* § 500.

[7] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2. Other capitalized terms in this definition also are defined in the NERC Rules of Procedure at Appendix 2.

Authority Area, and supports Interconnection frequency in real time."[8]

Because of the criticality of their respective roles, Reliability Coordinators and Balancing Authorities are subject to NERC's Organization Certification Program to ensure that they have "the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s)."[9]

NERC Reliability Standard EOP-011-4 addresses Emergency Operations. Requirement 2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area." Balancing Authorities are responsible for requesting that their respective Reliability Coordinators issue an EEA in accordance with Requirement 2 and Attachment 1 to Reliability Standard EOP-011-4. Among other things, Requirement 2.2.4 of this reliability standard authorizes Balancing Authorities to make "[p]ublic appeals for voluntary Load reductions." Moreover, section 2.2.9 requires Balancing Authority Operating plans to include provisions for "Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or underfrequency Load shedding," and section 2.2.10 requires such plans to determine reliability impacts of "extreme weather conditions."

According to Requirement 5,

> Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

According to Requirement 6,

> Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1.

Attachment 1 provides,

> Initiation by Reliability Coordinator. An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

***

[8] NERC Rules of Procedure app. 5B; *see also id.* app. 2.
[9] NERC Rules of Procedure § 501.

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary and need not proceed through the alerts sequentially.

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Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is online.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

***

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

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," 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."[10] This statutory language constitutes a specific grant of authority to the Secretary to authorize the operation of generation, delivery, and transmission resources that the Secretary has determined will best meet an emergency.

Given the emergency caused by the expected load stress, the responsibility of SPP to ensure maximum reliability of its system, and the ability of SPP to identify and

[10] 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).

dispatch generation resources and make available backup generation resources necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary and operation of backup generation resources may be necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the expected load stress, shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

Consistent with the anticipated circumstances, this Order is limited to the period of time that the significant hot weather event is expected to impact the SPP region. Because the additional generation or availability of backup generation may result in conflict with environmental standards and requirements, I am authorizing only the necessary additional resources on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by SPP for reliability purposes. Consistent with FPA section 202(c)(3) and DOE's February 4, 2026, Order Granting Rehearing, the emissions from, hours of operation of, and fuel burned by Specified Resources and backup generation resources while this Order is in effect will not be counted toward applicable rolling average-based limitations.[11]

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

A. In the event that SPP determines that generation from the Specified Resources is necessary to meet the electricity demand that SPP anticipates in its service territory, I direct SPP to dispatch such unit or units and to order their operation only as needed to maintain reliability. Specified Resources are those generating units set forth in Exhibit A, subject to updates directed here and as described in paragraph G, which DOE shall post on www.energy.gov.

B. From July 20, 2026, SPP, is authorized to direct backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system), to operate as a last resort before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load

[11] *See* 16 U.S.C. § 824a(c)(3).

interruption) or during an EEA 3.[12] SPP is authorized to call upon its Transmission Owners to implement this Order as needed.

C. This Order requires the operation of the backup generation resources described in paragraph B. Following the conclusion of the EEA conditions described in paragraph B, sufficient time for orderly ramp down is permitted, consistent with industry practices.

D. This order is not applicable to any backup generation resource serving a critical reliability or backup need, including those at defense, homeland security, first responder, air traffic control, hospital facilities, 911 call centers, water treatment or wastewater facilities, natural gas pipeline facilities, natural gas gathering facilities, or other similar facilities.

E. To minimize adverse environmental impacts, this Order limits operation of dispatched Specified Resources and backup generation resources to the times and within the parameters determined by SPP for maintaining grid reliability and to the maximum extent practicable is consistent with any applicable environmental law. SPP shall provide a daily notification to DOE (via AskCR@hq.doe.gov) reporting each Specified Resource and backup generation resource that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

F. All operations of the Specified Resource and backup generation resources must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent practicable while operating consistent with the emergency conditions.

G. In the event that SPP identifies additional generation units that it deems necessary to maintain the reliability of the power grid, SPP shall provide prompt written notice to DOE at AskCR@hq.doe.gov with the name and location of those units that SPP has identified. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to DOE updating Exhibit A, and SPP may dispatch such additional generation units, provided that if the DOE notifies SPP that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from DOE.

H. SPP shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by DOE from time to time.

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[12] *See* NERC Reliability Standard EOP-011-4, Attachment 1, at 3.1 ("The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.").

I. Each party affected by this order is directed to file with the Federal Energy Regulatory Commission any tariff, tariff revisions or waivers necessary to effectuate this Order, as applicable. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

J. This Order shall not preclude the need for the Specified Resources and backup generation resources to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

K. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, any backup generation resource subject to this Order shall not be considered a capacity resource.

L. This Order shall be effective upon issuance on July 20, 2026, at 11:59 PM EDT and shall expire at 11:59 PM EDT on July 21, 2026, with the exception of the reporting requirements in paragraph E and applicable compliance obligations in paragraph F. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. on this 20th day of July 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

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 4-09
Order No. 202-26-37

Department of Energy
Washington, DC 20585

Southwest Power Pool, Inc. Order No. 202-26-37
Regarding Specified and Backup Generation Resources

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) Organization Act,[2] and for the reasons set forth below, I hereby determine that a statutory emergency exists in the West Balancing Authority Area (BAA) and East BAA of the Southwest Power Pool, Inc. (SPP) Region,[3] due to a sudden increase in demand, a shortage of electric energy, a shortage of facilities for the generation and transmission of electric energy, and other causes. I direct SPP and backup generation resources defined below to comply with this Order.[4] SPP is authorized to call upon its Transmission Owners to implement this Order as needed. Issuance of this Order will meet the emergency and serve the public interest.

EMERGENCY SITUATION

On July 19, 2026, SPP issued a Conservative Operations Advisory for the West BAA due to "the potential of high peak loads, potential low output from wind and other variable energy resources (*also known as low VER forecast) leading into peak hours, and possible increase in resource outages."[5] SPP remained under a Conservative Operations Advisory on July 20, 2026, then extended the Conservative Operations Advisory on July 21 and again July 22, July 23, and July 24, due to "potential forecast uncertainty including higher than normal loads and outages, seasonally hot temperatures, and the potential for lower wind and solar."[6] In addition, on July 20, 2026, DOE issued DOE Order No. 202-26-36 pursuant to FPA section 202(c) to SPP effective July 20 through July 21, 2026, authorizing SPP to dispatch Specified Resources and to order their operations as needed to maintain reliability. The order also authorized SPP to direct

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] SPP serves as the Reliability Coordinator and Balancing Authority for its region and is, therefore, responsible for overseeing the dispatch of generation to meet system demand at all times within the limits of the transmission system.
[4] All geographical or electrical areas of the Bulk-Power System are under the oversight of one and only one Reliability Coordinator. *See North American Electric Reliability Corp.* (NERC) Rules of Procedure § 501.1.4.1. All Balancing Authorities are under the responsibility of one and only one Reliability Coordinator. *See id.* § 501.1.4.2. All load and generation is under the responsibility and control of one and only one Balancing Authority. *See id.* § 501.1.4.4.
[5] Southwest Power Pool Inc., *Current Grid Conditions, https://www.spp.org/grid-conditions.*
[6] *Id.*

backup generation resources to operate as a last resort before declaring an Energy Emergency Alert (EEA) 3 or during an EEA 3.[7]

On July 18 and July 24, 2026, SPP issued a Resource Advisory for the East BAA due to "forecasts of potential high peak loads, potential [low VER forecast] leading into peak hours, and possible increase in resource outages."[8] The Resource Advisory for the East BAA is effective through July 30, 2026 at 7:00 p.m. Central Daylight Time (CDT).

Based on discussions with SPP leadership, SPP anticipates hot weather conditions continuing through August 3, 2026, and thus verbally requested an order to allow specified generation units (Specified Resources) to exceed their Operating Limits as necessary to ensure reliability during the limited timeframe notwithstanding any applicable environmental limitations under federal, state, or local law or regulation.

SPP also requested authority to unlock and deploy backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk-power system) at data centers (including, but not limited to, hyperscaler facilities), and at other large load industrial and commercial customer sites as another tool to mitigate any undue risk to the bulk-power system. SPP expects employment of these backup generation resources will reduce stress on the grid and permit orderly, safe, and secure operations during the hot weather conditions and other causes, consistent with my letter issued on January 22, 2026, regarding the deployment of backup generation resources during emergency conditions.

REQUEST FOR ORDER

SPP requests that the Secretary issue an order effective upon issuance on July 26, 2026, through 11:59 PM CDT on August 3, 2026, the expected period to address stress on the grid caused by hot weather and other causes, consistent with the discussion herein.

DESCRIPTION OF MITIGATION MEASURES

In anticipation of this emergency, to date, SPP has issued Conservative Operations Advisory for the West BAA through August 1, 2026, and a Resource Advisory for the East BAA is effective through July 30, 2026.

APPLICATION OF EOP-011-4

Section 215 of the FPA[9] established a framework for development and implementation of mandatory and enforceable Reliability Standards that apply to Bulk-

[7] *Sw. Power Pool, Inc.*, Order No. 202-26-36 (July 20, 2026).
[8] *Southwest Power Pool, supra note 5.*
[9] 16 U.S.C. § 824o.

Power System owners, operators, and users, such as Reliability Coordinators and Balancing Authorities. NERC certifies Reliability Coordinators and Balancing Authorities pursuant to an Organization Certification program set forth in its Rules of Procedure,[10] because of the significant roles these two functional entity category types have in ensuring bulk-power system reliability. A Reliability Coordinator is defined as

> the entity that is the highest level of authority who is responsible for the Reliable Operation of the [Bulk Electric System (BES)], has the Wide Area view of the BES, and has the operating tools, processes, and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.[11]

A Balancing Authority is "the responsible entity that integrates resource plans ahead of time, maintains Load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time."[12]

Because of the criticality of their respective roles, Reliability Coordinators and Balancing Authorities are subject to NERC's Organization Certification Program to ensure that they have "the tools, processes, training, and procedures to demonstrate their ability to meet the Requirements/sub-Requirements of all of the Reliability Standards applicable to the function(s)."[13]

NERC Reliability Standard EOP-011-4 addresses Emergency Operations. Requirement 2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area." Balancing Authorities are responsible for requesting that their respective Reliability Coordinators issue an EEA in accordance with Requirement 2 and Attachment 1 to Reliability Standard EOP-011-4. Among other things, Requirement 2.2.4 of this reliability standard authorizes Balancing Authorities to make "[p]ublic appeals for voluntary Load reductions." Moreover, section 2.2.9 requires Balancing Authority Operating plans to include provisions for "Transmission Operators to implement operator-controlled manual Load shedding, undervoltage Load shedding, or

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[10] *See generally* NERC Rules of Procedure, https://www.nerc.com/globalassets/who-we-are/rules-of-procedure/nerc-rop-with-appendices-eff-20250520_signed.pdf; *see also id.* § 500.

[11] NERC Rules of Procedure, Appendix 5B; *see also id.* Appendix 2. Other capitalized terms in this definition also are defined in the NERC Rules of Procedure at Appendix 2.

[12] NERC Rules of Procedure app. 5B; *see also id.* app. 2.

[13] NERC Rules of Procedure § 501.

underfrequency Load shedding," and section 2.2.10 requires such plans to determine reliability impacts of "extreme weather conditions."

According to Requirement 5,

> Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

According to Requirement 6,

> Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1.

Attachment 1 provides,

> Initiation by Reliability Coordinator. An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
>
> ***
>
> To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.
>
> The Reliability Coordinator may declare whatever alert level is necessary and need not proceed through the alerts sequentially.
>
> ***
>
> Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:
>
> 2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is online.
>
> 2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.
>
> ***

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

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," 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."[14] This statutory language constitutes a specific grant of authority to the Secretary to authorize the operation of generation, delivery, and transmission resources that the Secretary has determined will best meet an emergency.

Given the emergency caused by the expected load stress, the responsibility of SPP to ensure maximum reliability of its system, and the ability of SPP to identify and dispatch generation resources and make available backup generation resources necessary to meet load requirements, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary and operation of backup generation resources may be necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on the expected load stress, shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes, and the potential loss of power to homes and local businesses in the areas that may be affected by curtailments or outages, presenting a risk to public health and safety.

Consistent with the anticipated circumstances, this Order is limited to the period of time that the significant hot weather event is expected to impact the SPP region. Because the additional generation or availability of backup generation resources may result in conflict with environmental standards and requirements, I am authorizing only the necessary additional resources on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. To minimize adverse environmental

[14] 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).

impacts, this Order limits operation of dispatched units to the times and within the parameters determined by SPP for reliability purposes. Consistent with FPA section 202(c)(3) and DOE's February 4, 2026, Order Granting Rehearing, the emissions from, hours of operation of, and fuel burned by Specified Resources and backup generation resources while this Order is in effect will not be counted toward applicable rolling average-based limitations.[15]

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

A. From July 26, 2026, in the event that SPP determines that generation from the Specified Resources is necessary to meet the electricity demand that SPP anticipates in its service territory, I direct SPP to dispatch such unit or units and to order their operation only as needed to maintain reliability. Specified Resources are those generating units that will be set forth in an Exhibit A, subject to updates directed here and as described in paragraph G, which DOE shall post on www.energy.gov.

B. From July 26, 2026, SPP, is authorized to direct backup generation resources (whether auxiliary, standby, directly-connected, battery storage or other, and whether synchronized or not to the bulk power system), to operate as a last resort before declaring an Energy Emergency Alert (EEA) 3 (i.e., before firm load interruption) or during an EEA 3.[16] SPP is authorized to call upon its Transmission Owners to implement this Order as needed.

C. This Order requires the operation of the backup generation resources described in paragraph B. Following the conclusion of the EEA conditions described in paragraph B, sufficient time for orderly ramp down is permitted, consistent with industry practices.

D. This order is not applicable to any backup generation resource serving a critical reliability or backup need, including those at defense, homeland security, first responder, air traffic control, hospital facilities, 911 call centers, water treatment or wastewater facilities, natural gas pipeline facilities, natural gas gathering facilities, or other similar facilities.

E. To minimize adverse environmental impacts, this Order limits operation of dispatched Specified Resources and backup generation resources to the times and within the parameters determined by SPP for maintaining grid reliability and to the maximum extent practicable is consistent with any applicable environmental law. SPP shall provide a daily notification to DOE (via AskCR@hq.doe.gov) reporting each Specified Resource and backup generation resource that has been

[15] *See* 16 U.S.C. § 824a(c)(3).

[16] *See* NERC Reliability Standard EOP-011-4, Attachment 1, at 3.1 ("The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.").

designated to use the allowance and operated in reliance on the allowances contained in this Order.

F. All operations of the Specified Resource and backup generation resources must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent practicable while operating consistent with the emergency conditions.

G. In the event that SPP identifies additional generation units that it deems necessary to maintain the reliability of the power grid, SPP shall provide prompt written notice to DOE at AskCR@hq.doe.gov with the name and location of those units that SPP has identified. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to DOE updating Exhibit A, and SPP may dispatch such additional generation units, provided that if the DOE notifies SPP that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from DOE.

H. SPP shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by DOE from time to time.

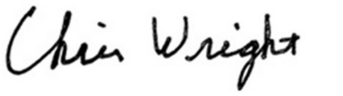
I. Each party affected by this order is directed to file with the Federal Energy Regulatory Commission any tariff, tariff revisions or waivers necessary to effectuate this Order, as applicable. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

J. This Order shall not preclude the need for the Specified Resources and backup generation resources to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

K. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, any backup generation resource subject to this Order shall not be considered a capacity resource.

L. This Order shall be effective upon issuance on July 26, 2026, at 12:22 PM CDT and shall expire at 11:59 PM CDT on August 3, 2026, with the exception of the reporting requirements in paragraph E and applicable compliance obligations in paragraph F. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. on this 26th day of July 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

Arizona Corporation Commission
Chair Nick Myers
Vice Chair Rachel Walden
Commissioner Lea Márquez Peterson
Commissioner Kevin Thompson
Commissioner René Lopez

Arkansas Public Service Commission
Chairman Doyle Webb
Commissioner Justin Tate
Commissioner Kate Anderson

Colorado Public Utilities Commission
Chairman Eric Blank
Commissioner Megan Gilman
Commissioner Tom Plant

Iowa Utilities Commission
Chair Sarah M. Martz
Commissioner Erik M. Helland
Commissioner Joshua J. Byrnes

Kansas Corporation Commission
Chairperson Andrew J. French
Commissioner Dwight D. Keen
Commissioner Annie Kuether

Louisiana Public Service Commission
Commissioner Eric Skrmetta
Commissioner Jean-Paul P. Coussan
Commissioner Davante Lewis
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Commissioner Foster L. Campbell

Minnesota Public Utilities Commission
Chair Katie Sieben
Vice-Chair Joseph K. Sullivan
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Commissioner Hwikwon Ham
Commissioner John Tuma

Missouri Public Service Commission
Chair Kayla Hahn
Commissioner Maida J. Coleman
Commissioner Glen Kolkmeyer
Commissioner John P. Mitchell

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Commissioner Tim Schram
Commissioner Eric Kamler
Commissioner Kevin Stocker

New Mexico Public Regulation Commission
Chair Patrick O'Connell
Commissioner Gabriel Aguilera
Commissioner Greg Nilbert

North Dakota Public Service Commission
Chair Randy Christmann
Commissioner Sheri Haugen-Hoffart
Commissioner Jill Kringstad

Oklahoma Corporation Commission
Chairman Kim David
Commissioner Brian Bingman
Commissioner Todd Hiett

South Dakota Public Utilities Commission
Chairman Chris Nelson
Vice Chairperson Kristie Fiegen
Commissioner Gary Hanson

Public Utility Commission of Texas
Chairman Thomas J. Gleeson
Commissioner Kathleen Jackson
Commissioner Courtney K. Hjaltman
Commissioner Morgan Johnson
Commissioner Patrick Rhode

Utah Public Service Commission
Chair Jerry Fenn
Commissioner David Clark
Commissioner John S. Harvey

Wyoming Public Service Commission
Chairman Mike Robinson
Deputy Chairman Chris Petrie
Commissioner Chris Bosswell