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 3-01
Department Order No. 202-25-14B

UNITED STATES OF AMERICA
Department of Energy
Washington, DC 20585

Tri-State Generation and Transmission Association, Platte River Power Authority, Salt River Project, PacifiCorp, Xcel Energy Inc., Western Area Power Administration – Rocky Mountain Region, and Southwest Power Pool Regarding Craig Station

Order No. 202-25-14B

ORDER ADDRESSING ARGUMENTS RAISED ON REHEARING

(Issued June 24, 2026)

1. On December 30, 2025, pursuant to section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE) Organization Act,[2] the Secretary of Energy (Secretary) issued an order determining that "an emergency exists within the Western Electricity Coordinating Council (WECC) Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes."[3] In the Emergency Order, the Secretary determined that "to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c), Craig Unit 1 shall be made available for operation."[4]

2. On January 26, 2026, the Public Service Company of Colorado (Public Service) filed a motion for leave to intervene. On January 28, 2026, requests for rehearing were filed by the State of Colorado (State) and by Public Interest Organizations (PIOs).[5] On

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] *Tri-State Generation & Transmission Ass'n*, DOE Order No. 202-25-14 (Dec. 30, 2025) (Emergency Order).

[4] *Id.* at 3.

[5] Sierra Club, GreenLatinos, Vote Solar, Public Citizen, and Environmental Defense Fund refer to themselves collectively as "Public Interest Organizations."

January 29, 2026, Tri-State Generation and Transmission Association (Tri-State) and Platte River Power Authority (Platte River) filed a request for clarification and rehearing.

3. On March 2, 2026, DOE issued a notice of denial of rehearing by operation of law and providing for further consideration.[6] However, as provided in sections 202(c) and 313(a) of the FPA,[7] DOE is modifying the discussion in the Emergency Order and continues to reach the same result in this Order, as discussed below.[8]

I. Background

4. Craig Station (Craig) is an electric generating facility in Craig, Colorado. Craig consists of three coal-fired generation units, Unit 1 (446.4 MW), Unit 2 (446.4 MW), and Unit 3 (534.8 MW), with a combined name plate capacity of 1427.6 MW. Unit 1 and Unit 2 are co-owned by Tri-State, Platte River, Salt River Project, PacifiCorp, and Xcel Energy (co-owners). Unit 3 is wholly owned by Tri-State. Unit 1 and Unit 2 began operations in 1980 and 1979, respectively. Unit 3 began operations in 1984. But for the Emergency Order, Unit 1 was scheduled to retire on December 31, 2025. Unit 2 and Unit 3 are slated to retire in 2028.[9]

5. In the Emergency Order, the Secretary determined that "an emergency exists within the [WECC] Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes," and that "[i]ssuance of this Order will meet the emergency and serve the public interest."[10] The Secretary therefore directed Tri-State and co-owners to "take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power

[6] *Tri-State Generation & Transmission Ass'n*, Notice of Denial, DOE Order No. 202-25-14A (Mar. 2, 2026).

[7] 16 U.S.C. §§ 824a(c), 825*l*(a). In the context of FPA section 202(c) orders, DOE interprets FPA section 313's references to "the Commission" to mean DOE. *See* 42 U.S.C. § 7151(b); *see also* 10 C.F.R. §§ 205.370 to 205.379 (2025).

[8] *See Allegheny Def. Project v. FERC*, 964 F.3d 1, 16–17 (D.C. Cir. 2020). DOE is not changing the outcome of the Emergency Order. *See Smith Lake Improvement & Stakeholders Ass'n v. FERC*, 809 F.3d 55, 56–57 (D.C. Cir. 2015).

[9] Emergency Order at 1.

[10] *Id*.

Administration (WAPA)—Rocky Mountain Region Western Area Colorado Missouri (WACM) [ ] or the Southwest Power Pool (SPP) West."[11]

6. The Emergency Order provided substantial support for the Secretary's emergency determination. In the Emergency Order, the Secretary reiterated that the North American Electric Reliability Corporation (NERC) 2024 Long-Term Reliability Assessment (2024 LTRA) found that in the WECC-Northwest assessment area,[12] "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio," and that "[f]ive [gigawatts] of baseload resource retirements are anticipated between 2024 and 2028," with energy needs to be replaced by solar, wind, and battery energy storage systems, "further increasing variability in the portfolio."[13] The Secretary further noted that the 2024 WECC Western Assessment of Resource Adequacy (2024 WARA) found that peak demand in WECC's Northwest-Central subregion is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034," while most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[14] The Emergency Order also observed that, according to the Energy Information Administration (EIA), since 2019, 571.3 MW of coal-fired generating capacity had retired in Colorado, and that approximately 3,700 MW of additional coal-fired generating capacity

[11] *Id.* at 3, Ordering Paragraph A.

[12] Tri-State and Platte River assert that the Emergency Order's reference to the WECC-Northwest assessment area is imprecise in light of NERC's subsequent revision of NERC's assessment boundaries. *See* Tri-State and Platte River Pet. at 28. However, the WECC-Northwest assessment area, as defined in the 2024 LTRA, upon which the Emergency Order relied, included Colorado and Craig within its geographic scope. The Secretary's emergency determination was thus directed at a region that encompassed the facilities and service territories at issue. NERC's reclassification does not alter the substance of the Secretary's emergency determination. Accordingly, this Order's references to the WECC-Northwest assessment area refer to the geographic region as delineated in the 2024 LTRA, which included Colorado. References to the WECC-Rocky Mountain assessment region, which likewise includes Colorado, refer to NERC's updated assessment boundaries.

[13] *Id.* at 1 (quoting NERC, *2024 Long-Term Reliability Assessment*, at 130, https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf (Dec. 2024, corrected July 11, 2025)).

[14] *Id.* at 2 (quoting WECC, *W. Assessment of Res. Adequacy 2024: Peak Demand by Subregion*, at 2, https://www.wecc.org/sites/default/files/documents/products/2024/WARA%202024%20Peak%20Demand%20by%20Subregion.pdf).

and 675.6 MW of natural gas-fired generating capacity in Colorado are scheduled to retire by 2029.[15]

7. As discussed further below, the Emergency Order also observed that, in 2025, President Donald Trump issued executive orders which underscored the severity of the current energy emergency in the United States.[16] In this respect, the Secretary noted DOE's July 2025 Resource Adequacy Report, which was prepared specifically in response to Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[17] The July 2025 Resource Adequacy Report stated that the United States' power grid will be "unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence [ ] innovation."[18]

8. In view of this evidence, the Secretary therefore determined that ensuring that Craig Unit 1 is available to operate is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). The need for the Order was further substantiated when the SPP ordered the Craig facility to operate. In April 2026, Craig Unit 1 generated over 67,600 MWh to the grid. The Secretary's expert determination was based on the fact that increasing electricity demand, coupled with accelerated retirements of generation facilities continuing in the near term as well as subsequent years would result in risk to public health and safety caused by the potential loss of power to homes and businesses in areas that may be affected by curtailments or outages. The Emergency Order was limited in duration to align with the emergency circumstances. In recognition of potential conflict with environmental standards and requirements, and consistent with FPA

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[15] *Id.* at 2.

[16] *Id.* at 2 (citing Exec. Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025), https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/; Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (declaring a national energy emergency), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[17] DOE, *Res. Adequacy Rep. Evaluating the Reliability & Sec. of the U.S. Elec. Grid* (July 2025) (Resource Adequacy Report), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf; *see also* Exec. Order No. 14262, § 3(b) (mandating the development of a uniform methodology for analyzing current and anticipated reserve margins across regions of the bulk power system regulated by the Federal Energy Regulatory Commission (FERC)).

[18] Emergency Order at 3 (quoting Resource Adequacy Report at 1).

section 202(c), the Secretary authorized only the necessary additional generation subject to specified conditions.[19]

II. Discussion

1. The Secretary's Authority to Determine the Existence of an "Emergency"

9. PIOs and Colorado State each raise similar arguments that the Emergency Order fails to meet the legal definition of an "emergency" within the meaning of FPA section 202(c).[20] PIOs and Colorado State similarly argue that, while FPA section 202(c) permits action in response to a "sudden increase in the demand for electric energy" or a "shortage of electric energy or of facilities for the generation or transmission of electric energy," the provision is limited to circumstances that are both imminent and unforeseen.[21] PIOs[22] and Colorado State[23] also cite to various dictionary definitions of "emergency" to assert the same point. PIOs[24] and Colorado State[25] also each similarly assert that the Emergency Order contravenes DOE's historic use of FPA section 202(c) to address natural disasters and "specific, imminent, and unexpected shortages," and that prior to 2025, DOE had never issued a FPA section 202(c) order to prevent the retirement of a generation facility absent a request "by a system operator or governmental body."

10. Further, PIOs and Colorado State rely on *Richmond Power & Light v. FERC* and *Otter Tail Power Co. v. Federal Power Commission* for the proposition that courts have interpreted FPA section 202(c) narrowly to apply only to temporary emergencies requiring an imminent response.[26]

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[19] *Id.* at 3–4.

[20] PIOs Pet. at 36–43; Colorado State Pet. at 19–29.

[21] 16 U.S.C. § 824a(c)(1); *see also* PIOs Pet. at 36–39; Colorado State Pet. at 19–26.

[22] PIOs Pet. at 37.

[23] Colorado State Pet. at 20 nn. 72–73.

[24] PIOs Pet. at 42–43.

[25] Colorado State Pet. at 26–29.

[26] PIOs Pet. at 41–42 (citing *Richmond Power & Light v. FERC*, 574 F.2d 610 (D.C. Cir. 1978); *Otter Tail Power Co. v. Fed. Power Comm'n*, 429 F.2d 232 (8th Cir.

DOE's Determination

11. The Secretary has the statutory authority under FPA section 202(c) to determine that an emergency exists and exercise his judgment to address such an emergency. The statute's plain text grants the Secretary authority to respond to threats to the Nation's electric infrastructure. Specifically, the Secretary "*shall* have authority" to act "*whenever* the [Secretary] determines that an emergency exists."[27]

12. Next, the statute sets forth three different categories of emergency where FPA section 202(c) action is permissible. An emergency may exist "by reason of [1] a sudden increase in the demand for electric energy, or [2] a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or [3] other causes."[28]

13. Pursuant to FPA section 202(c)(1), the Secretary has the authority to determine the existence of a statutory emergency, "either upon [his] own motion or upon complaint, with or without notice, hearing, or report."[29] Beyond providing categories of when an "emergency exists," the statute is silent on any additional requirements that must be satisfied. Here, as is evident from the face of the Emergency Order, and as is consistent with the text of FPA section 202(c) and prior DOE practice,[30] the Secretary exercised his authority under FPA section 202(c) and determined, in his statutory discretion and substantive expertise, that "an emergency exists within the [WECC] Northwest assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes."[31]

1970); Colorado State at 29–32 (same).

[27] 16 U.S.C. § 824a(c)(1) (emphases added).

[28] *Id.*; *see also* H.R. Rep. No 113-86, at 2 (2013) (House Committee on Energy and Commerce Report on then-proposed amendment to FPA section 202(c), which observed that "[r]eliability-related emergencies are not limited to bad weather, natural disasters, or terrorist attacks").

[29] 16 U.S.C. § 824a(c)(1).

[30] *See, e.g.*, *Puget Sound Power & Light Co.*, 6 F.P.C. 320, 1947 WL 1048 (1947) (in which the Federal Power Commission (FPC, the predecessor of DOE) used FPA section 202(c) to prevent an anticipated power shortage despite noting that the current power supply was adequate).

[31] Emergency Order at 1.

14. The argument that the Secretary can act only when a blackout is "imminent" does not comport with the statutory authority conferred by FPA section 202(c). The word imminent does not appear in FPA section 202(c). Further, the Secretary acted in response to the imminent shutdown of Craig on December 31, 2025. Were the Secretary to be required to wait until a blackout is "imminent" in order to address a shortage of generation facilities, his ability to take meaningful action under FPA section 202(c) to prevent the blackout would be gravely impaired. The imminent shutdown of Craig required immediate action. Once a power plant like Craig shuts down, it cannot feasibly be brought back online in response to a severe weather event or other circumstances requiring maximum generation.[32] FPA section 202(c) must be interpreted in the context of the electric energy industry. It can take months, if not years, to remedy a shortage of facilities for the generation of electric energy once a shortage is identified. For example, in 2024, the time from interconnection request to the beginning of commercial operations for the typical completed project was 55 months.[33]

15. This fact that it can take years to remedy shortages of electric energy is squarely recognized in DOE's implementing regulations for FPA section 202(c). These regulations, in effect since 1981, define the term "emergency" to include "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities."[34] Furthermore, the definition of "emergency" contained in DOE's regulations at 10 C.F.R. § 205.371—which generally provide guidance to applicants seeking FPA section 202(c) relief—does not supersede the statutory discretion FPA section 202(c) affords to the Secretary to *sua sponte* "determine[ ] that an emergency exists."[35] Accordingly, the Secretary's emergency determination is entirely consistent with the governing statutory requirements in FPA section 202(c) and DOE's regulations.

16. Similarly, the dictionary definitions cited by PIOs and Colorado State are not persuasive. Those dictionary definitions cannot limit the discretion Congress expressly delegated to the Secretary in FPA section 202(c). Moreover, the leading legal dictionary in 1935, when the FPA was enacted, variously defined the term "emergency" to include "a perplexing contingency or complication of circumstances," as well as a "relatively

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[32] *Id.* at 1 n.5.

[33] Lawrence Berkeley Nat'l Lab., *Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2024*, at 47 (Dec. 2025), https://perma.cc/2287-MSXU.

[34] 10 C.F.R. § 205.371 (2025); *accord Emergency Interconnection of Elec. Facilities & the Transfer of Elec. to Alleviate an Emergency Shortage of Elec. Power*, 46 Fed. Reg. 39984–01 (Aug. 6, 1981).

[35] 16 U.S.C. § 824a(c)(1).

permanent condition of insufficiency of service or of facilities resulting in social disturbance or distress."[36] The fact that dictionary definitions in existence at the time FPA section 202(c) was drafted and ratified acknowledge that emergencies may be of varying duration further undercuts Petitioners' reliance on selected sources.

17. The arguments made by PIOs and Colorado State based on the *Otter Tail* and *Richmond Power & Light* decisions are likewise misguided.[37] *Otter Tail* did not limit the Secretary's FPA section 202(c) discretion or the meaning of "emergency" because the court held that FPA section 202(c) *did not apply* to the case.[38] Instead, *Otter Tail* involved section 202(b) of the FPA and not an "emergency" within the meaning of FPA section 202(c).[39] In *Richmond Power & Light*, the Court of Appeals for the D.C. Circuit merely held that the FPC did not abuse its discretion in *declining* to invoke its emergency powers under FPA section 202(c).[40] The court determined that the FPC had discretion to choose a temporary, voluntary program rather than issue an order pursuant to FPA section 202(c), as the circumstance, in the FPC's discretion, did not warrant the use of emergency authority.[41]

18. A more relevant decision is *Board of Trade of Chicago v. Commodity Futures Trading Commission*.[42] In that case, the Court of Appeals for the Seventh Circuit recognized the broad power of the Commodity Futures Trading Commission (CFTC) to issue emergency actions under section 8a(9) of the Commodity Exchange Act (7 U.S.C. § 12a(9)).[43] Through section 8a(9), the CFTC issued an emergency order for the Board of Trade to suspend trading in certain wheat futures contracts, citing transportation and

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[36] *Emergency*, BLACK'S LAW DICTIONARY 654 (3d ed. 1933).

[37] *See, e.g.*, PIOs Pet. at 41–42; Colorado State Pet. at 29–32.

[38] *See Otter Tail,* 429 F.2d at 234.

[39] *See id.* (rejecting petitioner's contention that "any proceedings in the instant case must be dealt with in compliance with § 202(c)").

[40] *See Richmond Power & Light,* 574 F.2d at 614–15.

[41] *Id*.

[42] *Bd. of Trade of Chicago v. Commodity Futures Trading Comm'n,* 605 F.2d 1016 (7th Cir. 1979) (*Board of Trade*).

[43] 605 F.2d at 1025.

warehouse shortages and potential market manipulation.[44] In response, the Board of Trade sought an injunction against the order, arguing that no emergency existed.[45] The district court granted a preliminary injunction, and the CFTC appealed.[46]

19. In its decision to vacate and remand the district court's preliminary injunction, the Seventh Circuit concluded that Congress intended to grant the CFTC discretion in making emergency determinations under the Commodity Exchange Act.[47] The court reasoned: "Congress recognized that regulation of the volatile futures markets could be accomplished effectively only through the use of an expert Commission, that situations could occur suddenly for which the traditional enforcement powers would be an inadequate response, and that therefore the Commission should have emergency powers, the exercise of which is committed to the expertise and discretion of the Commission."[48] In addition, "[t]he fact that the Commission is authorized by Congress to take emergency action is, in itself, a suggestion of Congressional intent to commit such actions to the Commission's discretion."[49] Given the similarities between FPA section 202(c) and section 8a(9) of the Commodity Exchange Act, the *Board of Trade* decision confirms the conclusion that Congress intended to grant the Secretary broad discretion in FPA section 202(c) to determine when his emergency powers should be applied to protect the public interest.[50]

20. Congressional intent to empower the Secretary with broad discretion to determine when emergency conditions exist is further bolstered by the fact that, despite amending portions of the broader statute in 2015, Congress elected to leave the operative "emergency" language of FPA section 202(c) undisturbed. That year, Congress modified the statute to limit the duration of emergency orders that may conflict with environmental laws or regulations to 90 days.[51] Congress also mandated that, prior to renewal of a FPA section 202(c) order, DOE was to consult with the primary federal agency with expertise

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[44] *See id.* at 1018–19.

[45] *Id.* at 1019.

[46] *Id.* at 1019–20.

[47] *Id.* at 1023–25.

[48] *Id.* at 1025.

[49] *Id.* at 1023.

[50] *See id.* at 1023–25.

[51] 16 U.S.C. § 824a(c)(4)(A).

in the environmental interest protected by the law or regulation implicated.[52] However, it is notable that Congress did not restrict the number of times DOE could renew an emergency order. Likewise, Congress did not amend or constrain the definition of "emergency."[53] This decision affirms longstanding interpretations of the term "emergency" by the FPC and DOE and ratifies their prior use of FPA section 202(c) emergency authority.[54]

21. In sum, the Secretary acted within his authority to determine the existence of an emergency, and the statutory meaning of "emergency" has been satisfied here. In its 90-year history, no court has questioned the Secretary's (or, prior to its dissolution in 1977, the FPC's)[55] judgment in this respect. This history is consistent with the breadth of the Secretary's authority as expressly delegated in the statute.

2. The Secretary's Authority to Require Craig Unit 1 to Continue to Operate

22. PIOs, Colorado State, and Tri-State and Platte River argue that the Emergency Order impermissibly exceeds the Secretary's statutory authority under FPA section 202(c) in various respects.[56] For instance, Colorado State argues that the Emergency Order, in effect, impermissibly asserts the authority to further DOE's policy decisions by managing issues unrelated to addressing imminent emergencies including future energy needs, generalized supply concerns, or an alleged preference for coal-fired generation.[57]

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[52] *Id.* § 824a(c)(4)(B).

[53] *See* H.R. Rep. No. 113-86 at 5–6 (2013) (legislative history showing Congressional awareness of the *Mirant Corp.* order before 2015 amendments).

[54] *See Lorillard v. Pons*, 434 U.S. 575, 580 (1978) (noting that "Congress is presumed to be aware of an administrative or judicial interpretation of a statute and to adopt that interpretation when it re-enacts a statute without change").

[55] The FPC was dissolved in 1977, and the FPC's functions were split between FERC and DOE, with the Secretary retaining FPA section 202(c) power.

[56] PIOs Pet. at 39–41; Colorado State Pet. § V.B; Tri-State and Platte River Pet. §§ II.A, II.C.

[57] *See* Colorado State Pet. § V.B.

23. Similarly, PIOs and Colorado State contend that, in enacting FPA section 215,[58] Congress established a "circumscribed scheme" of federal action for addressing long-term reliability concerns in careful balance with the states, federal regulators, and other stakeholders.[59] Tri-State and Platte River similarly argue that the FPA strikes a comparable "careful balance" over regulations on resource and generation mix.[60] PIOs, Colorado State, and Tri-State and Platte River assert that DOE's use of FPA section 202(c) to address long-term reliability or generation mix concerns would effectively bypass the framework Congress provided under the FPA.[61]

24. Colorado State further argues that the Emergency Order is unlawful because DOE never provided the public notice or an opportunity to comment, as purportedly required by the Administrative Procedure Act (APA).[62] Specifically, Colorado State asserts that DOE now issues FPA section 202(c) orders based on an alleged "new interpretation[ ]" of FPA section 202(c) authority to "address longer-term reliability concerns or demand forecasts" without having subjected that change to public notice and comment, in violation of 5 U.S.C. § 553.[63]

25. Tri-State and Platte River further argue that the Emergency Order violated constitutional due process under the Fifth Amendment, as well as the APA and FPA's respective procedural requirements.[64] In particular, Tri-State and Platte River contend that, because the Emergency Order was predicated on long-term resource adequacy concerns rather than a sudden or imminent supply shortfall, the Order, in their view, did not justify dispensing with the pre-deprivation notice and hearing that due process ordinarily requires.[65]

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[58] 16 U.S.C. § 824o.

[59] PIOs Pet. at 39–41; Colorado State Pet. at 23–25, 36–37.

[60] Tri-State and Platte River Pet. at 32 n. 27.

[61] *See* PIOs Pet. at 39–40, 80–82 (citing 16 U.S.C. §§ 824(b)(1), 824a(c)(1), 824o(i)-(j)); Colorado State Pet. §§ V.A.ii, V.B (citing 16 U.S.C. §§ 824o(a)(3), (c)(2)(A), (d)(2)–(4), (e), (i), (j), 824h(b)).

[62] Colorado State Pet. at 29.

[63] *Id.* at 27–29.

[64] Tri-State and Platte River Pet. at 3, 26–29.

[65] *Id.* at 27.

DOE's Determination

26. There is no dispute that the Secretary has the statutory authority under FPA section 202(c) to (1) determine that an emergency exists, and (2) exercise his judgment to address that emergency. Rather, PIOs and Colorado State claim that the Secretary exceeded that authority in certain respects. As explained below, DOE is not persuaded by PIOs' and Colorado State's respective claims.

27. FPA section 201(b)(1) specifically reserves authority over "facilities used for the generation of electric energy" for the states "*except as specifically provided* in this subchapter."[66] FPA section 202(c) constitutes one such exception. It grants the Secretary the "authority, either upon [the Secretary's] own motion or upon complaint, with or without notice, hearing, or report, to require by order such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest."[67] Congress thus purposely provided discretion in FPA section 202(c) to require changes to the operations of electric generating facilities to meet the emergency.

28. PIOs and Colorado State attempt to avoid this clear grant of authority by arguing that the Emergency Order addresses issues unrelated to emergencies and instead concerns the issue of resource adequacy and long-term reliability.[68] But placing a different label on the Secretary's action cannot change the fact that actions taken in the Emergency Order fall squarely within the authority granted by FPA section 202(c). By its terms, FPA section 202(c) may be invoked to address a potential "shortage of electric energy or of facilities for the generation or transmission of electric energy," which is exactly the situation that led to the issuance of the Emergency Order.[69] The Secretary also is authorized to "require by order . . . such generation . . . of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest," which is exactly the action the Emergency Order requires. [70]

29. Moreover, DOE's regulations specifically provide that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct

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[66] 16 U.S.C. § 824(b)(1) (emphasis added).

[67] *Id.* § 824a(c)(1).

[68] *See, e.g.*, PIOs Pet. at 39–41; Colorado State Pet. at 32–35.

[69] 16 U.S.C. § 824a(c)(1).

[70] *Id*.

necessary facilities can result in an emergency as contemplated in these regulations."[71] Similarly, the fact that many previous FPA section 202(c) emergency orders lasted for years, or were even of indefinite duration,[72] undermines Petitioners' assertions that use of this power must be limited to short-term emergencies. As such, longstanding precedent reinforces the conclusion that FPA section 202(c) may be used to address long-term structural problems, not simply imminent and unexpected events—which is precisely the type of action the Secretary directed in the Emergency Order. DOE's regulations and established practice thus implement the broad grant of discretion FPA section 202(c) affords to the Secretary to "determine[] that an emergency exists."[73]

30. Contrary to the assertions of PIOs, Colorado State, and Tri-State and Platte River,[74] the Secretary is not taking action to address matters otherwise delegated to the states or the FERC, nor is he exceeding his statutory authority under FPA section 202(c). Specifically, due to "inadequate planning," and "the failure to construct necessary facilities," the Secretary took action to address the emergency in the WECC-Northwest assessment area.[75] As described in the Emergency Order, the resource crisis in the Craig service area arises, among other reasons, from the mismatch between resource retirements, such as Craig Unit 1, and accelerated load growth.[76] If not for the Emergency Order, Craig Unit 1 would have retired on December 31, 2025, further decreasing the available dispatchable generation within the Craig service region and deepening the reliability crisis. The actions directed by the Emergency Order thus preserve the reliability of the grid until new generation resources can be added and are entirely consistent with the governing statutory requirements in FPA section 202(c) and its implementing regulations.

31. Furthermore, contrary to Colorado State's contentions, DOE's FPA section 202(c) orders are not in conflict with the APA.[77] Colorado State's argument that DOE was

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[71] 10 C.F.R. § 205.371.

[72] BLACK'S LAW DICTIONARY, *supra* note 36.

[73] 16 U.S.C. § 824a(c)(1).

[74] PIOs Pet. at 39–41; Colorado State Pet. at 23–25, 36–37; Tri-State and Platte River Pet. at 32 n. 27.

[75] *See* 10 C.F.R. § 205.371 ("Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in the regulations.").

[76] Emergency Order at 3.

[77] Colorado State Pet. at 29.

required to conduct new notice-and-comment rulemaking rests on the flawed premise that DOE has "deviate[d] from its regulations" and prior interpretation of its FPA section 202(c) authority.[78] The Secretary's exercise of his emergency authority under FPA section 202(c) in the Emergency Order is consistent with the same statutory framework and implementing regulations that have long governed DOE's use of that authority. DOE has neither promulgated new rules nor adopted new binding procedures governing the exercise of FPA section 202(c) authority. Rather, the Secretary has applied the existing statutory standard—determining that "an emergency exists" and ordering the remedy that, in his judgment, "will best meet the emergency and serve the public interest"—to the specific facts and circumstances presented here.

32. Tri-State and Platte River's Fifth Amendment due process arguments[79] are likewise without merit. The Supreme Court has "often" recognized "that summary administrative action may be justified in emergency situations."[80] Here, the Secretary's determination that an emergency existed in WECC-Northwest assessment area was grounded in substantial evidence of ongoing and worsening resource adequacy conditions, including Craig's planned retirement. The nature of the emergency—a shortage of generation facilities compounded by accelerating retirements and load growth—required the Secretary to act before Craig Unit 1's permanent retirement rendered the situation irreversible. In these circumstances, the absence of a hearing before issuance of the Emergency Order does not constitute a constitutional violation; the statute itself provides the requisite authorization to act, and the ample process available after the Emergency Order's issuance, including this rehearing process provided under FPA section 313(a) and the cost-recovery mechanisms available under FPA section 202(c), afford Petitioners an adequate opportunity to be heard.[81]

3. The Factual Basis to Support the Secretary's Emergency Determination

33. PIOs and Colorado State raise similar arguments that there is no factual basis to support the Emergency Order and that the Secretary is required to set forth substantial

[78] *Id.*

[79] Tri-State and Platte River Pet. at 26–29.

[80] *Hodel v. Va. Surface Min. and Reclamation Ass'n, Inc.*, 452 U.S. 264, 299–300 (1981).

[81] *See id*. (explaining that the "[p]rotection of the health and safety of the public is a paramount governmental interest which justifies summary administrative action," and finding that an immediate cessation order directed at a coal mine did not violate the Fifth Amendment's Due Process Clause).

evidence in support of his emergency determination.[82] For example, PIOs and Colorado State argue that the 2024 LTRA does not support an emergency determination because it classifies the WECC-Northwest assessment area as "normal risk," projects "negligible unserved energy and load-loss risk," and finds no reliability metrics violations through 2028.[83] Similarly, PIOs and Colorado State argue that the 2024 WARA found zero demand-at-risk hours in 2026 in all relevant subregions and that the EIA data cited in the Emergency Order overstated planned coal retirements in Colorado by more than 900 MW while omitting planned generation additions.[84]

34. In addition, PIOs and Colorado State criticize the Emergency Order's references to the President's Executive Order No. 14156, "Declaring a National Energy Emergency," and Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid."[85] Colorado State further asserts that the Secretary's references to the President's executive actions, together with public statements by the Secretary and other administration officials, evince a pretextual effort to further the administration's policy preference for fossil fuels, and that the Emergency Order therefore reflects an impermissible prejudgment of the outcome.[86]

35. PIOs and Colorado State further argue that DOE failed to consider contrary evidence including: the 2025–2026 Winter Reliability Assessment (2025–2026 WRA); the resource plans of all five Craig co-owners; DOE's own contemporaneous export authorizations; the Bonneville Power Administration's 2025 "White Book"; the Washington Agencies' November 2025 resource adequacy meeting; the Grid Strategies resource adequacy report; and the E3 Resource Adequacy Phase 1 Presentation.[87] PIOs and Colorado State contend that these sources collectively demonstrate that the Craig service region has adequate resources to meet demand without Craig Unit 1.[88]

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[82] *See, e.g.*, PIOs Pet. § V.A.3; Colorado State Pet. § V.C.

[83] PIOs Pet. at 3, 46–47; Colorado State Pet. at 39–40.

[84] PIOs Pet. at 3, 47–50; Colorado State Pet. at 45–47.

[85] PIOs Pet. at 50–51 (discussing Executive Order No. 14156 and Executive Order No. 14262); Colorado State Pet. at 61–65.

[86] Colorado State Pet. §§ V.C.iv, V.F.

[87] PIOs Pet. § V.A.3.iii; Colorado State Pet. at 41–45, 48–61.

[88] *Id.*

DOE's Determination

36. The exigencies that FPA section 202(c) is designed to address necessarily require that the Secretary's determination is informed by the facts available at the time and by his sound expert judgment as to what situations constitute an emergency. The statute expressly states that no notice, hearing, or report is required prior to issuance of a FPA section 202(c) order. This confirms that the Secretary is authorized to exercise his FPA section 202(c) authority expeditiously in responding to emergency situations.

37. In any event, the Secretary's determination that an emergency exists is supported by substantial factual evidence and the exercise of the Secretary's judgment. When reviewing an order under the FPA, the Secretary's findings "as to the facts, if supported by substantial evidence, shall be conclusive."[89] The Emergency Order has met this threshold by citing evidence that reveals rising electricity demand in WECC-Northwest assessment area and WECC-Rocky Mountain assessment region coupled with a decrease in the availability of dispatchable generation.

38. As discussed above, the Emergency Order identified the ongoing emergency in the Craig service area "due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes."[90] The Secretary further observed that "the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years."[91] As such, the Secretary found that this emergency "could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety."[92] Consistent with his emergency determination, the Secretary thus ordered Tri-State and co-owners to take all measures necessary to ensure that the Craig Unit 1 is available to operate.[93]

39. As noted, the Secretary's determination was based on several different facts discussed in the Emergency Order and summarized here. First, the 2024 LTRA found that "[e]nergy variability is greater in the Northwest than other WECC regions due to the large share of wind and hydro in the portfolio," "[f]ive [gigawatts] of baseload resource retirements are anticipated between 2024 and 2028," and supply chain issues affecting

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[89] 16 U.S.C. § 825*l*(b).

[90] Emergency Order at 1.

[91] *Id.* at 3.

[92] *Id*.

[93] *See id.*, Ordering Paragraph A.

battery storage resources "are a concern."[94] PIOs' and Colorado State's contentions that the 2024 LTRA's "normal risk" classification forecloses reliance on that document misreads NERC's assessment.[95] The "normal risk" classification is a probabilistic base-case finding; it does not speak to the Secretary's independent determination that a shortage of generation facilities exists under FPA section 202(c), nor does it account for NERC's finding in the 2024 LTRA that the WECC-Northwest region's reserve margin fell below reference levels beginning in 2031 when Tier 2 (i.e., planned resources that have not yet achieved key development milestones, such as executed interconnection agreements or secured financing) resources are excluded.[96] The Secretary was not required to wait for NERC's long-term risk classifications to escalate before acting to prevent the permanent loss of a dispatchable generation resource.

40. Second, as the Emergency Order discussed, the 2024 WARA found that peak demand in WECC's Northwest-Central subregion is "forecast to grow by 8.5% over the next decade, from 33 GW in 2025 to 36 GW in 2034," while most planned retirements are "baseload generation, such as coal, natural gas, and nuclear."[97] Moreover, PIOs' and Colorado State's respective contentions regarding the 2024 WARA's finding of zero demand-at-risk hours in 2026 and the geographic footprint of the Northwest-Central subregion relative to the WECC-Northwest assessment area[98] miss the point. The absence of demand-at-risk hours under base-case assumptions does not negate the existence of a shortage of generation facilities. The geographic overlap between the Northwest-Central subregion and the WECC-Northwest assessment area is sufficient to render the 2024 WARA's findings probative, and the Secretary was not required to limit his analysis to sources whose geographic boundaries precisely coincide with the Order's footprint.

41. Third, the Emergency Order observed (citing EIA data) that, since 2019, 571.3 MW of coal-fired generating capacity had retired in Colorado, and that approximately 3,700 MW of additional coal-fired generating capacity and 675.6 MW of natural gas-fired generating capacity in Colorado are scheduled to retire by 2029.[99] PIOs' criticisms concerning particular generation retirement data overlook the fundamental finding that

[94] *Id.* at 1–2.

[95] *See* PIOs Pet. at 46–47; Colorado State Pet. at 38–42.

[96] *See NERC 2024* LTRA, at 127–28.

[97] Emergency Order at 2.

[98] *See* PIOs Pet. at 48–49; Colorado State Pet. at 45–47.

[99] Emergency Order at 2.

substantial baseload capacity is scheduled to retire within the relevant planning horizon.[100] Moreover, the argument that planned additions exceed planned retirements on a net megawatt basis conflates nameplate capacity with dispatchable, firm capacity. In other words, the resources planned to replace retiring coal generation are predominantly intermittent or limited-duration resources that cannot replicate the around-the-clock dispatchability of the baseload generation.

42. Fourth, the Emergency Order referenced DOE's July 2025 Resource Adequacy Report. As the Emergency Order noted, DOE's analysis concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence [ ] innovation."[101] Indeed, the recent increase in demand for electricity stands in sharp contrast to the period between 2005 and 2020, when demand grew at an average rate of 0.1%.[102] On these points, DOE notes a July 2025 report prepared by the Council of Economic Advisers entitled, *The Economic Benefits of Unleashing American Energy*.[103] The CEA Report highlighted rapid energy demand increases due to data centers,[104] while noting that "utilities can delay retirement of existing baseload capacity until a sufficient amount of reliable new generation and storage capacity comes online" to help mitigate price increases associated with heightened demand.[105]

43. Fifth, the Emergency Order noted that the Secretary's FPA section 202(c) actions as to Craig Unit 1 were preceded by President Trump's executive actions concerning this Nation's energy supply crisis. In particular, in Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial

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[100] *See* PIOs Pet. at 49–50.

[101] Emergency Order at 3; July 2025 Resource Adequacy Report, at 1.

[102] U.S. Energy Info. Admin., *After More than a Decade of Little Change, U.S. Elec. Consumption Is Rising Again* (May 13, 2025), https://perma.cc/X62V-VN4L.

[103] *See* Council of Econ. Advisers, *The Econ. Benefits of Unleashing Am. Energy*, at 8–9 (July 2025) (CEA Report), https://www.whitehouse.gov/research/2025/07/the-economic-benefits-of-unleashing-american-energy/.

[104] *Id.* at 2–6.

[105] *Id.* at 8–9.

intelligence data centers and an increase in domestic manufacturing."[106] As the President explained, this significant increase in electricity demand, "coupled with existing capacity challenges, places a significant strain on our Nation's electric grid."[107] Notably, Executive Order No. 14262 specifically ordered the Secretary to draw upon "all mechanisms available under applicable law, *including section 202(c) of the Federal Power Act*, to ensure any generation resource identified as critical within an at-risk region is appropriately retained as an available generation resource within the at-risk region."[108]

44. President Trump likewise recognized, in Executive Order No. 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[109] In declaring this national emergency, including pursuant to the National Emergencies Act,[110] the President specifically ordered the heads of executive departments to "identify and exercise any lawful emergency authorities available to them . . . to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources."[111] One such "lawful emergency authorit[y]" is the Secretary's FPA section 202(c) power. The executive orders informed the Secretary's decision and action, in addition to the other factors outlined in the Emergency Order and this Order.

45. PIOs and Colorado State maintain that this evidence does not show the existence of an imminent emergency. But if the Secretary had allowed the planned retirement of Craig Unit 1 on December 31, 2025, that generating unit would have never been available to address the ongoing emergency in the Craig service area. Accordingly, based on the evidence available, the Secretary reasonably exercised his judgment and issued the Emergency Order in compliance with FPA section 202(c).

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[106] Exec. Order No. 14262 § 1.

[107] *Id.*

[108] *Id.* § 3(c)(i) (emphasis added).

[109] Exec. Order No. 14156 § 1.

[110] 50 U.S.C. §§ 1601–1651.

[111] Exec. Order No. 14156 § 2(a).

46. With respect to the additional sources cited by PIOs[112] and Colorado State,[113] the Secretary considered the totality of the evidence available at the time of the Emergency Order and exercised his expert judgment accordingly. The sources cited by PIOs and Colorado State do not, individually or collectively, negate the Secretary's emergency determination. In fact, these sources further support the Secretary's findings in the Emergency Order.

47. For instance, the 2025–2026 WRA corroborates rather than undermines the Secretary's emergency determination. The 2025–2026 WRA designated the WECC-Rocky Mountain assessment area—the subregion in which Craig Unit 1 is located in this report—as exhibiting the highest year-over-year increase in net internal demand of any assessment area evaluated, with net internal demand rising 10.0%.[114] The 2025–2026 WRA further found that the Anticipated Reserve Margin for the WECC-Rocky Mountain area declined by 20.3% year-over-year.[115] The findings in the 2025–2026 WRA are fully consistent with the Secretary's determination that accelerating load growth, combined with the retirement of baseload generation resources such as Craig Unit 1, is producing a worsening shortage of generation facilities within the WECC-Northwest region. The 2025–2026 WRA's base-case finding that resources are adequate under normal peak conditions does not negate the Secretary's independent determination that a shortage of generation facilities exists or is developing under FPA section 202(c); rather, the dramatic demand growth and reserve margin deterioration documented in the 2025–2026 WRA confirm the growing emergency in the Craig service region.

48. Similarly, the resource plans of the Craig co-owners likewise do not negate the Secretary's emergency determination. PIOs and Colorado State point to the integrated resource plans and electric resource plans of Tri-State, Platte River, PacifiCorp, Xcel, and Salt River Project as evidence that the region has adequate resources without Craig Unit 1.[116] However, those plans are limited in that they only reflect each entity's individual assessment of its own load obligations and planned resource acquisitions within its respective service territory. The Secretary's emergency authority is not contingent upon any individual utility's resource adequacy assessment, and the co-owners' respective planning documents do not constitute a basis for rehearing.

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[112] PIOs Pet. § V.A.3.iii.

[113] Colorado State Pet. at 41–45, 48–61.

[114] *See* 2025–2026 WRA at 49.

[115] *Id.*

[116] *See* PIOs Pet. § V.A.3.iii.a; Colorado State Pet. § V.C.iii.

49. Furthermore, PIOs' contention that DOE's authorizations of electricity exports under FPA section 202(e) contradict the Secretary's emergency determination under FPA section 202(c) is without merit.[117] FPA sections 202(e) and 202(c) operate under distinct regulatory frameworks, each with different statutory purposes, standards, and criteria. DOE's exercise of these distinct statutory authorities under separate provisions of the FPA, each informed by its own set of considerations, is not contradictory.

50. Additionally, as DOE has explained in recent export authorization orders, the existing reliability framework ensures that export authorizations cannot compromise the sufficiency of supply or the operational reliability of the domestic transmission system.[118] NERC Reliability Standard IRO-001-4 requires that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions," including the suspension of exports if that electric energy is needed to support the regional power grid.[119] Reliability Standard EOP-011-4 also requires each Balancing Authority to develop, maintain, and implement Operating Plans to mitigate capacity and energy emergencies within its Balancing Authority Area.[120] These reliability safeguards ensure that, during periods of grid stress—precisely the conditions that the Emergency Order is designed to address—exports would be curtailed or suspended as necessary to preserve the reliability of the domestic system. In other words, section 202(e) export authorizations are necessarily subject to, and operate consistently with, the reliability imperatives underlying emergency action pursuant to FPA section 202(c).

51. Moreover, many of DOE's export authorizations, including those cited by PIOs, are issued to power marketers that do not own generation resources, do not have franchised service areas, and do not have native load obligations.[121] Such entities purchase and sell

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[117] *See* PIOs Pet. at 69–70.

[118] *See, e.g.*, *H.Q. Energy Servs. (US) Inc.*, Order No. EA-182-F, at 8 (Jan. 14, 2026), https://www.energy.gov/sites/default/files/2026-02/EA-182-F_HQEnergy ServicesUSInc_Order.pdf ("Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid.").

[119] *See* NERC Reliability Standard IRO-001-4, at 1, https://www.nerc.com/ (search "Reliability Standard IRO-001-4"; then select "IRO-001-4").

[120] *See* NERC Reliability Standard EOP-011-4, at 3, https://www.nerc.com (search "Reliability Standard EOP-011-4"; then select "EOP-011-4")

[121] *See, e.g.*, *Rcsh. Power Corp.*, Order No. EA-365-C (Oct. 21, 2025), https://www.energy.gov/sites/default/files/2025-11/EA-365C%20Research%20Po

electricity in the wholesale market; their export transactions do not withdraw power from load-serving obligations or diminish the generation capacity available to serve domestic demand. Accordingly, DOE's continued authorization of electricity exports under section 202(e) is fully consistent with the Secretary's emergency determination under FPA section 202(c).

52. Further, the evidence subsequently available after issuance of the Emergency Order further confirms the Secretary's exercise of sound discretion and judgment in issuing the Emergency Order. In January 2026, NERC released its 2025 Long-Term Reliability Assessment (2025 LTRA),[122] which independently corroborates the resource adequacy concerns in Craig's service region. While NERC assessed that the WECC-Rocky Mountain region, which includes Colorado, is at normal risk of energy shortfalls over the next five years, the area has an anticipated reserve margin that falls below the Reference Margin Level in Summers 2034 and 2035, and Winter 2034–35.[123] The 2025 LTRA also notes that the WECC-Rocky Mountain assessment area faces challenges from an aging thermal resource fleet that can lead to unplanned outages, a risk further exacerbated by supply chain constraints and limited vendor availability. Additionally, both solar and wind variability are year-round concerns, and while the region is pursuing advancement into Regional Transmission Organizations to leverage a wider footprint, smaller entities currently have limited geographic diversity to counteract these generation constraints.[124]

53. Furthermore, the WECC Western Assessment of Resource Adequacy (2025 WARA) notes that "the West's planned resource buildout will not keep up with anticipated load growth over the next decade, particularly in the Basin and Northwest subregions," and that "[t]he West could see energy shortfalls as early as 2028."[125] The 2025 WARA further found that if resources are added as planned, loss of load may be limited to the Basin and Northwest subregions; however, if planned resource additions are

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wer%20Corporation%20-%20Export%20Authorization%20Order.pdf; *Macquarie Energy LLC*, Order No. EA-479-A (July 11, 2025), https://www.energy.gov/sites/default/files/2025-08/EA-479A%20Macquarie%20Energy%20LLC%20Export%20Authorization%20Order.pdf.

[122] NERC, *LTRA* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[123] *Id.* at 160–61.

[124] *Id.* at 161.

[125] WECC, *2025 W. Assessment of Res Adequacy*, https://feature.wecc.org/2025wara/index.html.

delayed or cancelled, other subregions could also be at risk.[126] The 2025 WARA also highlights that 90% of planned resources over the next decade are inverter-based resources, which "continue the rapid evolution of the resource mix away from traditional dispatchable resources to more weather-dependent resources."[127] The 2025 LTRA and 2025 WARA thus provide substantial, independent confirmation that the conditions underlying the Secretary's emergency determination are real, material, and worsening.

4. Best and Appropriate Means for Addressing the Emergency

54. PIOs, Colorado State, and Tri-State and Platte River raise similar arguments that Craig Unit 1 is neither the best nor an appropriate means of alleviating the capacity shortfall addressed by the Emergency Order.[128] PIOs, Colorado State, and Tri-State and Platte River contend that DOE failed to consider Craig Unit 1's operational shortcomings in determining that it represents the best means of addressing the emergency.[129] PIOs, Colorado State, and Tri-State and Platte River similarly contend that DOE was required to consider alternatives and evaluate other possible methods for addressing the emergency, which they argue the Emergency Order failed to do.[130]

55. Tri-State and Platte River and PIOs additionally argue that the Emergency Order fails to consider the various policies of the FPA.[131] Specifically, Tri-State and Platte River contend that, by ordering that Craig Unit 1, an "uneconomic unit," remain available to operate on the eve of its retirement, the Emergency Order "is inconsistent" with the FPA's core objectives.[132] PIOs similarly argue that the public interest element of FPA section 202(c) requires the Secretary to advance, or at minimum consider, the FPA's core

[126] *Id.*

[127] *Id.*

[128] PIOs Pet. § V.B; Colorado State Pet. § V.D; Tri-State and Platte River Pet. at 29–32.

[129] PIOs Pet. § V.B.2; Colorado State Pet. at 65–66; Tri-State and Platte River Pet. at 29–30.

[130] *See* PIOs Pet. § V.B.3; Colorado State Pet. at 67–73; Tri-State and Platte River Pet. at 30–32.

[131] PIOs Pet. at 74–78; Tri-State and Platte River Pet. § II.C.

[132] Tri-State and Platte River Pet. at 32–33.

policies, and that the Emergency Order fails to do so—particularly in light of Craig Unit 1's unavailability at the time the Order was issued.[133]

DOE's Determination

56. The Secretary, in issuing the Emergency Order, adhered to the process established in FPA section 202(c) in exercising his judgment by directing Tri-State and co-owners to undertake specific actions as to Craig Unit 1.[134] The Secretary, as the presidentially-appointed and Senate-confirmed head of DOE,[135] is the appropriate individual to determine the existence of an emergency within the meaning of FPA section 202(c) and exercise "[the Secretary's] judgment" as to what actions "best meet the emergency and serve the public interest."[136] As discussed above, the Secretary exercised his discretion in responding to an emergency pursuant to an express delegation of authority under FPA section 202(c). Further, as explained below, there is no basis to grant rehearing to review the Secretary's exercise of his judgment in prescribing the required response to the emergency.

57. As noted, FPA section 202(c)(1) affords the Secretary discretion as to what remedy "will best meet the emergency and serve the public interest."[137] Similarly, the fact that FPA section 202(c)(1) permits the Secretary to issue emergency orders "upon [his] own motion . . . with or without notice, hearing, or report" reinforces the breadth of his discretionary authority.[138] The statute expressly delegates the decision on the appropriate remedy to the Secretary's "judgment" (similar to the express delegation to "determine[ ] that an emergency exists").[139] The statute does not contain any requirement to consider and evaluate in writing any alternative means for addressing the emergency.[140] Here, the

[133] PIOs Pet. at 74–78.

[134] *See generally* Emergency Order.

[135] *See* 42 U.S.C. § 7131.

[136] 16 U.S.C. § 824a(c)(1).

[137] *Id*.

[138] *Id.*

[139] *Id*.

[140] The assertion of PIOs and Tri-State and Platte River (*see* PIOs Pet. at 74–75; Tri-State and Platte River Pet. at 30) that the Secretary must consider a wide range of possible means of addressing an emergency relies on a DOE regulation that sets forth rules for

Secretary soundly exercised his judgment in determining that "continued operation [of Craig Unit 1] will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity."[141]

58. What is more, the PIOs'[142] and Tri-State and Platte River's[143] respective contentions that Craig Unit 1 is an uneconomic and unreliable resource do not support their requested relief on rehearing. The Emergency Order directs WAPA-WACM, in its role as Balancing Authority, and SPP West, in its role as Reliability Coordinator, to dispatch Craig Unit 1 only as necessary to address the emergency, which minimizes unnecessary operational costs to ratepayers.[144] The Secretary's expert judgment that the continued availability of Craig Unit 1 best meets the emergency is not undermined by the facility's economic status or its maintenance history—including the outage at the time the Order was issued—both of which are concerns that the co-owners and the applicable Balancing Authority and Reliability Coordinator are directed to address under the terms of the Emergency Order.[145]

59. In addition, Ordering Paragraph G of the Emergency Order provides that "Craig Unit 1 shall not be considered a capacity resource." As used in the Emergency Order, the term "capacity resource" refers to a generation unit that is committed or counted upon to satisfy forward capacity obligations or planning reserve margin requirements under applicable tariffs, market rules, or resource adequacy programs—such as those administered by SPP West or WAPA-WACM. The Emergency Order's direction reflects the Secretary's determination that Craig Unit 1 is being retained to best meet the identified emergency shortage of generation facilities under FPA section 202(c), and not to satisfy any market-based or tariff-based capacity obligation of the co-owners or any other entity. This distinction ensures that the Emergency Order does not distort capacity market signals and is consistent with the Secretary's judgment that the continued availability of Craig

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applications for emergency orders. 10 C.F.R. § 205.373. That regulation is not applicable here because the Secretary issued the Emergency Order upon his own initiative.

[141] Emergency Order at 3.

[142] *See* PIOs Pet. at 75–78.

[143] *See* Tri-State and Platte River Pet. § II.C.

[144] Emergency Order at 3, Ordering Paragraph A.

[145] *See id.*

Unit 1 represents the means that will best meet the emergency and serve the public interest.[146]

60. PIOs, Colorado State, and Tri-State and Platte River offer alternatives that they deem to be better and more appropriate solutions to the emergency.[147] But the Secretary's determination need not consider, or reconsider, this after-the-fact analysis. FPA section 202(c)(1) authorizes the Secretary to determine the existence of an emergency and to order the means to address such an emergency. It does not require the Secretary to engage in a lengthy weighing of options or explanation of the Secretary's actions prior to issuing the emergency order. Indeed, such a process would defeat the very purpose of the statutory emergency power to act expeditiously and within the judgment of the Secretary.[148]

5. Fifth Amendment Takings Claims and Cost Recovery Consideration

61. Tri-State and Platte River contend that the Emergency Order constitutes an uncompensated taking in violation of the Fifth Amendment to the U.S. Constitution.[149] In support of this position, they assert that the Emergency Order gives rise to both a physical taking and a regulatory taking under the Fifth Amendment and that neither FERC rate recovery nor any other available mechanism provides just compensation.[150]

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[146] DOE notes that PIOs and Colorado State raise concerns regarding the meaning and legal effect of Ordering Paragraph G of the Emergency Order. (*See* Colorado State Pet. at 78 n. 301; PIOs Pet. at 82–83). The Secretary clarifies, as set forth above, that Ordering Paragraph G is intended solely to define the operational and market status of Craig Unit 1 during the pendency of the Emergency Order and does not purport to affect any ratemaking determination, state regulatory proceeding, or FERC-jurisdictional tariff obligation. To the extent any party believes that Ordering Paragraph G requires further clarification in connection with a specific tariff filing or cost recovery proceeding before FERC, such matters may be addressed in the appropriate forum.

[147] PIOs Pet. 63–70; Colorado State Pet. at 67–75; Tri-State and Platte River Pet. at 29–32.

[148] 16 U.S.C. § 824a(c) ("[T]he Commission shall have authority . . . with or without notice, hearing, or report, to require by order such temporary . . . generation . . ..").

[149] Tri-State and Platte River Pet. § I (citing U.S. CONST. amend. V).

[150] *Id.*

62. Tri-State and Platte River advance two grounds on which they assert the Emergency Order constitutes a physical taking.[151] First, they contend that the Emergency Order effectuates a taking through its directives to (1) ensure Craig Unit 1's operational availability and (2) limit Craig Unit 1's operations to certain times and parameters to minimize adverse environmental impacts.[152] According to Tri-State and Platte River, a taking occurred because compliance with the Emergency Order requires Tri-State and Platte River to involuntarily undertake "extensive repairs" to Craig Unit 1 and maintain employees to operate the unit.[153]

63. Second, Tri-State and Platte River contend that the Emergency Order compels discrete physical changes to their property, each of which independently constitutes a *per se* physical taking.[154] Such changes include: (1) repairs and deferred maintenance to Craig Unit 1, including the restoration of out-of-service equipment that would not otherwise be used absent the Emergency Order;[155] (2) diversion of coal from fuel reserves dedicated to Craig Units 2 and/or 3 to Craig Unit 1;[156] and (3) potential interference concerning transmission infrastructure shared between the Craig Generating Station and the Axial Basin generating facility.[157]

64. In addition, Tri-State and Platte River assert that the Emergency Order constitutes a regulatory taking under factors articulated in *Penn Central Transportation Co. v. New York City*.[158] Under the *Penn Central* test, courts evaluating an alleged regulatory taking consider three factors: (1) the economic impact of the regulation, (2) the regulation's

[151] *Id.* § I.A.

[152] *Id.* at 14–15.

[153] *Id.* § I.A.1.

[154] *Id.* § I.A.2.

[155] *Id.* at 16–18.

[156] *Id.* at 18–19.

[157] *Id.* at 19.

[158] *Penn Cent. Transp. Co. v. N.Y.C.*, 438 U.S. 104 (1982) (*Penn Central*); Tri-State and Platte River Pet. § I.B.

interference with reasonable investment-backed expectations, and (3) the character of the government action.[159]

65. Applying these factors, Tri-State and Platte River argue that all three weigh in favor of finding a compensable regulatory taking here. First, with respect to economic impact, they assert that the Emergency Order imposes significant operations and maintenance costs "with no economic benefit" and prevents them from "efficiently and affordably managing the transmission and generation system."[160] Second, as to investment-backed expectations, they contend that DOE's current exercise of its FPA section 202(c) authority represents "a substantial and novel change" from prior uses of that authority, and that Tri-State and Platte River "could not have fairly anticipated" the Emergency Order when Craig Unit 1's planned retirement was announced.[161] Third, with respect to the character of the government action, they argue that the Emergency Order "directs operational control for a public reliability aim" that should instead be addressed through alternative means.[162]

66. Finally, Tri-State and Platte River argue that expected cost recovery through FERC's rate-making process, as contemplated under FPA section 202(c)(1) and DOE's implementing regulations, does not constitute "just compensation" for the Emergency Order within the meaning of the Fifth Amendment's Takings Clause.[163] They anticipate that the purported complexity of the FERC rate-making process will prevent complete recovery of their costs.[164] Furthermore, they assert that because costs for the continued operation of Craig Unit 1 are intended to be recovered through the FERC rate-making process, the financial burden of compliance will ultimately be borne by Tri-State's members and Platte River's ratepayers (rather than by the Government itself).[165] On this basis, Tri-State and Platte River contend that DOE cannot discharge its constitutional

[159] *See* 438 U.S. at 124.

[160] Tri-State and Platte River Pet. § I.B.1.

[161] *Id.* § I.B.2.

[162] *Id.* § I.B.3.

[163] *Id.* § I.C.; *see also* 10 C.F.R. § 205.376 (DOE implementing regulations)

[164] *Id.* at 24.

[165] *Id.* at 24–25.

obligation to provide just compensation by shifting that burden onto private parties who ultimately may not even bear the Emergency Order's full costs.[166]

DOE Determination

67. Tri-State and Platte River's arguments that DOE's exercise of its legitimate regulatory and emergency authority over private property implicates the Takings Clause of the Fifth Amendment are unavailing and do not warrant rehearing, as discussed below. Further, even if DOE's actions did implicate the Takings Clause, Petitioners' contention that the FPA framework for recovering costs arising from compliance with an FPA section 202(c) emergency order does not provide "just compensation"[167] as required by the Fifth Amendment is likewise without merit.

68. The Takings Clause provides that "private property [shall not] be taken for public use, without just compensation."[168] This constitutional limit, however, does not prohibit the Government from exercising its legitimate regulatory and emergency authority over private property.[169] Rather, a compensable taking is recognized only where "regulation goes too far."[170] Accordingly, petitioners seeking constitutional relief must overcome a demanding threshold to demonstrate a compensable taking.[171] This is particularly so in the context of highly regulated fields, such as utilities, where market participants must reasonably expect and accept significant governmental involvement.[172] Indeed,

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[166] *Id.* at 25.

[167] Tri-State and Platte River Pet. at 23–24.

[168] U.S. CONST. amend. V.

[169] *See Lingle v. Chevron*, 544 U.S. 528, 538 (2005) (explaining that "government regulation—by definition—involves the adjustment of rights for the public good," and "[g]overnment hardly could go on if to some extent values incident to property could not be diminished without paying for every such change in the general law" (quoting *Andrus v. Allard*, 444 U.S. 51, 65 (1979), and *Penn. Coal Co. v. Mahon*, 260 U.S. 393, 413 (1922))).

[170] *Mahon*, 260 U.S. at 415.

[171] *See, e.g.*, *Keystone Bituminous Coal Ass'n v. DeBenedictis*, 480 U.S. 470, 493, 501 (1987) (noting "the heavy burden placed upon one alleging a regulatory taking" and rejecting petitioner's taking claim).

[172] *See generally Connolly v. Pension Benefit Guar. Corp.*, 475 U.S. 211, 227 (1986) ("Those who do business in the regulated field cannot object if the legislative scheme is buttressed by subsequent amendments to achieve the legislative end."); *Ruckelshaus v.*

construction, operation, pricing, interconnection, and retirement of an electric generating unit is conditioned on government permission and is subject to extensive federal, state, and local regulation, including in the areas of energy law, environmental law, health and safety law, state utility regulation, and local land use law.[173] Furthermore, it is well-established that a government entity may ensure that generating units continue to operate past their planned retirement dates.[174]

69. Here, Tri-State and Platte River first argue that the Emergency Order constitutes a physical taking because the Secretary directed them to maintain and operate Craig Unit 1—a unit previously slated for retirement on December 31, 2025.[175] This argument, however, mischaracterizes the nature of the Emergency Order. DOE has not assumed operational control of Craig Unit 1. The Emergency Order does not transfer Craig Unit 1's ownership or occupy the facility for the Government's own use, and Tri-State and Platte River retain possession and control of the facility. Rather, in the Emergency Order, the Secretary properly exercised his FPA section 202(c) authority to direct Tri-State and co-owners to

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Monsanto Co., 467 U.S. 986, 1006–07 (1984) (recognizing that reasonable investment-backed expectations are shaped by the regulatory environment in which a party operates).

[173] *See, e.g.*, Federal Power Act, 16 U.S.C. §§ 824d-824e; Clean Air Act §§ 7401 *et. seq.*; Clean Water Act, 33 U.S.C. §§ 1251 *et seq.*; Occupational Safety and Health Act §§ 651 *et seq.*; Standards of Performance for New Stationary Sources, 40 C.F.R. pt. 60 (2025); Steam Elec. Power Generating Point Source Category, 40 C.F.R. pt. 423; COLO. CODE REGS. §§ 40-1-101 *et seq*. (2026).

[174] *See, e.g.*, *Sw. Power Pool, Inc.*, 194 FERC ¶ 61,198 (2026) (approving System Support Resource program to prevent a generating resource retirement when needed to ensure the reliability of the transmission system); *see also* Midcontinent Indep. Sys. Operator, Inc., FERC Electric Tariff, Module A, § 1.S (Definitions), System Support Resource (SSR) (80.0.0) (describing units that are required by the transmission provider for reliability purposes); Letter from Michael E. Bryson, Senior Vice President, PJM, to Chris Wright, Secretary, DOE, at 3 (May 21, 2026) (requesting emergency order under FPA section 202(c) and describing PJM's determination that retirement of certain units will adversely affect reliability and PJM's request for continued operation of the units to support reliability), https://www.energy.gov/documents/pjm-wagner-unit-4-202c-application; Cal. S.B. 846, 2021–2022 Reg. Sess. (Cal. 2022) (requiring the California Energy Commission to determine the need to extend Diablo Canyon's license to operate beyond its expiration date of 2025); *In re Comanche Unit 2 Retirement Extension*, No. 25V-0480E, Decision No. C25-0892 (Colo. Pub. Utils. Comm'n Dec. 10, 2025) (granting request to extend operating life of Pueblo Unit 2).

[175] Tri-State and Platte River Pet. at 14.

"take all measures necessary to ensure that Craig Unit 1 is available to operate" to meet the emergency conditions in Craig's service area.[176]

70. The cases cited by Tri-State and Platte River are inapposite. In both *United States v. Pewee Coal Co.* and *United States v. General Motors Corp*., the Government seized or condemned private property and displaced the owner from physical possession and control.[177] For instance, in *Pewee Coal*, the President issued an executive order directing the Secretary of the Interior to take immediate possession and operational control of certain coal mines in response to wartime labor stoppages.[178] The Secretary of the Interior subsequently seized the mines, required the American flag to be flown at every mine, and directed placards reading "United States Property!" to be posted on the premises.[179] Here, by contrast, DOE has neither assumed physical control of Craig Unit 1 nor asserted any claim of ownership over the facility or any portion of it.

71. Similarly, in *General Motors*, the Government condemned the temporary occupancy of a warehouse, physically ousted the tenant—who was required to remove all personal property and dismantle fixtures—and took physical possession of the premises for temporary use pursuant to the Second War Powers Act of 1942.[180] The Emergency Order involves no comparable action: DOE has not condemned or physically occupied Craig Unit 1, ousted Tri-State or Platte River from the facility, nor taken possession of the premises in whole or in part.

72. Tri-State and Platte River's contention that the Emergency Order constitutes a *per se* physical taking likewise lacks merit. As discussed above, Tri-State and Platte River's argument in this respect focuses on physical changes purportedly arising from compliance with the Emergency Order: (1) repairing out-of-service equipment, (2) using coal reserves allocated to other Craig units, and (3) potentially interfering with transmission infrastructure concerning the Axial Basin facility.[181] None of these grounds is availing.

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[176] Emergency Order at 3, Ordering Paragraph A.

[177] *United States v. Pewee Coal Co.*, 341 U.S. 114 (1951) (*Peewee Coal*); *United States v. Gen. Motors Corp*., 323 U.S. 373 (1945) (*General Motors*).

[178] *See Peewee Coal*, 341 U.S. at 116.

[179] *Id.*

[180] *General Motors*, 323 U.S. at 375.

[181] Tri-State and Platte River Pet. at 16–19.

73. First, operating the electric energy generation facility at the Order of Secretary is specifically contemplated by Congress and authorized by the statute. The fact that Tri-State and co-owners are undertaking repairs or modifications to comply with an emergency directive is an ordinary incident of operating within a regulated industry. Tri-State and Platte River cite *Furey v. City of Sacramento*, for the proposition that government-mandated improvements to property that confer no benefit to the owner evince a taking.[182] *Furey*, however, is inapposite. The Court of Appeals for the Ninth Circuit simply held that the challenged measures—additional improvements to an existing sewage system—*did not* constitute a taking, because it was a landowner-formed assessment district, rather than the government itself, that directed the improvements.[183]

74. More relevant here is *Union Bridge Co. v. United States*, in which the Supreme Court held that a government order requiring a bridge owner to alter its structure at its own expense did not constitute a compensable taking under the Fifth Amendment.[184] The Court in *Union Bridge*—a foundational case not discussed by Tri-State and Platte River—relied on the established principle that "uncompensated obedience to a regulation enacted for the public safety under the police power of the state was not taking property without due compensation."[185] The Court further held that the company "erected the bridge subject to the possibility that Congress might, at some future time, when the public interest demanded, exert its power by appropriate legislation to protect navigation against unreasonable obstructions."[186] The Court accordingly opined that "an order to so alter a bridge over a water way of the United States that it will cease to be an unreasonable obstruction to navigation will not amount to a taking of private property for public use for which compensation need be made," even where compliance would "compel the Bridge Company to make a very large expenditure in money."[187]

75. Similarly, in *AT&T Corp. v. City of Toledo*, the court held that a city's directive requiring a company to relocate its telecommunication cables at its own expense did not effect an unconstitutional taking, because the company's easement was "implicitly subject

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[182] Tri-State and Platte River Pet. at 17–18 (citing *Furey v. City of Sacramento*, 780 F.2d 1448 (9th Cir. 1986)).

[183] 780 F.2d at 1457; *see also id.* at 1454–55.

[184] *Union Bridge Co. v. United States*, 204 U.S. 364 (1907).

[185] 204 U.S. at 395 (citing *Chicago, B. & Q. R. Co. v. Chicago*, 166 U.S. 226, 254 (1897)).

[186] *Id.* at 400.

[187] *Id.* at 401, 403.

to [the city's] continuing duty and right under the police power to engage in the types of construction activities at issue for the preservation of the public health and safety."[188] The court grounded its holding in the well-established principle that "the enforcement of uncompensated obedience to a regulation established under [the police] power for the public health or safety is not an unconstitutional taking."[189]

76. The same general principles reflected in *Union Bridge* and *AT&T* apply here. The Emergency Order advances a compelling governmental interest to address an emergency impacting grid reliability, pursuant to Congress's express delegation of authority in FPA section 202(c). Tri-State and co-owners retain full ownership of Craig Unit 1, notwithstanding the need to make certain repairs to comply with the Emergency Order.

77. Second, Tri-State and Platte River's contention that a taking arose from their reallocation of coal fuel resources from other Craig units to satisfy the Emergency Order's requirements also is unpersuasive. Tri-State and Platte River cite *Horne v. Department of Agriculture*, for the proposition that a "forced depletion of a utility's fuel reserves" constitutes a taking.[190] In *Horne,* the government compelled raisin growers to physically surrender a specific portion of their crop to a government-controlled reserve for redistribution.[191] Here, by contrast, DOE has not directed Tri-State or Platte River to transfer title to any coal or surrender it to a government entity. Any reallocation of fuel reserves reflects an internal operational decision by Tri-State and its co-owners as to the manner of compliance with the Emergency Order—no property has changed hands with the government.

78. Third, Tri-State and Platte River's contention that the Emergency Order constitutes a "physical intrusion" on Tri-State's transmission infrastructure is misguided.[192] This argument rests on the flawed assumption that the Emergency Order requires Craig Unit 1 to continuously dispatch power to the grid. As noted, however, the Emergency Order directs Tri-State and co-owners to "take all measures necessary to ensure that Craig Unit 1 is *available to operate* at the direction of either [WAPA-WACM] in its role as Balancing

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[188] *AT&T Corp. v. City of Toledo*, 351 F. Supp. 2d 744, 747–48 (N.D. Ohio 2005).

[189] *Id.* at 748 (quoting *Tennessee v. United States*, 256 F.2d 244, 256–57 (6th Cir. 1958) (quoting *Atl. Coast Line R.R. Co. v. Goldsboro*, 232 U.S. 548, 558–59 (1914))).

[190] *Horne,* 576 U.S. 350, 357–65 (2015); Tri-State and Platte River Pet. at 18–19.

[191] 576 U.S. at 352 ("The reserve requirement imposed by the Raisin Committee is a clear physical taking. Actual raisins are transferred from the growers to the Government. Title to the raisins passes to the Raisin Committee.").

[192] Tri-State and Platte River Pet. at 19.

Authority or the [SPP] West in its role as the Reliability Coordinator."[193] Accordingly, those entities are empowered to address concerns related to transmission capacity on existing infrastructure.

79. Furthermore, and as discussed above, Tri-State and Platte River argue that the Emergency Order also constitutes a regulatory taking under the *Penn Central* standard, which evaluates (1) the economic impact of the regulation, (2) the regulation's interference with reasonable investment-backed expectations, and (3) the character of the government action.[194] These arguments are equally unavailing. Tri-State and Platte River state that compliance with the Emergency Order imposes economic burdens on them, such as operations and maintenance costs.[195] However, the mere fact that a regulation may impose economic costs is insufficient to establish a taking.[196] The economic impact factor demands something approaching a wholesale deprivation of economically viable use—and not merely the incremental costs of complying with an emergency regulatory order.

80. In addition, Tri-State and Platte River argue that the Emergency Order upsets their investment-backed expectations, including in view of DOE's "novel" use of FPA section 202(c) to address long-term reliability risks and Tri-State and Platte River's operational and financial decisions concerning Craig Unit 1's planned retirement.[197] These arguments overstate both the nature of DOE's action and the protection afforded by the investment-backed expectations factor.

81. Government regulation is an inherent and expected element of operating an electric generating unit because Congress and state legislatures have determined that electric generation is an activity with important public interests that benefit from government involvement.[198] In other words, a reasonable investment-backed expectation for an electric

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[193] Emergency Order at 3, Ordering Paragraph A (emphasis added).

[194] *See* 438 U.S. at 124; Tri-State and Platte River § I.B.

[195] Tri-State and Platte River Pet. at 20–21.

[196] *Penn Central*, 438 U.S. at 131 (noting that courts "uniformly reject the proposition that diminution in property value, standing alone, can establish a 'taking'").

[197] Tri-State and Platte River Pet. at 21–22.

[198] *See, e.g.*, 16 U.S.C. § 824(a) ("It is declared that the business of transmitting and selling electric energy for ultimate distribution to the public is affected with a public interest, and that Federal regulation of matters relating to generation . . . is necessary in the public interest").

utility is that it is subject to substantial (and sometimes costly) government regulation.[199] In issuing the Emergency Order, the Secretary exercised, in view of the specific emergency circumstances presented here, the same statutory authority that has governed the application of FPA section 202(c) since the FPA's inception in 1935.[200] Indeed, the exercise of FPA section 202(c) authority is well established, dating back to its inaugural use in June 1941.[201] DOE has not adopted any new methodology or interpretation of its emergency authority, and the fact that the ongoing emergency in the Craig service region was not anticipated in Tri-State and Platte River's internal planning does not render the mechanism by which DOE acted disruptive to reasonable investment-backed expectations.

82. Tri-State and Platte River also argue that the character of the Emergency Order further strengthens their case for a regulatory taking, asserting that the Order effectively commandeers Craig Unit 1, its fuel, the potential dispatch of the Axial Basin facility, and related infrastructure.[202] This argument also is misplaced. The character of the Emergency Order is that of a temporary, narrowly tailored emergency measure responding to documented resource adequacy conditions, not a commandeering of private property. As noted, Tri-State and co-owners retain ownership of Craig Unit 1. The Emergency Order imposes conditions on the use of Craig Unit 1 in service of a compelling public interest: preventing the loss of power to homes and businesses in areas that may be impacted by curtailments or power outages, creating a risk to public health and safety.[203] This is precisely the kind of government action that *Penn Central* and its progeny recognize as falling short of a taking, and the fact that Tri-State and Platte River believe that other

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[199] *See, e.g.*, FERC Filing of Rate Schedules and Tariffs, 18 C.F.R. pt. 35 (2026) (requiring the filing of rate schedules, tariffs, and service agreements); EPA National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units, 40 C.F.R. pt. 63, subpt. UUUUU (2026) (establishing standards to limit emissions of mercury and other hazardous air pollutants); COLO. CODE REGS. § 40-5-101 (2026) (requiring a certificate of public convenience and necessity to construct and to operate a facility or an extension of a facility).

[200] *See, e.g.*, *Ruckelshaus*, 467 U.S. at 1006–07 ("[Plaintiff] can hardly argue that its reasonable investment-backed expectations are disturbed when [the Agency] acts . . . in a manner that was authorized by law at the time of the submission.").

[201] Recommendation for Curtailment of the Use of Elec. Energy in the Se. States, 2 F.P.C. 990, 990 (1941).

[202] Tri-State and Platte River Pet. at 23.

[203] *See generally* Emergency Order at 3.

utilities or other means could address the emergency does not transform a legitimate exercise of emergency regulatory authority into a constitutional violation.[204]

83. Even if Petitioners were correct that the Emergency Order constituted a taking under the Fifth Amendment, Petitioners' contention that the FPA framework for recovering costs arising from compliance with an FPA section 202(c) emergency order does not provide "just compensation"[205] as required by the Fifth Amendment is unavailing. FPA section 202(c)(1) expressly establishes:

> If the parties affected by [a FPA section 202(c)] order fail to agree upon the terms of any arrangement between them in carrying out such order, [FERC], after hearing held either before or after such order takes effect, may prescribe by supplemental order such terms as it finds to be just and reasonable, including the compensation or reimbursement which should be paid to or by any such party.

84. Furthermore, DOE's regulations address the procedures that DOE follows when relevant entities are unable to agree on rate issues arising from a FPA section 202(c) order:

> The applicant and the generating or transmitting systems from which emergency service is requested are encouraged to utilize the rates and charges contained in approved existing rate schedules or to negotiate mutually satisfactory rates for the proposed transactions. In the event that the DOE determines that an emergency exists under [FPA] section 202(c), and the "entities" are unable to agree on the rates to be charged, the DOE shall prescribe the conditions of service and refer the rate issues to the Federal Energy Regulatory Commission for determination by that agency in accordance with its standards and procedures.[206]

85. As FERC recently explained in a cost-recovery proceeding related to another 202(c) order,[207]

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[204] 438 U.S. at 123–28; *Tahoe-Sierra Pres. Council, Inc. v. Tahoe Reg'l Planning Agency*, 535 U.S. 302, 321–22 (2002) (applying *Penn Central* and holding temporary moratorium on development did not constitute a *per se* taking); *Keystone*, 480 U.S. at 485 (applying *Penn Central* and finding no taking where regulation served a substantial public interest and did not render the property economically unviable).

[205] Tri-State and Platte River Pet. at 23–24.

[206] 10 C.F.R. § 205.376.

[207] *PJM Interconnection, L.L.C.*, DOE Order No. 202-25-8 (Aug. 27, 2025)

> DOE and [FERC] have distinct roles under the DOE Organization Act. DOE has sole responsibility to determine that "an emergency exists" due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and to require temporary connections of facilities that, "in its judgment will best meet the emergency and serve the public interest." [FERC] is responsible for prescribing "compensation or reimbursement."[208]

86. Indeed, the Secretary followed this process here. Specifically, the Emergency Order directed "Tri-State and co-owners" "to file with [FERC] [t]ariff revisions or waivers to effectuate this Order. Rate recovery is available pursuant to 16 U.S.C. § 824a(c)."[209] In this respect, DOE finds Tri-State and Platte River's assertion that the process detailed above does not "guarantee [their] complete recovery"[210] as speculative and unfounded. Tri-State and Platte River's concerns about the purported procedural "complexity" of such proceedings do not override the cost-recovery framework Congress provided in FPA section 202(c), so the Emergency Order does not amount to an uncompensated taking.

The cases Tri-State and Platte River cite for the proposition that FERC cost recovery is not "just compensation" because some costs would be borne by ratepayers are inapposite. *Baker v. City of McKinney*, involved incidental third-party donations or collateral insurance recoveries, not a statutorily authorized recovery framework.[211] The decision in *U.S. Bank, National Association v. SFR Investments Pool 1, LLC* is likewise inapposite.[212] There, the plaintiff sought redress against a private purchaser rather than the government,[213] and the court held that the plaintiff bore the burden of demonstrating that state compensation

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(concerning Units 3 and 4 of the Eddystone Generating Station in Eddystone, Pennsylvania).

[208] *PJM Interconnection, L.L.C.*, 195 FERC ¶ 61,002, at P 26 (2026) (citations omitted).

[209] Emergency Order at 4, Ordering Paragraph E.

[210] Tri-State and Platte River Pet. at 24.

[211] *Baker v. City of McKinney*, 608 F. Supp. 3d 457, 464–67 (E.D. Tex. 2022).

[212] *U.S. Bank, Nat'l Ass'n v. SFR Invs. Pool 1, LLC*, 2016 WL 1248704 (D. Nev. Mar. 28, 2016).

[213] 2016 WL 1248704, at *4.

remedies were unavailable or inadequate.[214] The case thus fails to support the notion that the congressionally established cost-recovery mechanism under FPA section 202(c) does not or cannot provide "just compensation."

6. Potential Environmental Impacts

87. PIOs and Colorado State contend that the Emergency Order fails to comply with FPA section 202(c)'s requirements to ensure that any order that may result in a conflict with environmental law or regulation requires generation only during hours necessary to meet the emergency, is consistent with applicable environmental laws to the maximum extent practicable, and minimizes any adverse environmental impacts.[215] Specifically, PIOs and Colorado State contend that the Emergency Order may conflict with multiple environmental requirements applicable to Craig Unit 1, such as Colorado's Clean Air Act State Implementation Plan (SIP) and regional haze requirements.[216] According to PIOs and Colorado State, the Emergency Order also lacks detailed reporting obligations, without which DOE has no mechanism to minimize potential adverse environmental impacts.[217]

88. Moreover, PIOs and Colorado State argue that the Emergency Order fails to ensure that Craig Unit 1 generates electric energy "only during hours necessary to meet the emergency and serve the public interest," as required by FPA section 202(c)(2)."[218] In particular, PIOs and Colorado State argue that, absent clear temporal limitations on Craig Unit 1's operational status, the Emergency Order will be in direct conflict with state and federal environmental laws.[219]

DOE's Determination

89. FPA section 202(c)(2) requires the Secretary to ensure that any FPA section 202(c) order that may result in a conflict with a requirement of any environmental law or regulation to the "maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[ ] any adverse environmental

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[214] *Id.* at *4–5.

[215] PIOs Pet. § V.D. (citing 16 U.S.C. § 824a(c)(2)); Colorado State Pet. § V.E.ii (citing 16 U.S.C. § 824a(c)(2)).

[216] PIOs Pet. at 84–90; Colorado State Pet. at 79–83.

[217] *Id*.

[218] 16 U.S.C. § 824a(c)(2); PIOs Pet. at 87–88; Colorado State Pet. at 77–79.

[219] PIOs Pet. at 87–88; Colorado State Pet. at 77–79.

impacts."[220] In addition, FPA section 202(c)(2) requires the Secretary to ensure that any directed action that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest."[221]

90. PIOs and Colorado State argue the Emergency Order does not adequately limit the operating hours of any Craig Unit 1 to those necessary to meet the emergency.[222] This argument is not valid. The Emergency Order expressly provides that, "[t]o minimize adverse environmental impacts, this Order limits operation of Craig Unit 1 to the times and within the parameters established in paragraph A."[223] The applicable Balancing Authority and Reliability Coordinator retain full discretion to dispatch Craig Unit 1 only as necessary to address the emergency as identified in the Emergency Order. The Emergency Order thus does not authorize unlimited or unrestricted operation of Craig Unit 1; rather, it confines operation to those hours necessary to meet the emergency and serve the public interest, consistent with FPA section 202(c)(2).

91. PIOs and Colorado State further contend that the Emergency Order does not identify sufficient conditions to minimize adverse environmental impacts.[224] However, the Emergency Order expressly recognizes the potential for conflict with environmental requirements and responds to it. The Order requires that "[a]ll operations of Craig Unit 1 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions" and further confirms that the Order "does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions."[225] In addition, the Emergency Order requires Tri-State to provide daily notifications to DOE reporting whether Craig Unit 1 has operated consistently with the Order and in compliance with applicable environmental requirements.[226] These conditions provide a mechanism for DOE to monitor compliance and obtain information concerning any adverse environmental impacts of the emergency

[220] 16 U.S.C. § 824a(c)(2).

[221] *Id.*

[222] PIOs Pet. at 87–88; Colorado State Pet. at 77–79.

[223] Emergency Order at 4, Ordering Paragraph B.

[224] PIOs Pet. at 87–90; Colorado State Pet. at 79–83.

[225] Emergency Order at 4, Ordering Paragraph C.

[226] *Id.*, Ordering Paragraph B.

operations, and DOE may modify the Emergency Order to require additional actions as the Secretary deems appropriate within his judgment and in view of the declared emergency.

92. Finally, DOE notes that Congress recognized, by including the phrase "to the maximum extent practicable," that emergency circumstances would at times make compliance with all Federal, state, and local environmental requirements infeasible.[227] Furthermore, the FPA provides that any "omission or action [taken to comply with an order issued under FPA section 202(c)] shall not be considered a violation of such environmental law or regulation."[228] To the extent that continued availability to operate or dispatch the Craig Unit 1 creates compliance challenges under those requirements, Tri-State is directed to comply with applicable environmental requirements to the maximum extent feasible while continuing to fulfill the terms of the Emergency Order.

7. NEPA Concerns

93. Colorado State claims that the Emergency Order violates the National Environmental Policy Act (NEPA) because it constitutes a major federal action significantly affecting the quality of the human environment that requires compliance with NEPA.[229] Colorado State argues that, because DOE has allegedly misused its FPA section 202(c) emergency authority, DOE cannot rely on the determination in its NEPA Implementing Procedures that NEPA does not apply to the issuance of emergency orders pursuant to FPA section 202(c).[230] According to Colorado State, there is no "emergency situation that demands immediate action," and therefore the exception for 202(c) emergency orders is unavailable.[231]

94. Colorado State further asserts that DOE's NEPA Implementing Procedures preclude the use of a categorical exclusion where an action has the potential to cause significant impacts on environmentally sensitive areas, including federally and state-designated wilderness areas and national parks.[232] Colorado State contends that Craig Unit 1's retirement by December 31, 2025 was required under Colorado's federally approved State

[227] 16 U.S.C. § 824a(c)(2).

[228] *Id.* § 824a(c)(3).

[229] Colorado State Pet. at 19, 87–88.

[230] *Id.* at 87.

[231] *Id*. (citing 10 C.F.R. § 1021.103).

[232] *Id.* at 88 (citing 10 C.F.R. pt. 1021, app. B).

Implementation Plan, which is designed to protect national parks and wilderness areas in Colorado from visibility impairment.[233]

DOE's Determination

95. DOE disagrees with Colorado State's contention that the Order "requires evaluation under NEPA."[234] NEPA does not apply "where compliance would be inconsistent with other statutory requirements."[235] Preparing an environmental document under NEPA's generally applicable provisions would be inconsistent with the emergency provisions in the FPA, which explicitly authorizes the Secretary to exercise certain emergency authorities "with or without notice, hearing, or report."[236] Requiring compliance with the analytic and procedural burdens of preparing an environmental document under NEPA prior to issuing a FPA section 202(c) emergency order is inconsistent with the congressional authorization to exercise such emergency authority without report and would render the emergency relief statute a nullity.

96. Moreover, Congress enacted specific environmental compliance requirements for emergency orders. Specifically, the FPA requires that any emergency order that may result in a conflict with a Federal, State, or local environmental law or regulation must be limited to the "hours necessary to meet the emergency," must be consistent with applicable environmental laws "to the maximum extent practicable," and must minimize "any adverse environmental impacts."[237] Additionally, an emergency order that may result in a conflict with an environmental law or regulation is capped at 90 days and only may be renewed after consultation with the primary Federal agency with expertise in the environmental interest protected by law.[238] These statutory directives provide the governing framework for addressing environmental compliance for an emergency order issued under FPA section 202(c), and the FPA statutory scheme controls. NEPA review would be inconsistent with the FPA statutory requirements, thus the FPA displaces the need for NEPA review.

97. While DOE previously followed the steps provided in DOE's NEPA regulations governing emergency actions, as described in the prior 10 C.F.R. § 1021.343 (for example,

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[233] *Id.*

[234] *Id.* at 87.

[235] 42 U.S.C. § 4332(C).

[236] 16 U.S.C. § 824a(c)(1).

[237] *Id.* § 824a(c)(2).

[238] *Id.* § 824a(c)(4).

by preparing a special environmental analysis after the issuance of a FPA section 202(c) order), those regulations have been revised.[239] DOE is using its NEPA Implementing Procedures and is not bound by its prior approach. NEPA states that agencies are "not required to prepare an environmental document with respect to a proposed agency action if . . . the preparation of such document would clearly and fundamentally conflict with the requirements of another provision of law."[240] Accordingly, DOE has determined, in consultation with the Council on Environmental Quality, that "NEPA does not apply to DOE's issuance of emergency Orders pursuant to section 202(c) of the [FPA] (16 U.S.C. § 824a(c)) because preparing an environmental document under NEPA's generally applicable provisions would clearly and fundamentally conflict with the emergency provisions in the [FPA]."[241]

98. In addition, by including the phrase "to the maximum extent practicable," Congress recognized that emergency circumstances would at times make compliance with all Federal, State, and local environmental requirements and minimization of all potential adverse environmental impacts infeasible. This phrase illustrates Congressional intent to subordinate environmental concerns to ensure an adequate supply of electric energy, providing DOE with discretion to fulfill its obligations under FPA section 202(c). Accordingly, the Emergency Order's limits on duration, the conditions that authorize only the additional generation necessary, and the requirement that operation of the Craig Unit complies with environmental laws to the maximum extent feasible, as well as the reporting requirements that allow DOE to monitor compliance with the Emergency Order, were sufficient to satisfy the Secretary's obligation under FPA section 202(c)(2).

99. DOE's environmental obligations were met through the conditions imposed via the Emergency Order's limitation on the duration of the emergency operations, the authorization only of the additional generation necessary, the requirement that operation of Craig Unit 1 comply with environmental laws to the maximum extent feasible, and Tri-State's obligation to report to DOE on its compliance with the Emergency Order and corresponding environmental impacts, if any. Preparation of a NEPA environmental document would be inconsistent with issuing an emergency order under FPA section 202(c), preparing a NEPA environmental document would clearly and fundamentally

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[239] *See* 10 C.F.R. § 1021.343; Revision of Nat'l Env't Pol'y Act Implementing Procs., 90 Fed. Reg. 29676 (July 3, 2025).

[240] Fiscal Responsibility Act of 2023, Pub. L. No. 188-5, § 321(b), 137 Stat. 10, 39 (2023).

[241] DOE, *Nat'l Env't Pol. Act* (*NEPA) Implementing Procs.*, at 6 (June 30, 2025), https://www.energy.gov/sites/default/files/2025-06/2025-06-30-DOE-NEPA-Procedures.pdf.

conflict with the requirements of FPA section 202(c), and FPA section 202(c) displaces the need for NEPA review.

100. Colorado State's contention[242] that DOE cannot invoke NEPA's conflict-based exclusion because DOE has allegedly "misused" its emergency authority is without merit. As addressed above, the Secretary's emergency determination under FPA section 202(c) is lawful and well-supported. Similarly, Colorado State's argument that DOE's NEPA implementing regulations preclude the use of a categorical exclusion for actions affecting environmentally sensitive areas is inapposite.[243] DOE's determination that NEPA does not apply to FPA section 202(c) orders rests on the statutory conflict between NEPA and FPA section 202(c), not on the application of a categorical exclusion. Because the conflict-based exclusion renders NEPA inapplicable to the Emergency Order in its entirety, the categorical exclusion framework—and any potential limitations thereon—are not implicated.

III. Procedural Issues

1. Requests for Stay

101. PIOs and Colorado State each move for a stay of the Emergency Order pending resolution of judicial review.[244] In support of their request, PIOs and Colorado State contend that (1) absent a stay, they will be irreparably harmed by the Emergency Order, (2) a stay will not harm any other interested parties, and (3) the public interest favors a stay.[245]

DOE's Determination

102. In considering a request for a 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 other parties; and (3) whether a stay serves the public interest.[246]

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[242] Colorado State Pet. at 87.

[243] *Id.* at 88.

[244] PIOs Pet. § VI; Colorado State Pet. § VI.

[245] PIOs Pet. § VI; Colorado State Pet. § VI.

[246] *See Nken v. Holder*, 556 U.S. 418, 434–36 (2009); *Ohio v. Env't Prot. Agency*, 603 U.S. 279, 291 (2024).

103. By its terms, the Emergency Order terminated on March 30, 2026.[247] Consequently, the stay request is now moot.

104. In any case, DOE finds that a stay is not warranted here based on a broader consideration of the equities at issue. First, PIOs and Colorado State also fail to present any evidence of substantial and irreparable harm. Indeed, a stay would substantially harm other stakeholders and is therefore not within the public interest. Specifically, the Emergency Order was issued to address a shortage of electric energy and a shortage of facilities for the generation of electric energy in Craig's service region. As discussed above, this determination is based on the insufficiency of dispatchable capacity and anticipated demand, as well as the risk to the public health and safety presented by the potential loss of power to homes and local businesses in areas that may be affected by curtailments or outages. Imposition of a stay would also harm those citizens residing in the Craig's service region who would face potentially critical electric energy shortages, and therefore the stay would have been contrary to the public interest. The balance of equities thus favors denial of a stay.

2. Motions to Intervene

105. On January 26, 2026, Public Service filed a motion for leave to intervene. On January 28, 2026, PIOs and Colorado State also filed a motion to intervene and request for rehearing. On January 29, 2026, Tri-State and Platte River filed a motion to intervene. Public Service, PIOs, Tri-State and Platte River, and Colorado State each cite various alleged interests which may be affected by the outcome of this proceeding.[248]

DOE's Determination

106. The motions to intervene in this administrative proceeding are hereby permissively granted for Public Service, PIOs, Tri-State and Platte River, and Colorado State, but DOE takes no position on whether Public Service, PIOs, and Colorado State are "aggrieved" parties for purposes of FPA section 313.[249]

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[247] Emergency Order at 4, Ordering Paragraph H.

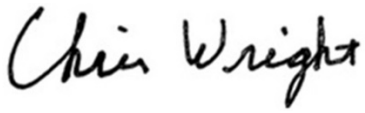
[248] Public Service Pet. at 1–3; PIOs Pet. § III; Colorado State Pet. § II.

[249] *See* 16 U.S.C. § 825*l*(b) ("Any party to a proceeding under this chapter aggrieved by an order issued by the Commission in such proceeding may obtain a review of such order in the United States court of appeals for any circuit wherein the licensee or public utility to which the order relates is located or has its principal place of business, or in the United States Court of Appeals for the District of Columbia, by filing in such court, within sixty days after the order of the Commission upon the application for rehearing, a written

* * * * *

The Emergency Order is hereby modified upon the issuance of this Order and the result sustained, as discussed in the body of this Order.

_____
Issued on this 24th day of June 2026.



_____
Chris Wright
Secretary of Energy

petition praying that the order of the Commission be modified or set aside in whole or in part.").

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 3-02
Queued Up: 2025 Edition

BERKELEY LAB
LAWRENCE BERKELEY NATIONAL LABORATORY



Queued Up: 2025 Edition

Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2024

Joseph Rand[1], Nick Manderlink[1], Steven Zhang[2], Chris Talley[2], Will Gorman[1], Ryan Wiser[1], Joachim Seel[1], Julie Mulvaney Kemp[1], Seongeun Jeong[1], Fritz Kahrl[1]

1. Lawrence Berkeley National Laboratory
2. Interconnection.fyi

December 2025

This work was funded by the U.S. Department of Energy under Contract No. DE-AC02-05CH11231. The views and opinions of the authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Image source: Vecteezy.com

Interconnection.fyi
Tracking U.S. ISO & utility interconnection queues

i2X INTERCONNECTION INNOVATION e-XCHANGE
U.S. DEPARTMENT OF ENERGY

About This Report:

The *Queued Up* report presents an annual snapshot of trends in requests for generator interconnection to the bulk-power (transmission) electric grid. This report summarizes empirical data from transmission providers' (i.e., ISO/RTOs and utilities) publicly-available interconnection queues. In some cases, the analysis leverages additional (non-public) data provided to LBNL directly from transmission providers to fill in gaps from the public data.
The 2025 edition of the report summarizes interconnection queue data through the end of 2024. Therefore, any updates to the data and trends that occurred since January 2025 would not be represented in this report.
The report neither directly comments on nor recommends any specific policies – it simply summarizes and explains data trends.

The most up-to-date version of the report, alongside a complete data file, previous versions of the report, and other resources, can always be found at: https://emp.lbl.gov/queues

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  - Hybrid projects in the queues
- Operational and Withdrawn Requests
  - Volume of operational and withdrawn projects
  - Completion + withdrawn rates and trends
- Duration Trends – Time in Queues
- Conclusions

What are interconnection queues?

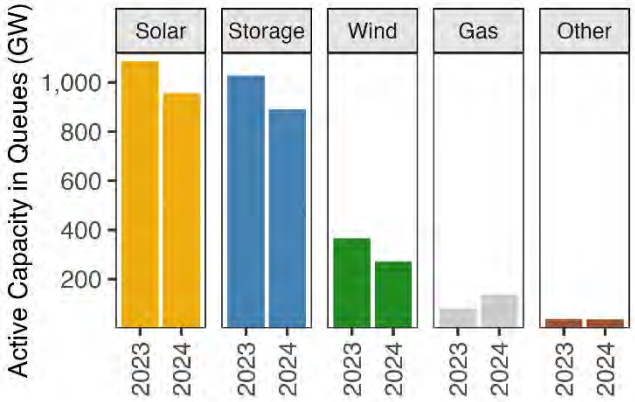
Utilities and regional grid operators (a.k.a., ISOs or RTOs) require projects seeking to connect to the grid to undergo a series of studies before they can be built. This process establishes what new grid system upgrades may be needed before a project can connect to the system and then estimates and assigns the costs of that equipment. The lists of projects that have applied to connect to the grid and initiated this study process are known as “interconnection queues”.

Visit https://emp.lbl.gov/queues to access related resources including the complete dataset used for this analysis and interactive data visualization tools

High-Level Findings

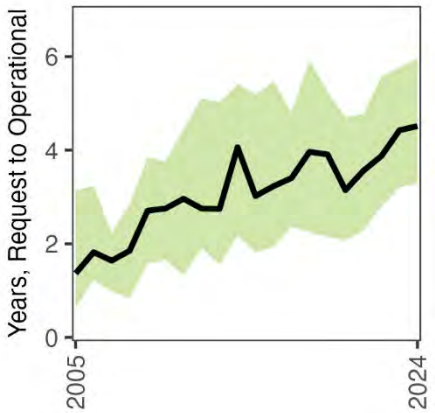
Overall queue volume decreased year-over-year, but gas increased

- Roughly 2,290 gigawatts (GW) of capacity actively seeking interconnection (1,400 GW of generation; 890 GW of storage)
- Natural gas capacity increased (+72%), while solar (-12%), storage (-13%), and wind (-26%) decreased in 2024



Completion rates are generally low; wait times are long

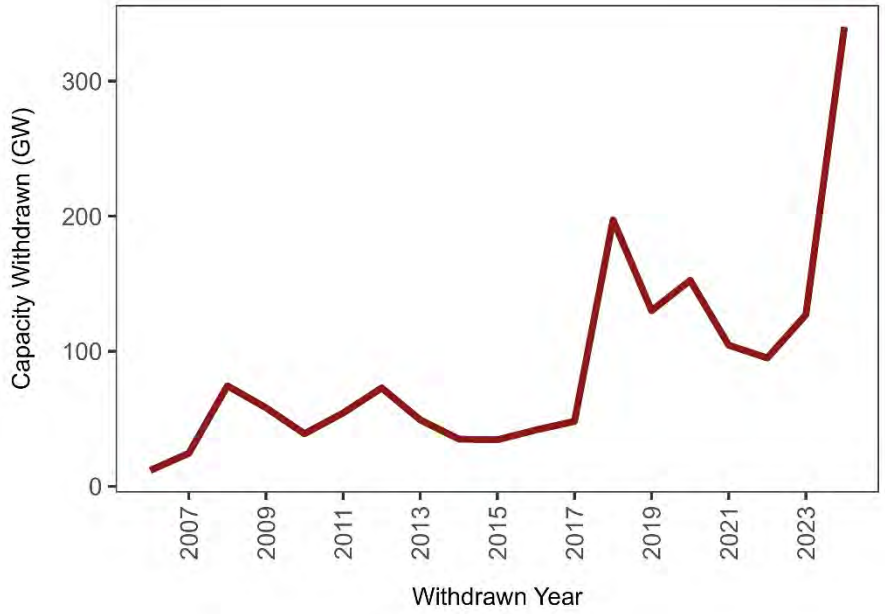
- About 19% of projects (13% of capacity) requesting interconnection from 2000-2019 reached commercial operations by the end of 2024



- The average time projects spent in queues remains high in most, but not all, regions. The typical project built in 2024 took 55 months from the interconnection request to commercial operations[1], compared to 36 months in 2015 and 22 months in 2008
- These trends raise concerns for meeting growing electricity demand and resource adequacy needs

Major process reforms have resulted in historic withdrawal rates, as well as reduced volume of new requests

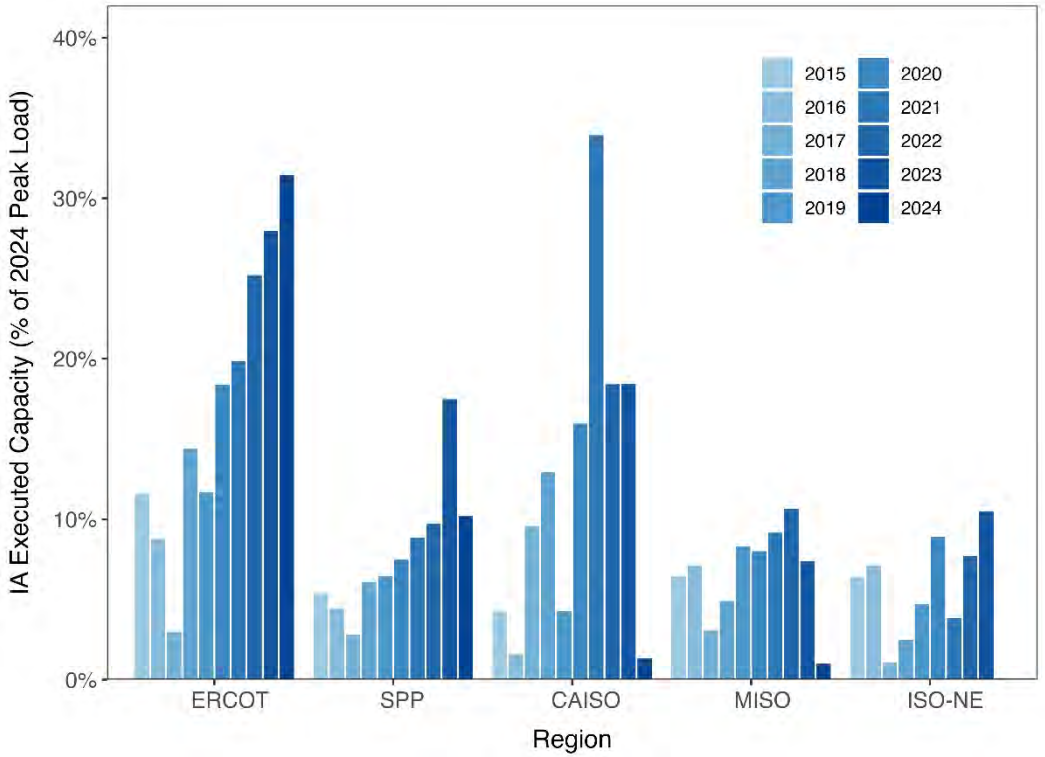
- More than 700 GW[2] of capacity withdrew in 2024, while ~500 GW submitted new requests
- Federal interconnection process reforms such as FERC Order 2023 alongside major ISO reforms (e.g., CAISO, PJM, MISO, and SPP) are driving these trends
- But, market conditions, project financing, transmission constraints, and permitting barriers may also lead to high withdrawals and reduced applications



1. In-service date was only available for 72% of all operational projects. 2. Withdrawn year was only available for 51% all withdrawn requests, so the chart illustrates less than the total withdrawn capacity in each year.

New additions for the 2025 edition of Queued Up:

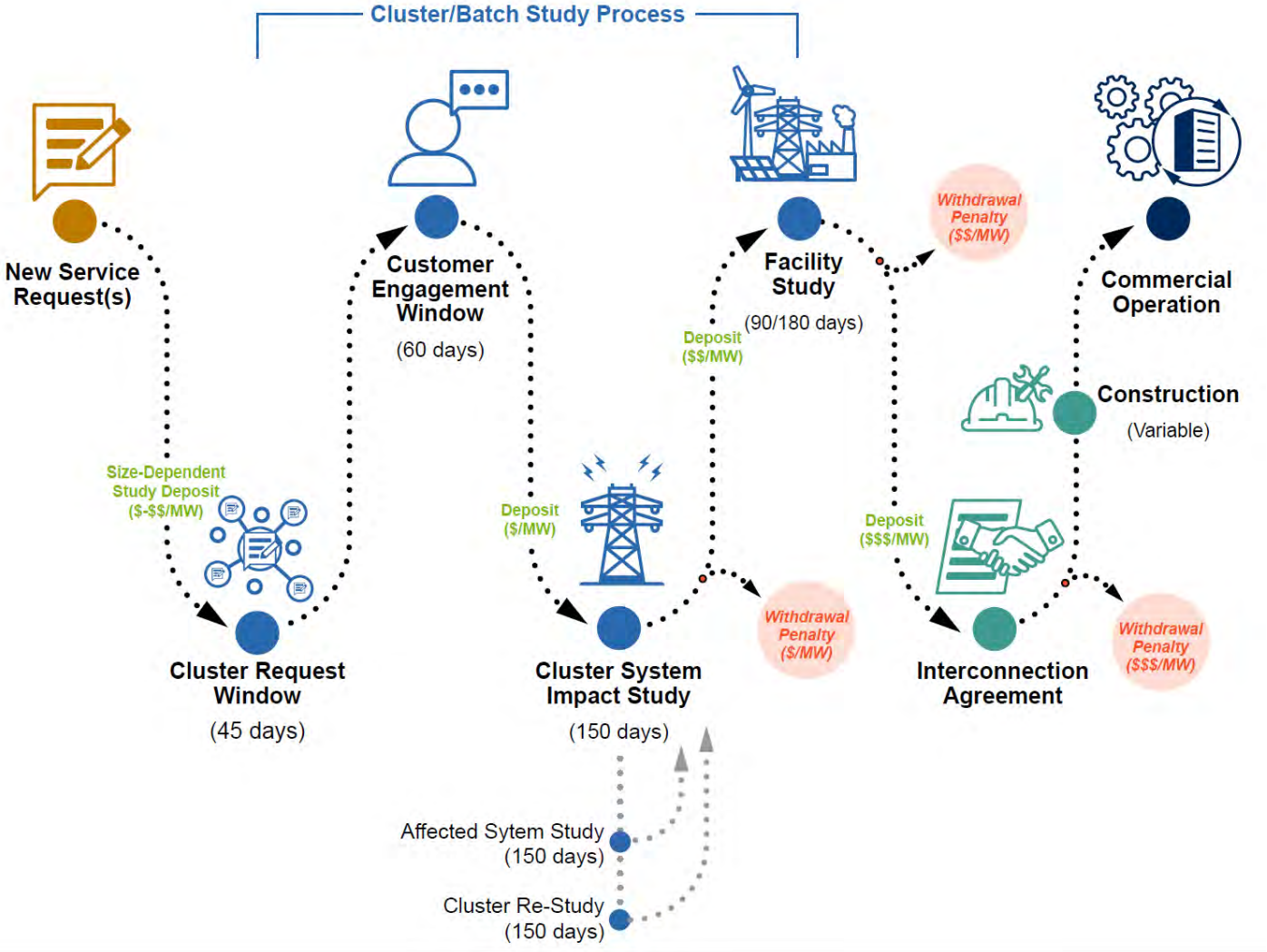
- **Additional detail on data processing methods and data gaps**
  - Detail on data cleaning and processing methods (slide 8)
  - Description and quantification of data gaps (slide 9)
- **Updates to interconnection reforms + regulatory activities**
  - Updated summary of key activities at the federal and balancing area level (slide 10)
- **Drivers of reduction in overall queue volume**
  - Description of potential drivers of reduction in queue volume (slide 14)
- **New analysis on interconnection agreements (IAs)**
  - Additional analysis on the volume of IAs executed, and fraction of requests reaching the IA stage, by region and over time (slide 25)
  - Analysis on fraction of requests that reach commercial operations after signing an IA (i.e., post-IA completion rates) (slide 34)
- **Miscellaneous items**
  - New data provider (interconnection.fyi – see slide 7)
  - Additional detail on natural gas requests (see, e.g., slide 20)
  - New data visualization style for duration time trends (slides 38-49)
  - Several additional balancing areas included (see slide 55)



Annual volume of interconnection agreements executed by region as a fraction of 2024 peak load. See slide 25 for detail.

Typical Interconnection Study Process and Timeline

- A project developer initiates a new ***interconnection request (IR)*** and thereby enters the ***queue***
- A series of ***interconnection studies*** establish what new transmission equipment or upgrades may be needed and assigns the costs of that equipment
- The studies culminate in an ***interconnection agreement (IA)***: a contract between the ISO and/or utility and the generation owner that stipulates operational terms and cost responsibilities
- Most proposed projects are ***withdrawn,*** which may occur at any point in the process
- After executing an IA, many projects are built and reach ***commercial operation***

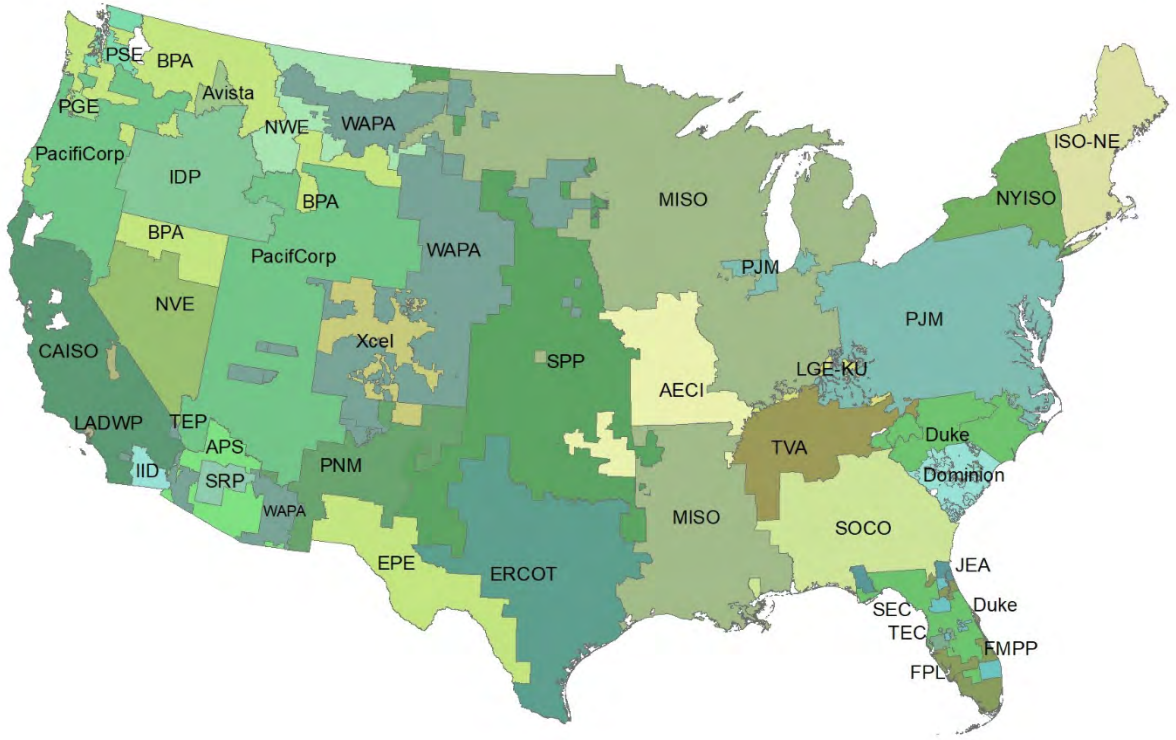


Note: These steps are in accordance with Federal Energy Regulatory Commission (FERC) pro-forma interconnection procedures as outlined in FERC Order 2023. Some ISOs already use a cluster-study approach. The data presented in this report pre-date Order No. 2023 implementation.

Data Sources

Interconnection.fyi
Tracking U.S. ISO & utility interconnection queues

- Data collection led by Interconnection.fyi
- Data collected from interconnection queues for 7 ISOs / RTOs and 49 non-ISO balancing areas (including utilities and Power Marketing Administrations), which collectively represent ~97% of currently installed U.S. electric generating capacity
  - Queue data files are downloaded from transmission provider websites and/or OASIS web pages
  - Includes projects that connect to the bulk-power system, not distribution-connected or behind-the-meter[1]
  - Includes projects in queues through the end of 2024
- The full sample[2] includes:
  - 4,432 “operational” projects (~511.8 GW)
  - 10,303 “active”[3] projects (~2,290 GW)
  - 546 “suspended”[4] projects (~113.6 GW)
  - 20,921 “withdrawn” projects (~3,924 GW)



Coverage area of entities for which data was collected
Data source: Homeland Infrastructure Foundation-Level Data (HIFLD)
Note that service areas can overlap
No data collected for Hawaii or Alaska

A full list of included balancing areas can be found in the appendix

Notes: (1) There are different processes for transmission- and distribution-system interconnection. This report only covers transmission interconnection. (2) The full ‘Queued Up’ data sample can vary somewhat year-over-year – particularly as missing records or data fields are filled in over time. (3) “Active” requests include those that are actively requesting or undergoing grid interconnection studies, as well as those that have already executed interconnection agreements but have not yet reached commercial operations. (4) The implication of “suspended” differs by balancing area but generally means the request is on hold; see slide 24 notes for detail.

Data Cleaning and Post-Processing Methods

- The initial data collection effort involves downloading >80 queue data files from 56 transmission providers (ISO/RTOs and utilities)
  - These “raw” data files are unstandardized in terms of format, layout, data fields included, and file type (Excel, CSV, PDF, HTML)
- In order to compile a clean dataset for this analysis, substantial data cleaning, standardization, and QA/QC was conducted by LBNL and Interconnection.fyi teams:
  - Standardizing all raw data fields into a specified set of columns
  - Mapping generator types into standardized categories
  - Mapping interconnection status into standardized categories
  - Generating separate capacity columns for hybrid plants (mw_1, mw_2)
  - Cleaning and standardizing other fields (e.g., dates, county, state)
  - In-filling missing data (e.g., dates) with other available data sources (e.g., non-public data shared by transmission providers) where possible
- Additional processing required for hybrid power plants
  - Some transmission providers do not explicitly identify hybrid (co-located) power plants; LBNL identifies and matches these
  - Many transmission providers do not provide separate capacity data for each component of hybrid plants. Where *storage* capacity is missing, LBNL estimates and imputes the missing values

The final cleaned, processed, and fully compiled dataset is available at: https://emp.lbl.gov/queues

Field Name	Description
q_id	queue ID number
q_status	current queue status (active, withdrawn, suspended, or operational)
q_date	interconnection request date (date project entered queue)
prop_date	proposed online date from interconnection application
on_date	date project became operational (if applicable)
wd_date	date project withdrawn from queue (if applicable)
ia_date	date of signed interconnection agreement (if applicable)
IA_status_raw	interconnection study phase / status from queue
IA_status_clean	standardized interconnection study phase / status
county	county where project is located
state	state where project is located
county_state_pairs	concatenated county and state
fips_codes	5-digit FIPS code
poi_name	point of interconnection name
region	region where project is located (ISO or non-ISO region)
project_name	project name
utility	utility name
entity	transmission provider entity name (ISO or utility)
developer	project developer name
cluster	queue cluster
service	interconnection service type (e.g., ERIS or NRIS, energy or capacity)
project_type	type of project or interconnection request (load/transmission/generation)
type1	resource type 1
type2	resource type 2
type3	resource type 3
mw1	capacity of type 1 (MW)
mw2	capacity of type 2 (MW)
mw3	capacity of type 3 (MW)
type_clean	resource type - standardized
q_year	year project entered queue
prop_year	proposed online year from interconnection application

Notable Interconnection Data Gaps

Data	Detail
Interconnection Agreement (IA) / study phase status	Unknown for ~49% of records
Commercial operations date (actual COD for operational plants)	Unknown for ~24% of operational plants (lack of interoperable IDs prevents merging dates from other sources)
Withdrawn date	Unknown for ~49% of withdrawn requests
IA date (date of executed agreement)	Unknown for ~39% of requests with draft or executed IA *including operational* (*see table*)
Hybrid capacity (breakdown for hybrid plants, i.e. MW_1, MW_2)	Missing or partially missing in most regions (complete in CAISO, ERCOT); imputed (estimated) where missing
Geospatial information	Additional spatial data on the location (lat/long) of requests (or their point of interconnection) is not available
Interconnection costs	The interconnection upgrade costs assigned to project developers are typically not accessible; (see emp.lbl.gov/interconnection_costs for LBNL's data and analysis of costs)

Completeness of "IA Date" data by region

	Count with IA (includes operational)	Count with IA Date	**Percent Populated**
CAISO	470	346	74%
ERCOT	1085	1011	93%
ISO-NE	187	144	77%
MISO	2,034	1,655	81%
NYISO	*Unknown*	109	NA
PJM	1,677	249	15%
SPP	651	561	86%
Southeast	581	164	28%
West	1,397	772	55%
All	**8,192**	**5,011**	**61%**

Berkeley Lab (with support from DOE's i2X program and Grid Deployment Office) is actively seeking to fill these data gaps through partnerships, data sharing agreements, and data transparency initiatives.

FERC Order 2023[1] overhauled the interconnection process, and many RTOs are proposing or implementing major interconnection process updates and reforms[2]

Interconnection Reforms in FERC Order 2023

- ***Cluster studies***; ***first ready, first served***; higher ***deposits & readiness*** criteria for developers
- ***Timeline, process, and reporting*** requirements for transmission providers; ***Financial penalties*** for delays
- Visual representation ***(heatmaps) of available transmission capacity***
- Improved and standardized process for ***affected system studies***
- Improved procedures and ***flexibility for storage and hybrid resources***
- Consideration of ***alternative transmission technologies (GETs)***
- Compliance filing deadline: ***May 2024***

Major ISO/RTO Reforms & Updates

CAISO

- Interconnection Process Enhancements (IPE) (*approved by FERC Oct. 2024*).
- Prioritizes requests where transmission system has available existing or planned capacity and limit requests in a study area based on planed transmission capacity.
- Delayed Cluster 16 request application window from April 2024 (new date TBD) due to queue volume and reforms (thus, no new requests in 2024).

PJM

- Implemented transition from serial first-come, first-served queue process to a first-ready, first-served clustered cycle approach, grouping projects into three-phase cluster cycles for studying and allocating interconnection costs (*approved by FERC Nov. 2022*).
- New requests received in 2024 were not immediately available for study as they were still processing the backlog through the transition process.
- New one-time only fast-track process for high resource adequacy projects (*approved by FERC Feb. 2025*).

MISO

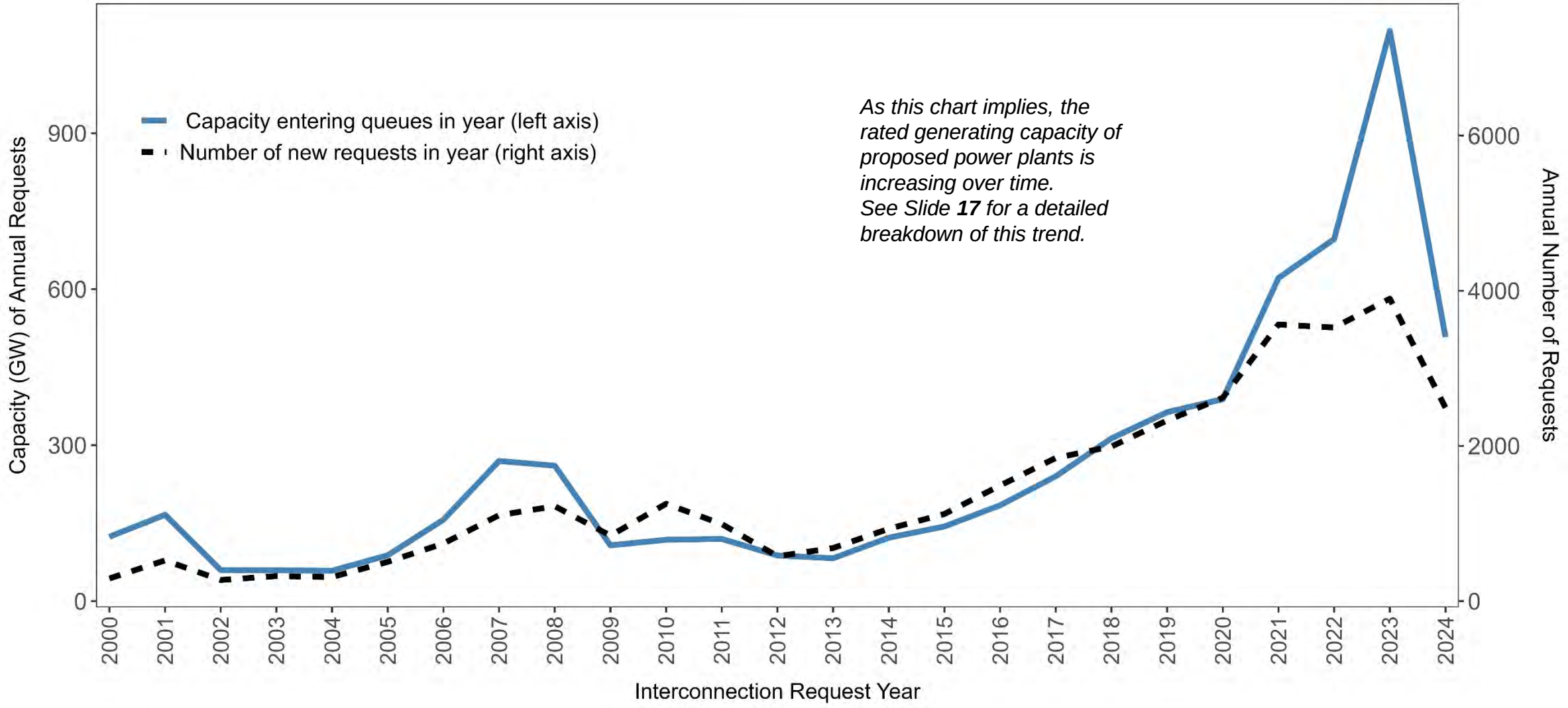
- Increased milestone payments, adopted an automatic withdrawal penalty, and expanded site control requirements for interconnection facilities (*approved by FERC Jan. 2024*).
- Proposal to cap total queue size was approved by FERC (*January 2025*).

SPP

- Filed a waiver to postpone closing of 2024 queue request window until March 2025, and defer opening the 2025 request window until April 2026 (*approved by FERC Oct. 2024*).

Notes: (1) FERC Order 2023 - RM22-14-000. https://www.ferc.gov/media/e-1-order-2023-rm22-14-000. (2) The effects of Order 2023 and other reforms will not be immediate; most data presented in this report pre-date these reforms.

Annual interconnection requests surged from 2013-2023, but slowed in 2024; Still, nearly 2,500 requests representing over 500 GW were added in 2024



Notes: (1) This total annual volume includes projects with a current queue status of "active", "suspended", "withdrawn", or "operational". (2) All values – especially for earlier years – should be considered approximate.

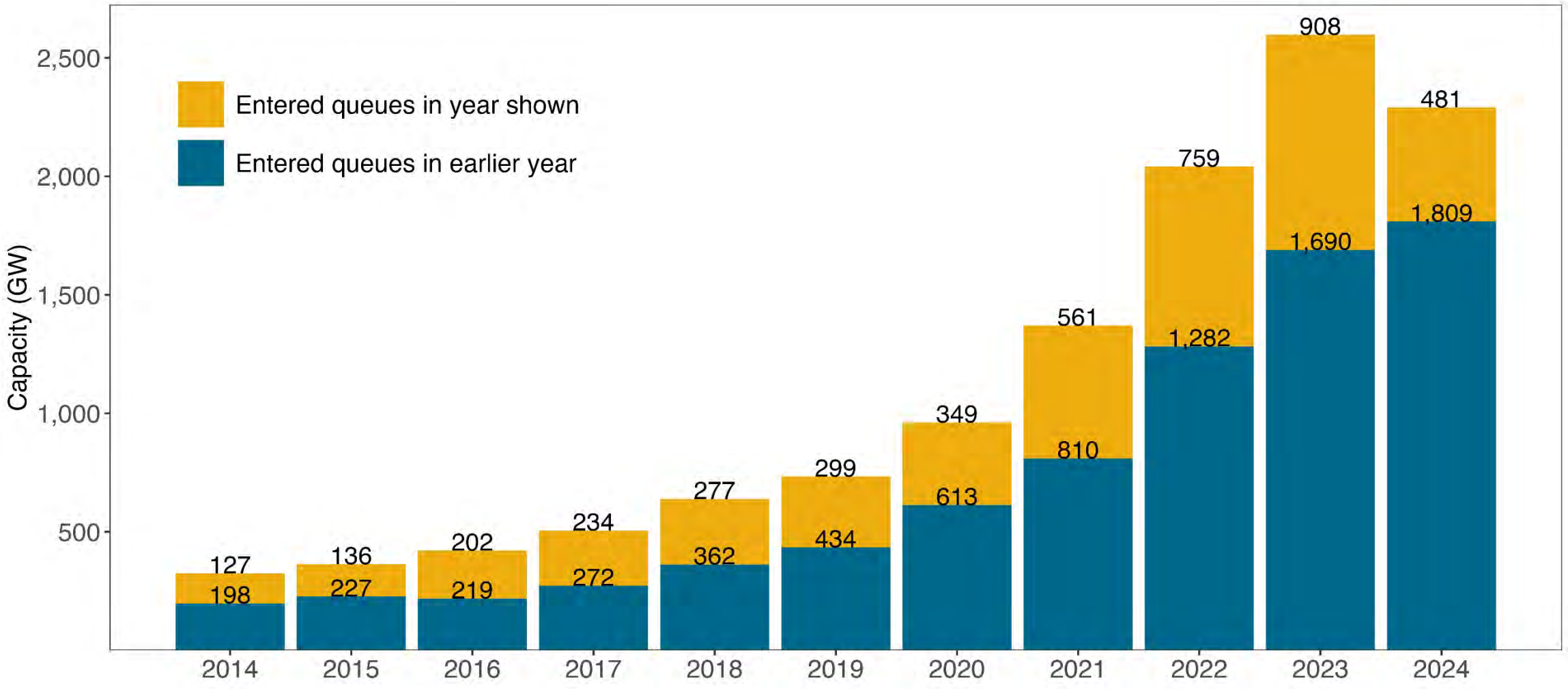
Active Projects in Interconnection Queues: Volume, Regional Trends, Study Phase, and Hybrids

Includes data from all 7 ISO/RTOs and 49 non-ISO balancing areas, totaling 10,303 requests and 2,290 GW

Region	*n* (active)	Capacity (GW)
CAISO	638	272.8
ERCOT	1,447	346.1
ISO-NE	399	45.6
MISO	2,213	447.5
NYISO	402	78.5
PJM	1,942	211.5
SPP	643	142.4
Southeast (non-ISO)	1,002	162.5
West (non-ISO)	1,617	583.5

Notes: (1) Active capacity (GW) shown includes some estimates for hybrid storage capacity in cases where it was missing. (2) Data were sought from 7 ISOs and 49 non-ISO BAs (full list available in appendix). (3) CAISO includes Cluster 15. (4) "Active" requests include those that are actively requesting or undergoing grid interconnection studies, as well as those that have already executed interconnection agreements but have not yet reached commercial operations. (5) See appendix for more detailed summary tables

Total (cumulative) active capacity in queues decreased 12% in 2024, to 2,290 GW; New (annual) requests were down by nearly half in 2024 compared to 2023



Note that some requests can be submitted and withdrawn in the same year; this chart only includes capacity remaining as of the end of each year. Therefore, the yellow bars are lower than the total capacity of new requests in a given year (as shown on slide 11).

Factors that may have contributed to the reduction in new requests and cumulative active queue capacity in 2024

Federal Reform: FERC Order 2023

- Many balancing areas transitioning to cluster studies
- Requires higher at-risk deposits from developers
- Requires 90% site control to submit request; 100% site control at facility study phase

ISO Reforms and Delays

- **CAISO:** Interconnection Process Enhancement
  - Cluster 15 request window closed in April, 2023
  - Cluster 16 was delayed; no new requests in 2024
- **PJM:** Transition cycle process
  - Major overhaul to PJM interconnection process
  - New requests received in 2024 were not immediately available for study as they were still processing backlog
- **SPP:** Postponed request window closing
  - Extended 2024 request window to 2025

See slide 10 for more detail on these reforms

Higher Withdrawal Rates

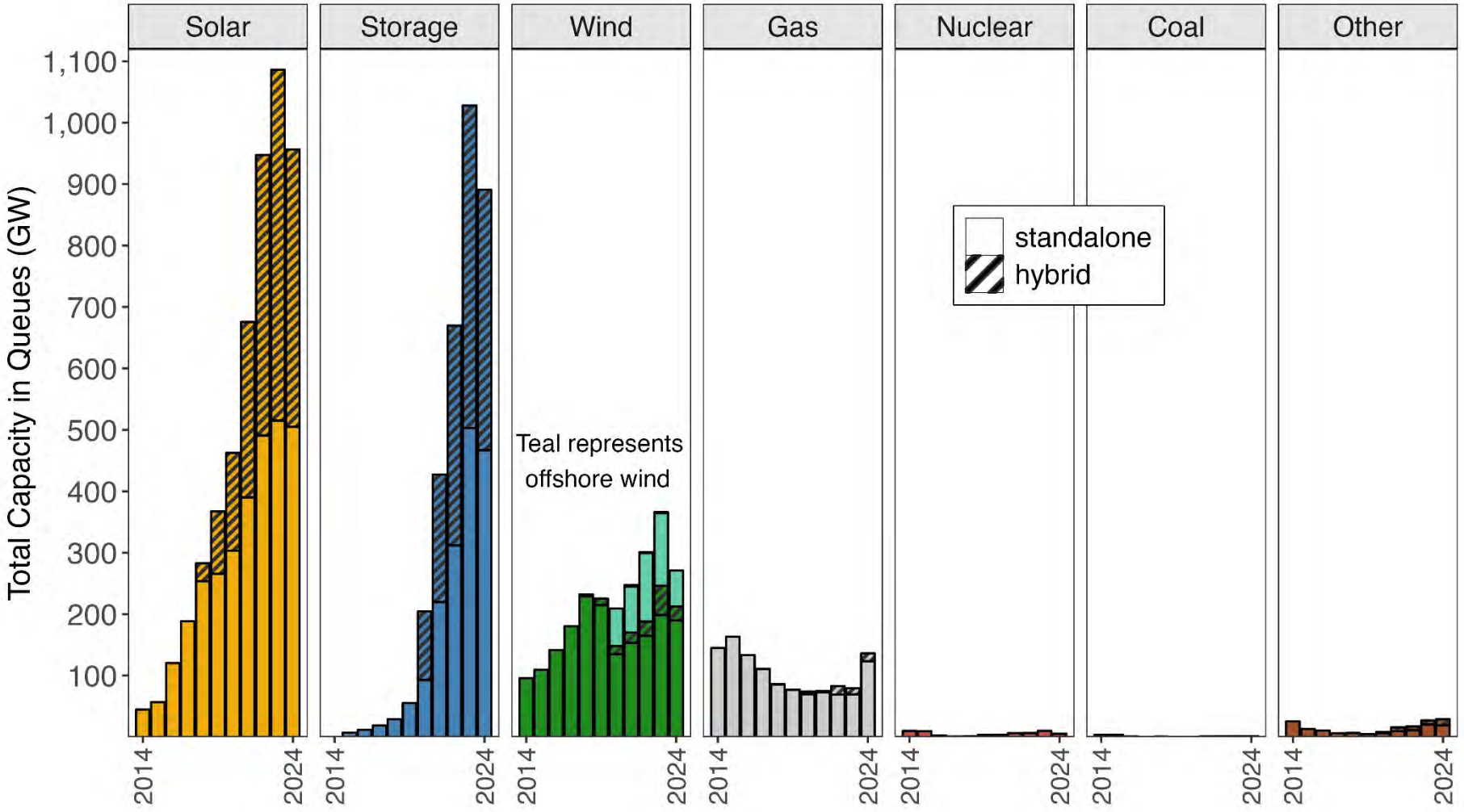
- In addition to reduced new requests, several regions experienced significant withdrawal rates in 2024, likely due to reforms (see left) as well as policy and market drivers. For example:
  - **NYISO:** Substantial offshore wind capacity withdrew in 2024
  - **CAISO:** Many withdrawals from Cluster 15 as IPE reforms go into effect
  - **PJM:** Many withdrawals as transition cluster cycles begin

High Interconnection Upgrade Costs

- Limited available transmission capacity has resulted in high network upgrade costs for new requests, which contributes to high withdrawals and may deter developers from submitting new requests
- See LBNL's related research on interconnection costs:

https://emp.lbl.gov/interconnection_costs

Gas (136 GW) capacity increased by 72% year-over-year, whereas Solar (956 GW, -12%), Storage (890 GW, -13%), and Wind (271 GW, -26%) all decreased in 2024

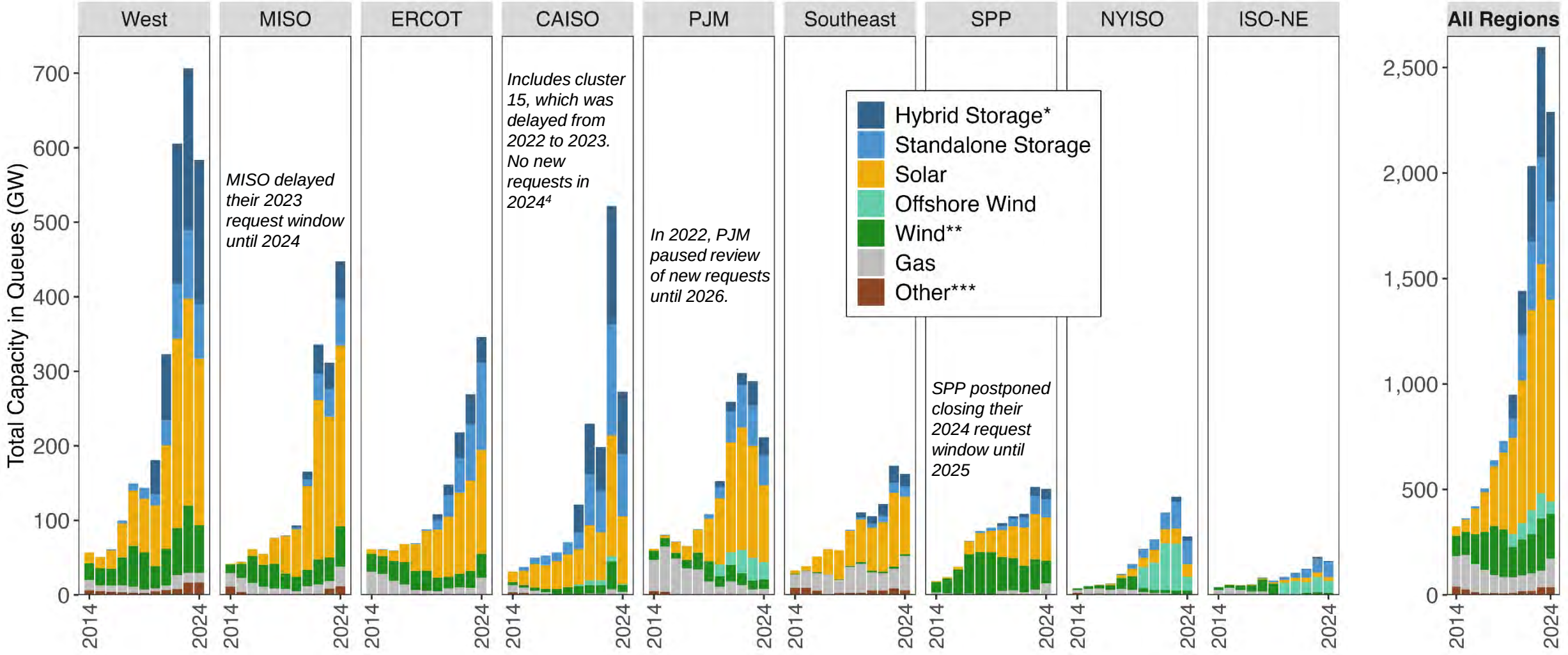


- **Wind** includes both onshore and offshore
- **Other** includes
  - Hydropower
  - Geothermal
  - Biomass/biofuel
  - Landfill gas
  - Solar thermal
  - Oil/diesel
- **Storage** is primarily (99%) battery, but also includes pumped storage hydro, compressed air, gravity rail, and hydrogen

See https://emp.lbl.gov/queues to access an interactive data visualization tool.

Notes: (1) Hybrid storage capacity is estimated for some projects using storage:generator ratios from projects that provide separate capacity data, and that value is only included starting in 2020. Storage duration is not provided in interconnection queue data. (2) Wind capacity includes onshore and offshore for all years, but offshore is only broken out starting in 2020. (3) Hybrid capacity is included separately in respective resource categories (see slide 27 for detail). (4) Not all of this capacity will be built.

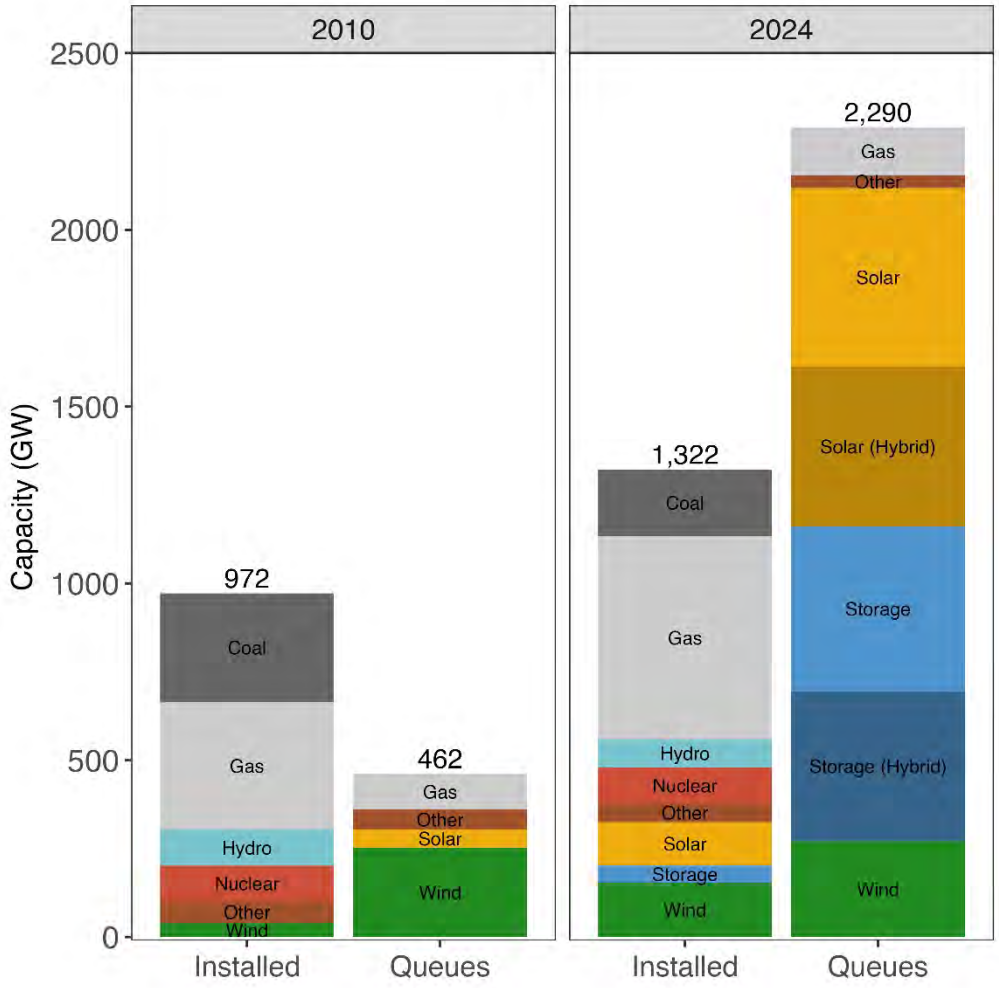
Active queue capacity is highest in the West (584 GW), followed by MISO (447 GW). Several regions have paused or delayed new requests as reforms are implemented



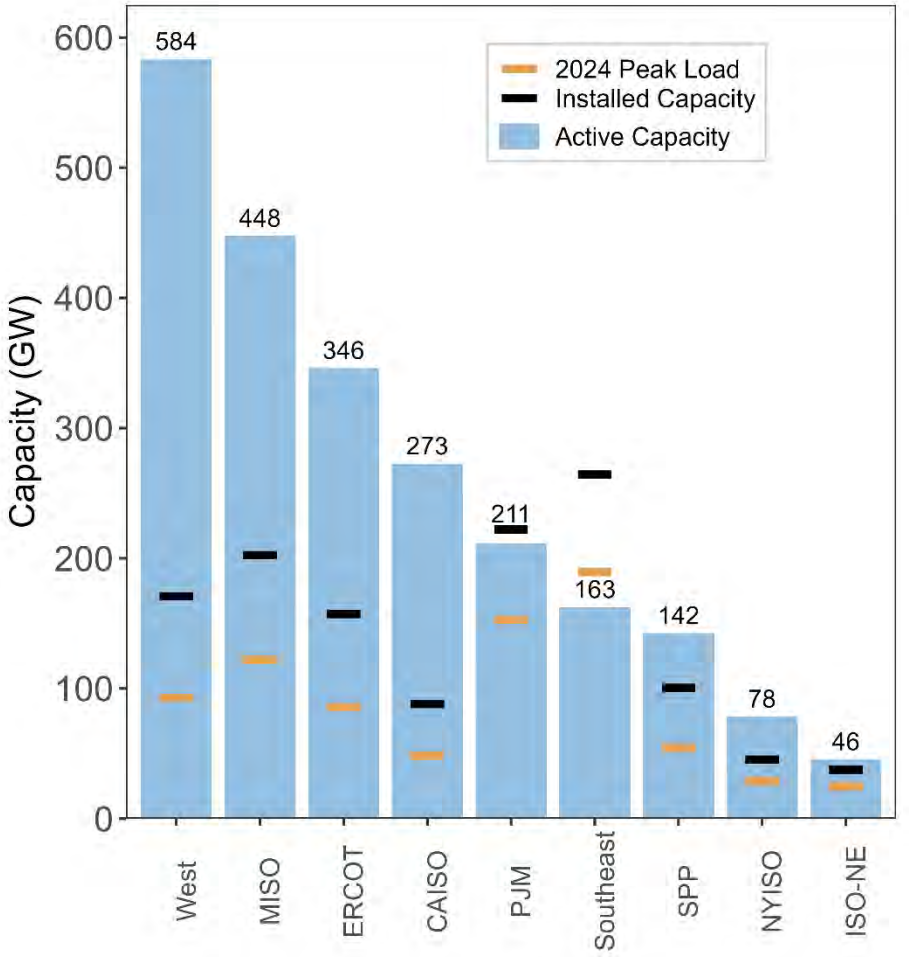
*Notes: (1) *Hybrid storage capacity is estimated for some projects using storage:generator ratios from projects that provide separate capacity data, and that value is only included starting in 2020. Storage duration is not provided in interconnection queue data. (2) **Wind capacity includes onshore and offshore for all years, but offshore is only broken out starting in 2020. (3) ***Other in this chart includes Coal, Nuclear, Hydro, Geothermal, and Other / Unknown. (4) CAISO required cluster 15 to pause due to FERC Order 2023 and resubmit in 2024, resulting in many withdrawals and some changes to requested capacity. (5) Not all of this capacity will be built.*

Active capacity in 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

Entire U.S. Installed Capacity vs. Active Queues



Regional Installed Capacity & Peak Load vs. Active Queues

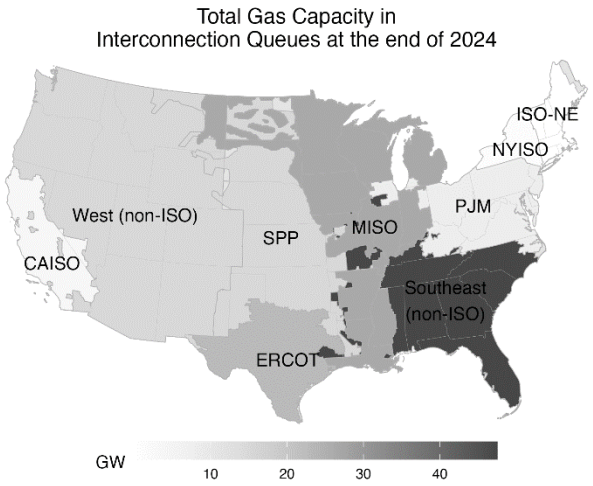


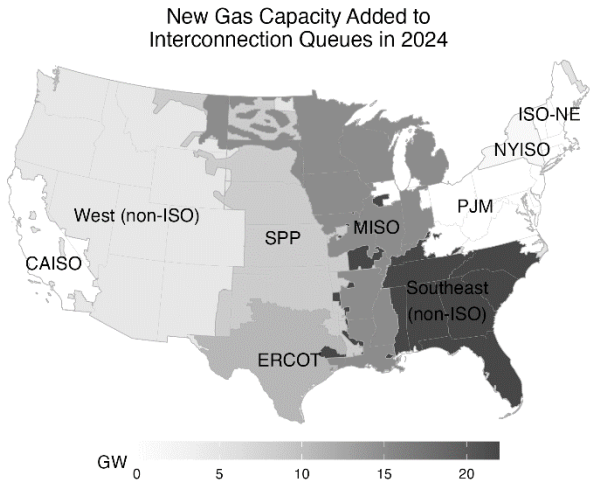
This is not an assessment of resource adequacy. Comparisons of queue capacity to installed capacity or peak load should also consider generators' contributions to resource adequacy. As variable resources, the potential contribution of solar and wind to resource adequacy and peak load requires significant analysis and it is not directly comparable to dispatchable generation resources like natural gas.

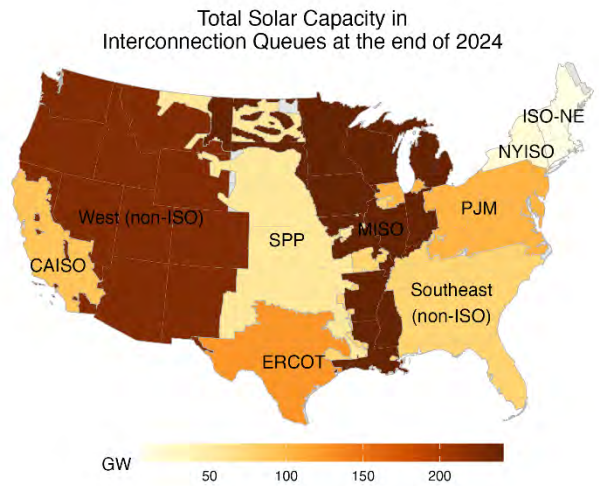
It is highly unlikely that all of this capacity will be built (see slide 31).

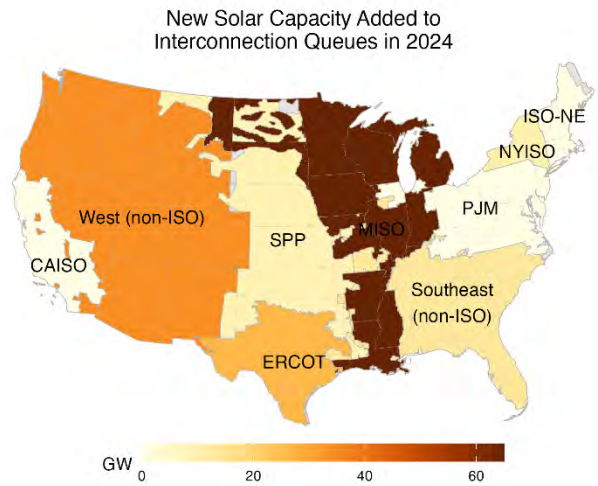
Notes: (1) Hybrid storage in queues is estimated for some projects. (2) Total and regional installed capacity from EIA-860, December 2024. (3) Peak load data from RTO websites or from NERC for non-RTO regions.

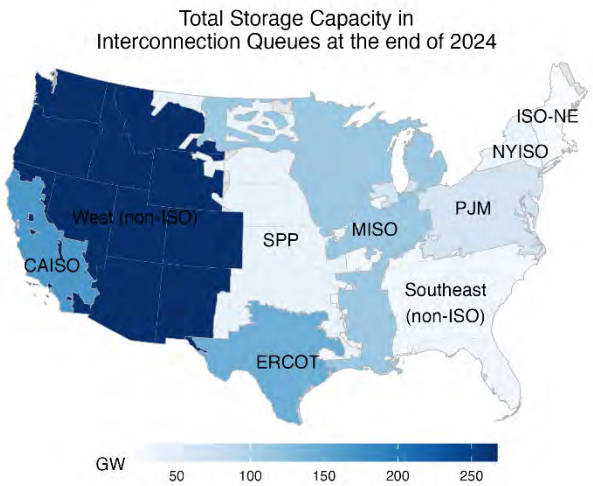
Active gas requests are primarily in the Southeast; solar is widespread, with less in SPP and Northeast; storage requests highest in the West but growing in ERCOT and MISO; most wind in the West and MISO

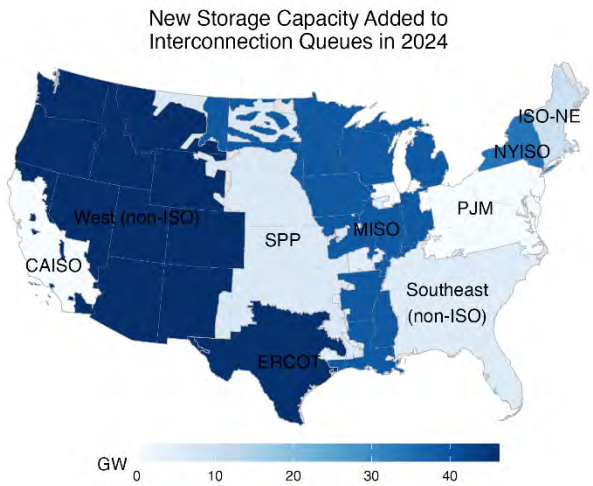


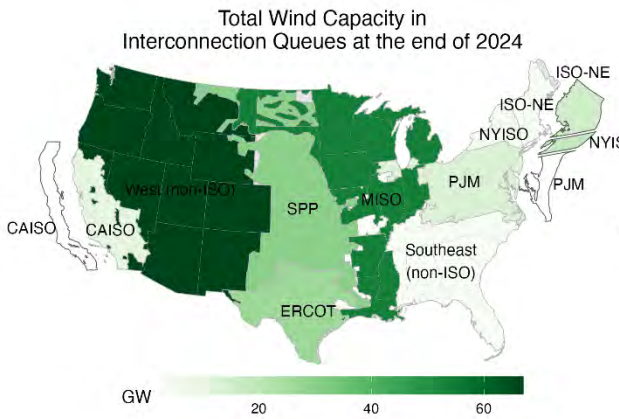


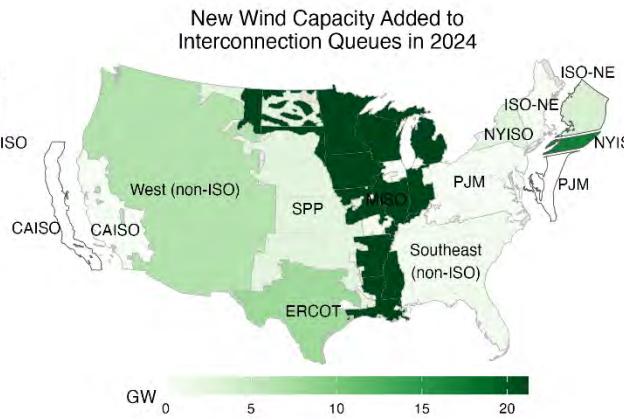








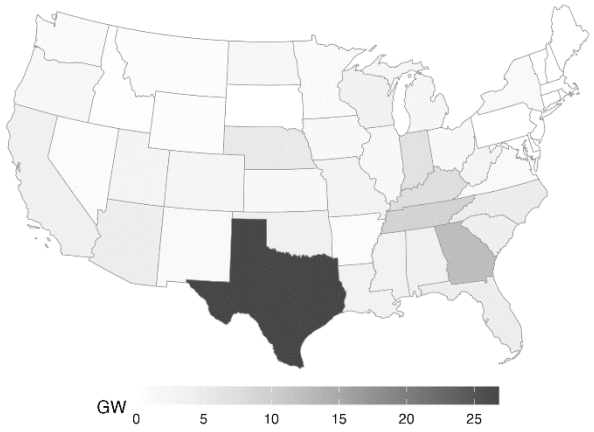




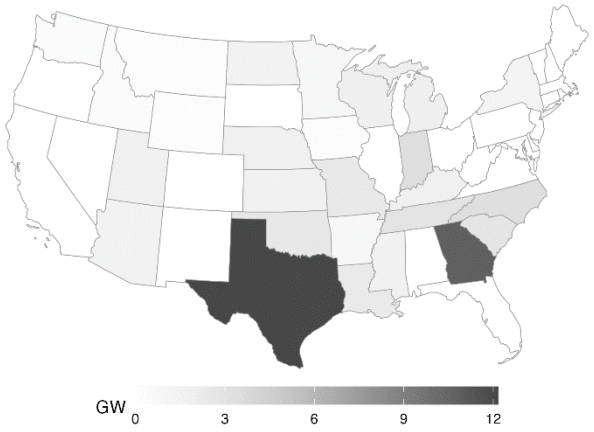
Note: Proposed and ongoing reforms in CAISO, SPP, and PJM resulted in few (or no) new requests in those regions in 2024 (see slide 10)

Texas is a very strong market across all resources. Gas requests are primarily in Texas and the Southeast. Solar requests exist in every state, but most capacity in the Southwest.

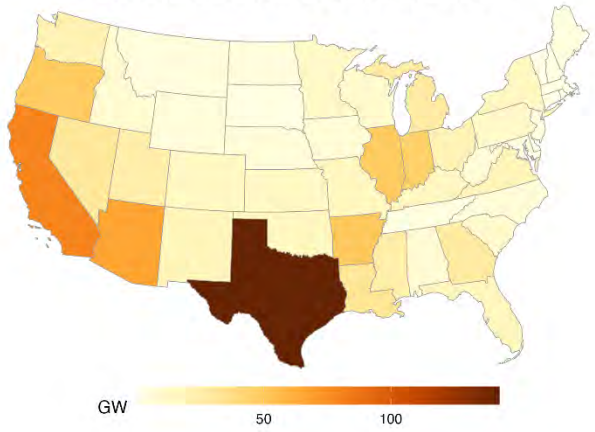
Total Gas Capacity in Interconnection Queues at the end of 2024



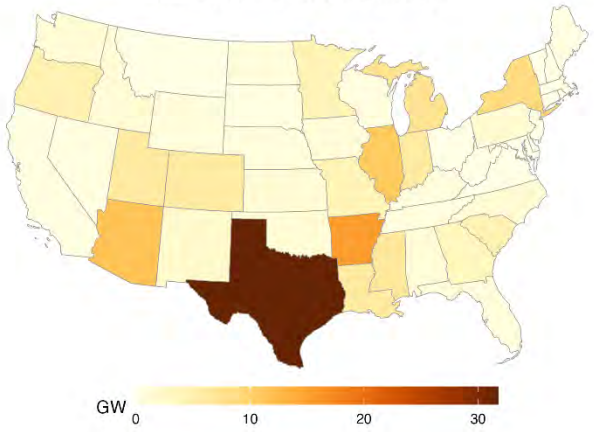
New Gas Capacity Added to Interconnection Queues in 2024



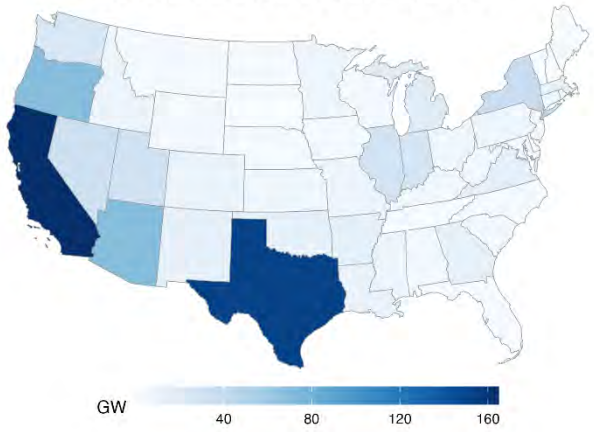
Total Solar Capacity in Interconnection Queues at the end of 2024



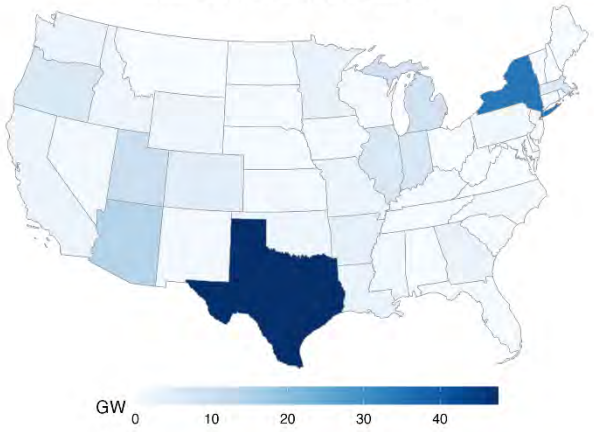
New Solar Capacity Added to Interconnection Queues in 2024



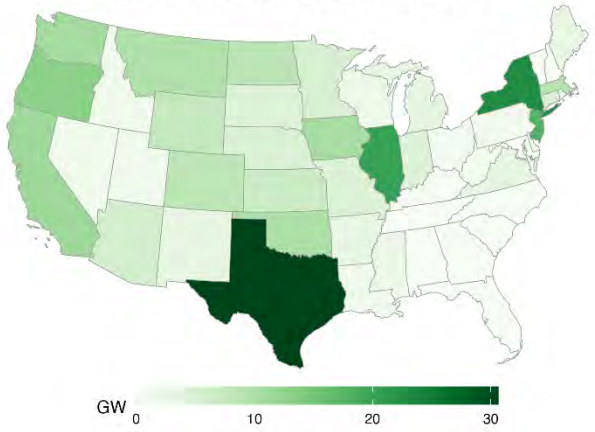
Total Storage Capacity in Interconnection Queues at the end of 2024



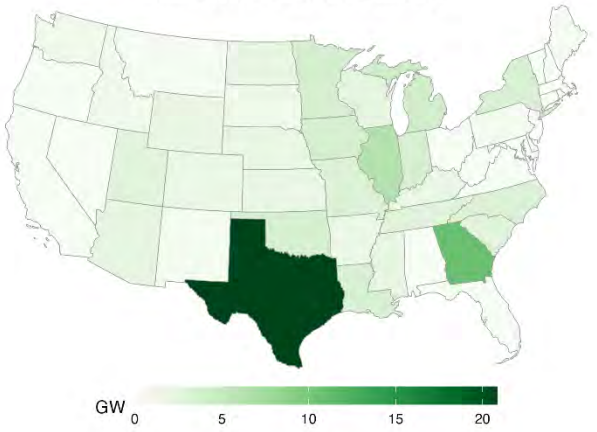
New Storage Capacity Added to Interconnection Queues in 2024



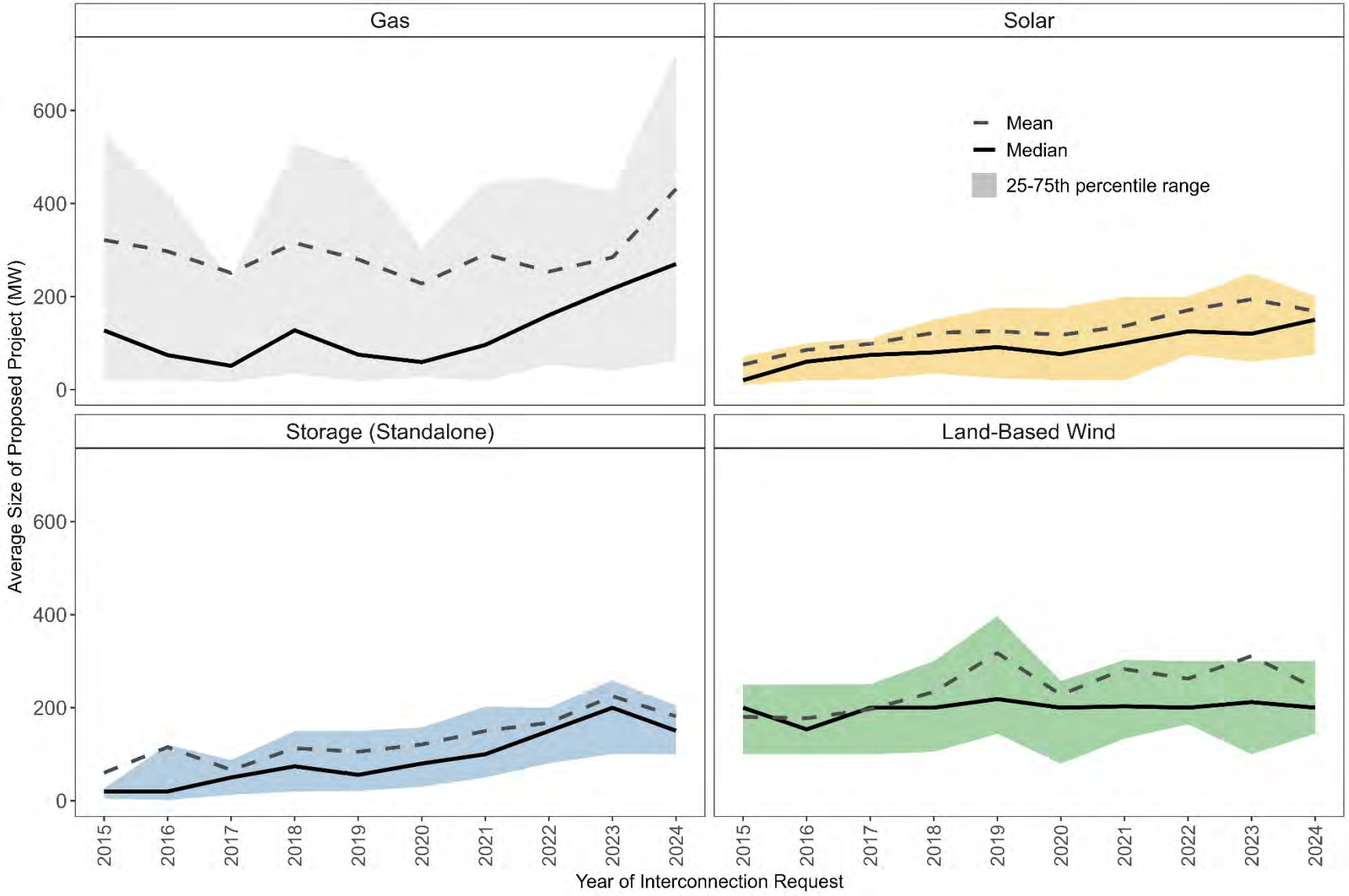
Total Wind Capacity in Interconnection Queues at the end of 2024



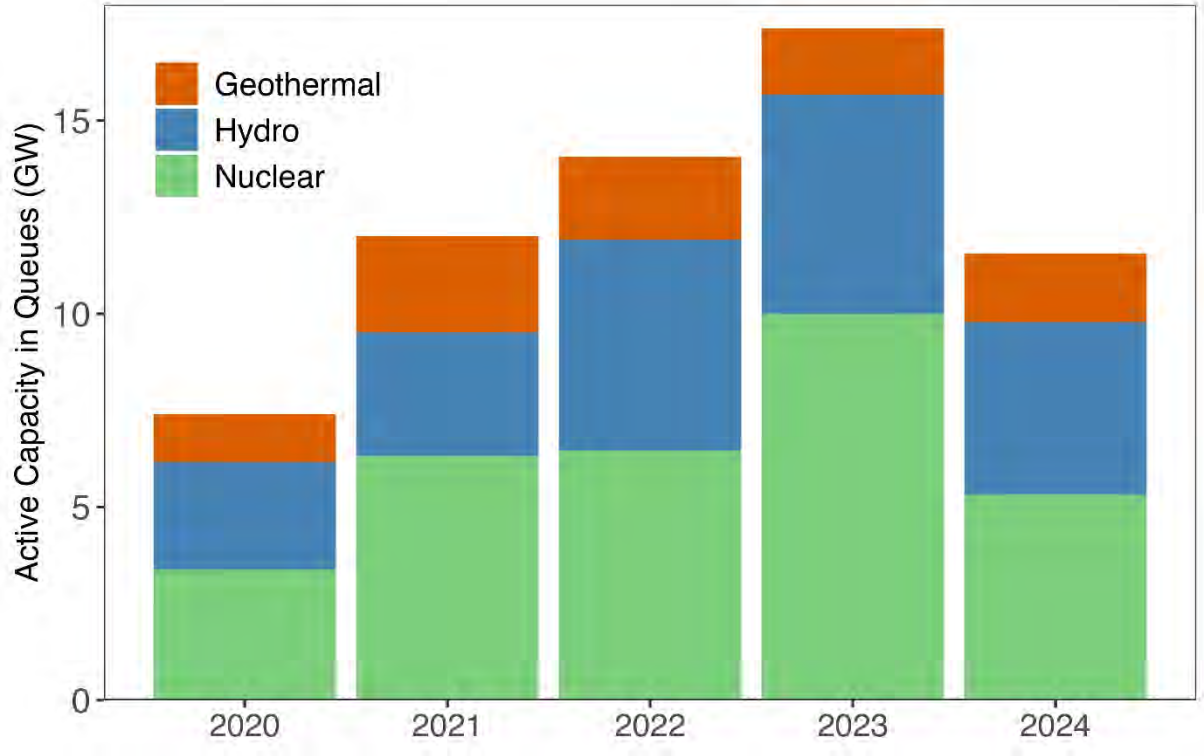
New Wind Capacity Added to Interconnection Queues in 2024



The average (plant-level) interconnection request size has grown over time: Mean gas (+34%), solar (+214%), storage (+202%), and wind (+34%) plants have all grown substantially since 2015



Active Nuclear capacity declined in 2024, while Hydro and Geothermal held relatively steady. These resources represent ~12 GW of capacity, indicating significant development interest



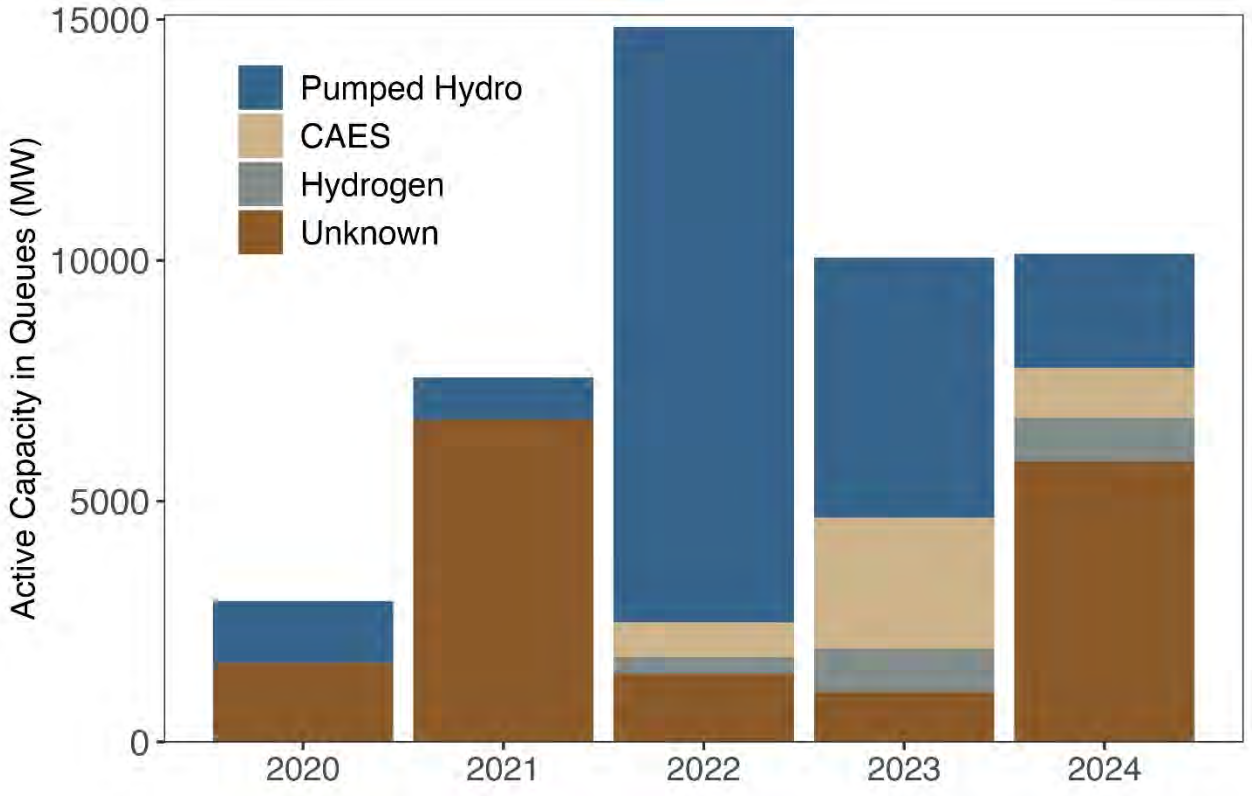
	Active Capacity in Queues (MW)		
Region	Hydro	Nuclear	Geothermal
CAISO	5		53
ISO-NE	28		
MISO	201	153	
PJM	88	44	
Southeast (non-ISO)	620	3,274	
West (non-ISO)	3,525	1,890	1,718

Active Nuclear capacity seeking grid connection decreased[1] to 5.3 GW in 2024 (down from ~10 GW in 2023), while Hydropower (4.5 GW) and Geothermal (1.8 GW) capacity held roughly steady.

Hydropower plants are proposed in several regions, but the majority of capacity is in the non-ISO West. Proposed Nuclear is primarily in the non-ISO Southeast and West, and Geothermal is only found in the West and CAISO.

Note: (1) Decrease in active Nuclear capacity is primarily due to the Vogtle nuclear plant in Georgia coming online in 2024 (and therefore moving from "active" to "operational").

Batteries make up ~99% of storage capacity in the queues, but there are 10 GW of active requests for Pumped Hydro, Hydrogen, Compressed Air (CAES), and Unknown storage

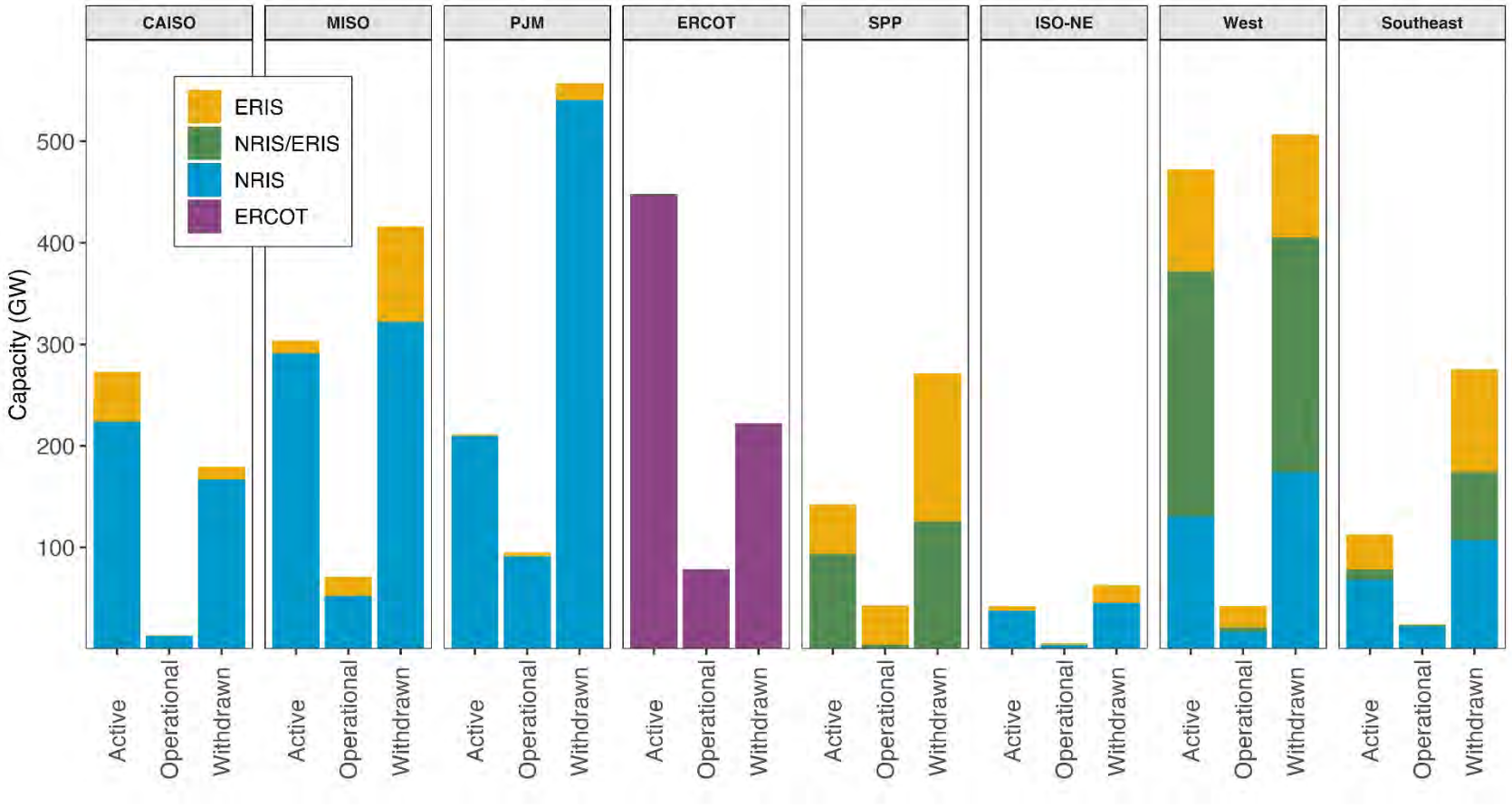


	Active Capacity in Queues (MW)			
Region	Pumped Storage	CAES	Unknown	Hydrogen
CAISO	569	1,035	44	
ERCOT			1,232	
Southeast (non-ISO)			216	
West (non-ISO)	1,800		4,340	902

Note: (1) It is not always possible to determine the type of storage being proposed from available data (hence the "Unknown" category). Some portion of the unknown storage may, in fact, be battery storage requests.

The majority of all active capacity requested to be studied for Network Resource Interconnection Service (NRIS). ERCOT's approach is similar to Energy Resource Interconnection Service (ERIS)

Outside of ERCOT, **84%*** of active capacity requested to be studied for NRIS.



Network Resource Interconnection Service (NRIS) allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System and be deliverable during congested grid conditions, such that the generator can be designated as a capacity resource and contribute to resource adequacy requirements.

Energy Resource Interconnection Service (ERIS) allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider's Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or non-firm capacity of the Transmission Provider's Transmission System on an "as available" basis.

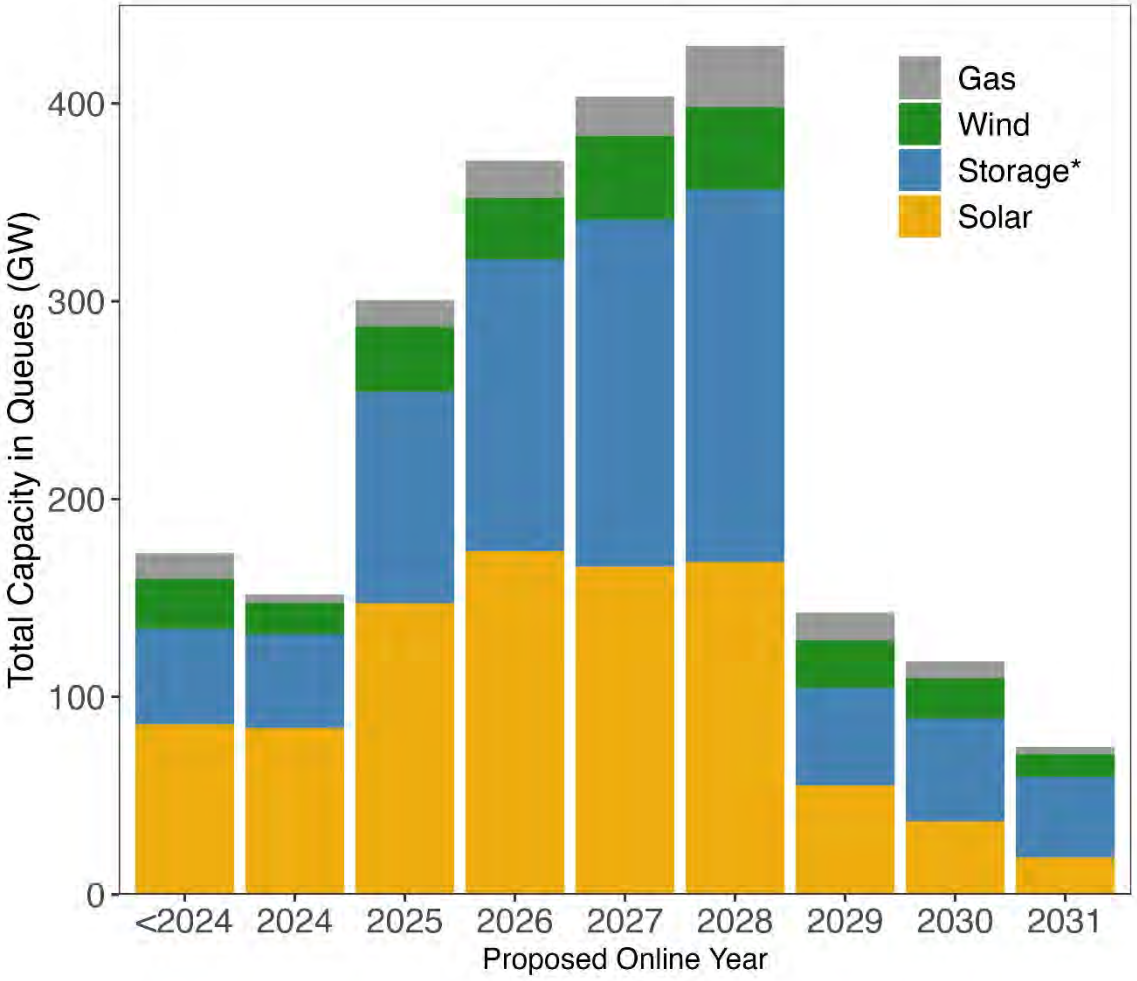
	% of Active Capacity	
region	ERIS	NRIS*
CAISO	18%	82%
MISO	4%	96%
PJM	1%	99%
SPP	34%	66%
ISO-NE	11%	89%
West	21%	79%
Southeast	31%	69%

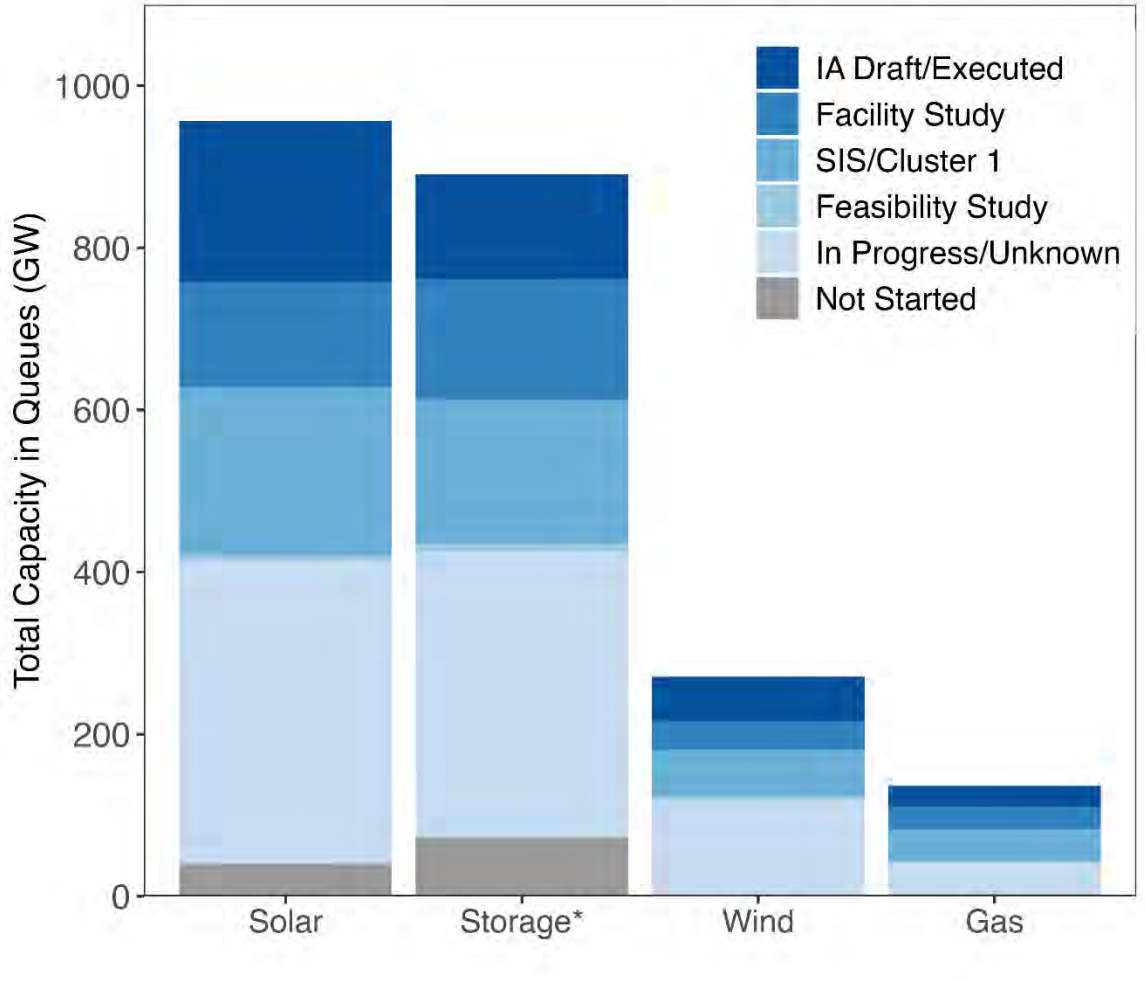
Notes: (1) NRIS and ERIS were developed under FERC Order 2003, and apply to FERC-jurisdictional transmission providers. (2) ERCOT is not FERC jurisdictional, but uses a "connect and manage" interconnection service that is more similar to ERIS. (3) Data available for 29,744 requests from 6 ISOs and 32 non-ISO balancing areas.

**These calculated percentages include projects choosing the NRIS/ERIS study option at time of request, which is allowed in a few regions as indicated in the graph*

61% (1,400 GW) of active capacity in queues has proposed online date before 2028; 18% (408 GW) has a draft or executed interconnection agreement (IA)

69% of solar capacity (657 GW) originally proposed to come online before 2028, compared to 59% of storage (525 GW), 55% of wind (148 GW), and 51% of gas (69 GW). 21% of solar and wind capacity has a draft or signed IA, 19% of gas, and 15% of storage[1].

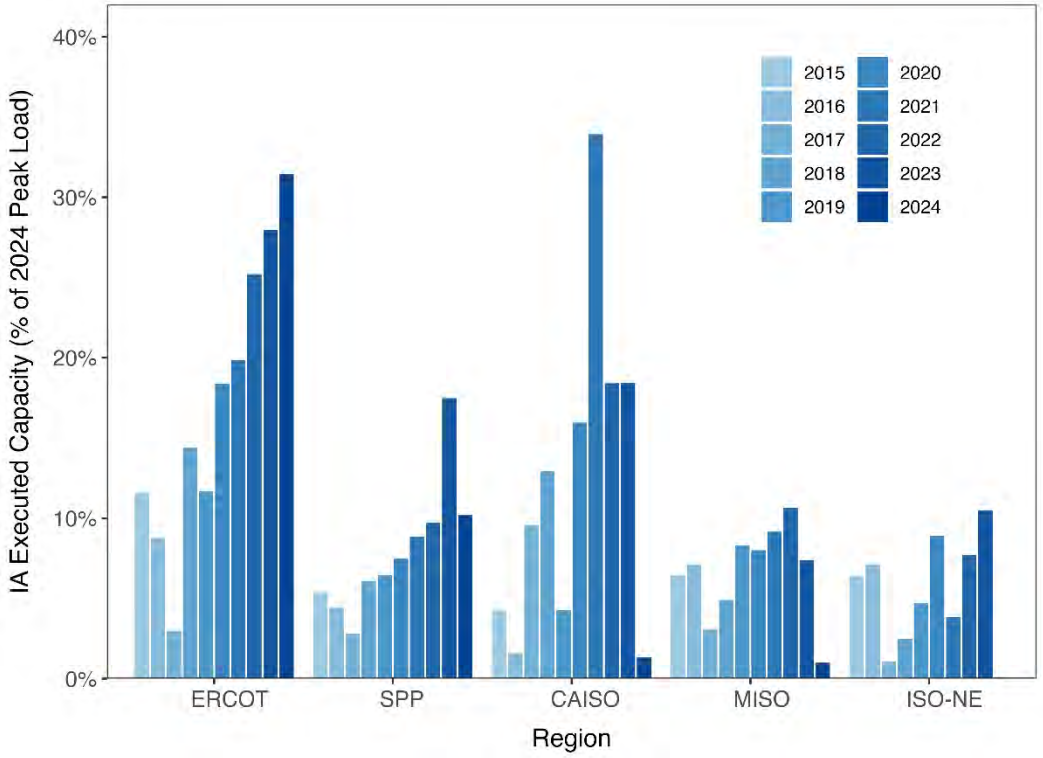




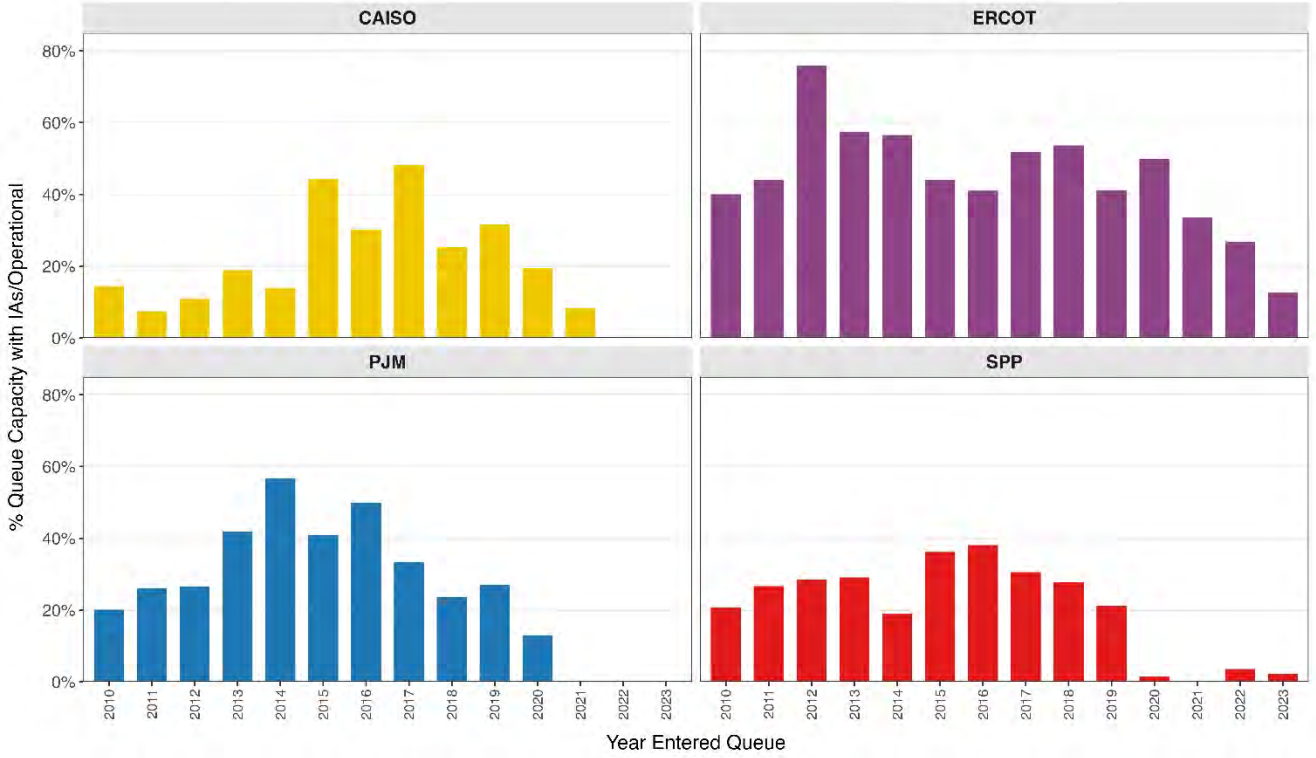
*Notes: (1) See appendix for breakdown of capacity with IA by resource type. (2) *Hybrid storage capacity is estimated for some projects. (3) Proposed online dates are included in the developer's original interconnection request, and may differ from actual online date. (4) Not all of this capacity will be built. (5) Study status categories are simplified and correspond to the process pre- FERC Order No. 2023 reforms.*

ERCOT executed IAs amounting to >30% of their peak load in 2024; ERCOT also tends to have a relatively high share of total requests reach IA stage

Annual volume of interconnection agreements executed by region as a percentage of 2024 peak load



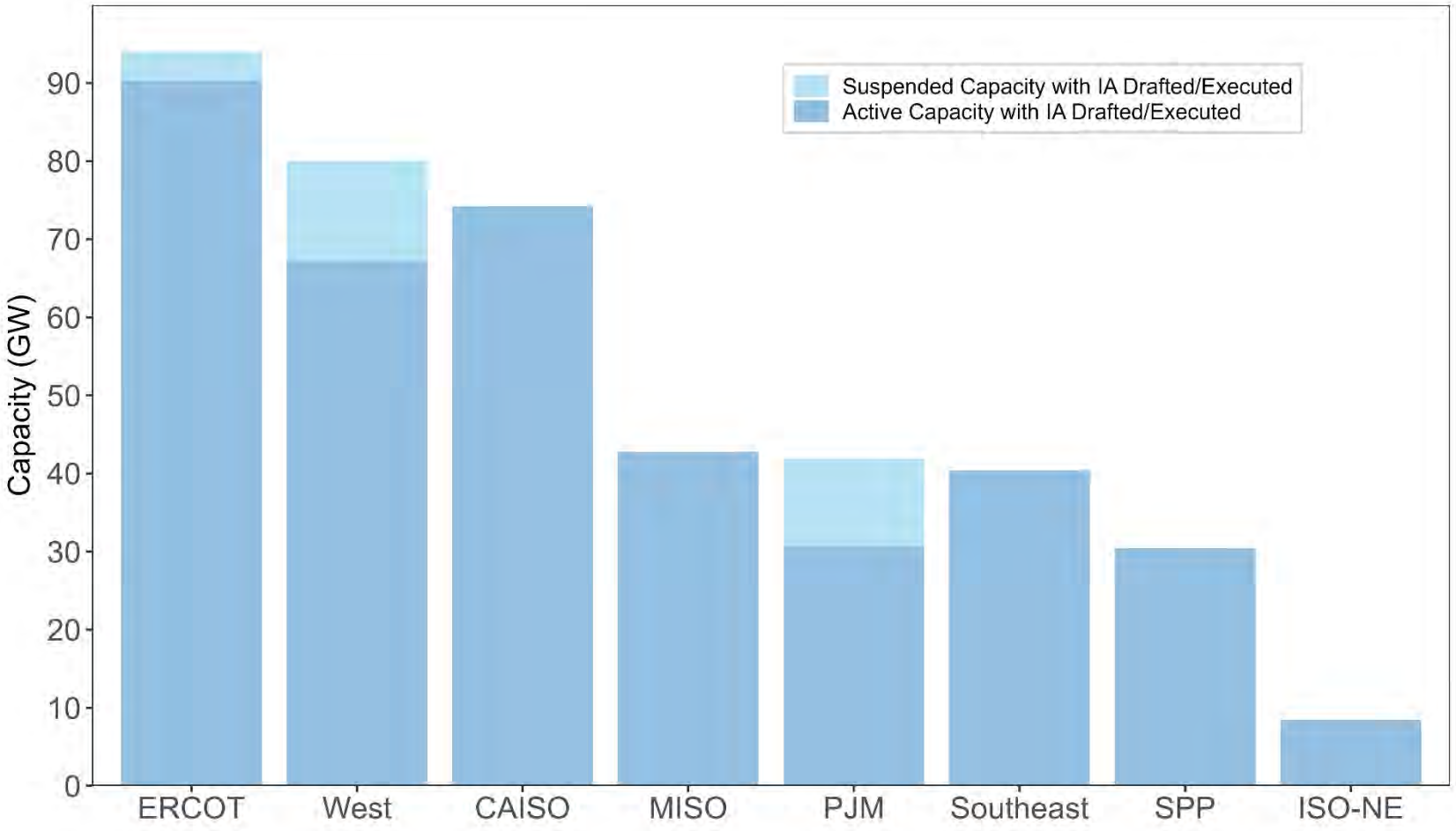
Fraction of annual interconnection request volume that have executed interconnection agreements by the end of 2024



ERCOT's "connect and manage" approach to generator interconnection does not require network upgrades for interconnections, instead managing grid congestion through redispatch and curtailment. This approach differs from other balancing areas, and is likely one reason for the higher IA rates seen in ERCOT.

Notes: (1) Left chart limited to regions where "IA date" is at least 70% populated (see table on slide 9). See appendix for absolute (GW) volume rather than fraction. Available data for 2024 IAs may be lagging in some regions. (2) Right chart (fraction) limited to regions with complete information on interconnection phase / agreement status, as well as complete data on total annual requests. (3) Not all requests executing IAs will ultimately come online – see slide 34 for detail on post-IA completion rates.

ERCOT has the most capacity with draft or executed IAs (90 GW active; 4 GW suspended), followed by CAISO (74 GW active) and the West (67 GW active; 13 GW suspended)



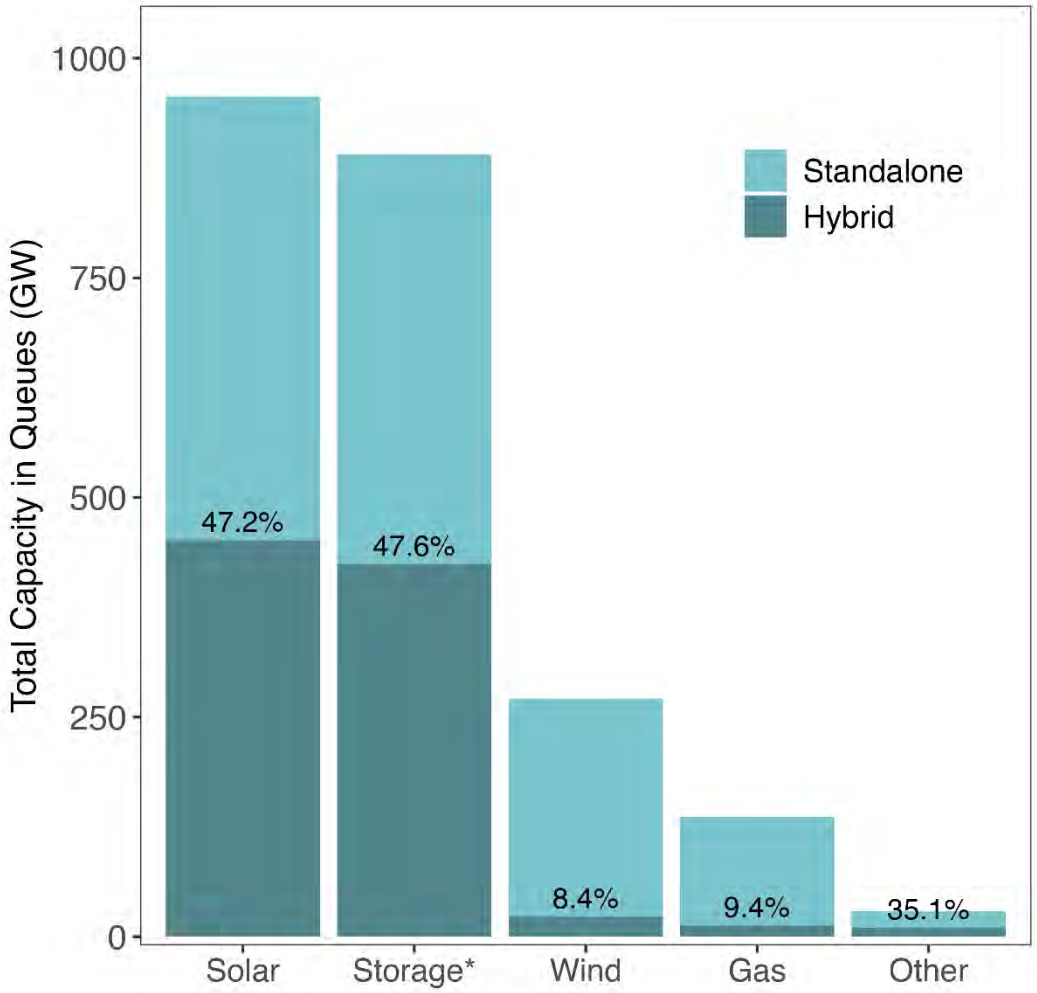
Note: Not all of these plants will be built.

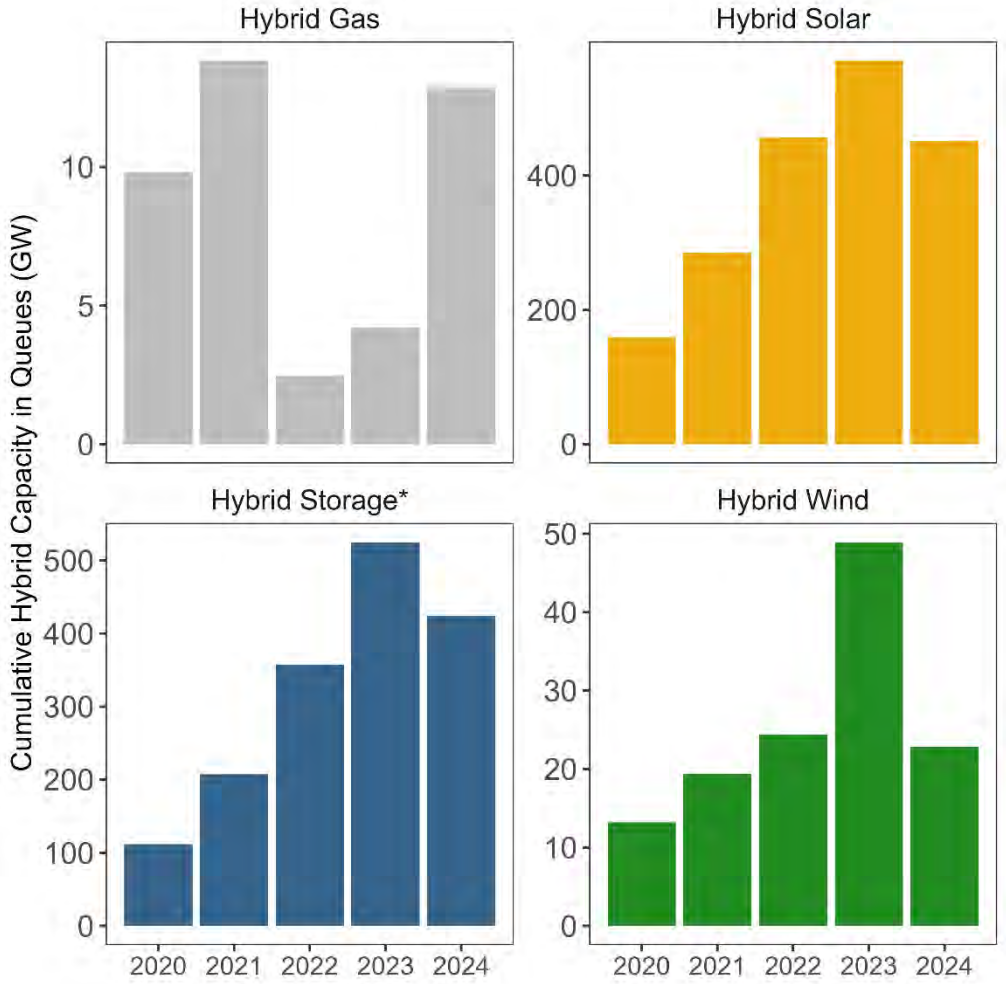
Signed interconnection agreements can provide a useful signal about the nearer-term pipeline of proposed power plants, but many other factors influence whether a proposed power plant is ultimately built or not. Many requests with signed IAs have historically withdrawn (*see slide 34*).

Capacity shown is the *nameplate* capacity for these interconnection requests, which is not necessarily deliverable at all times and may be lower during peak or critical load hours.

Notes: (1) IA capacity bars include capacity in the queues that has either a draft or fully executed interconnection agreement but has not yet reached commercial operations. The darker blue portion of the bar includes only active capacity; light blue portion includes suspended queue requests with an executed/drafted IA. The implication of "Suspended" queue status differs by ISO. e.g., in PJM it is voluntary and elected by the developer; in MISO it requires a force majeure event to suspend a project.

Requests for hybrid plants are common: Hybrids comprise 47% of active solar (451 GW), 48% of storage (424 GW), and <10% of wind (23 GW) and gas (13 GW)





**Hybrid storage capacity is estimated when missing in source data using storage:generator ratios from requests that provide separate capacity data*

Notes: (1) Some hybrids shown may represent storage capacity added to existing generation; only the net increase in capacity is shown; (2) Capacity for hybrid plants (e.g., Wind+Solar+Storage) is included separately in each resource category (i.e., the solar component shows up in hybrid solar, storage in hybrid storage), presuming the capacity is known for each type. "Hybrid Storage" therefore represents only the storage portion of generator+storage hybrid plants.

Hybrids comprise a sizable fraction of all proposed solar plants in multiple regions; gas and wind hybrids are less common overall but still a large proportion in CAISO

	% of Active Capacity in Hybrid Configurations			
Region	Solar	Wind	Gas	Storage*
CAISO	93%	60%	81%	50%
ERCOT	47%	4%	3%	23%
ISO-NE	29%	0%	69%	7%
MISO	22%	7%	17%	45%
NYISO	32%	2%	0%	15%
PJM	23%	0%	0%	37%
SPP	22%	2%	4%	36%
Southeast	25%	0%	2%	55%
West	83%	16%	26%	72%
TOTAL	**47%**	**8%**	**9%**	**48%**

**Hybrid storage capacity is estimated when missing in source data using storage:generator ratios from requests that provide separate capacity data*

- Hybrid configurations are especially common in CAISO, and somewhat common in the non-ISO West
- **Solar** hybridization has been steady around 45-50% overall in recent years, with CAISO consistently having >90% of solar capacity in hybrids
- **Gas** hybridization decreased from 12% last year, with new gas requests predominantly standalone
- **Wind** hybridization also decreased from 13% last year, with fewer hybrid wind requests in the West in particular

Operational & Withdrawn Projects: Volume and Completion Rates

Operational project data were available from all 7 ISO/RTOs and 35 non-ISO balancing areas, totaling 4,432 projects.

Region	*n* (Operational)	Capacity (GW)
CAISO	228	36.4
ERCOT	489	78.6
ISO-NE	219	15.8
MISO	492	71.9
NYISO	112	12.5
PJM	1,195	97.0
SPP	287	43.8
Southeast (non-ISO)	444	90.9
West (non-ISO)	966	64.9

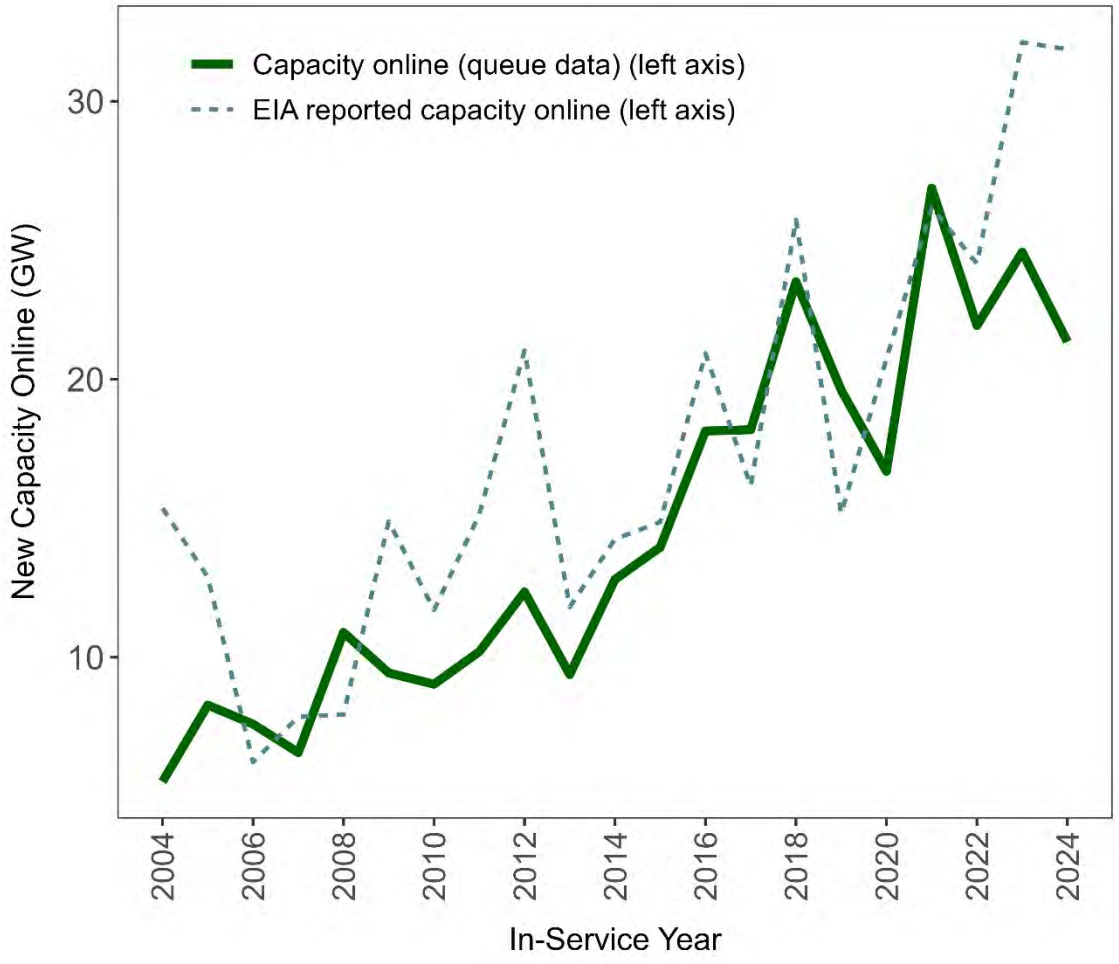
Withdrawn request data were available from all 7 ISO/RTOs and 43 non-ISO balancing areas, totaling 20,921 requests.

Region	*n* (Withdrawn)	Capacity (GW)
CAISO[4]	1,971	596.2
ERCOT	955	222.1
ISO-NE	663	90.7
MISO	2,272	432.1
NYISO	1,303	278.4
PJM	4,885	580.2
SPP	1,531	308.9
Southeast (non-ISO)	2,470	558.8
West (non-ISO)	4,871	856.9

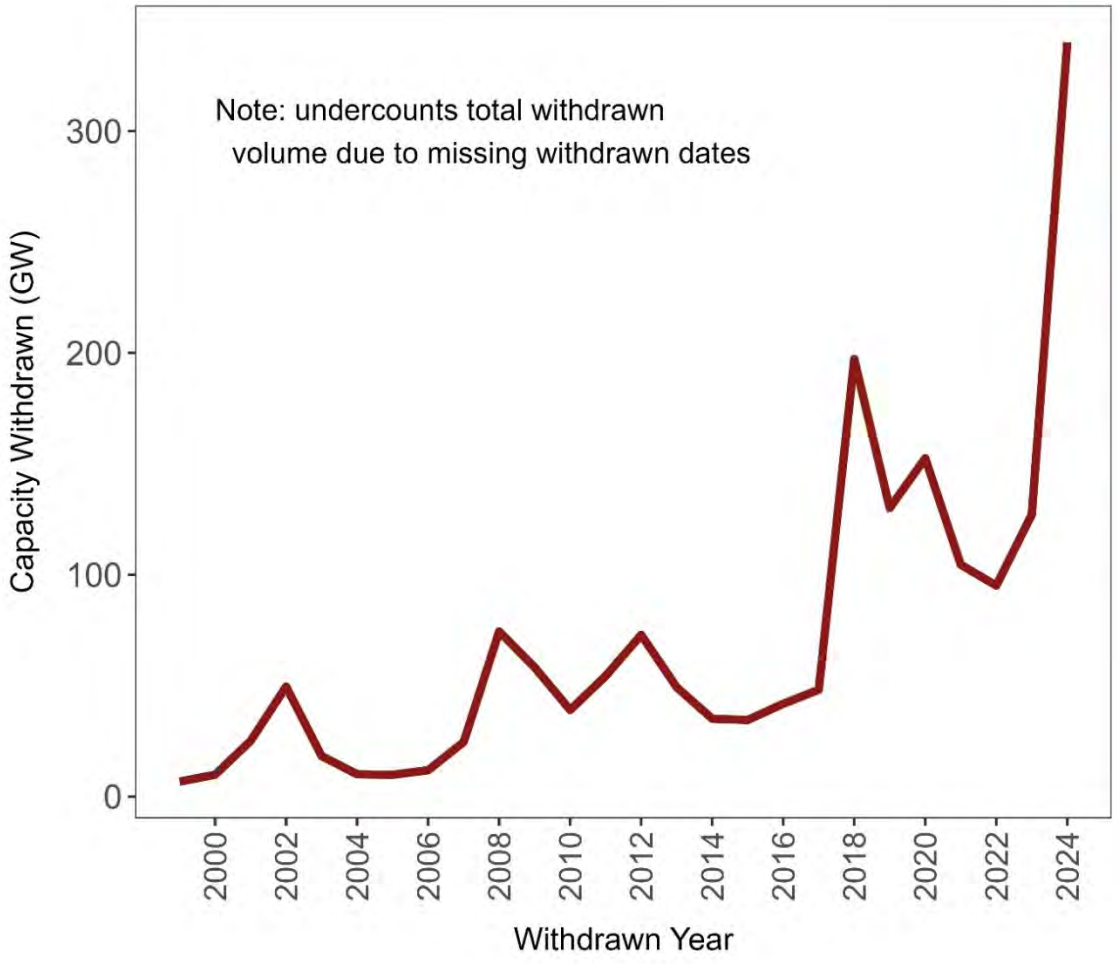
*Notes: (1) The number of operational and withdrawn projects with available data may be fewer than the total number of operational or withdrawn projects for each entity. (2) Data were sought from 7 ISOs and 49 non-ISO BAs; operational and withdrawn project data may be delayed or unavailable. (3) Capacity (GW) shown in these tables does **not** include estimates for missing hybrid storage capacity. (4) Withdrawn includes CAISO cluster 15 requests that were not resubmitted in 2024 (as required by CAISO to continue).*

Volume (capacity) of operational and withdrawn projects is trending upward; more than 700 GW[1] of capacity was withdrawn in 2024

Operational Projects[2]

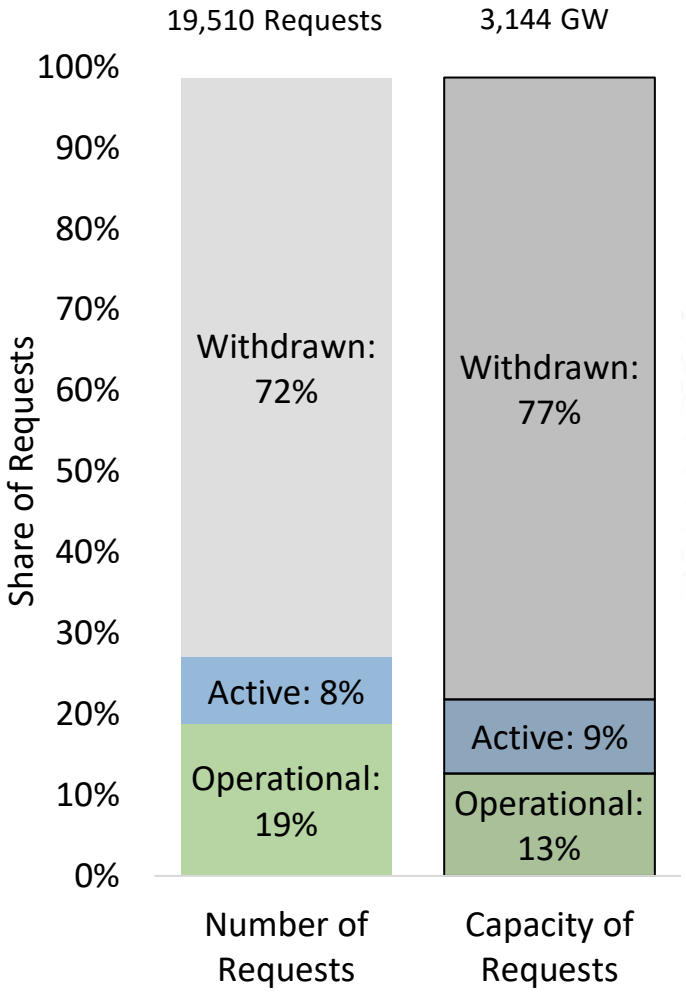


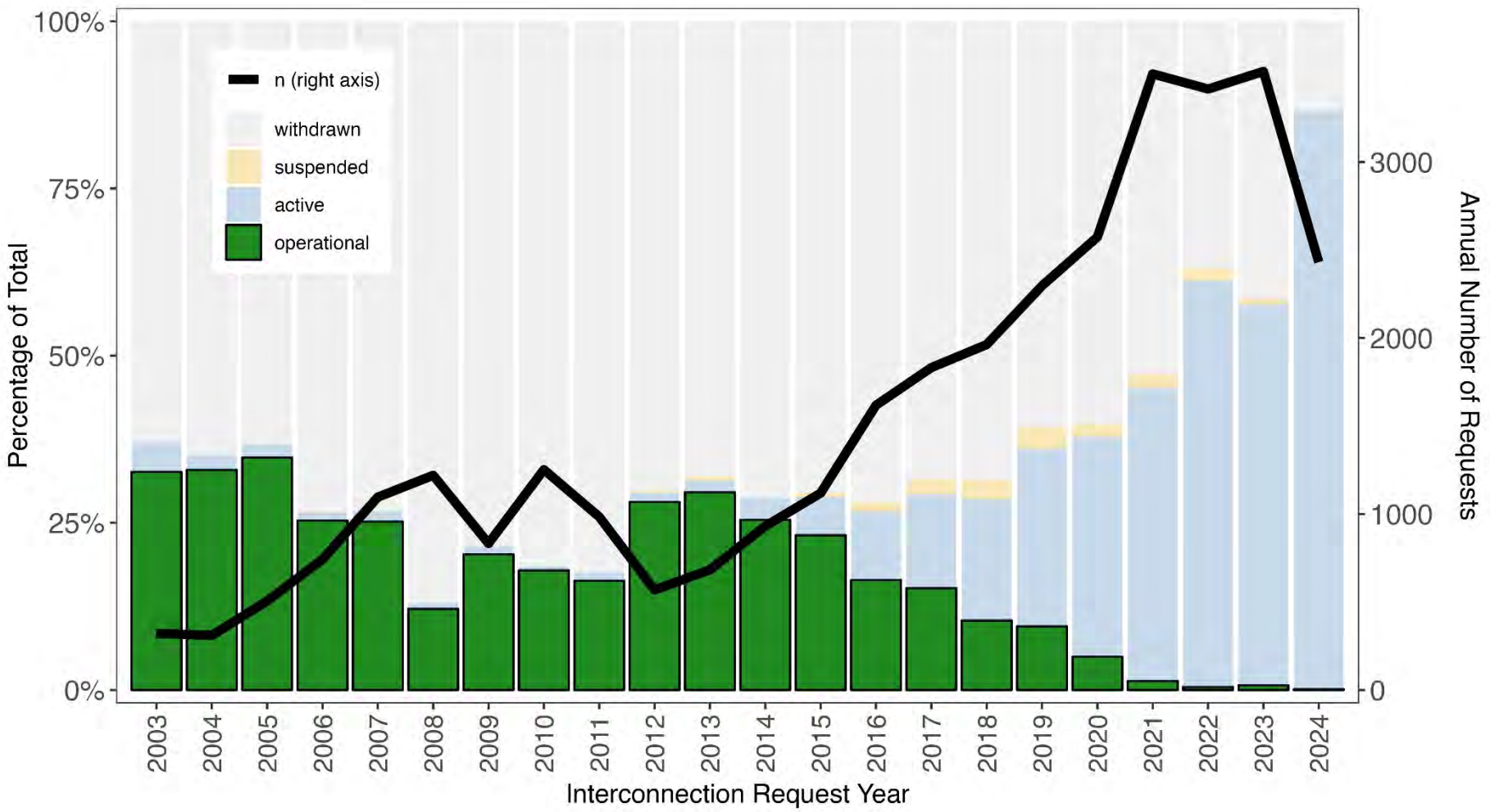
Withdrawn Requests[3]



Note: (1) In-service year only available for 64% of the "operational" project sample; withdrawn year only available for 51% of the "withdrawn" project sample. These figures therefore only include a subset of total data. (2) The discrepancy between queue capacity and EIA capacity is primarily due to missing in-service dates and lags or gaps in reporting in the queue data. EIA data are filtered to only include balancing areas for which LBNL collects queue data, and only include transmission-interconnected plants. (3) Includes CAISO cluster 15 requests that were not resubmitted in 2024 (as required by CAISO to continue).

The majority (>70%) of interconnection requests are withdrawn. Just 13% of capacity submitted into queues from 2000-2019 had come online as of the end of 2024

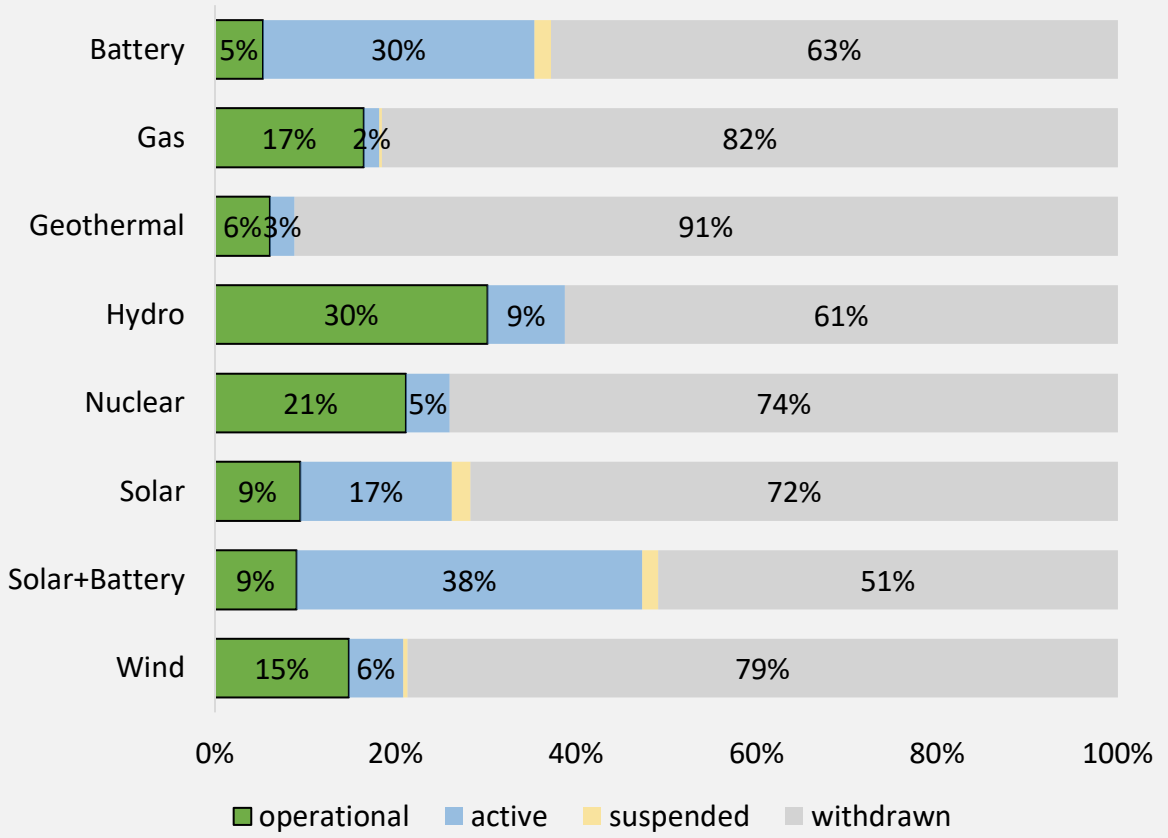




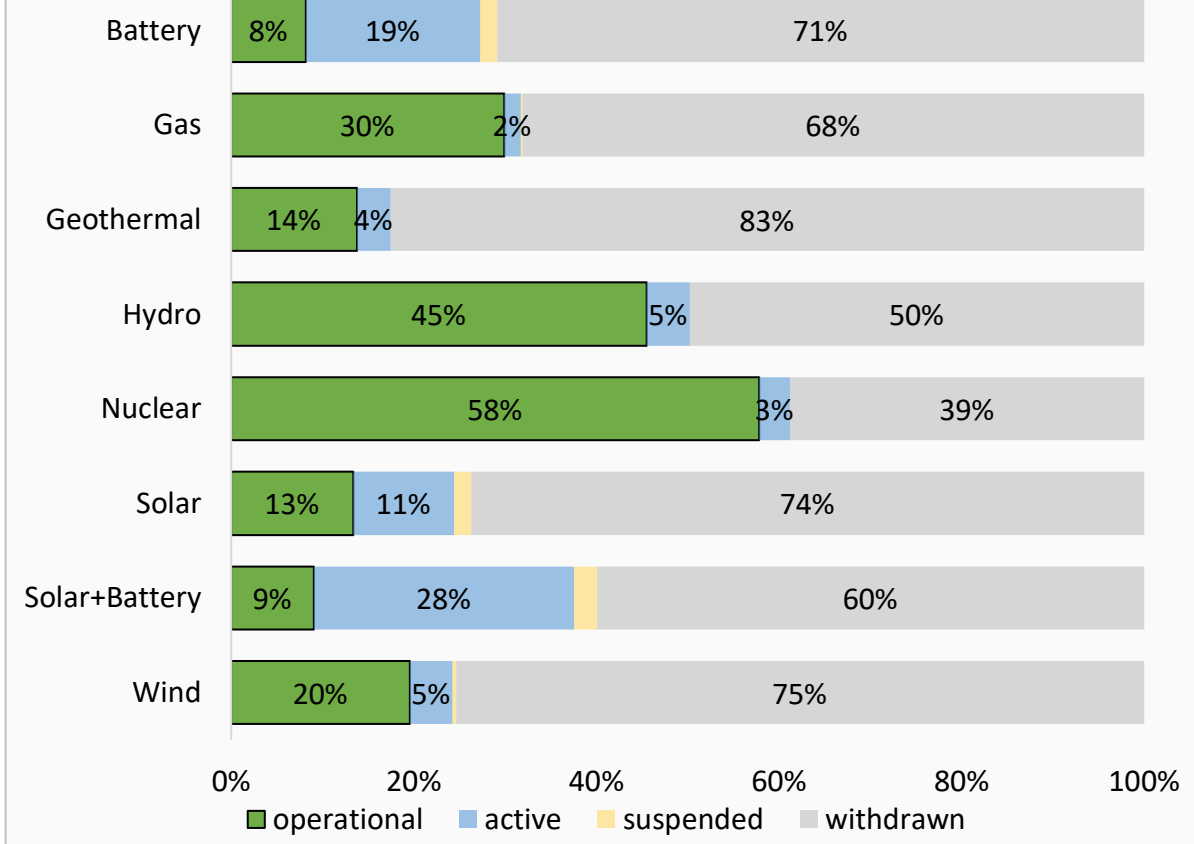
Notes: (1) Final outcome for projects entering the queues in recent years may not yet be determined; some take 5 or more years from request to COD. (2) Status shown represents a snapshot of all available data as of the end of 2024. (3) Completion rate shown in chart on right is calculated by number of projects, not capacity. (4) Limited to data from 7 ISO/RTOs and 32 non-ISO balancing areas which provide comprehensive status information (but, since online date is not required for this analysis, data are roughly complete for these regions).

There is considerable variation in completion rates across generator types; In terms of capacity, Hydro (30%), Nuclear (21%), and Gas (17%) have highest average completion rates

By Capacity of Requests

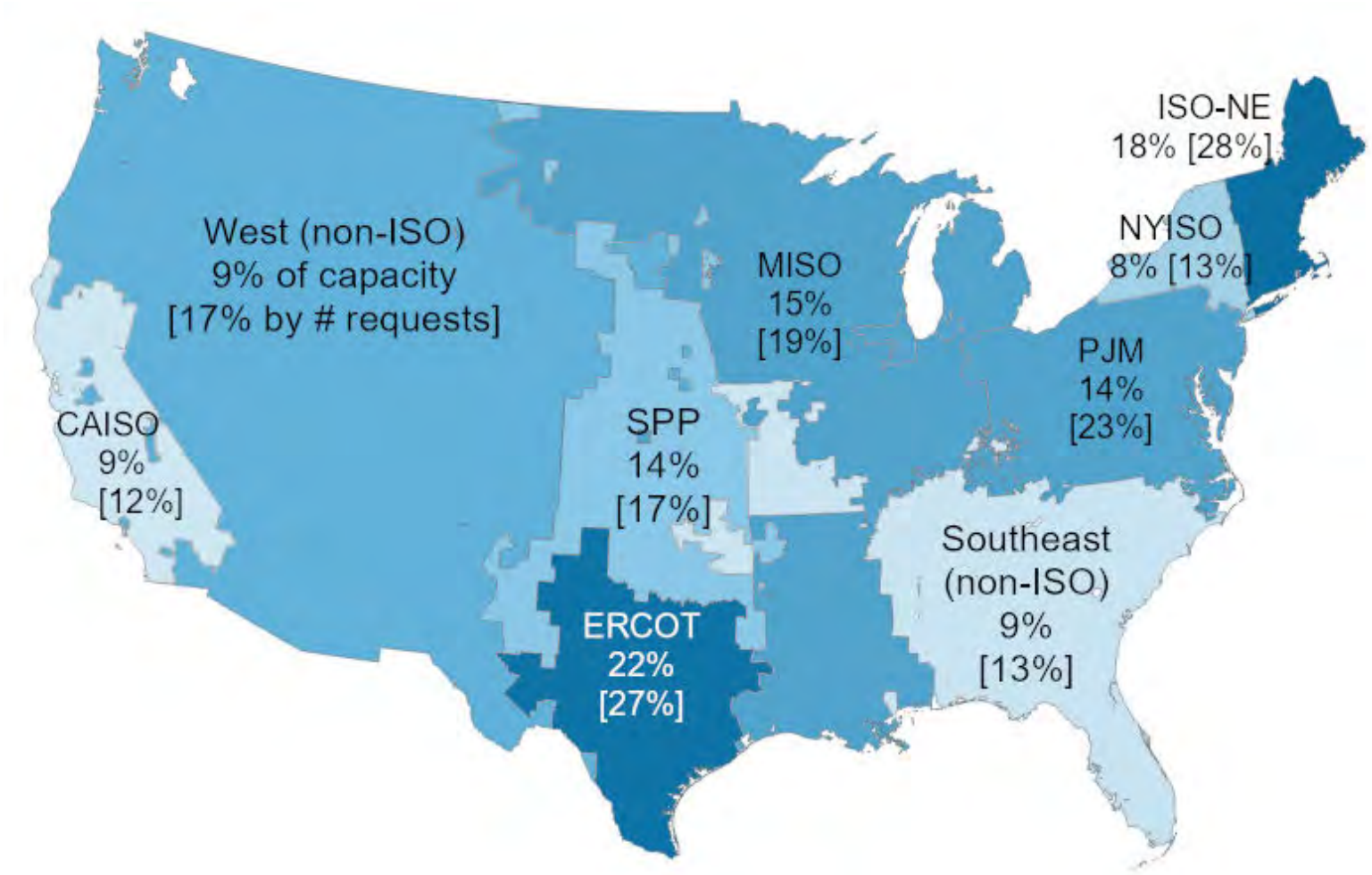


By Number of Requests



Notes: (1) Calculated as number of projects operational as of EOY 2024 divided by the total number of requests from 2000-2019. (2) Includes data from 7 ISOs and 32 non-ISO BAs which provide comprehensive status information.

The share of projects requesting interconnection from 2000-2019 that have reached COD is relatively low across regions: Only ERCOT exceeds 20% completion (by capacity)



- Completion rates by number of requests are slightly higher overall (in brackets [%])
  - Still, only ERCOT and ISO-NE exceed 25% completion by number of requests
- For interconnection requests from 2000-2019, ERCOT (22%) and ISO-NE (18%) had the highest project completion percentages, with NYISO (8%), CAISO (9%), the West (9%), and the Southeast (9%) lower on average
- These rates are variable over time, and trends may be shifting as queue volumes and reforms evolve
- Completion rates are a factor of the amount of developer interest in a given market alongside various factors that enable or disable project completion
  - Although not assessed here, comparing annual built capacity to forecasted need in each region could be a useful metric

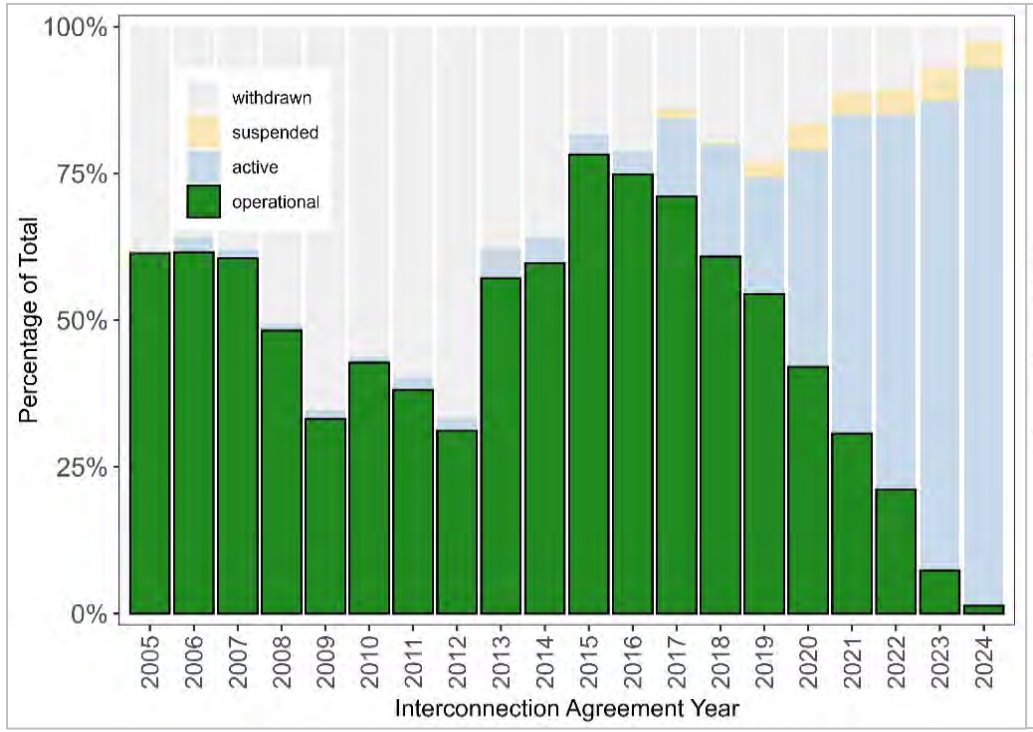
Notes: (1) Capacity-weighted completion rates are shown first, completion by number of requests shown in brackets [ ]. (2) Percentages only include projects requesting interconnection from 2000-2019. (3) Includes data from 7 ISOs and 32 non-ISO balancing areas which provide comprehensive status information.

Even after signing an interconnection agreement (IA), many requests withdraw. 36% of IAs (43% of capacity) signed 2000-2021 had withdrawn by the end of 2024

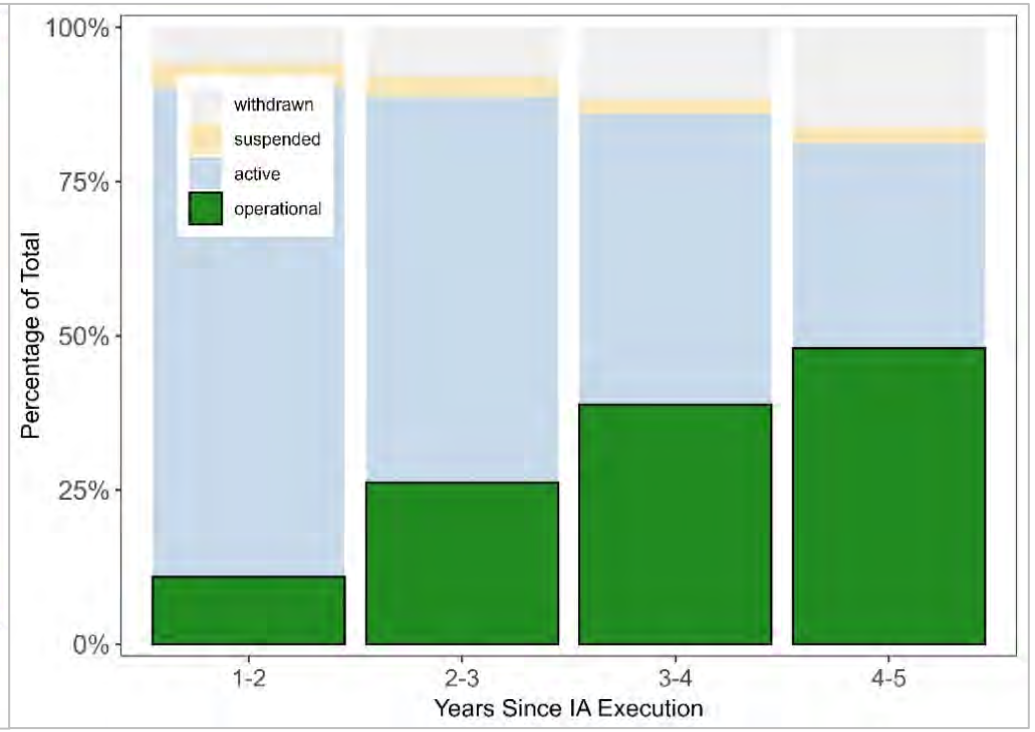
Count of IAs signed 2000-2021…		
Status *(as of end of 2024)*	Count	Percentage
operational	1878	49%
active	509	13%
suspended	39	1%
withdrawn	1379	36%

Capacity (GW) of IAs signed 2000-2021…		
Status *(as of end of 2024)*	Cap. (GW)	Percentage
operational	271	42%
active	92	14%
suspended	6	1%
withdrawn	281	43%

Current (2024) status for requests with executed interconnection agreements (IA), by IA year

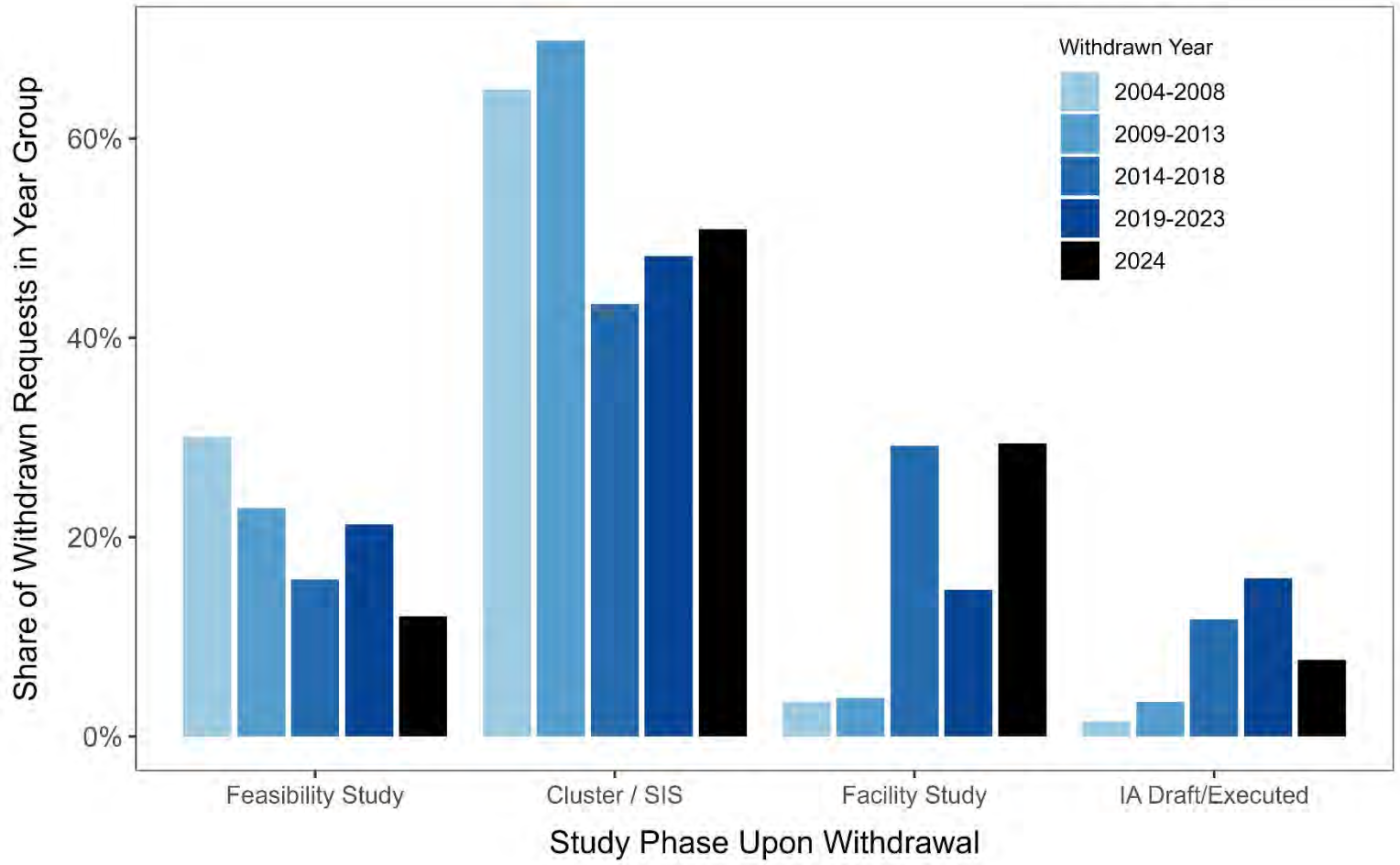


Status by number of years after IA execution



Notes: (1) Table and charts only include requests with executed interconnection agreements and for which the IA date was available. (2) Includes data from 7 ISOs and 5 non-ISO BAs that provide IA dates. (3) Overall this data sample is dominated by requests in MISO (34%) and ERCOT (20%), but MISO requests particularly dominate the earlier years (55% of requests from 2005-2012). (4) Right-hand chart compiles data from LBNL's historical annual interconnection queue datasets - not just the most recent data year.

Most withdrawals occur in earlier study phases, but more than 1/3 of 2024 withdrawals occurred at the facility or IA phases



Later-stage withdrawals can be more costly for developers (sunk costs, deposits) and can trigger re-studies for other projects in the queue, increasing delays and costs.

Note: Only includes data for entities that provide study phase for withdrawn projects (33% of withdrawn projects).

Duration Trends: How Long Do Projects Spend In the Queues?

Withdrawn Requests:

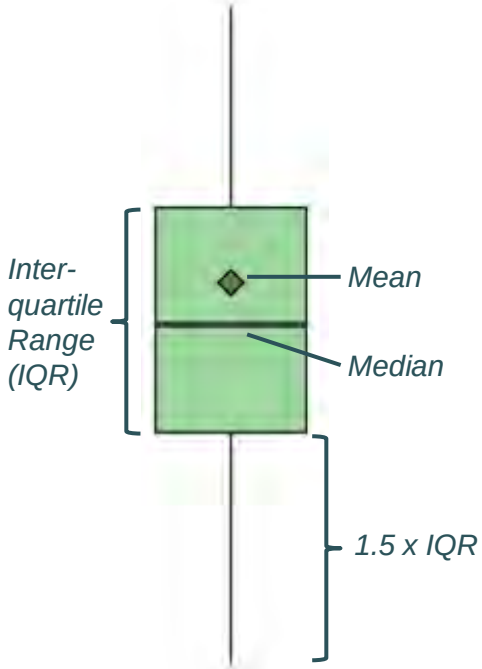
- Duration from Interconnection Request (IR) to Withdrawn Date
  - By region and generator type

Requests with Signed Interconnection Agreements (IA):

- Duration from IR to IA
  - By region, generator type, size, and service type

Operational Projects:

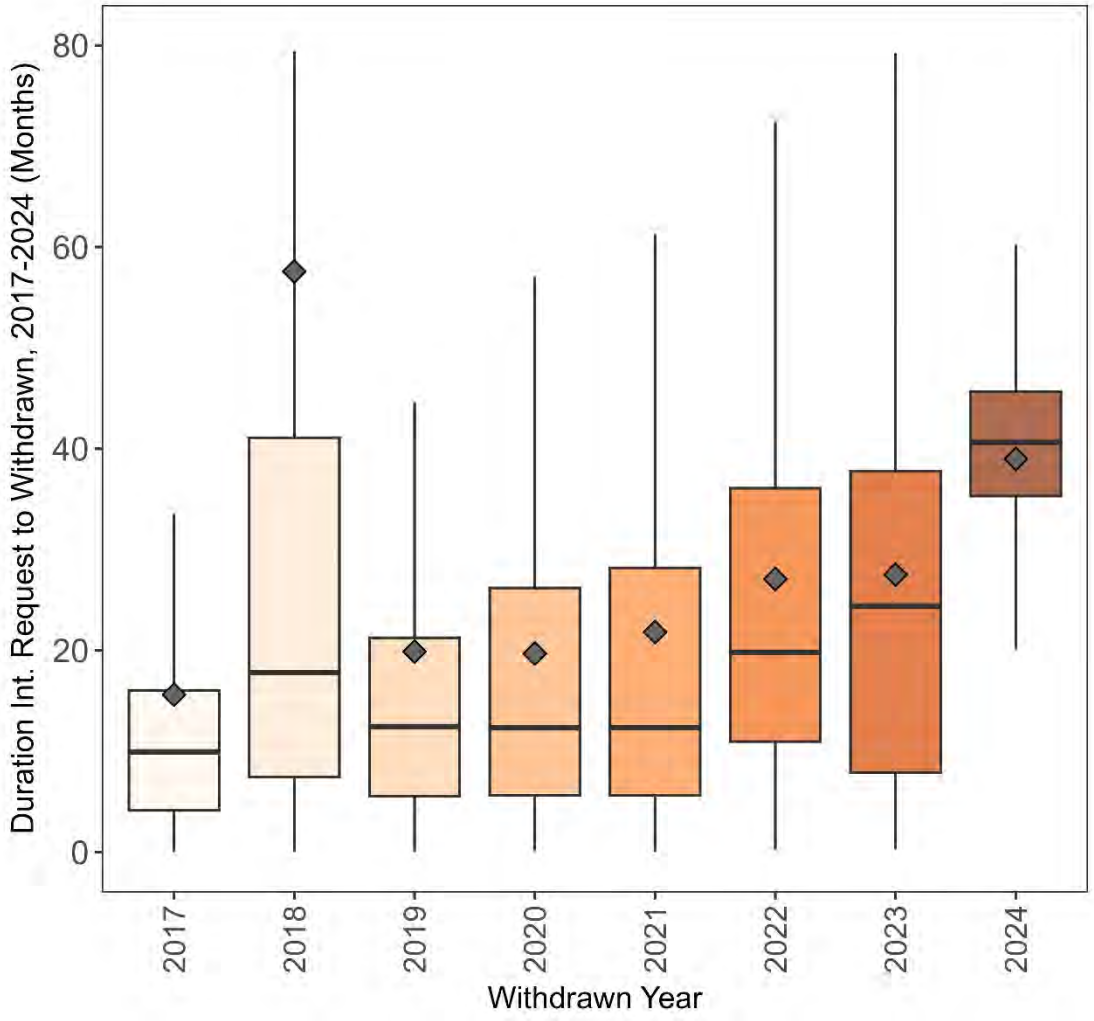
- Duration from IA to Commercial Operations Date (COD)
  - By region and generator type
- Duration from IR to COD
  - By region, generator type, and size



***Note on Boxplots**: Many of the following slides utilize box and whisker plots. The boxes represent the interquartile range (IQR – the middle 50% of data), with the central horizontal line being the median. Gray diamonds are the mean. Whiskers (vertical lines) are 1.5 times the IQR (up to min / max). Outliers are not shown.*

The average duration from interconnection request to withdrawal date has increased considerably in recent years – especially for 2024 withdrawals



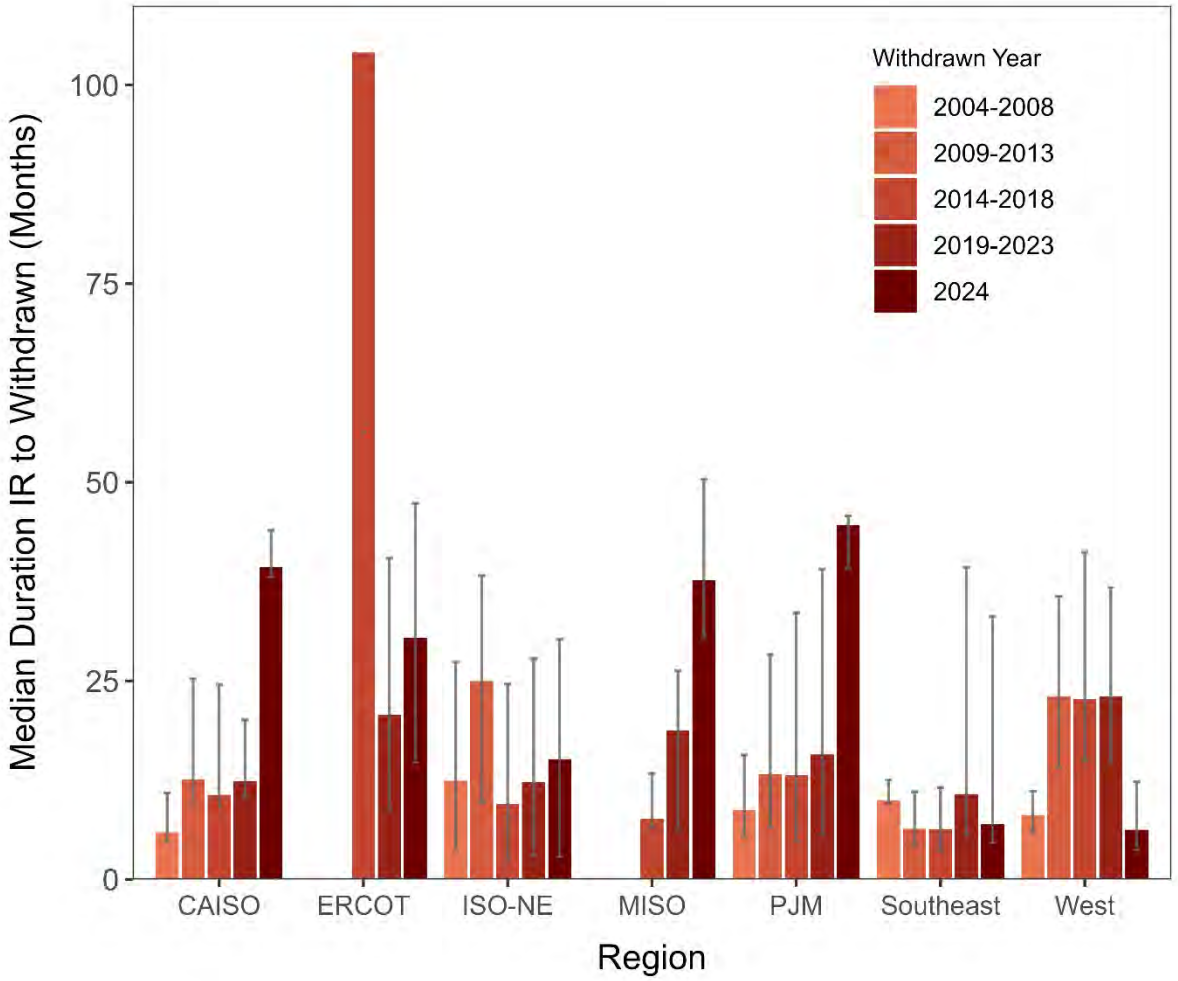


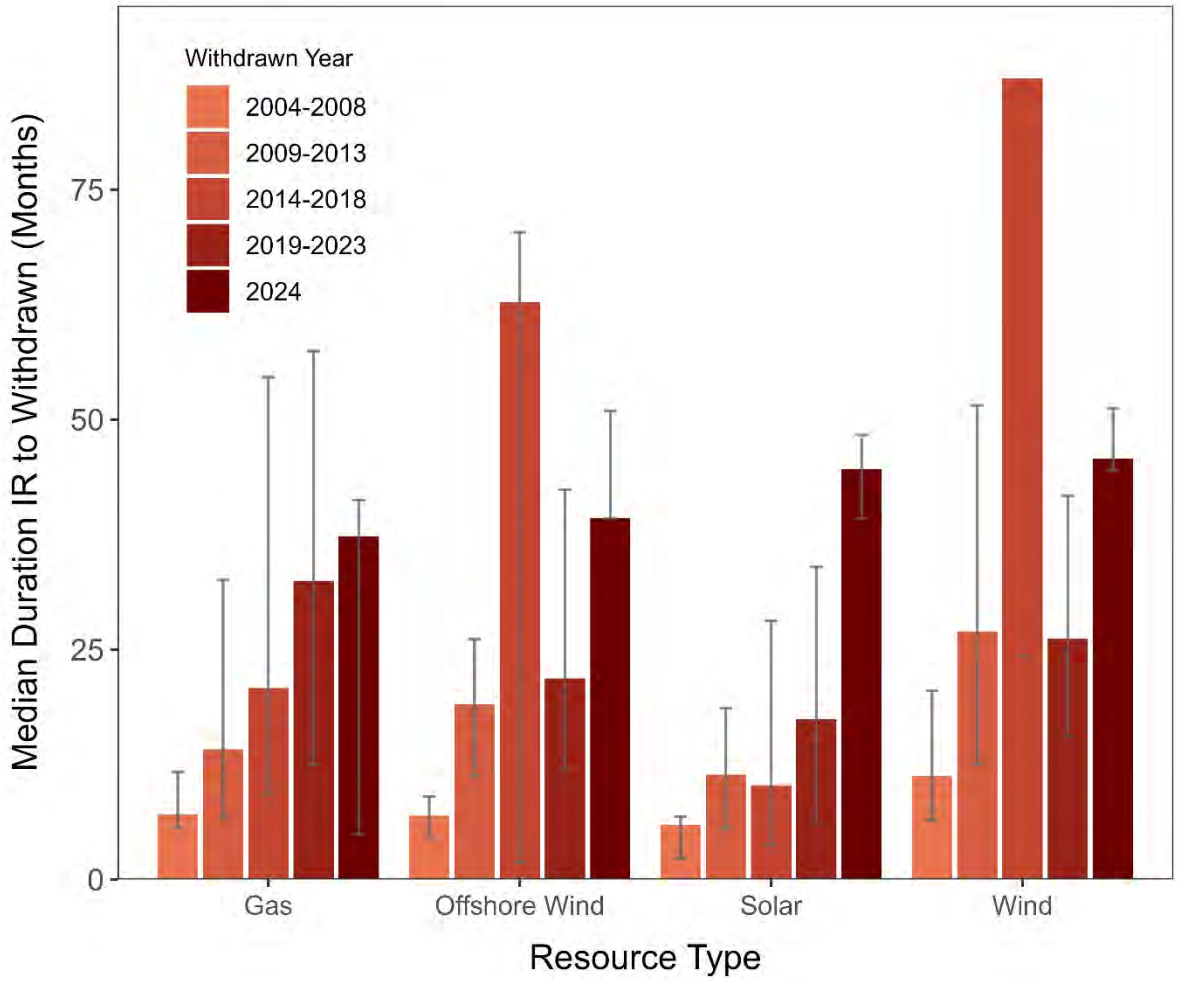
- This trend implies that some recently-withdrawn projects have waited longer in the queues before making the determination to withdraw
- FERC Order 2023 and other reforms may have motivated some older, less viable requests to withdraw in 2024
- Later stage withdrawals can be costly for developers and can disrupt assumptions built into other projects' interconnection studies, necessitating re-studies in some cases and lengthening study durations
  - Withdrawals from cluster studies can also raise costs to requests remaining in the cluster

Notes: (1) Withdrawn date was available for 9,978 requests from 7 ISOs and 8 non-ISO balancing areas. (2) Duration is calculated as the number of months from the queue entry date to the date the project was withdrawn from queues.

Time from request to withdrawal is trending upward in several regions, and across resource types



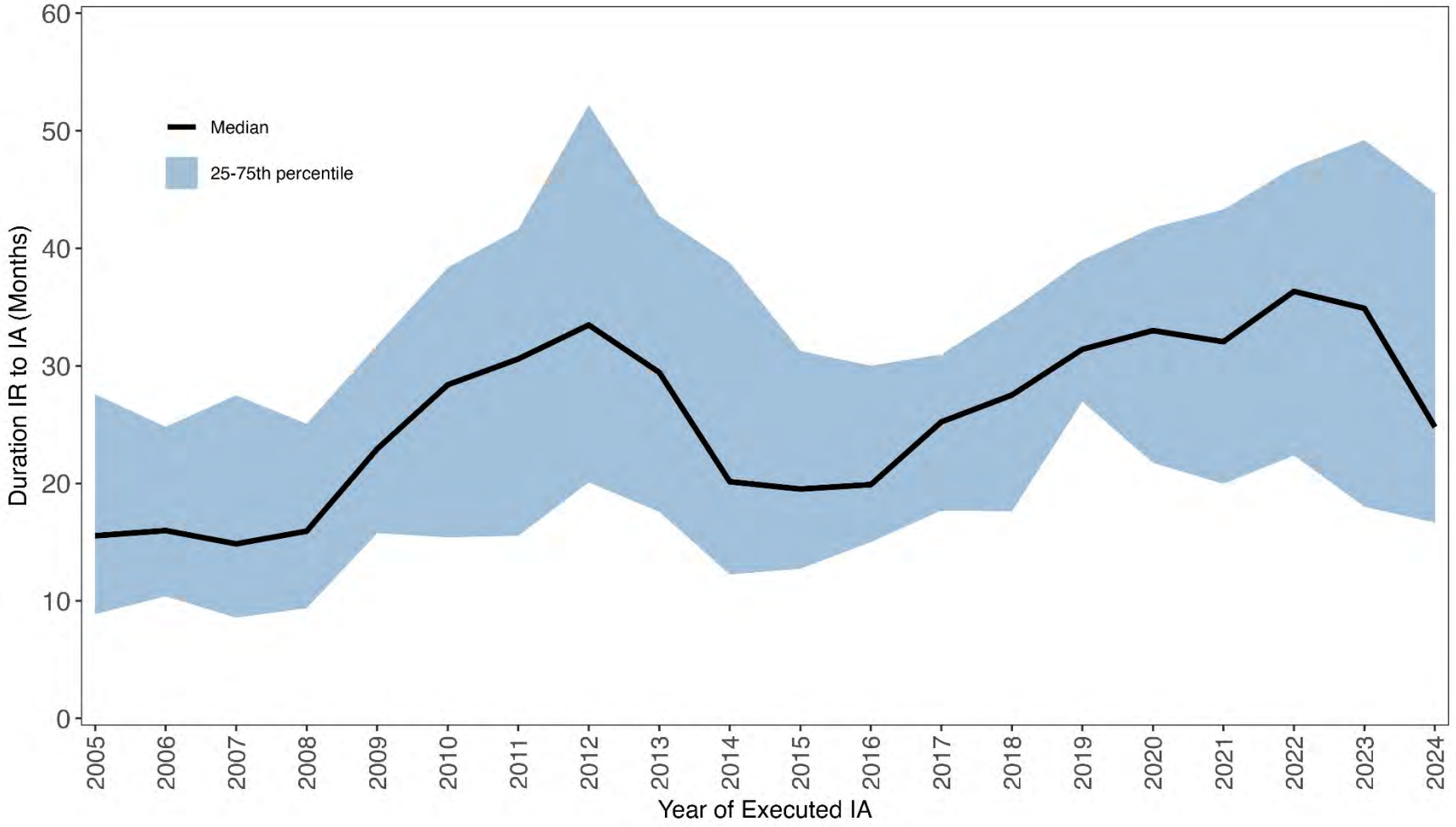




Notes: (1) Withdrawn date was available for 9,978 requests from 7 ISOs and 8 non-ISO balancing areas. (2) Duration is calculated as the number of months from the queue entry date to the date the project was withdrawn from queues. (3) Withdrawn dates were not available for CAISO Cluster 15, though a large number from that cluster withdrew in 2024; those requests would shorten the 2024 durations for CAISO and Solar, but are not included in these charts.

Duration from interconnection request to interconnection agreement had increased recently, but moderated slightly in 2024 (note: 2024 data sample is dominated by ERCOT)





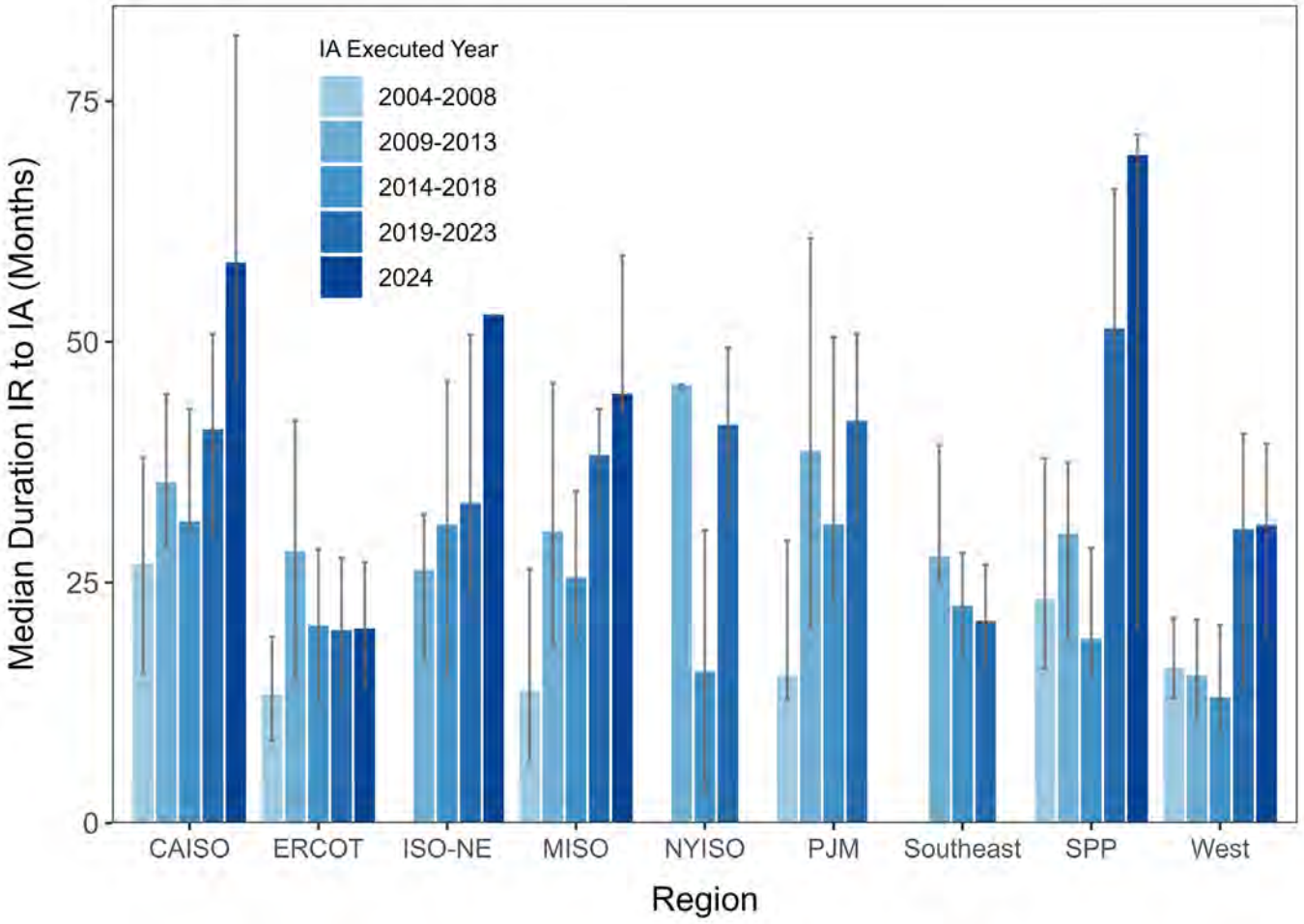
Sample Size (# IA dates) by Region and Year

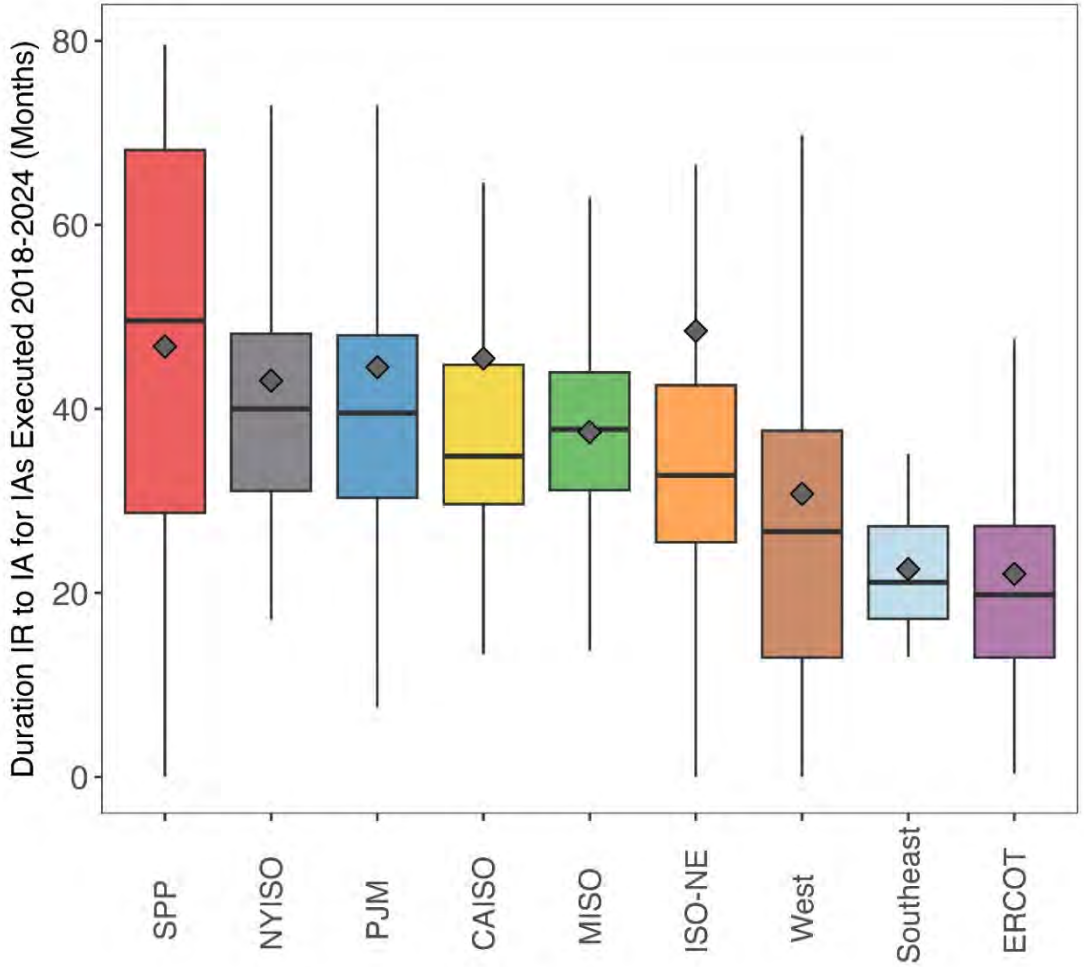
Region	2018	2019	2020	2021	2022	2023	2024
CAISO	22	14	25	32	20	25	4
ERCOT	56	49	83	85	105	135	123
ISO-NE	12	5	17	16	9	19	1
MISO	22	65	54	76	82	102	24
NYISO	4	14	24	35	8	23	0
PJM	17	30	25	35	10	0	0
Southeast	21	25	6	6	0	0	0
SPP	26	30	38	33	46	76	48
West	43	51	44	34	25	61	14

Notes: (1) The majority of the 2024 data sample for this analysis came from ERCOT (57%), which typically has relatively shorter durations (see next slide); date of IA execution for projects with IA agreement completed in 2023-2024 was not accessible in database format from PJM. (2) Sample includes 4,393 projects from 7 ISO/RTOs and 5 non-ISO balancing areas with executed interconnection agreements since 2005. (3) Not all data used in this analysis are publicly available.

IR to IA duration is typically longer in FERC-jurisdictional ISOs. ERCOT and the non-ISO regions (Southeast and West) have faster processing times



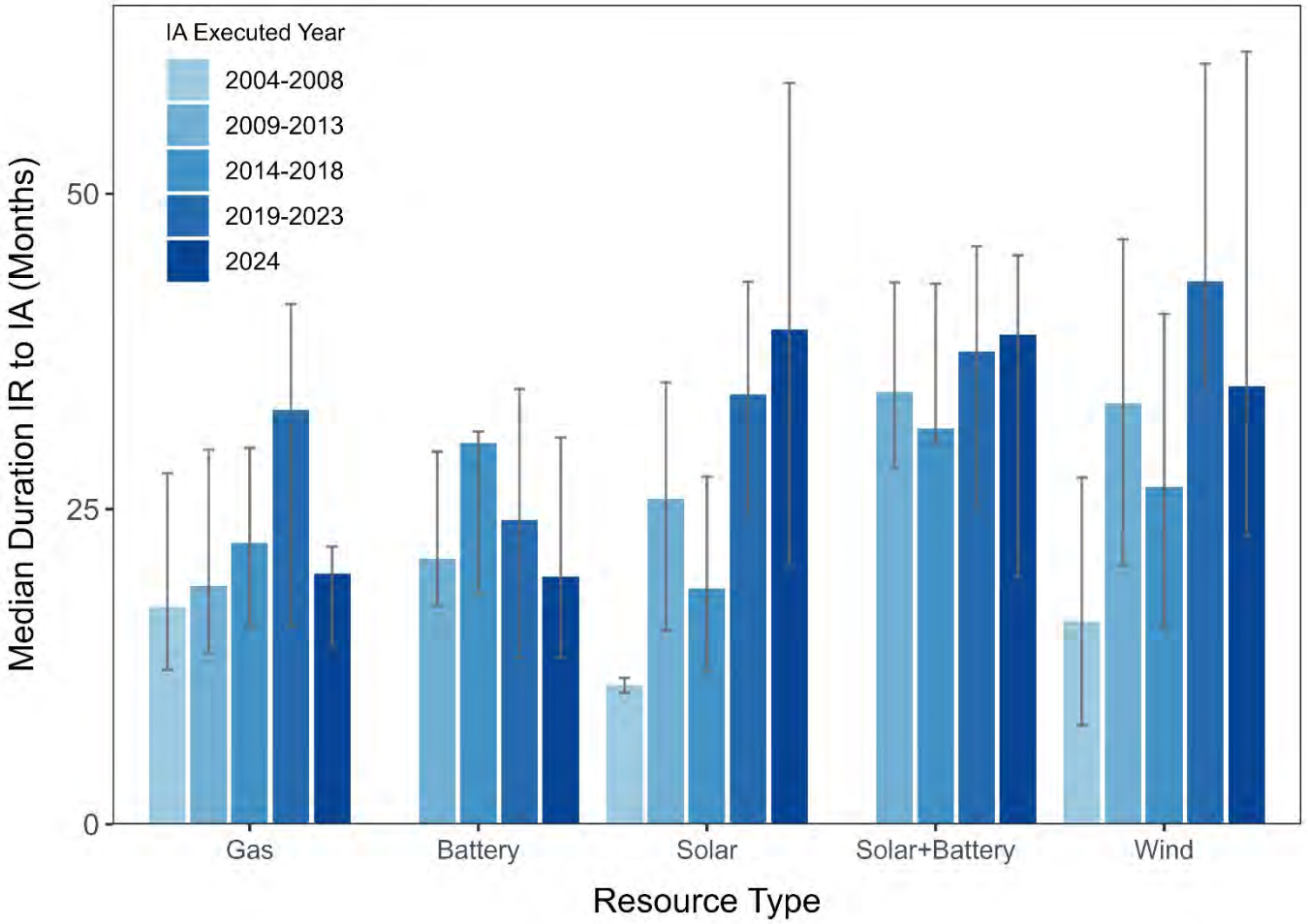


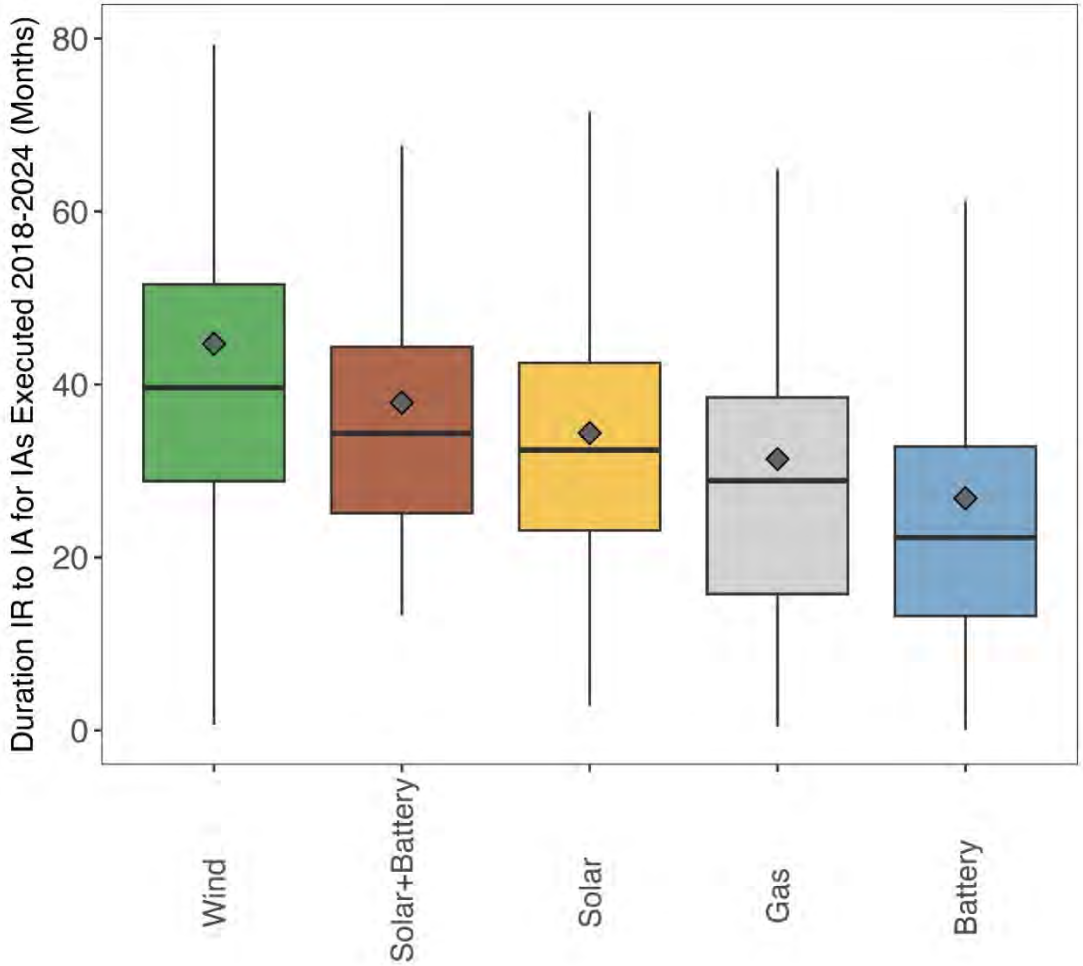


Notes: (1) Sample includes 4,393 projects from 7 ISO/RTOs and 5 non-ISO balancing areas with executed interconnection agreements since 2005. (2) The majority of the 2024 data this analysis are from ERCOT (57%). (3) Not all data used in this analysis are publicly available. (4) Date of IA execution for projects with IA agreement completed in 2023-2024 was not accessible in database format from PJM.

Wind projects typically face longer interconnection study timelines, but recent solar requests are trending up. Recent battery and gas projects have been processed more quickly



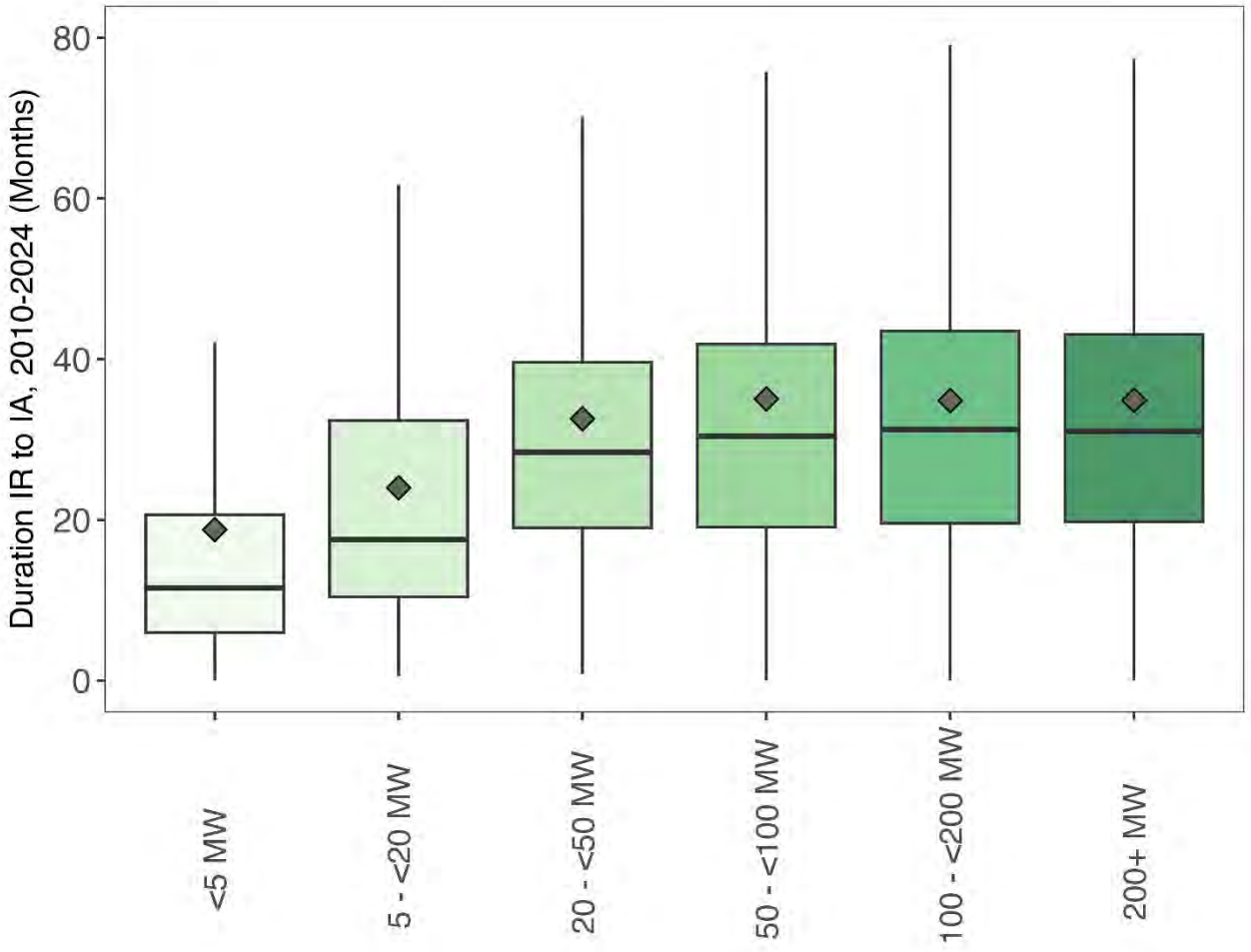




Notes: (1) Sample includes 4,393 projects from 7 ISO/RTOs and 5 non-ISO balancing areas with executed interconnection agreements since 2005. (2) The majority of the 2024 data this analysis are from ERCOT (57%). (3) Not all data used in this analysis are publicly available.

There is a clear step change in IR to IA duration between “small” (<20 MW) and “large” (>20 MW) generator interconnection procedures



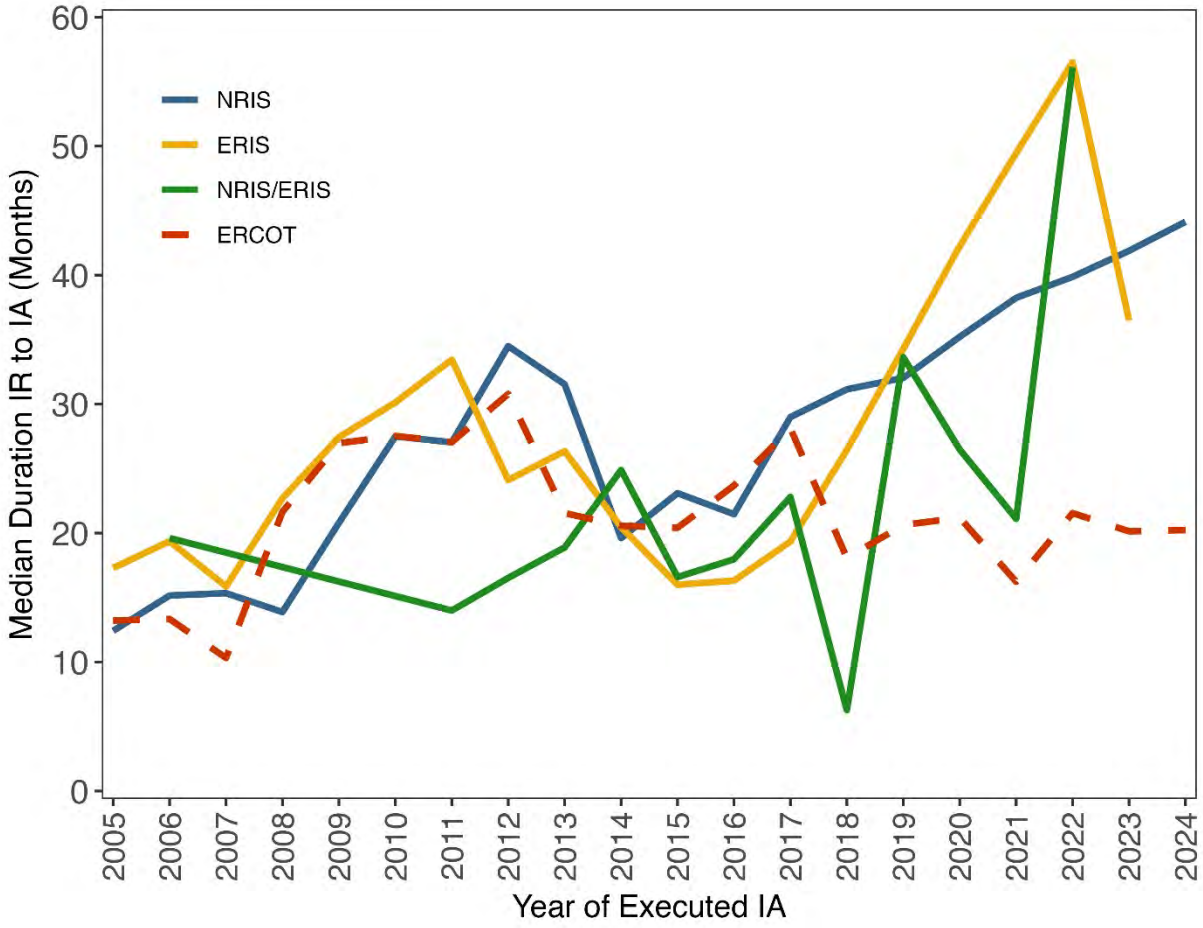


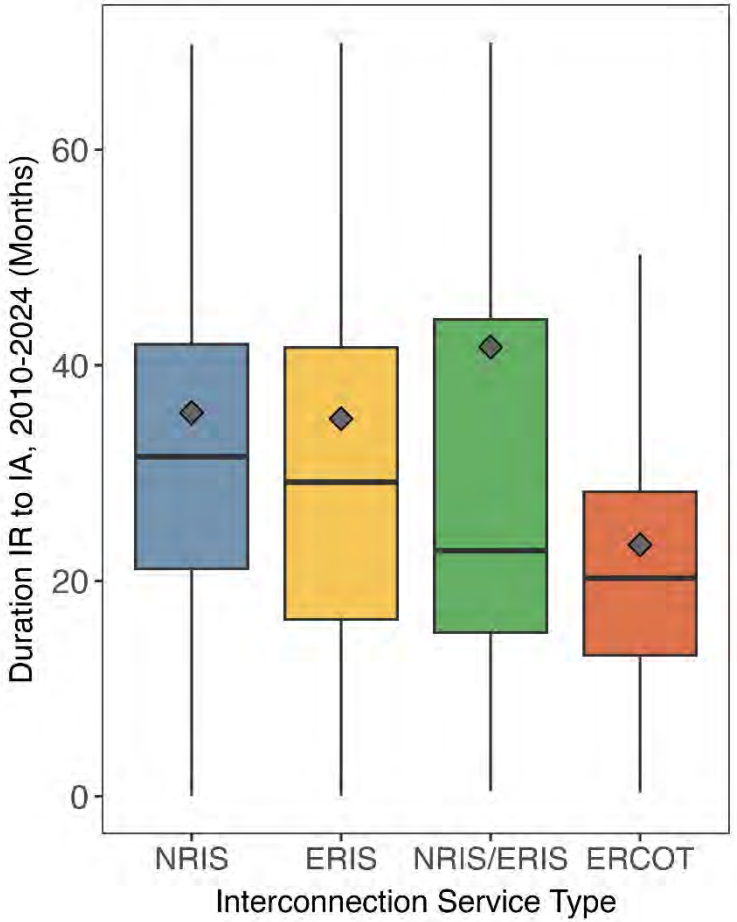
- Projects with rated capacity <20 MW typically complete studies and execute interconnection agreements much faster than larger projects
  - Median is 12 months for projects <5 MW
  - 18 months for projects 5 - <20 MW
- The median duration for projects 20 MW or larger hovers around 30 months across the four larger project groups analyzed
- 20 MW is the threshold between the FERC “large” and “small” generator interconnection procedures (LGIP / SGIP)
  - The median LGIP duration is twice the median SGIP duration for projects in our sample

Notes: (1) Sample includes 4,393 projects from 7 ISO/RTOs and 5 non-ISO balancing areas with executed interconnection agreements since 2005. (2) The majority of the 2024 data this analysis are from ERCOT (57%). (3) Not all data used in this analysis are publicly available.

Energy Resource Interconnection Service (ERIS) requests are not significantly faster to process than Network Resource Interconnection Service (NRIS), though ERCOT requests are faster







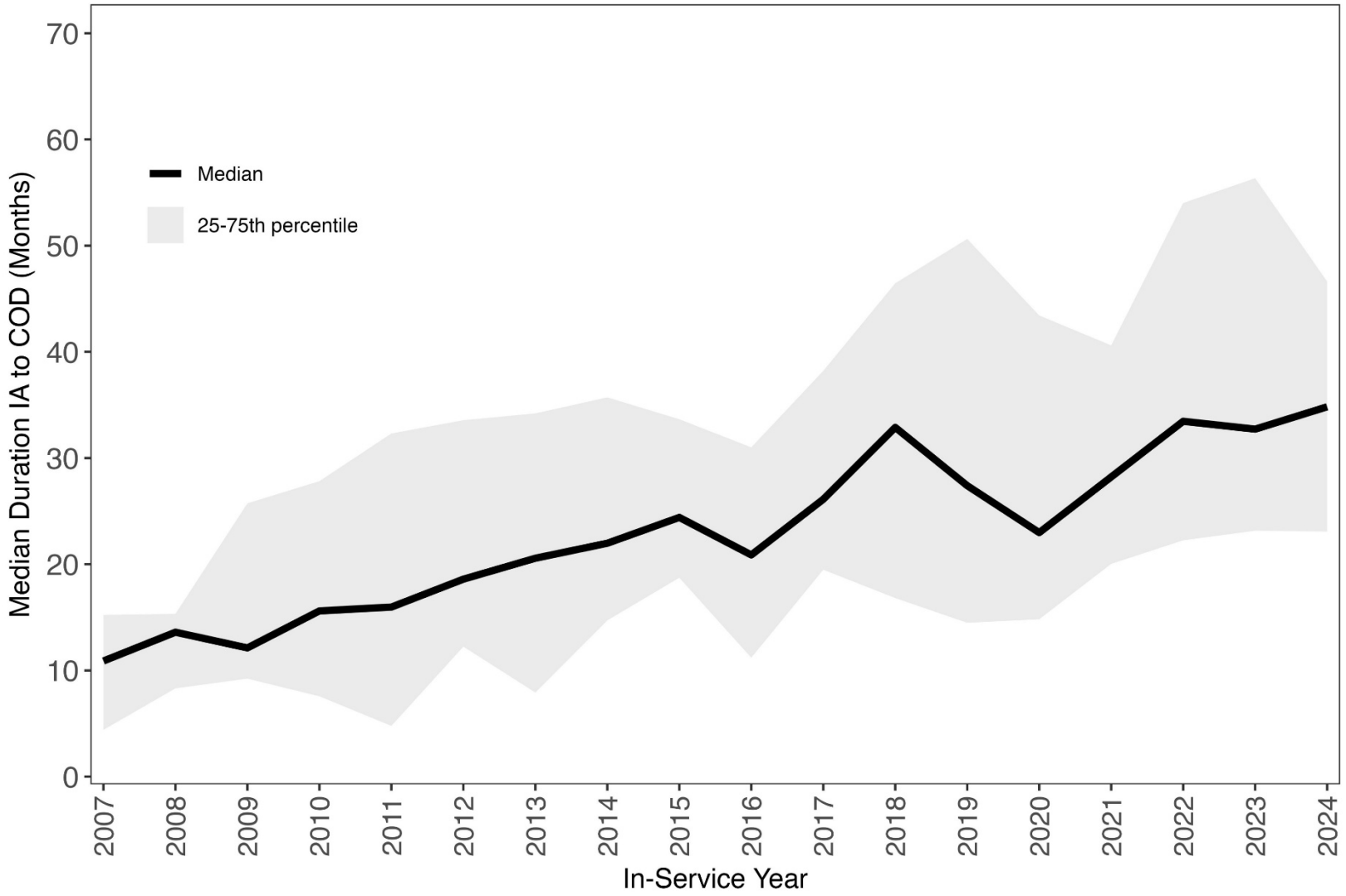
Based on t-tests of mean durations, the average IR-IA duration for ERIS requests submitted since 2010 (35 months) is not significantly (p = 0.3)[1] shorter than that for NRIS requests (~36 months).

ERCOT – which is not FERC jurisdictional – utilizes a 'connect and manage' approach, which is similar to ERIS. But ERCOT requests are processed significantly (p < 0.001) faster on average (~23.3 months) than ERIS requests in other regions since 2010.

Notes: (1) T-tests were used to determine whether there is a statistically significant difference between the mean duration of groups. We consider a p-value less than 0.05 to be statistically significant. (2) Sample includes 4,164 projects from 6 ISO/RTOs and 4 non-ISO balancing areas with executed interconnection agreements since 2005 that also provided service type information (3,493 since 2010). (3) Not all data used in this analysis are publicly available.

Projects can face substantial delays *after* securing an interconnection agreement (IA). The median duration from IA to commercial operations date (COD) has increased over time



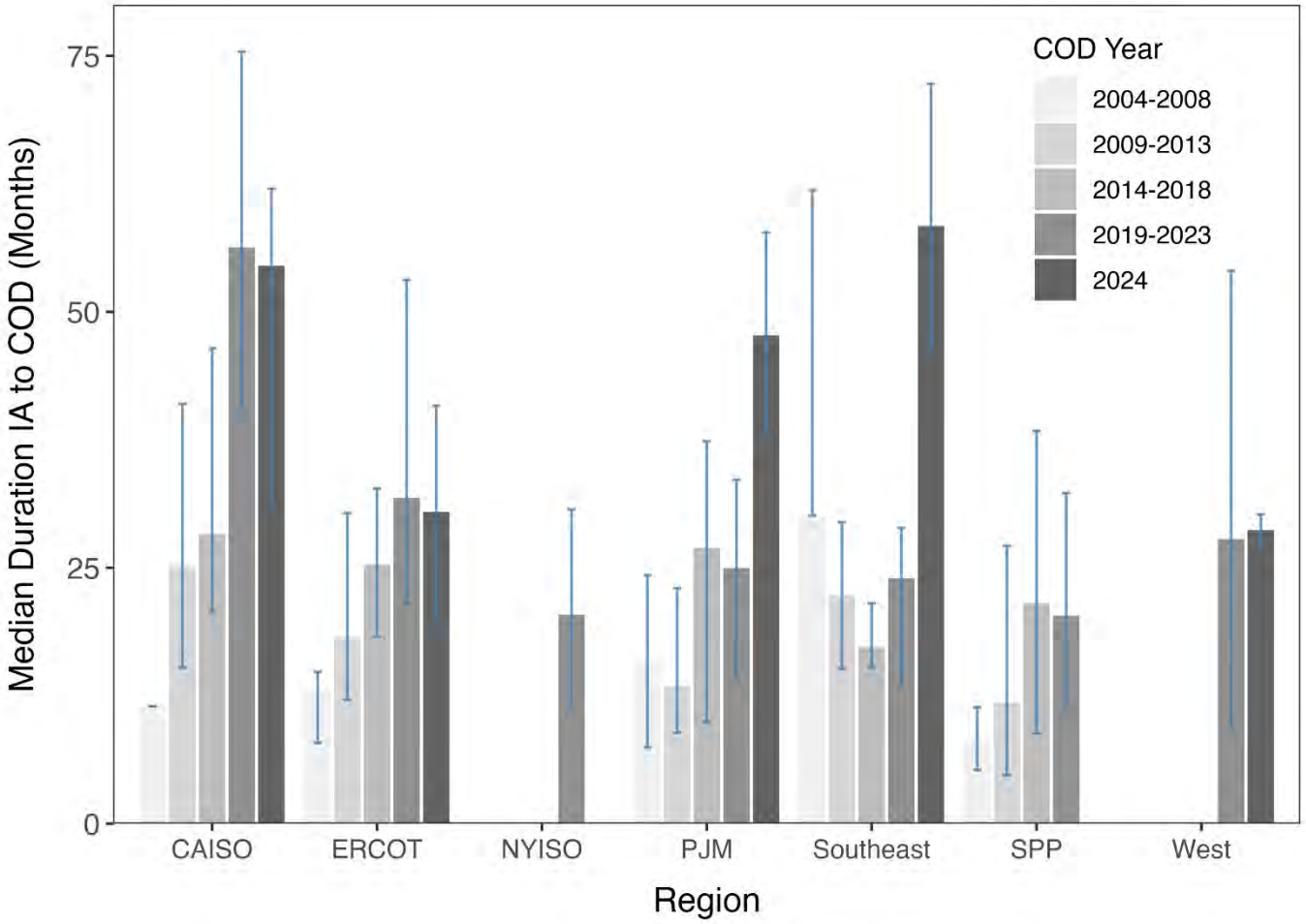


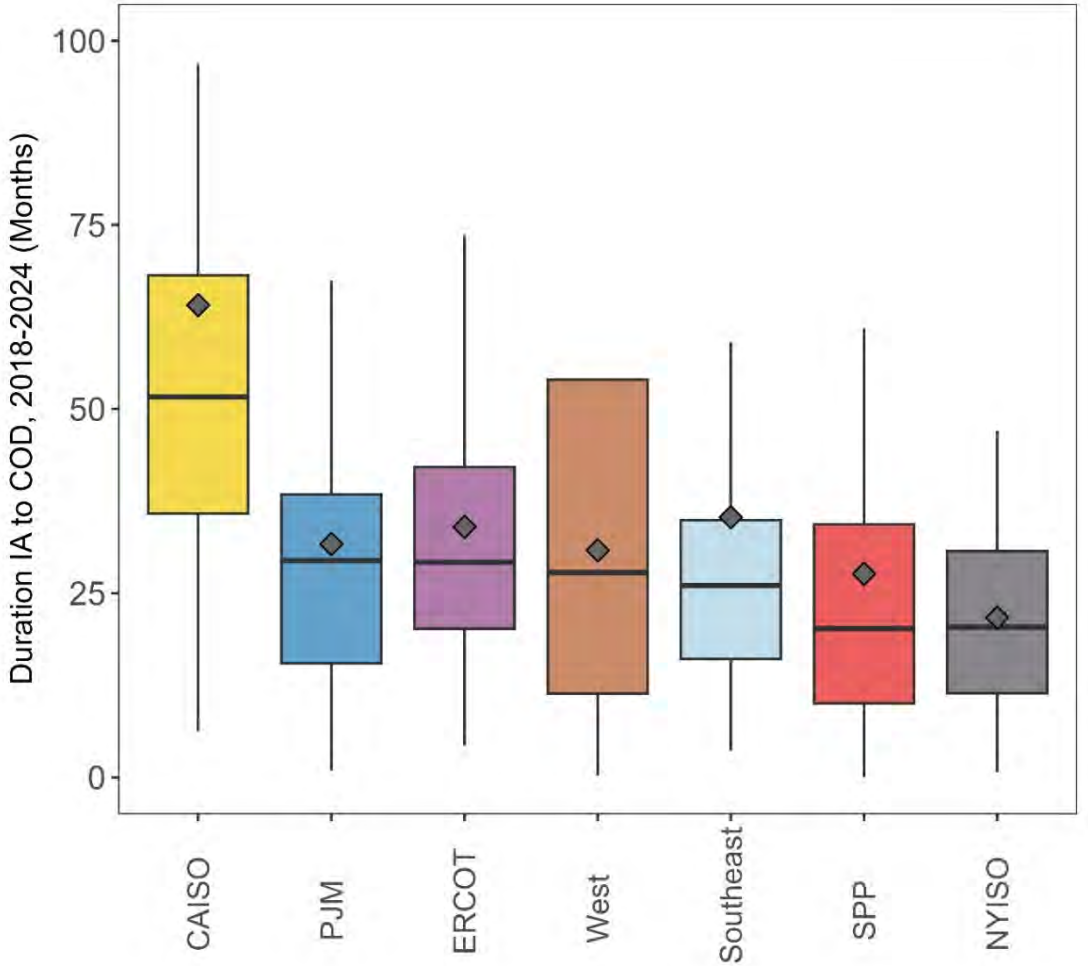
- Limited data were available to analyze typical durations from interconnection agreement to commercial operations
- Considering 1,161 projects across 7 entities, the median IA to COD duration has increased notably
  - From 11 months for projects built in 2007, 19 months in 2015, and **35 months for those built in 2024**
- But, that duration has been especially high in CAISO recently (see next slide)
  - The typical solar project built in CAISO since 2018 took over 4 years to reach commercial operations *after securing an interconnection agreement*; those built in 2022 averaged over 5 years
  - This is largely due to factors outside of the interconnection process, such as procurement / offtake, permitting, and transmission completion

Notes: (1) Data were only available for 1,161 projects across 5 ISO/RTOs and two utilities, out of 4,432 total "operational" projects in the full dataset. (2) Not all data used in this analysis are publicly available.

The timeline from IA to COD is increasing across regions; this period is typically longest in CAISO, though PJM and the Southeast also had long durations for projects built in 2024



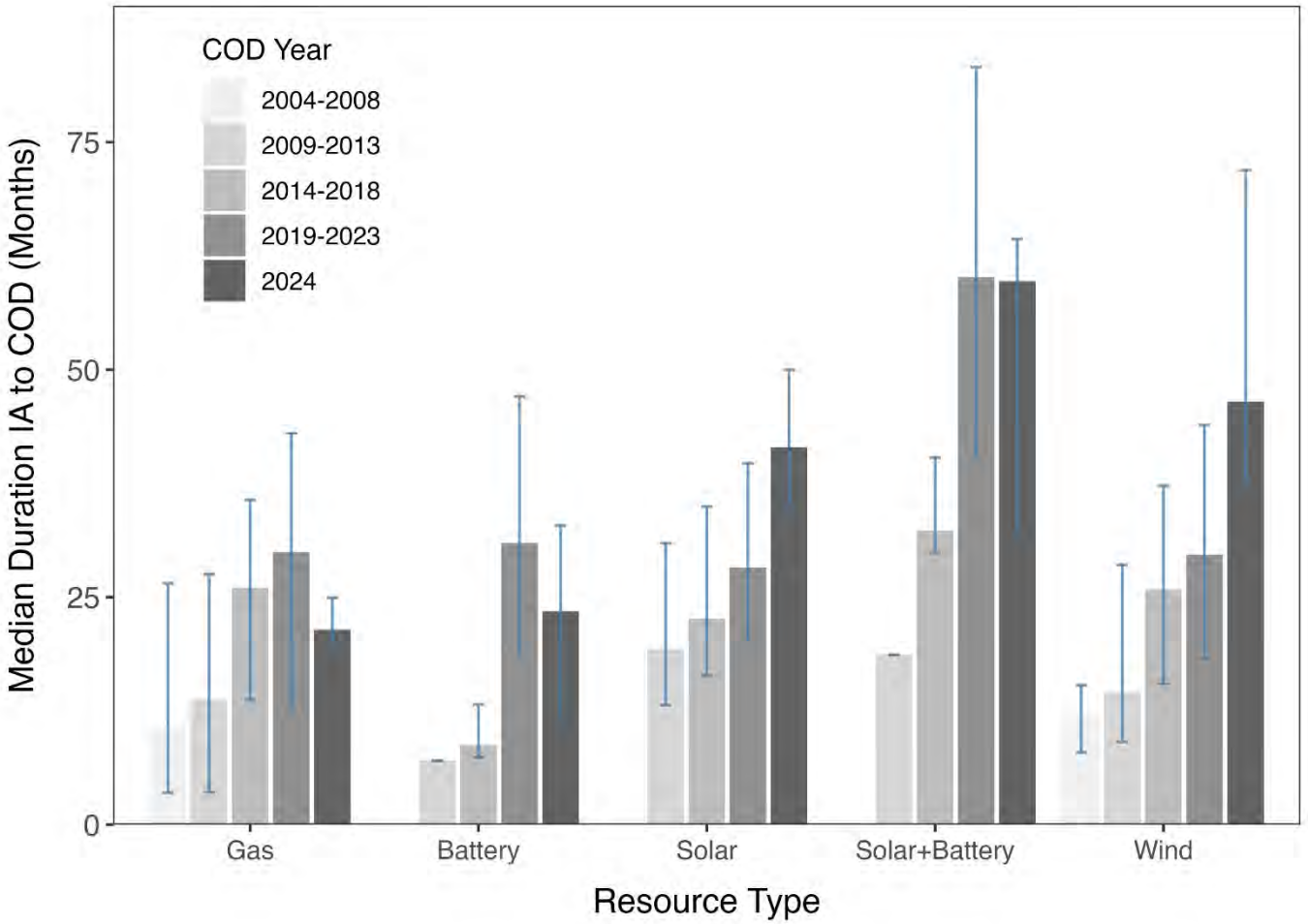


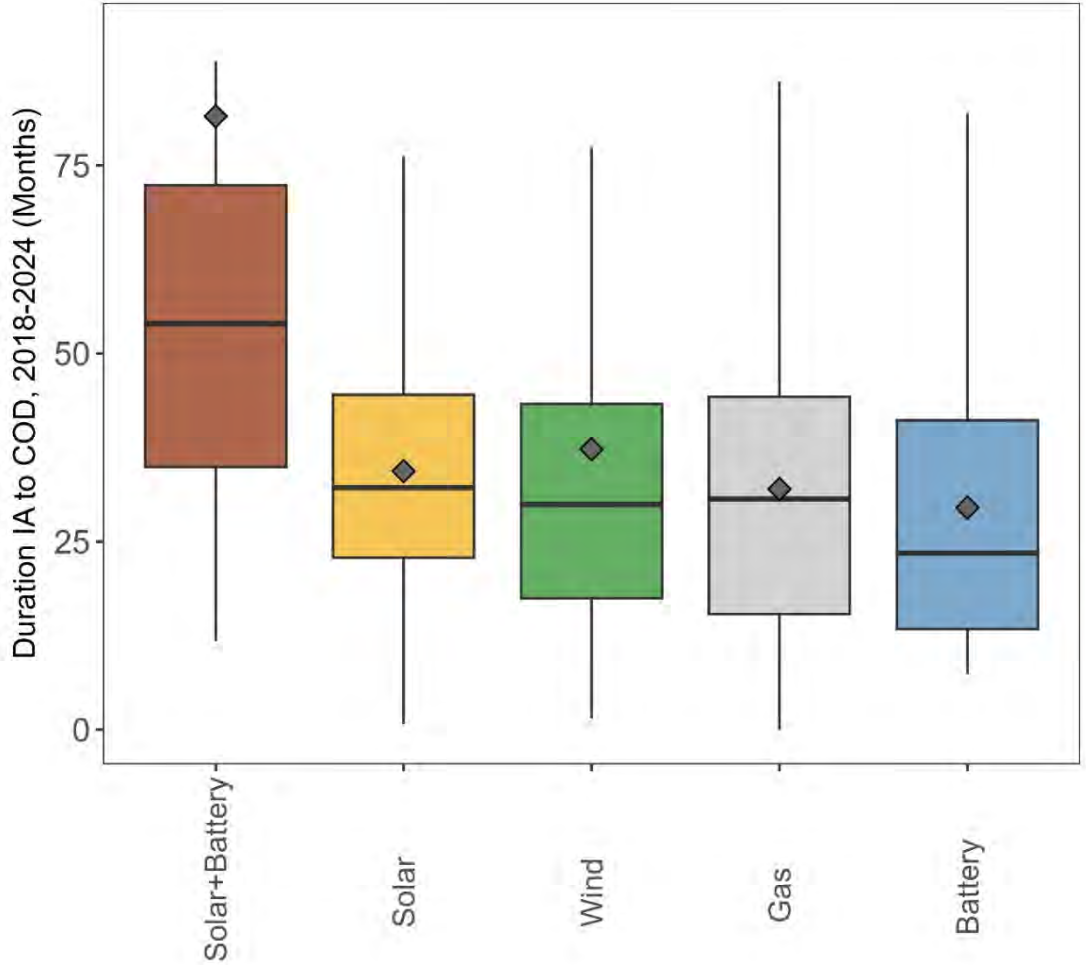


Notes: (1) Data were only available for 1,161 projects across 5 ISO/RTOs and two utilities, out of 4,432 total "operational" projects in the full dataset. (2) Not all data used in this analysis are publicly available.

IA to COD duration is increasing across resource types, too. Solar+battery projects typically take longest[1], whereas standalone battery plants tend to move fastest



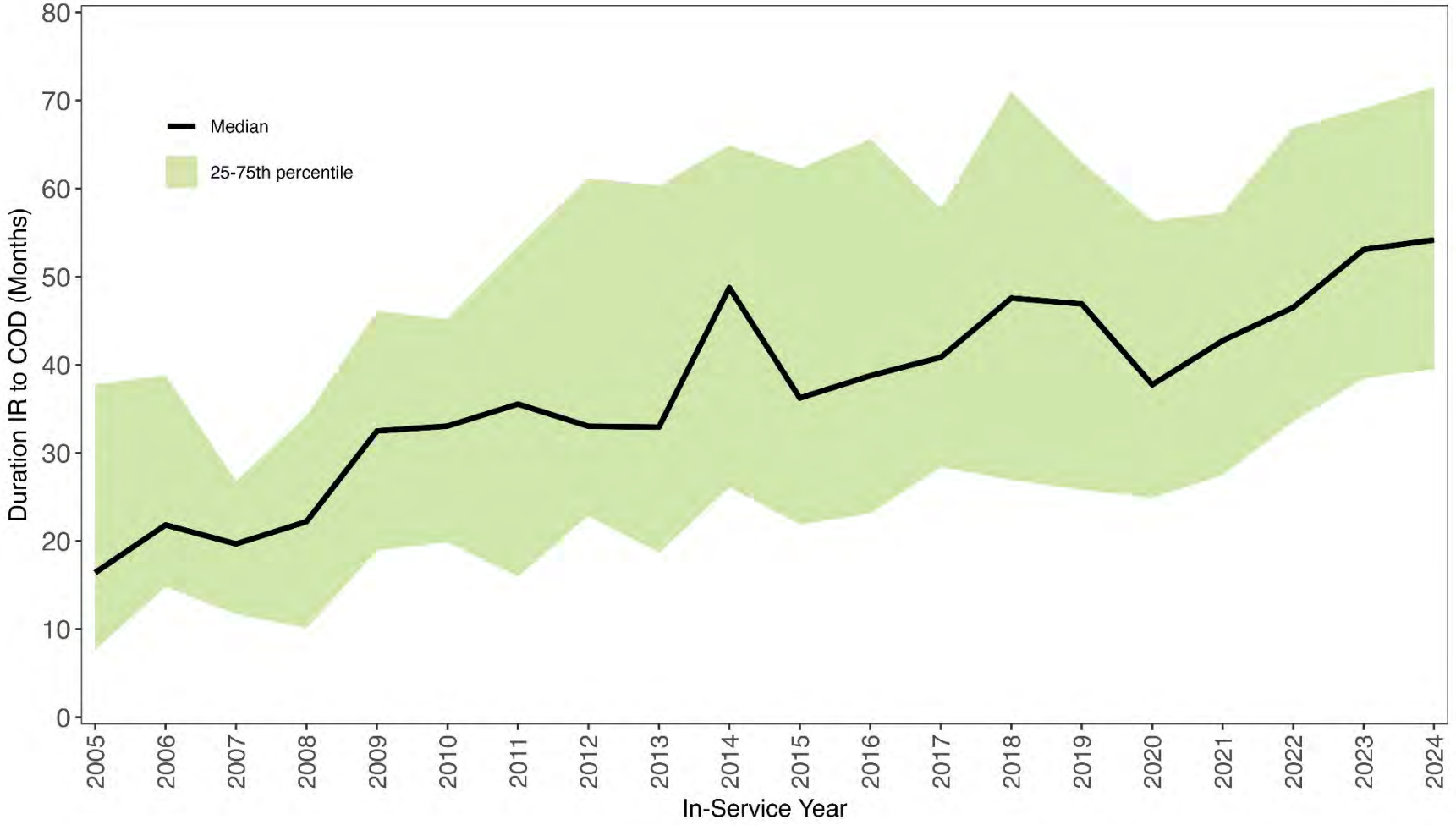




Notes: (1) The sample of Solar+Battery plants in this analysis are predominantly from CAISO, where there were recent procurement / offtake delays (see previous slides). (2) Data were only available for 1,161 projects across 5 ISO/RTOs and two utilities, out of 4,432 total "operational" projects in the full dataset. (3) Not all data used in this analysis are publicly available.

The median duration from interconnection request (IR) to commercial operations date (COD) continues to rise: 55 mo. for projects completed in 2024 (2024 sample dominated by ERCOT)

Duration Analyzed: *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*



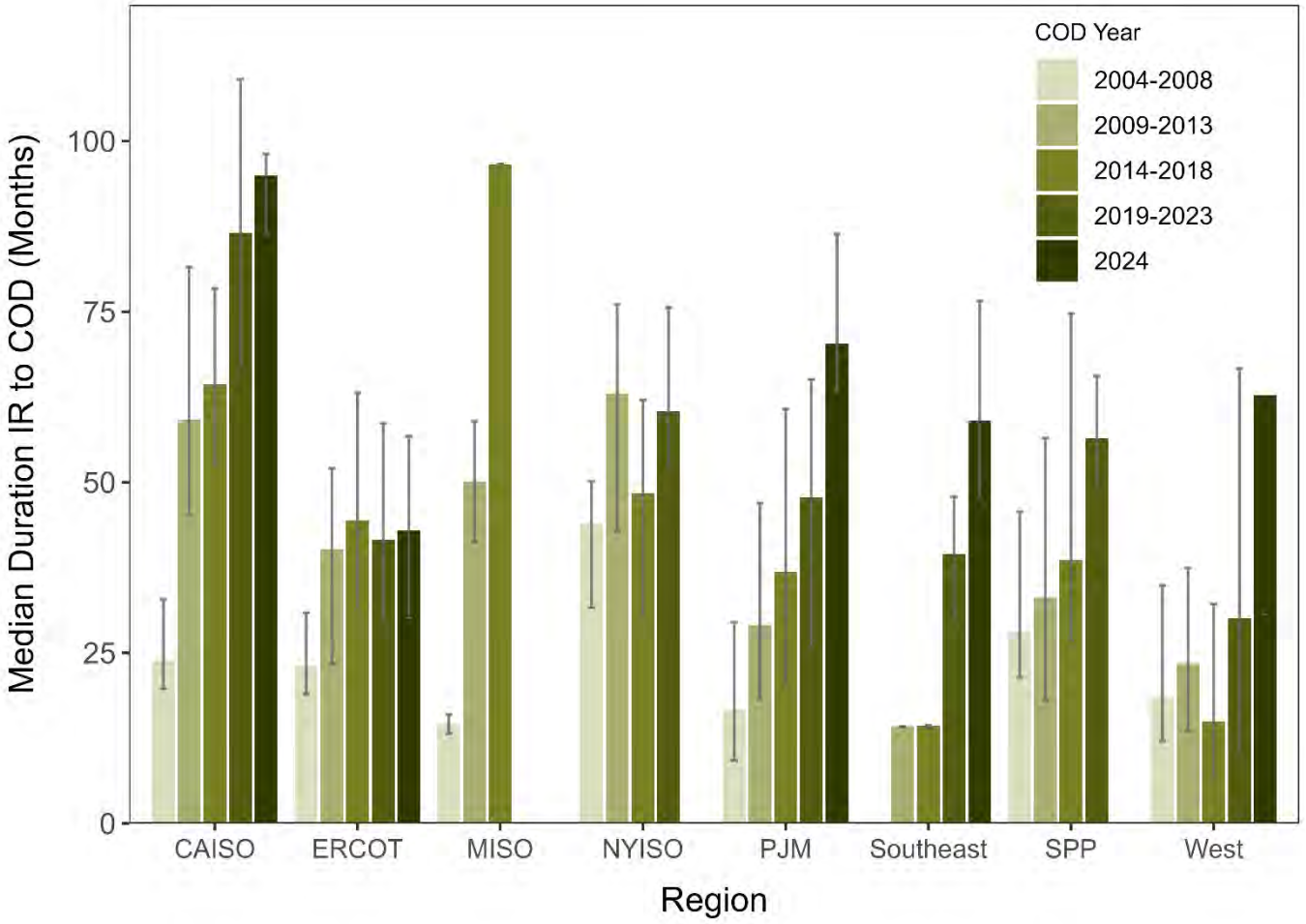
Sample Size (# requests) by Region and Year

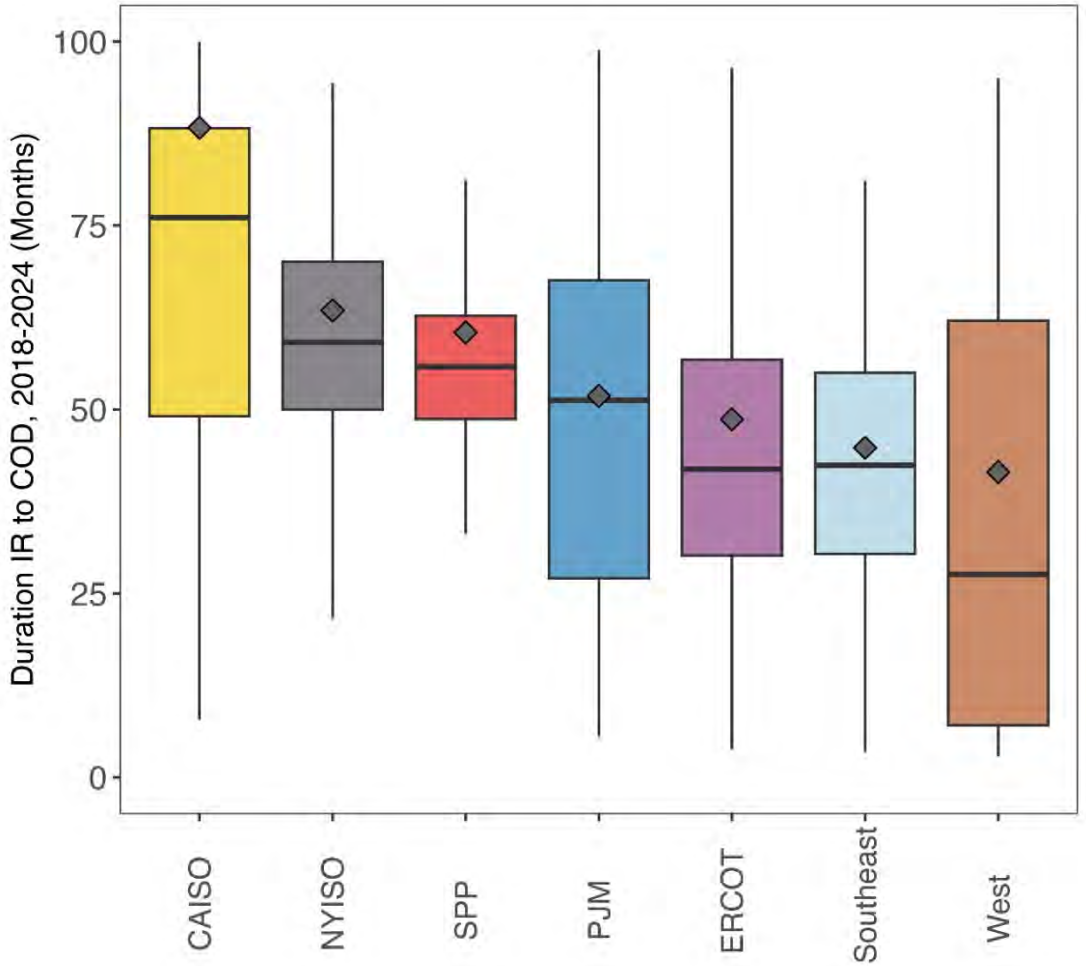
Region	2018	2019	2020	2021	2022	2023	2024
CAISO	8	11	8	18	13	12	7
ERCOT	62	76	79	139	91	95	144
NYISO	3	10	1	4	9	4	0
PJM	67	55	92	50	35	63	60
Southeast	4	4	29	36	31	43	46
SPP	15	9	27	15	7	4	0
West	6	2	2	9	10	7	7

Notes: (1) The majority of the 2024 data sample for this analysis came from ERCOT (55%), which typically has relatively shorter durations (see next slide); (2) Includes data from 5 ISOs and 17 non-ISO BAs representing 72% of all operational projects in our sample. (3) Duration is calculated as the number of months from the queue entry date to the commercial operations date.

The request to operational timeline has increased in many regions; duration tends to be longer in FERC-jurisdictional ISOs

Duration Analyzed:	Interconnection Request (IR)	→	Interconnection Agreement (IA)	→	Commercial Operations (COD)

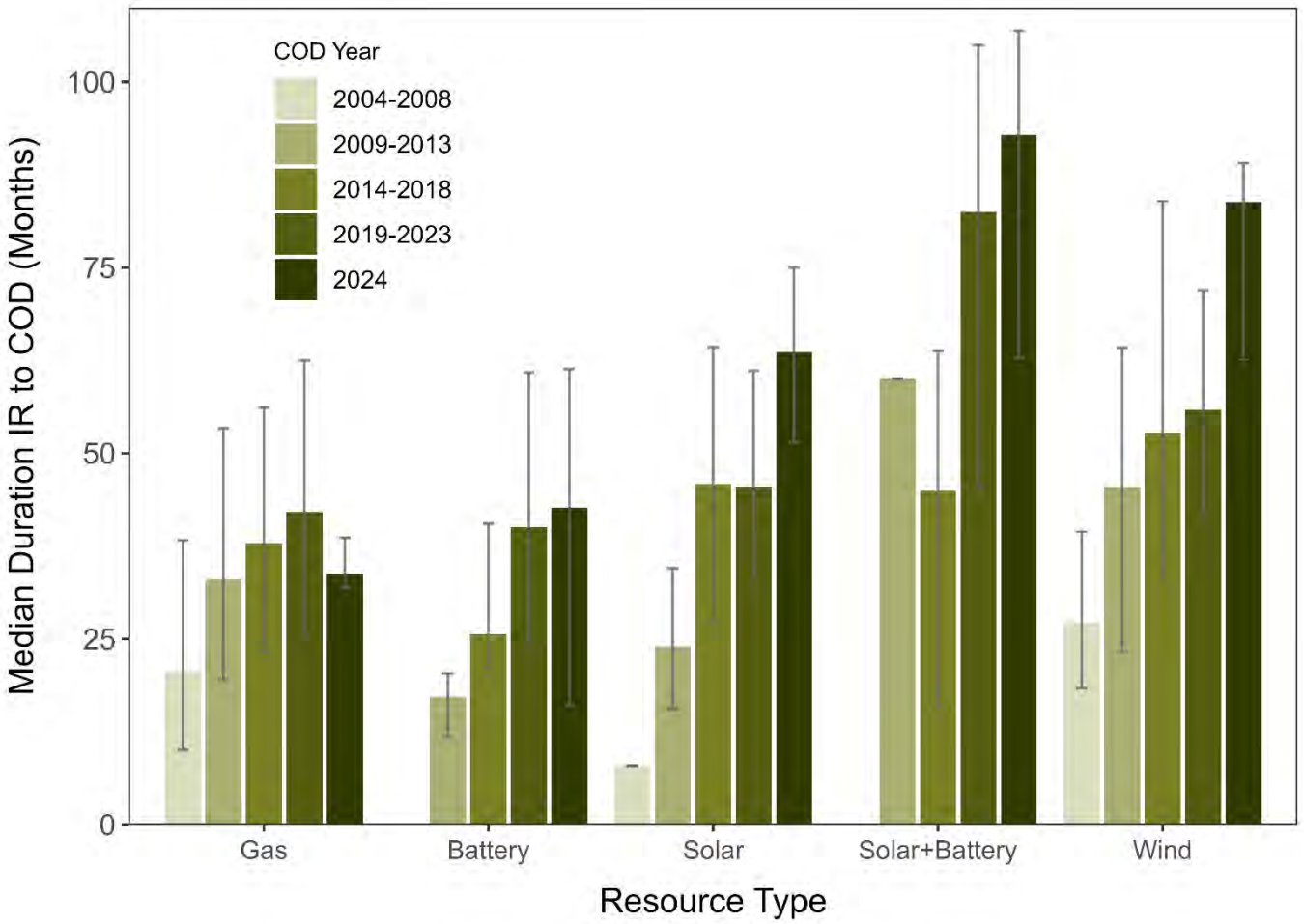


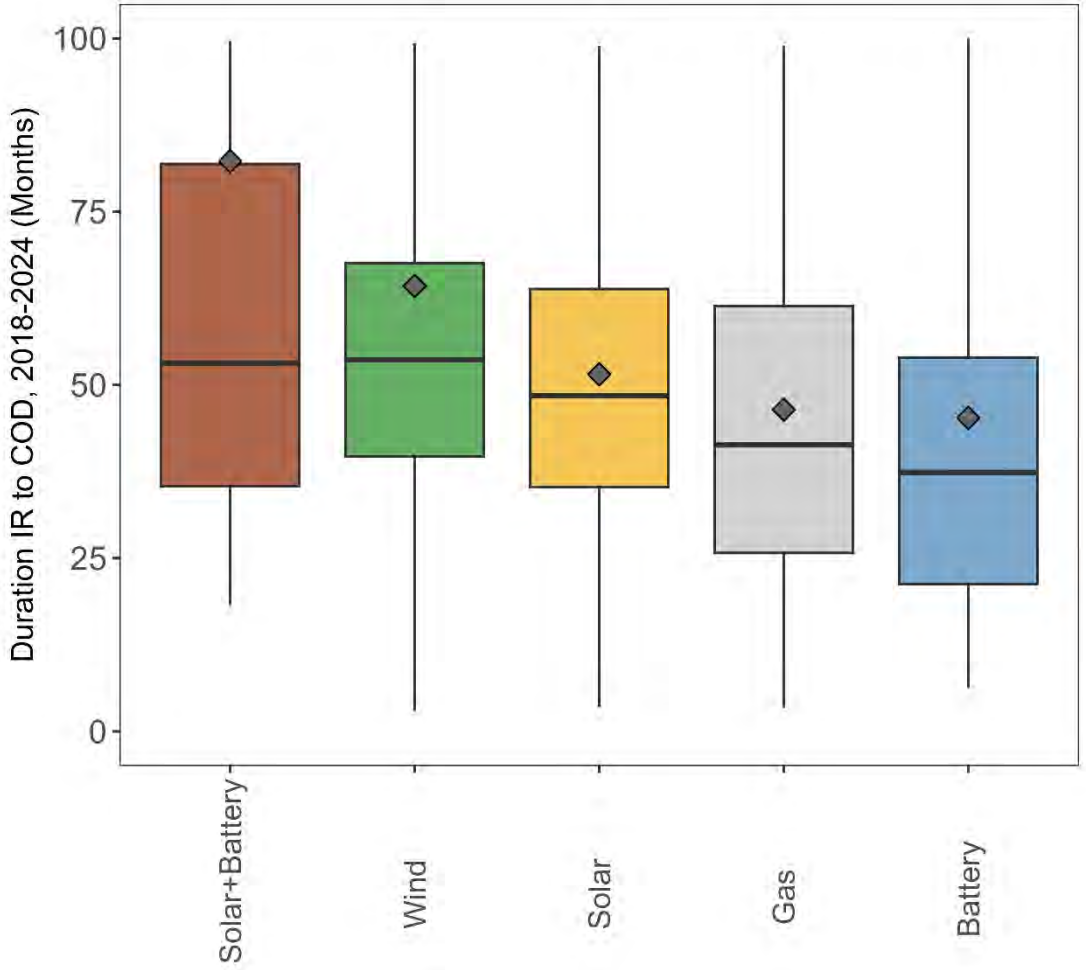


Notes: (1) Includes data from 5 ISOs and 17 non-ISO BAs representing 72% of all operational projects in our sample. (2) Duration is calculated as the number of months from the queue entry date to the commercial operations date.

Duration from request to COD is also increasing across resource types. Solar+battery and wind projects typically take longest

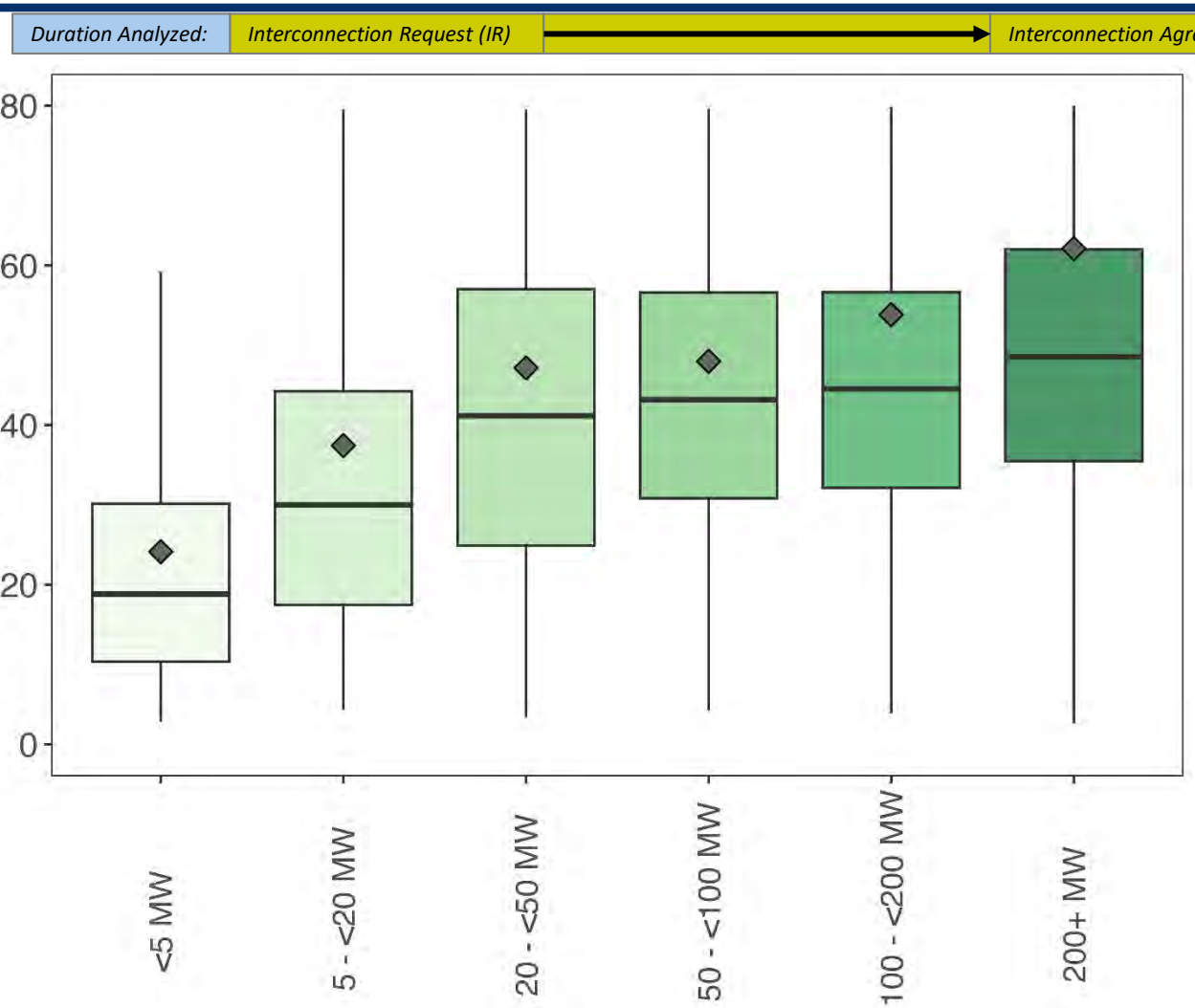






Notes: (1) Includes data from 5 ISOs and 17 non-ISO BAs representing 72% of all operational projects in our sample. (2) Duration is calculated as the number of months from the queue entry date to the commercial operations date.

Larger projects have longer development timelines: The average IR to COD duration increases by project size (MW) – especially up to the 20 MW LGIP limit



- For the smallest projects in our sample (<5 MW), the median project came online less than 2 years (18 months) after the interconnection request
- The median 5-20 MW project, meanwhile, takes nearly 3 years (32 months) from IR to COD
- Larger projects spend even more time in the interconnection and development process, with the median 100-200 MW project taking >4 years (49 months) and the median 200+ MW project taking nearly 5 years (56 months) from IR to COD

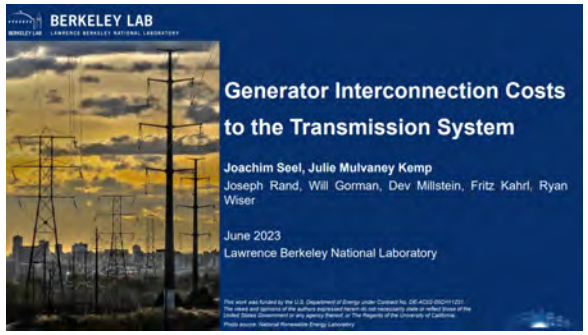
Notes: (1) Box-plot includes projects reaching commercial operations from 2010-2024. (2) Includes data from 5 ISOs and 17 non-ISO BAs representing 72% of all operational projects in our sample. (3) Duration is calculated as the number of months from the queue entry date to the commercial operations date.

As of the end of 2024, there were ~10,300 projects actively seeking grid interconnection across the U.S., representing 1,400 GW of generation and approximately 890 GW of storage.

- Historic withdrawal rates alongside relatively fewer requests resulted in a 12% decrease in total active queue volume in 2024.
- Active natural gas capacity (136 GW, +72% year-over-year) increased in 2024, while solar (956 GW, -12%), storage (890 GW, -13%), and wind (271 GW, -26%) capacity decreased.
- Capacity in queues is widespread across the U.S., but some states dominate: Texas has 15% of all solar capacity, 19% of gas, 17% of storage, and 19% of wind; California has 19% of storage and 8% of solar.
- There is a relatively modest amount of nuclear (~5 GW) and geothermal (~2 GW) capacity active in the queues.
- Hybrid power plants comprise a large share of proposed projects, particularly in CAISO and the West. 451 GW of solar hybrids (primarily solar+battery) are active. Roughly half of all active solar and storage capacity is in hybrid plant configurations[1].
- 408 GW of capacity already has a draft or executed interconnection agreement (IA) but has not yet reached commercial operations, including 199 GW of solar, 129 GW of storage, 54 GW of wind, and 26 GW of gas.
- The time projects spend in queues before reaching COD is increasing. For the regions with available data[2], the median duration from IR to COD has doubled from <2 years for projects built in 2000-2007 to over 4 years for those built in 2018-2024.
  - The full interconnection process timeline (from IR to IA) has also increased, though moderated somewhat in 2024.
  - Larger projects have longer development timelines; interconnection study duration increases notably for projects >20 MW.
  - Generally, timelines are increasing across resource types and regions, though ERCOT and the non-ISO regions tend to be faster.
- Ultimately, most of this proposed capacity will not be built. Only 13% of capacity that submitted interconnection requests from 2000-2019 had reached commercial operations by the end of 2024; 77% of that capacity had been withdrawn and 10% was still active.
- FERC Order 2023 and various other reforms are being implemented. These are important measures to reduce interconnection bottlenecks and enhance grid system reliability, but it is too early to measure and assess their full impact.

Notes: (1) Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data. (2) Data for this analysis were only available for 72% of all operational projects in our sample.

Related Berkeley Lab transmission interconnection research + resources



- Collecting and analyzing the cost of interconnecting new resources
  - Analysis of interconnection cost data for projects in MISO, PJM, SPP, ISO-NE, NYISO, and CAISO for studies performed between 2010 and 2023. ISO-specific technical briefs and cleaned interconnection cost data files are available for download
  - New draft work on non-ISO BA interconnection costs (PACE, BPA, and Duke Utilities)



- Researching opportunities for interconnection solutions and reforms
  - Developed Transmission Interconnection Roadmap by engaging broad stakeholder community via DOE's i2X initiative through multiple webinars and workshops to identify 35 solutions enabling an improved interconnection process of new energy resources while enhancing reliability, resiliency, and security of our electric grid

i2X INTERCONNECTION INNOVATION e-XCHANGE U.S. DEPARTMENT OF ENERGY

- Connecting stakeholders, improving data transparency, and developing solutions
  - i2X is a DOE program to enable simpler, faster, and fairer interconnection of electric resources while enhancing the reliability, resiliency, and security of our electric grid
  - Visit https://www.energy.gov/eere/i2x/ to find resources and find upcoming events

Contact:

Joseph Rand (jrand@lbl.gov)

More Information:

- Visit https://emp.lbl.gov/queues to download the data used for this analysis and access an interactive data visualization tool
- Visit https://emp.lbl.gov/interconnection_costs for related research on interconnection costs

Acknowledgements:

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Appendix

Balancing areas included in data:

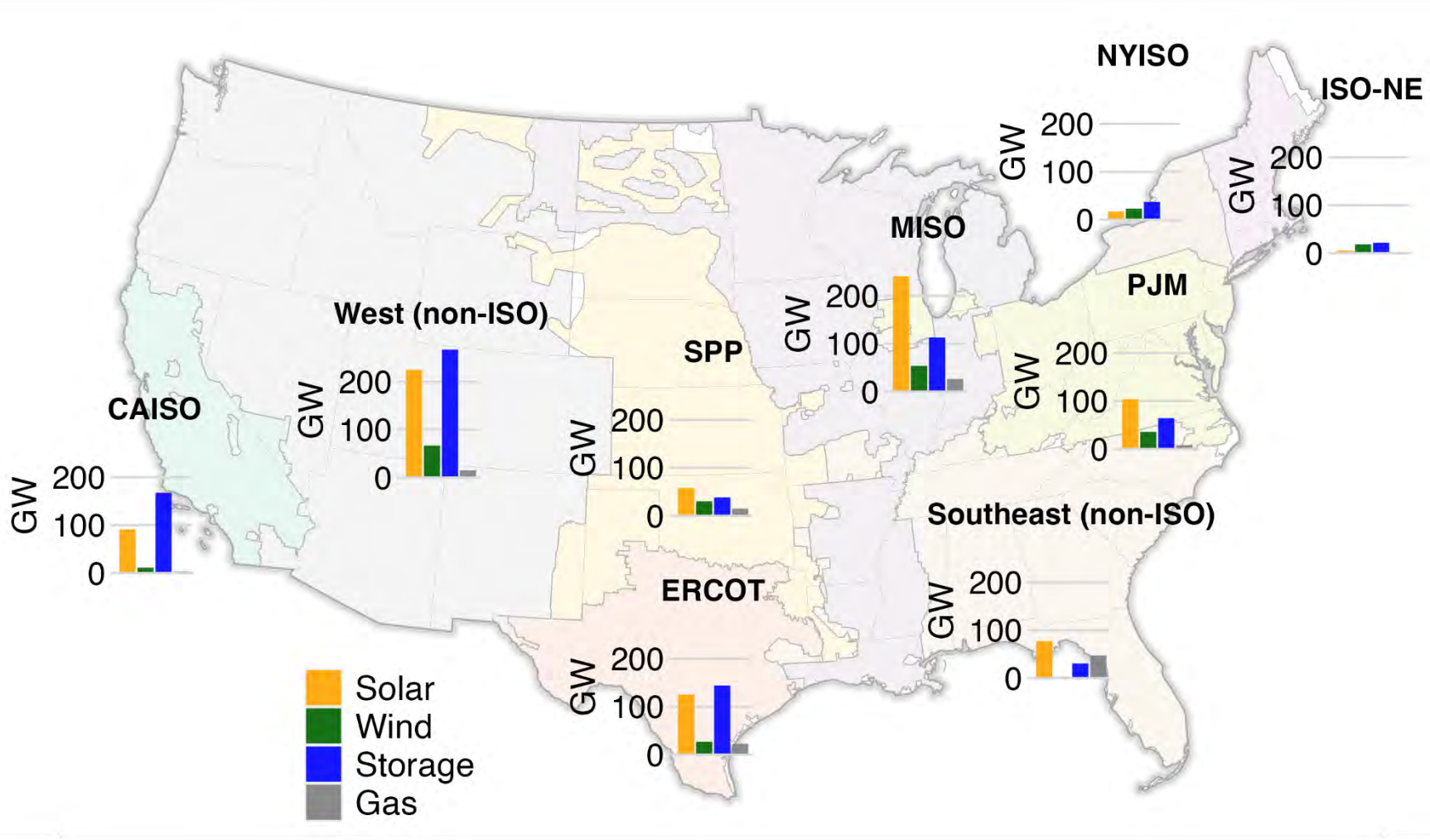
ISO/RTOs	Southeast (non-ISO)	
CAISO	Associated Electric Coop.	Jacksonville Electric Authority
ERCOT	Dominion	LG&E & KU Energy
ISO-NE	Duke Carolinas	Orlando Utilities Commission
MISO	Duke Florida	Santee Cooper
NYISO	Duke Progress	Seminole Electric Coop.
PJM	Duke/Progress	Southern Company
SPP	Florida Power & Light	Tampa Electric Co.
	Georgia Transmission Corp.	Tennessee Valley Authority
West (non-ISO)		
Arizona Public Service	Idaho Power	Portland General Electric
Avista	Imperial Irrigation District	Public Service Co. of CO / Public Service Co. of NM
Black Hills / Black Hills Colorado	L.A. Dept. Water & Power	Puget Sound Energy
Bonneville Power Admin.	Minnkota Power Cooperative	Sacramento Municipal Utility District
Chelan PUD	Navajo-Crystal	Salt River Projects (5 entities)
Cheyenne Light Fuel & Power	NorthWestern	Tacoma Public Utilities
Colorado Springs Utilities	NV Energy	Tri-State G&T
El Paso Electric	PacifiCorp	Tucson Electric Power
Grant PUD	Platte River Power Authority	WAPA (5 entities)

Number of active interconnection requests by capacity

Count of Active Requests by Capacity and Type						
Capacity	**Gas**	**Solar**	**Storage**	**Wind**	**Offshore Wind**	**Other**
<5 MW	10	139	37	10	0	86
5 - <20 MW	60	335	101	36	2	154
20 - <50 MW	57	516	168	49	1	236
50 - <100 MW	49	838	384	83	2	333
100 - <200 MW	41	1090	929	226	2	715
200+ MW	189	979	1033	472	53	1123

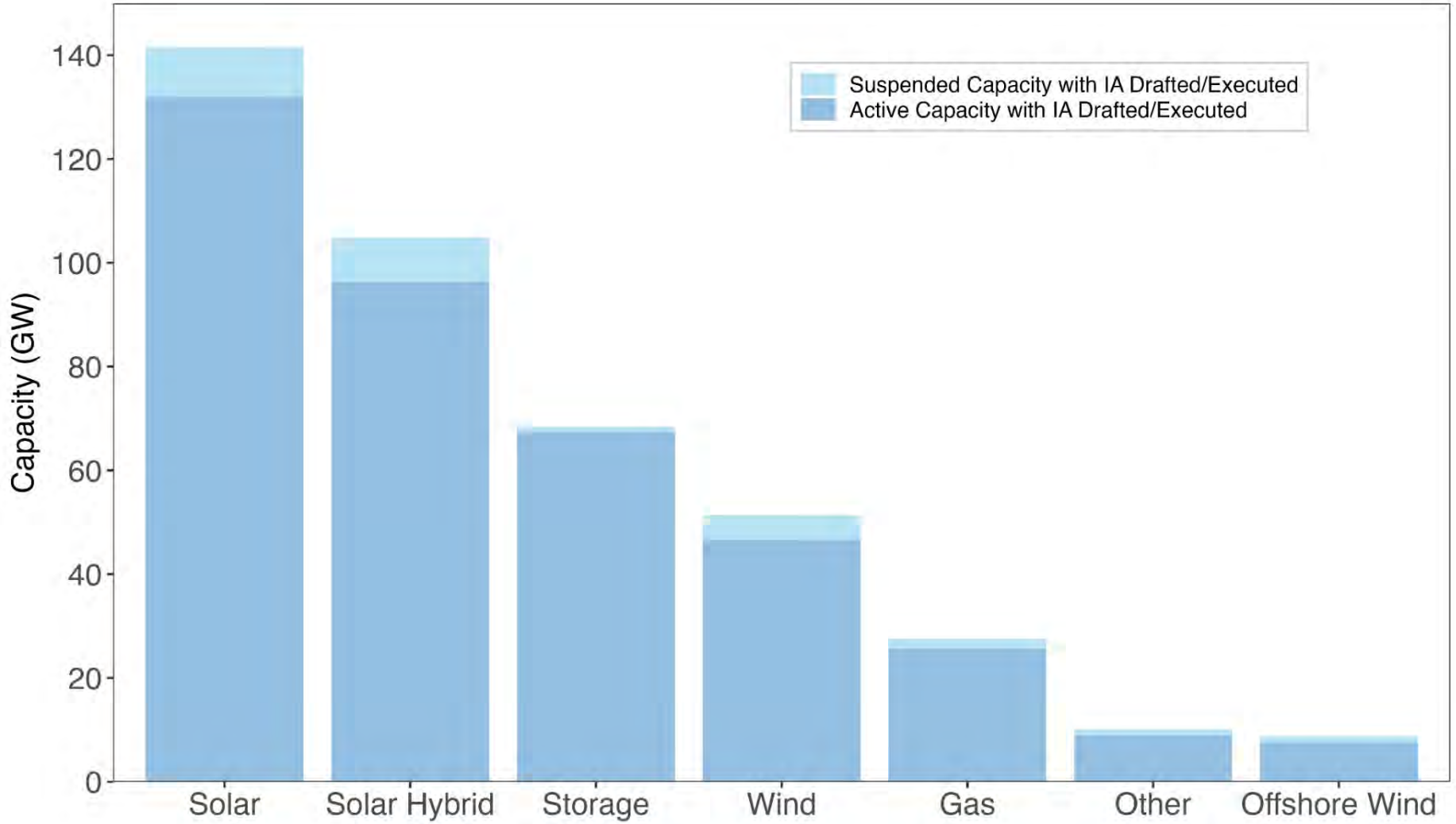
Count of Active Requests by Capacity and Region									
Capacity	**CAISO**	**ERCOT**	**ISO-NE**	**MISO**	**NYISO**	**PJM**	**SPP**	**Southeast**	**West**
<5 MW	4	12	105	20	0	60	0	29	52
5 - <20 MW	8	78	121	32	7	323	4	64	51
20 - <50 MW	18	46	43	106	67	519	18	82	128
50 - <100 MW	50	164	18	259	85	421	91	427	174
100 - <200 MW	120	559	48	917	149	380	212	192	426
200+ MW	438	823	64	879	94	239	318	208	786

Active solar, storage, wind, and gas capacity by region



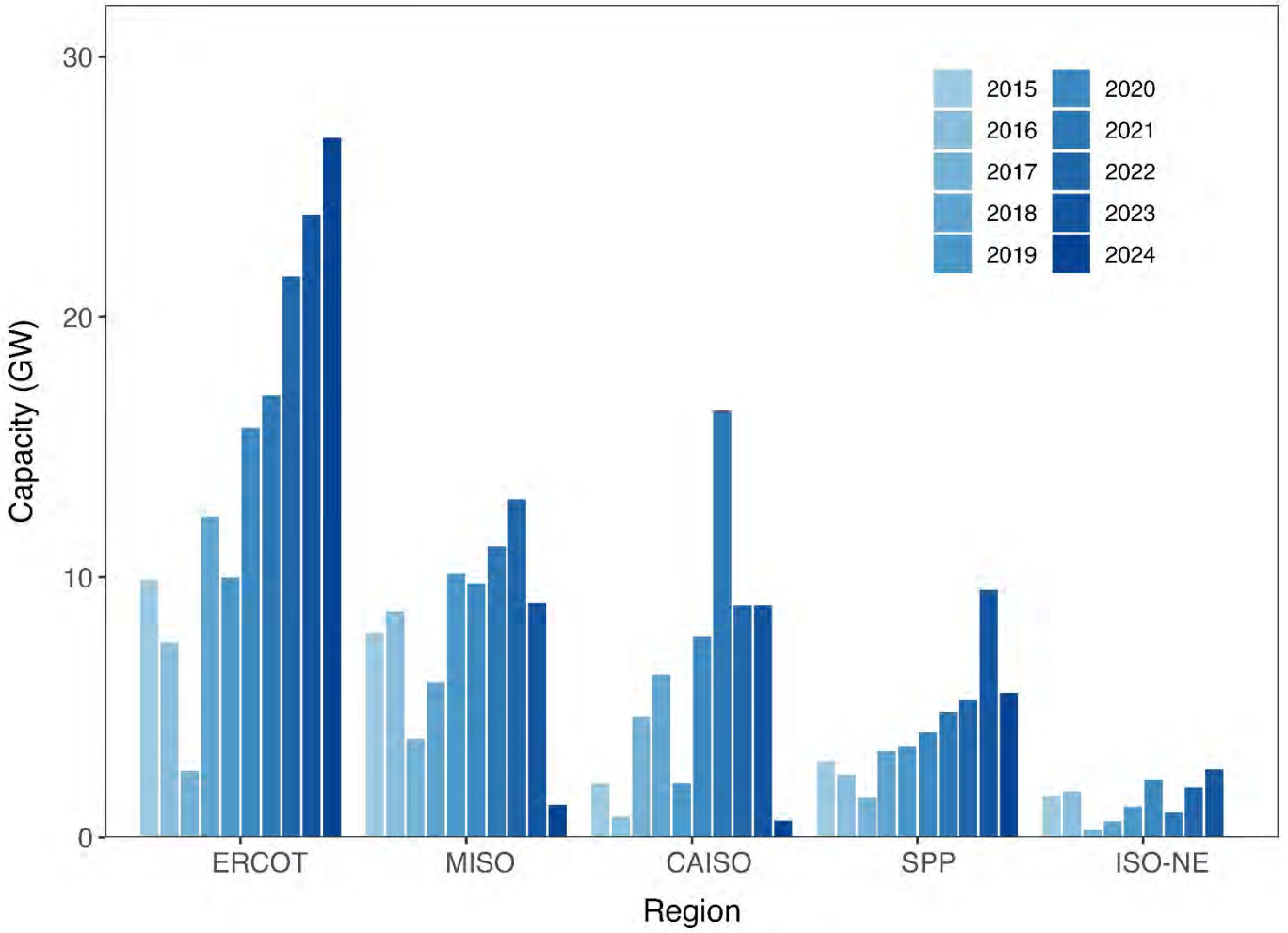
Note: "Active" requests include those that are actively requesting or undergoing grid interconnection studies, as well as those that have already executed interconnection agreements but have not yet reached commercial operations.

Active capacity with draft or executed interconnection agreement by resource type



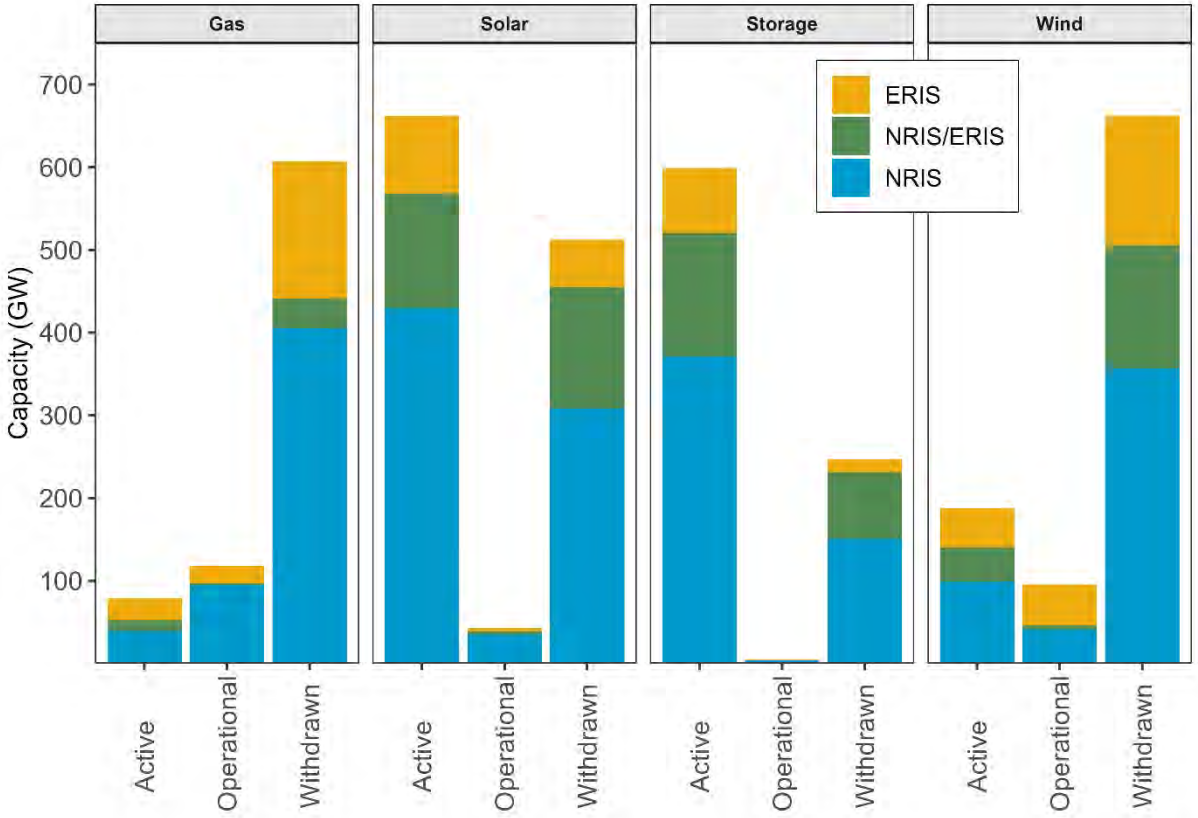
Notes: (1) IA capacity bars include capacity in the queues that has either a draft or fully executed interconnection agreement but has not yet reached commercial operations. The darker blue portion of the bar includes only active capacity; light blue portion includes suspended queue requests with an executed/drafted IA. The implication of "Suspended" queue status differs by ISO. e.g., in PJM it is voluntary and elected by the developer; in MISO it requires a force majeure event to suspend a project.

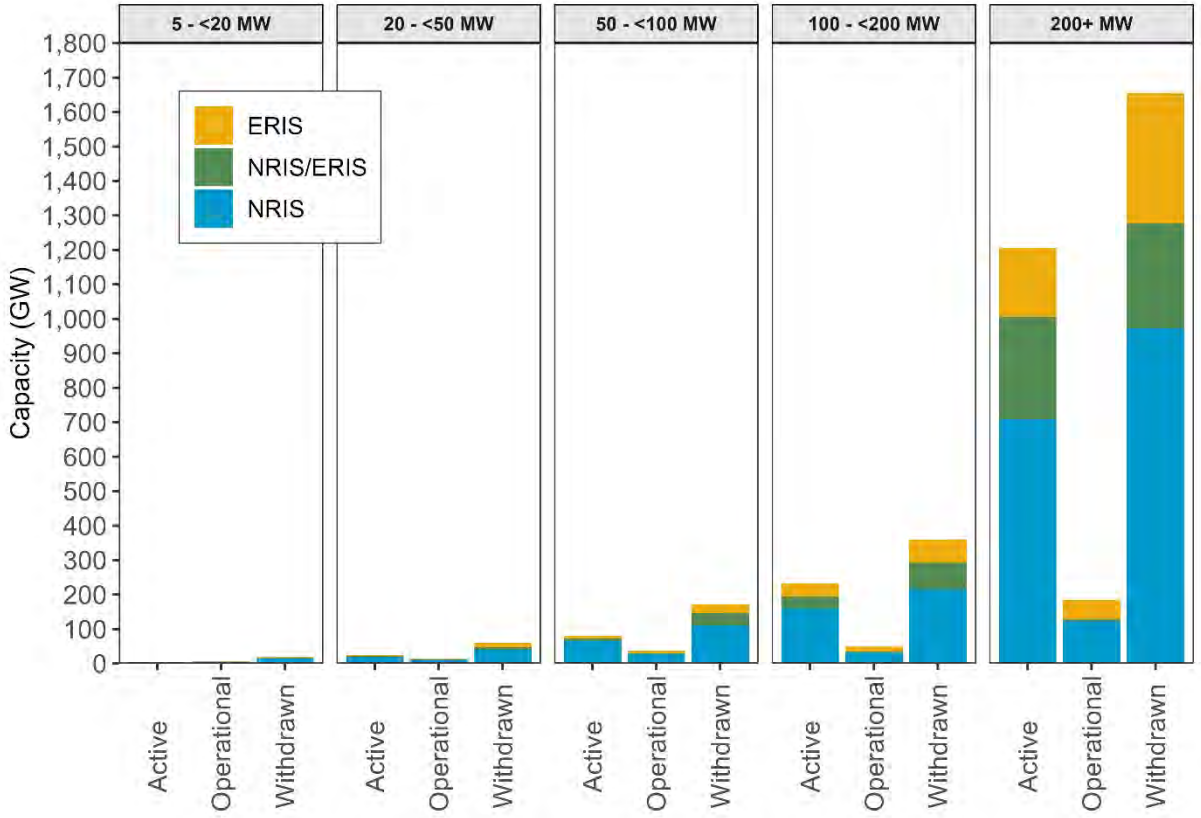
Annual volume (GW) of interconnection agreements executed by region



Notes: (1) Chart limited to regions where "IA date" is at least 70% populated (see table on slide 9). See slide 25 to see IA executed volume as a fraction of each region's 2024 peak load. Available data for 2024 IAs may be lagging in some regions.

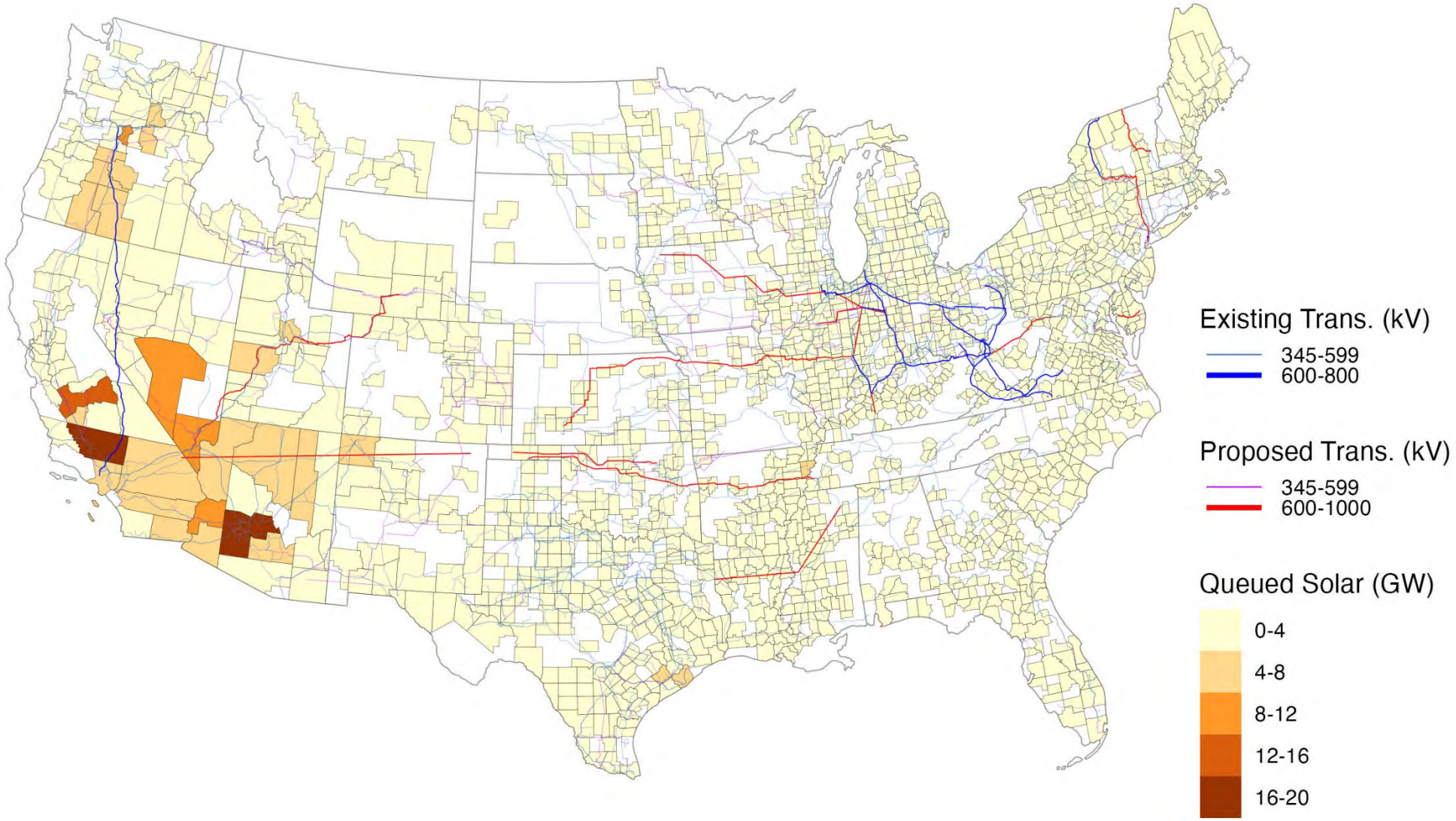
Interconnection service type (ERIS / NRIS) by status, resource type, and project size





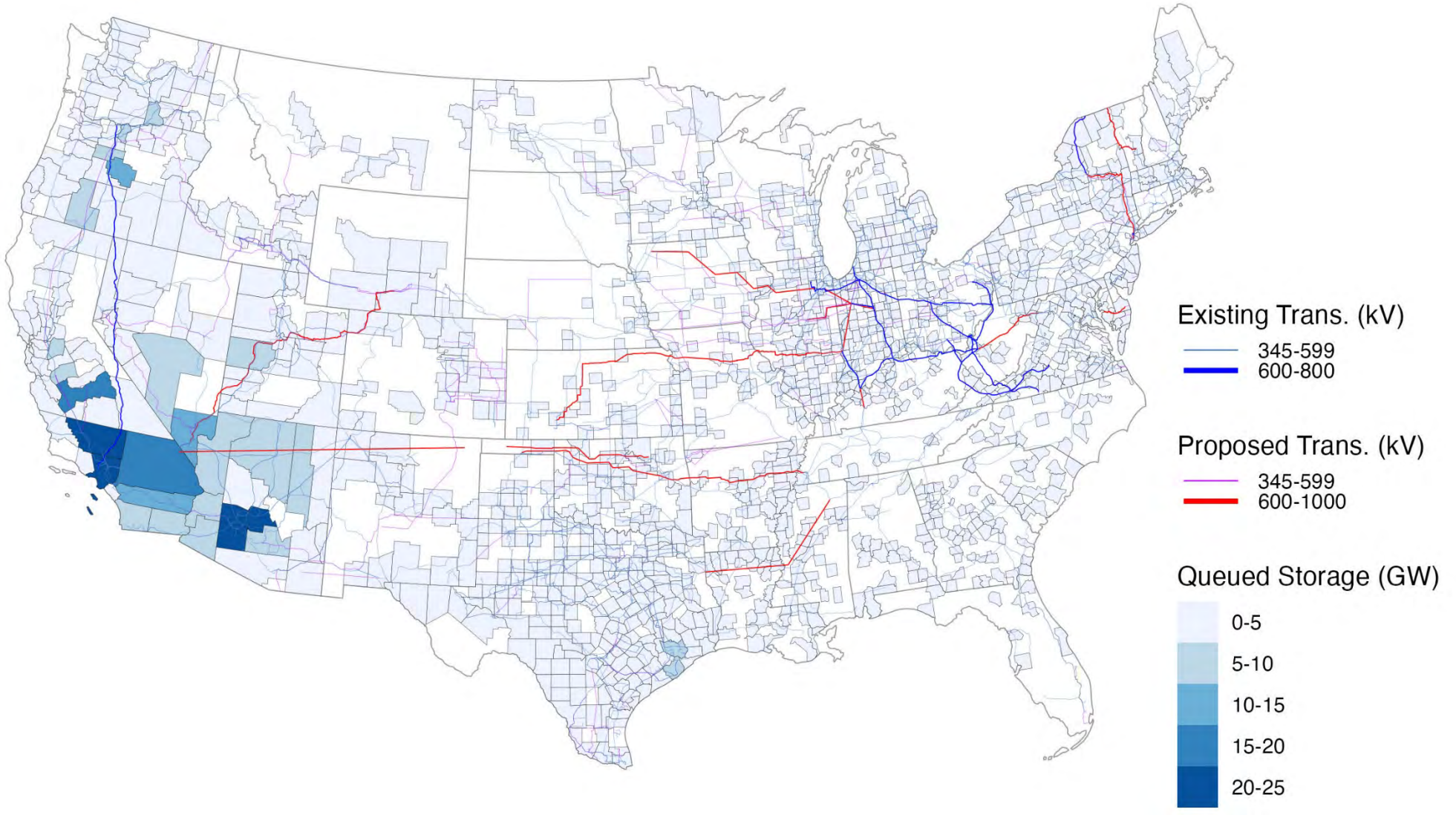
Notes: (1) NRIS and ERIS were developed under FERC Order 2003, and apply to FERC-jurisdictional transmission providers. (2) These charts exclude ERCOT.

Active solar capacity in queues at the end of 2024, by county



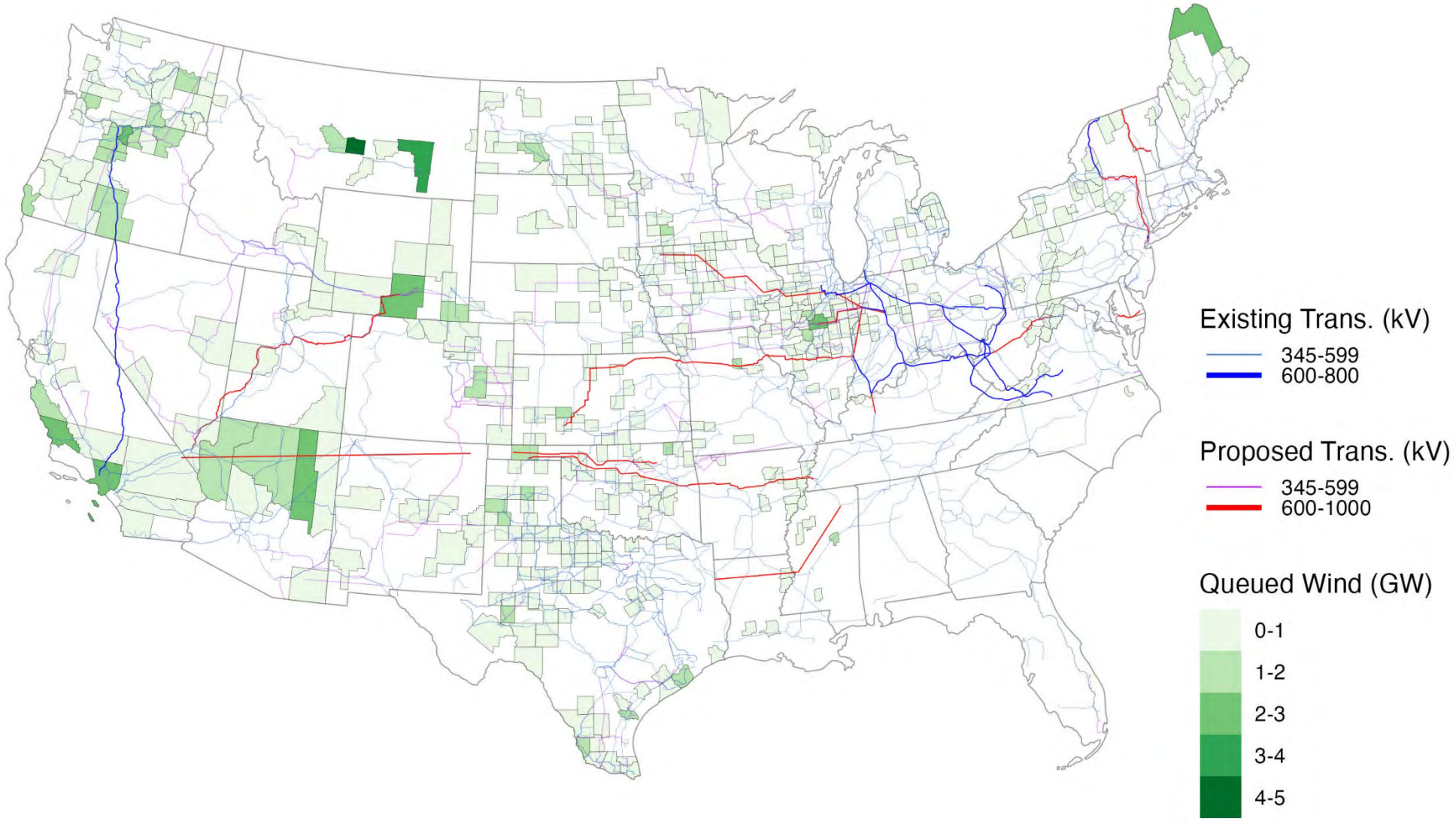
Notes: (1) Includes "active" interconnection requests only. (2) County was missing or could not be determined for 0.7% of active solar requests. (3) Transmission line data from Hitachi Velocity Suite. (4) See https://emp.lbl.gov/queues to access an interactive data visualization of these maps

Active storage capacity in queues at the end of 2024, by county



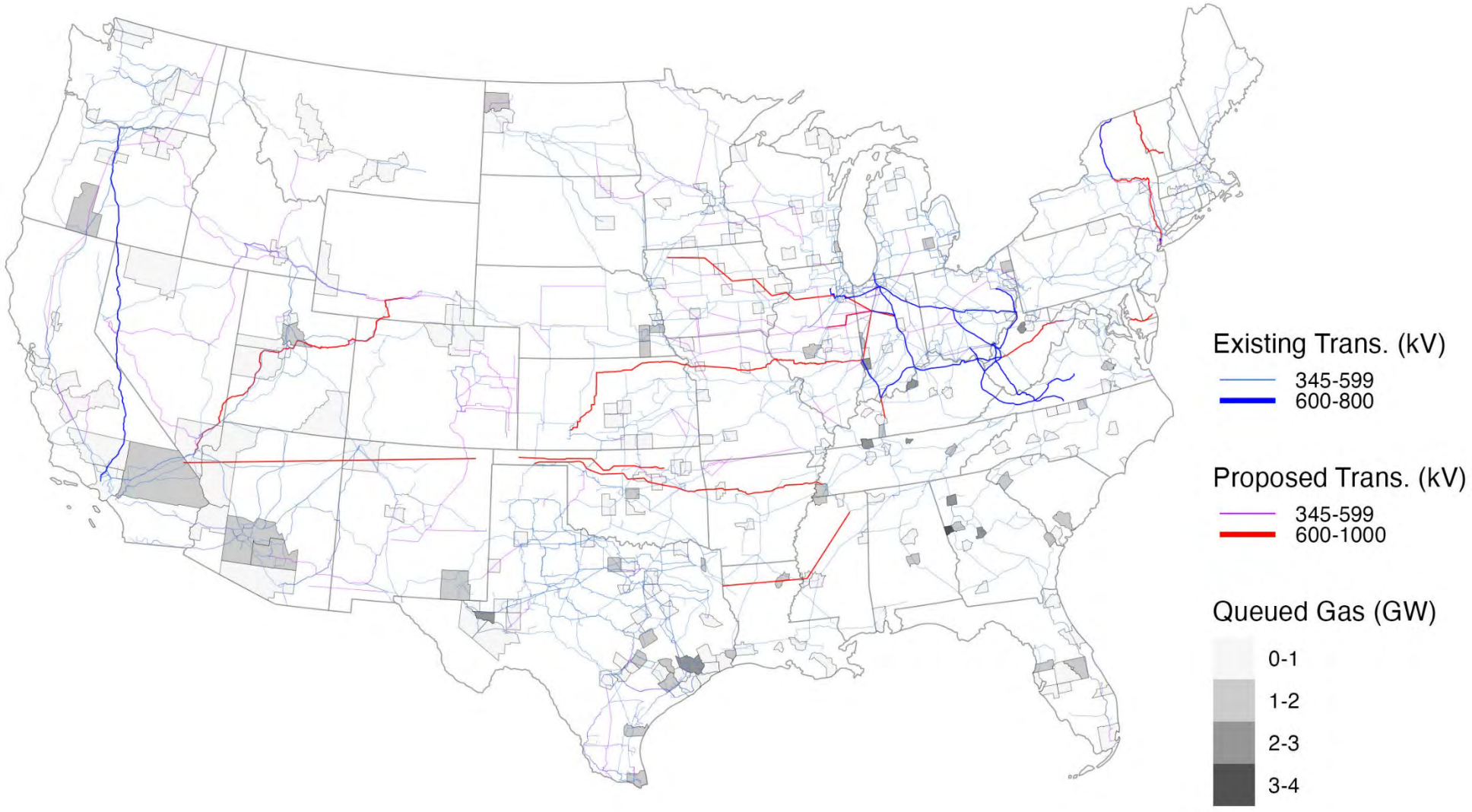
Notes: (1) Includes "active" interconnection requests only. (2) County was missing or could not be determined for 0.3% of active storage requests. (3) Transmission line data from Hitachi Velocity Suite. (4) See https://emp.lbl.gov/queues to access an interactive data visualization of these maps

Active wind capacity in queues at the end of 2024, by county



Notes: (1) Includes "active" interconnection requests only. (2) County was missing or could not be determined for 7.6% of wind requests. (3) Transmission line data from Hitachi Velocity Suite. (4) See https://emp.lbl.gov/queues to access an interactive data visualization of these maps

Active gas capacity in queues at the end of 2024, by county



Notes: (1) Includes "active" interconnection requests only. (2) County was missing or could not be determined for 1.1% of active gas requests. (3) Transmission line data from Hitachi Velocity Suite. (4) See https://emp.lbl.gov/queues to access an interactive data visualization of these maps

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 3-03
Business Models for Coal Plant Decommissioning

Pacific Northwest
NATIONAL LABORATORY

PNNL-31348

Business Models for Coal Plant Decommissioning

August 2021

Jennifer D Lessick
Bethel W Tarekegne
Rebecca S O'Neil

U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

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PNNL-31348

Business Models for Coal Plant Decommissioning

August 2021

Jennifer D Lessick
Bethel W Tarekegne
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Prepared for
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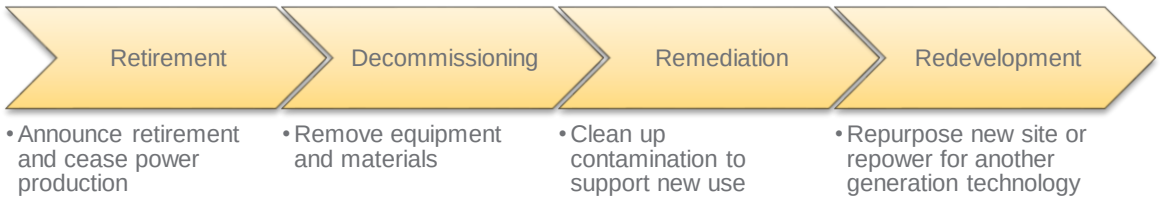
Pacific Northwest National Laboratory
Richland, Washington 99354

Executive Summary

Aging coal-fired power plants are retiring across the United States. Researchers at Pacific Northwest National Laboratory studied coal-fired power plant decommissioning business models to support program development for the U.S. Department of Energy's Office of Energy Efficiency & Renewable Energy to engage with communities affected by power plant retirement processes. Evaluating and reducing the impact on coal-dependent communities from phasing out coal production is a crucial part of nationwide economic development and community-directed engagement in the clean energy future.

This report describes the steps in the typical coal-fired power plant decommissioning process (as depicted below), including analysis of the following key factors:

- *Drivers* including policy and regulations, competition with other fuels, and corporate emissions goals.
- *Types* of coal plant decommissioning including plant retirement without full decommissioning, repurposing with fuel switching, redeveloping to use existing transmission, and decommissioning and repurposing with other commercial activities.
- *Costs* of coal plant decommissioning, including variations across regulated and deregulated markets and the funding resources to support decommissioning activities.



The details described in this report relied heavily on the availability of local news reports and communications regarding plant decommissioning, because the researchers identified a lack of formal literature surrounding business models for coal plant decommissioning and a need for a more robust source material collection. Future research regarding coal plant decommissioning can include conducting quantitative studies of power plant decommissioning drivers, procedures, and costs; conducting quantitative and qualitative assessments of the effects decommissioning has on surrounding communities, investors, and other stakeholders; and identifying best practices for community involvement in the decommissioning process.

Acknowledgments

The authors wish to thank those who reviewed the report for their thoughtful comments and suggestions.

Acronyms and Abbreviations

ARO	Asset Retirement Obligation
EPA	Environmental Protection Agency
POWER	Partnerships for Opportunity Workforce and Economic Revitalization

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Figure 1 Status of coal-fired power plant retirements, 2011 – 2024. Recent and planned retirements are overlayed on poverty rate as indicator of economic vulnerability. (Data: EIA, US Census; Analysis: PNNL) 2

Figure 2 Shamokin Dam, PA, coal plant was closed in 2014, and the site still holds the infrastructure intact. (Source: NPR) 5

Figure 3 The Brayton Point coal plant site (50 miles from Boston, Massachusetts) is an ideal location for redevelopment, given its access to I-95, proximity to a planned offshore wind farm, and 2,000 MW of transmission capabilities. (Source: MassCEC) 7

Figure 4 Named “Exchange 55,” a distribution center offers a Leadership in Energy and Environmental Design-certified warehouse building, over 1,000 jobs for the surrounding community, and accommodation of rooftop solar panels, electric vehicle charging infrastructure, and green landscaping. (Source: Exchange-55.com) 8

Tables

Table 1 Decommissioning Options 2

1.0 Introduction

Most coal power plants in the United States (U.S.) are at least 30 years old and have an average life of 40 years.[1] New coal plant constructions have been mothballed across the nation, and the only coal facility built in the past decade was the 17 MW facility at the University of Alaska Fairbanks in 2018.[2,3] New and economically advantaged generating facilities are taking over the role of producing energy. According to the Energy Information Administration, 102 GW of coal-fired power plants were retired between 2010 and 2019, and an additional 17 GW are slated to be retired by 2025 (Figure 1).[4]

While nuclear and hydroelectric facilities operate under a federal license, from the U.S. Nuclear Regulatory Commission and the Federal Energy Regulatory Commission respectively, coal facilities are typically authorized by state permits. Decommissioning processes are therefore nonstandard, and plants may be "mothballed" rather than fully decommissioned, meaning that they are in operational stasis. Some coal power plant owners are faced with the choice to either continue operation, likely at a loss, through the end of a plant's expected life or to idle until it is economically feasible to reactivate production. In situations where power plants are idled or closed temporarily, workers and environmental remediation efforts could be left in limbo. In certain cases, substitution fuels have been examined such as the torrefied[5] biomass fuel switch test at the Boardman power plant in Oregon to maintain operation.[6] In other cases, power plant operators elect to commit to decommissioning the facility.

Operators commonly assess four options (associated terms defined in Table 1) as part of the decommissioning process:[7]

- Maintain the facility at minimal levels and plan for potential restart (*mothballing*).
- Implement the "cold and dark" option where the owner does a partial demolition and retains and secures the site. In this case, the owner retains environmental liabilities and financial obligations (*decommissioning*).
- Decommission and repower or repurpose the site (*remediating and repurposing*).
- Sell the plant as is and the new owner will decide how and when to repurpose the site (see Section 3). In this case, the new owner takes responsibility for the financial obligation and environmental liabilities of the site. If bankruptcy occurs, the previous owner will take the responsibility of the environmental liabilities.

[1] U.S. EIA. Most coal plants in the United States were built before 1990. April 2017
[2] Scientific American. Will the U.S. ever build another big coal plant? August 2017.
[3] Anchorage Daily News. There's only one coal plant being built in the nation, and it's at UAF. September 2017.
[4] U.S. EIA. More U.S. Coal-fired power plants are decommissioning as retirements continue. July 2019.
[5] Relating to Torrefaction, which is a thermal process that converts biomass into a coal-like material to improve its properties before it can be used together or as a replacement for coal.
[6] POWER. Successful torrefied biomass test burn at a coal power plant. March 2018.
[7] Resources for the Future. Decommissioning US Power Plants: Decisions, costs, and key issues. October 2017.

Table 1 Decommissioning Options

Terms	Definitions
Retirement/Shutdown	Announce retirement/closing and cease power production.
Mothballing	Deactivate and preserve the production facility for possible future use or sale.
Decommissioning	Remove equipment and materials. Close or comply with permits, as necessary. Demolish buildings.
Remediation	Clean up contamination to support new use.
Redevelopment	Repurpose or construct a new site or repower for another generation technology.

This report explores the drivers for coal plant decommissioning, the types of decommissioning that owners undertake, and the process and financial obligations that are entailed in the decommissioning of a coal power plant. The details in this report rely heavily on the availability of local news reports and communications regarding plant decommissioning because of the lack of national datasets and uniform guidelines for coal plant decommissioning processes.

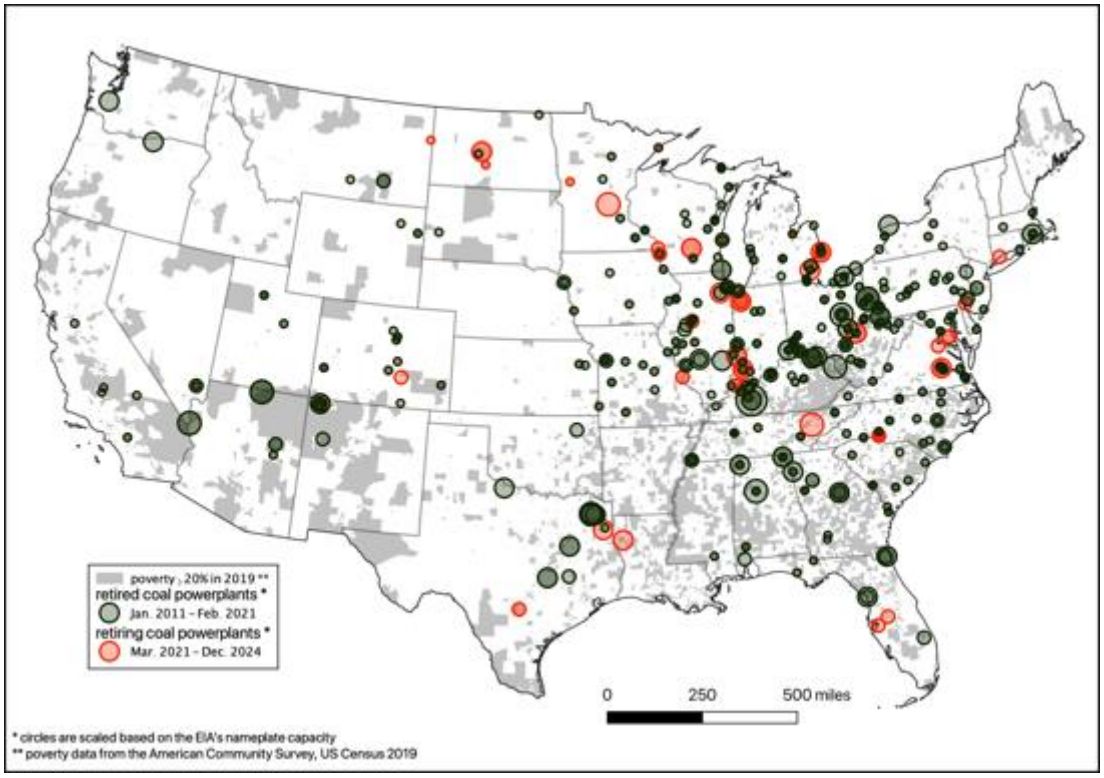

Figure 1 Status of coal-fired power plant retirements, 2011 – 2024. Recent and planned retirements are overlayed on poverty rate as indicator of economic vulnerability. (Data: EIA, US Census; Analysis: PNNL)

2.0 Drivers for Coal Plant Decommissioning

There are several reasons why a power plant owner would choose to retire a coal plant, including costs or decisions associated with policy and regulations, cost competition with other fuels, and corporate emissions reduction goals.

2.1 Policy and Regulations

Coal power plants accrue many costs associated with environmental compliance, and regulatory violations may lead to forced plant decommissioning. Clean Air Act limitations on mercury, heavy metal, acid gas, and sulfur dioxide emissions and Clean Water Act limitations on water pollutants, discharge, and intakes may require facilities to operate in a less economically efficient fashion due to necessary pollution controls infrastructure, or may require more frequent upgrades and other major investments in pollution mitigation.[1] If a plant exceeds limits placed on pollutants, the plant may be forced to retire. For example, if the temperature of post-cooling discharge water exceeds limits specified in the plant's permit, those violations can potentially cause the plant to curtail production until the limits specified in the permit are met.[2]

The U.S. Environmental Protection Agency or other non-governmental organizations can also litigate to retire plants. For example, Duke Energy was forced to retire 11 of the 13 units at the Allen power plant in 2015 following a 15-year litigation process regarding lack of installation of proper pollution control technology.[3] In addition to federal regulation, state Public Utility Commissions may also decide to force plants to decommission if electricity demand does not meet online generating resources. For example, the Mississippi Public Utility Commission is currently forcing Mississippi Power to retire 950 MW of unneeded coal capacity following an overestimation of demand needed over the utility's planning period.[4]

In addition, many states have implemented Renewable Portfolio Standards that offer economic incentives and prioritization of other generating resources. These policies are reinforced by tax breaks and other financial incentives for certain generating resources.[5] In this policy environment, many electric utilities subject to these requirements and economic incentives have indicated an intent to retire coal plants in order to deploy more renewable energy resources.

2.2 Cost Competition with Other Fuels

There are several reasons why coal generation has become less economically attractive than alternative sources of power. Environmental compliance costs, aging infrastructure that requires updates, and exponentially decreasing costs of other fuels have contributed to utility decisions to retire coal plants. A particularly important point of cost comparison is the comparison of the costs of coal and natural gas. The Energy Information Administration Annual Energy Outlook 2021 highlights the impact of low natural gas prices on coal-fired power plant retirements because generation from gas sets the wholesale market price.[6] In addition, Lazard's 2020

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[1] 33 U.S.C §1251 et seq. (1972) "Clean Water Action 316(b)"

[2] Ibid.

[3] U.S. EPA. Duke Energy Corporation Clean Air Act (CAA) Settlement. September 2015.

[4] Energy and Policy Institute. Mississippi regulators force Mississippi Power to close unneeded coal and gas plants. February 2021.

[5] DSIRE. Renewable Portfolio Standards. September 2018

[6] U.S. Energy Information Agency. Annual Energy Outlook. February 2021.

Levelized Cost of Energy Analysis shows a lower cost per unit of energy for solar, wind, and natural gas when compared to coal in both the subsidized and unsubsidized analysis.[1] Utility resource portfolio decision-making is often contingent on fuel cost competition, and coal-fired generation has been unable to prove economically beneficial enough to maintain its historically dominant role in utility electricity generation portfolios.

According to a report published by Energy Innovation, Policy, and Technology, LLC and Vibrant Clean Energy, existing coal-fired generation is increasingly more expensive than local (within 35 miles) wind and solar power.[2] When using 2018 levelized cost of energy estimates, wind and solar showed pricing across the United States as low as $15/MWh for wind and $28/MWh for solar, whereas the lowest pricing for majority of coal plants was $33/MWh. The report conducted a study to replace all the annual megawatt-hours generated by individual coal plants with local wind or local solar to identify sites that are available for deployment. Using this method, the report determined that more than 49 GW of coal were “at risk” from local wind and 69 GW of coal were “at risk” from local solar in 2018.[3] In this study, “at risk” indicates that replacement with the local renewable energy resource would be at least 25 percent cheaper than the costs of running existing coal plants.

2.3 Corporate Emissions Goals

According to the Smart Electric Power Alliance, as of 2020, 69 electric utilities had publicly stated carbon emission reduction targets. Usually, these targets signal a change in portfolio generating sources from higher carbon-emitting sources like coal power[4] to lower carbon-emitting sources like natural gas, wind, or solar power. For example, Southern Company[5], Duke Energy[6], and Tennessee Valley Authority[7] have all stated plans to decommission some portion of coal-fired capacity in order to meet carbon emission or sustainability goals. In addition, the Sierra Club published a report in 2021 analyzing climate pledges from 79 operating utilities. The utilities studied accounted for 68 percent of remaining coal generation and have already publicly committed to retire 25 percent of that coal-fired generation by 2030, and have plans to replace that capacity with new natural gas, wind, and solar plants.[8]

3.0 Types of Coal Plant Decommissioning

Decommissioning of coal-fired units can be complex and expensive, encompassing a decommissioning process that entails cleanup and waste removal, remediation, and redevelopment efforts. Unlike nuclear power plants, coal decommissioning is not regulated with uniform national procedures and guidelines to be followed during the plant decommissioning process, leaving room for many different outcomes affecting communities, shareholders, and utility companies. Once the decision has been made to retire a generating coal plant, the plant owner has several options, including retiring the plant without decommissioning, repurposing the

[1] LAZARD. Lazard’s Levelized Cost of Energy Analysis Version 14.0 October 2020.
[2] Energy Innovation. The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources. March 2019.
[3] *Ibid.*
[4] U.S. EIA. Carbon Dioxide Emissions Coefficients. February 2016.
[5] Southern Company. Southern Company Net Zero Report. September 2020.
[6] Duke Energy. Transforming the Future: Sustainability Report. April 2019.
[7] Tennessee Valley Authority. Fiscal Year 2019 Sustainability Report. July 2020.
[8] Sierra Club. The Dirty Truth About Utility Climate Pledges. January 2021.

plant with a fuel switch, repurposing to handle load pockets or remote transmission, or redeveloping the site for other commercial activity.

3.1 Plant Retirement without Decommissioning

Power plant retirement without decommissioning is a process that may or may not include remediation and redevelopment of the plant property. Estimates of retired coal plants that remain unremediated and unrepurposed are as high as 95%.[1,2] Many of these retired power plants, like the Pennsylvania-based Shamokin Dam power plant (Figure 2), may remain structurally intact but will no longer generate power, and have no announced plans to decommission the site and redevelop it for alternative use.[3]

The reason so many coal plants remain structurally intact post-retirement relates to the costs associated with cleaning up accumulated toxic coal ash and waste. Developers are rarely willing to take on that risk (as described in Section 3.4). Because of costs associated with decommissioning and the lack of regulation putting the burden on plant owners to do so, remediation and redevelopment futures are either nonexistent or uncertain for many coal plants across the country. In response to this, many states and localities have developed task forces, like the Lansing Town Council described in Section 3.4, to remedy how to move forward with abandoned plants, but many do not have the funds to remediate and redevelop the sites.[4]



Figure 2 Shamokin Dam, PA, coal plant was closed in 2014, and the site still holds the infrastructure intact. (Source: NPR)

One example of a fully retired coal plant that featured a complex remediation effort is the Navajo Generating Station, which was retired in 2019. At the end of the power plant lease period in

[1] UCS. A Dwindling Role for Coal. October 2017.
[2] Utility Dive. Shuttered coal plant fixer-uppers for sale all over the U.S. January 2018.
[3] NPR. Finding New Opportunity for Old Coal-Fired Power Plant Sites. May 2019.
[4] Ithaca.com. What's next for the Cayuga power plant. January 2020.

2017, the operating utility, Arizona Public Service, along with the plant owners, the Salt River Project, stated that the plant had become too expensive to run compared to lower cost, lower carbon alternatives that were preferable for the utility's generation portfolio.[1] The 40-year-old, 2,043 MW plant retired after Peabody Energy, the plant's coal supplier, was unsuccessful in finding new owners.[2] The shutdown, which began in late 2020, will consist of an expensive remediation and reclamation process executed by Salt River Project, including a complete restoration of the land to its original state. In early 2021, Salt River Project released the decision to turn the land occupied by the facility completely over to the Navajo Nation after land remediation is completed.[3] In recognition of the detrimental health and environmental effects the plant had caused to the surrounding community during its operation, this decision includes a $144.45 million long-term plan to transition economically affected communities in light of job losses due to plant closure.[4] The Navajo Nation has not yet confirmed a plan for redevelopment efforts, and many believe the land will remain undeveloped post-reclamation.[5]

3.2 Repurposing with Fuel Switch

Retired coal power plant sites have substantial transmission infrastructure that may be attractive to potential development of alternative forms of energy generation (e.g., solar, natural gas, storage), or otherwise risk stranded infrastructure and new transmission needs. Interconnection rights are lucrative and utilities repurposing their transmission rights will save hundreds of millions of dollars and face shorter timeline in the approval process. For example, Xcel Energy estimated it would cost customers approximately $350 million[6] in transmission upgrades to connect a solar project[7] replacing its Sherco coal plant elsewhere on the grid. However, while many utilities have announced plans to replace retired coal generation with alternative forms of energy at the portfolio scale, it has been less common[8] for the actual coal plant site to be redeveloped for this purpose.[9]

One way to repurpose a coal plant with a fuel switch is to site a new plant close by and use existing transmission infrastructure. Idaho Power has recently announced the decommissioning of the North Valmy coal power plant, and aims to replace the capacity lost from its coal plant with a 20-year solar power purchase agreement from Jackpot Holdings, LLC. The utility-scale solar array will not be located directly at the site of the North Valmy plant, but the array will be sited close by, and will be able to use the existing transmission line that delivers energy from North Valmy coal today.[10]

Portland Gas and Electric was forced to retire the Boardman Coal Plant by the end of 2020 following environmental compliance orders under the Clean Air Act.[11] The utility explored

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[1] Greentech Media. The Navajo Generating Station Coal Plant Officially Powers Down. November 2019.
[2] *Ibid.*
[3] Vox. After decades of activism, the Navajo coal plant has been demolished. December 2020.
[4] azcentral. APS offering $144M to Arizona tribes and others affected by coal plant closures. November 2020.
[5] *Ibid.*
[6] E&E News. https://subscriber.politicopro.com/article/eenews/1063731765. May 2021.
[7] businesswire. https://www.businesswire.com/news/home/20200617005810/en/Xcel-Energy-proposes-one-of-largest-packages-of-energy-investments-in-state-history. June 2020.
[8] Solar or storage has not been common but switcing with natural gas or biomass is relatively available.
[9] *Ibid, page 3.*
[10] Idaho Power. Idaho power invests in clean, affordable solar energy. March 2019.
[11] *Ibid, page 1.*

options for incorporating torrefied biomass as a fuel replacement, running four successful test-burns at the coal site.[1] The replacement plan at Boardman has since been cancelled, but the trend of replacing coal with biomass has been increasing globally. One of the largest coal plants in the United Kingdom, the Drax power plant, is beginning efforts to transition from burning coal to burning biomass, and another coal plant in Denmark has proposed a plan to convert to 100% biomass. Alternatively, China has announced intentions to replace several coal plants with nuclear reactors.[2]

3.3 Redevelopment to Handle Load Pockets or Remote Transmission

Many coal plants are located in areas that are also suitable for redevelopment to handle load pockets or remote transmission. For example, the former Brayton Point coal plant (Figure 3), a four-unit 1,600 MW station on the southern coast of Massachusetts, was retired in 2017. The site quickly became a magnet for redevelopment proposals, partly due to the attractive locational aspects of the site, including transmission capabilities for 2,000 MW of power and access to major infrastructure point Interstate 95 (I-95), and the introduction of the Massachusetts Plant Revitalization Task Force.

Remediation efforts on Brayton Point to date have entailed asbestos and waste abatement, demolishment of the cooling towers, crushing of onsite concrete, recycling of metal demolition debris, and site re-grading. Because of the site's proximity to a planned offshore wind farm 35 miles away, Anbaric Development Partners has announced its intention to build the Anbaric Renewable Energy Center, a logistics hub with a 1,200 MW high-voltage direct current converter and 400 MW of battery storage. The project hopes to maximize the potential of Massachusetts' offshore wind energy resource.[3]



Figure 3 The Brayton Point coal plant site (50 miles from Boston, Massachusetts) is an ideal location for redevelopment, given its access to I-95, proximity to a planned offshore wind farm, and 2,000 MW of transmission capabilities. (Source: MassCEC)

[1] *Ibid.*

[2] BBC. The UK plans to end coal-fired electricity by 2025. August 2018.

[3] Massachusetts Clean Energy Center. Information on the Brayton Point power plant site.

3.4 Repurposing with Other Commercial Activity

Aside from the locational benefits associated with fuel switches and remote transmission, coal plants are often located in areas that can also benefit other commercial activities. With access to railroad, waterways, ports, highways, utility grids, and an existing industrial workforce, commercial development in replacement of the plant can be an attractive option for developers. However, coal plant remediation efforts are costly and lengthy, and commercial developers are usually cautious about accepting the risk associated with cleanup. This gap has been largely filled by development firms that specialize in the cleanup of especially costly sites like coal plants. Commercial Development Company (CDC) and Hilco Redevelopment Partners are examples of firms that target industrial real estate, including power plants, for redevelopment, taking on the risk of remediation and selling the land for development, whether it involves a fuel switch or another commercial activity.

An example of this is the $100 million-plus project taken on by Hilco Redevelopment on the Crawford Power Generating Station outside of Chicago, Illinois.[1] Shuttered in 2012, the facility, located along Interstate 55 and the Ship Canal, was demolished and replaced with 1 million square feet of warehouse space (Figure 4).[2]



Figure 4 Named “Exchange 55,” a distribution center offers a Leadership in Energy and Environmental Design-certified warehouse building, over 1,000 jobs for the surrounding community, and accommodation of rooftop solar panels, electric vehicle charging infrastructure, and green landscaping. (Source: Exchange-55.com)

The owners of both the Widows Creek power station in Alabama[3] and the State Line power plant in Illinois[4] have announced plans to convert the sites into data center locations powered by renewable energy. Similarly, the Cayuga Operating Company has announced a proposal to redevelop the Cayuga coal plant in New York State into a data center location.[5] The Lansing Town Council passed a resolution to establish an advisory committee to oversee the future of

[1] Chicago Tribune. Former Little Village coal plant to be demolished, replaced with distribution center. February 2018.
[2] Exchange 55. A 21st century transformation in Little Village.
[3] The Guardian. Google to convert Alabama coal plant into renewable-powered data center. June 2015.
[4] Energy News Network. Northwest Indiana defunct coal plant slated for massive data center. April 2018.
[5] The Ithaca Voice. Plans in motion to convert Cayuga power plant to data center. May 2019.

the plant, thereby ensuring an open line of communication between community stakeholders and the operating company.[1]

4.0 Costs of Coal Plant Decommissioning

The costs of full decommissioning include expenses related to decommissioning and redevelopment costs. The initial decommissioning costs include asbestos and hazardous material abatement, structural demolition, salvage and scrap recovery, remediation, restoration of the site to a safe condition, engineering project management, and public engagement.[2] For the next stage of redevelopment, the costs could range from those for site planning, acquisition, and new construction to commercial operation. The most substantial costs among these are the costs of closing coal ash facilities.[3]

Once the plant owner decides to decommission a coal plant, financing the plant decommissioning activities is the key next step in the process. The financing mechanisms for coal decommissioning vary across states. These distinctions mainly depend on whether the state has a regulated or deregulated energy market.

4.1 Funding Decommissioning in Regulated Markets

For states that have regulated energy markets (or cost-of-service regions), the decommissioning cost could be transferred to ratepayers depending on the decision of their public service commissions.[4] In these states, the utilities perform a cost estimate for decommissioning the plant in the future and that cost is added into the rate base to generate the funds over time. This process allows plant owners to accrue funds in advance of plant decommissioning, which also protects the state from a company's liability default. This method, however, could lead to ratepayers financing the development, operation, and decommissioning of the plant. To address such scenarios and minimize ratepayer risk and responsibility, states like North Carolina and Nevada have passed laws that regulate the types of decommissioning costs that utilities may (or may not) recoup through rates. For example, in Nevada, utilities are required to develop plans that adhere to a "timely cleanup" and failure to comply with this requirement means the state will withhold the utility's right to recoup decommissioning costs through rates.[5]

4.2 Funding Decommissioning in Deregulated Markets

For states that have deregulated energy markets (or competitive regions), plant owners do not directly recoup decommissioning costs from ratepayers. These companies are expected to plan and incorporate decommissioning costs as part of their cost of doing business and report them as an asset retirement obligation (ARO).[6] An ARO, simply defined as the "obligation associated with the retirement of a tangible long-lived asset,"[7] is part of the annual financial report submitted to the U.S. Securities and Exchange Commission by publicly listed generating

[1] *Ibid, page 4.*
[2] POWER. Coal power plant post-retirement options. September 2016.
[3] S&P Global. Cost questions loom as utilities prepare to close hundreds of coal ash sites. June 2019.
[4] *Ibid, page 1.*
[5] *Ibid, page 1.*
[6] *Ibid, page 1.*
[7] WebCE. Asset Retirement Obligations.

companies. As the EPA regulations on coal combustion residual (CCR) cleanup requirements change and become more stringent,[1] plant owners will adjust their AROs to reflect these changes. The plant owner's estimates of ARO costs are critical to avoiding bankruptcy. For these reasons, in deregulated markets there is an increased chance for a retired plant site to be left idle. For example, in Pennsylvania, plant owners chose the "cold and dark" option instead of investing to decommission[2] the Mitchell Power Station. The plant, located south of Pittsburgh, was closed in 2013 after 65 years of operation. Policy, environmental, and economic factors with resulting costs led to the plant's cessation of operation.

4.3 Funding to Support Decommissioning

Power plants are a significant revenue asset for the local economy in which they operate, and their geographic setting determines their decommissioning options. Pre-existing access to infrastructure—natural gas pipelines, electricity transmission, or other major infrastructure—is a good indicator of whether new generating units are likely to be built at the site. For plant sites in city centers or near other amenities, there is a strong demand for the land. In those cases, there is a higher chance that the site will be revitalized for residential, commercial, or industrial development.

For rural areas and locations where land is not as limited or at the same premium, the incentive for decommissioning and remediation is minimal, and facilities tend to sit idle for longer periods. This is especially true in rural areas under deregulated markets where decommissioning costs are the responsibility of the plant owner. In such cases, the plant owner (or the shareholders) could choose to go "cold and dark" because the return on investment from decommissioning is negligible. Local fiscal implications of idled facilities are substantial for rural areas, because large power plants make up a sizable portion of the local economy.[3]

Federal, state, and local governments offer various incentives for redeveloping plant sites. For example, in 2017, the EPA's Brownfields and Land Revitalization program provided grants and technical assistance amounting to $59 million in decommissioning process support for local governments.[4,5] At the local level, the City of Baltimore offers a city property tax rate reduction for redeveloping a plant site.[6] There are also state-level efforts designed to address the impacts of the energy transition process, especially as it relates to communities affected by these changes. State-level policies can be organized into a set of responsive strategies: transition planning, fund development, worker protections, and requirements for new development. [7]

4.4 Communities and Decommissioning

Communities may have a sense of connection with plant facilities because large power plants have a symbolic meaning to the place, which leads to a sense of loss in these communities as

[1] U.S. EPA. Disposal of coal combustion residuals from electric utilities rulemakings.
[2] AP News. As coal-fired power plants switch off, new businesses sought. April 2018.
[3] *Ibid, page 1.*
[4] U.S. EPA. Brownfields grant fact sheet.
[5] *Ibid, page 1.*
[6] Baltimore Development Corporation. Brownfields tax credit.
[7] UNC Center for Climate, Energy, Environment and Economics. Communities in transition: State responses to energy-sector job losses. December 2019.

plants are retired.[1] In Adams County, Ohio, the closure of the Stuart and Killen plants was a loss for the surrounding communities. For some who built and worked at the facilities, the power plants were a reflection or representation of their contribution to their community.[2] In addition, if retired plants are not repurposed with quality job-creating activity, the associated workforce might be jobless during the transition. For regions with idled power plants, there is the added burden of decreased property values.[3]

4.4.1 Worker Compensation and Workforce Development

Various worker compensation and workforce development resources exist for those negatively affected by the coal power plant decommissioning process and the subsequent job losses. The Partnerships for Opportunity Workforce and Economic Revitalization (POWER) grant program is an example of an initiative at the federal level that invests in workers and jobs to address legacy costs in coal communities.[4] In 2016, 11 federal agencies including the U.S. Department of Energy's Jobs Strategy Council participated in and allocated resources to the POWER initiative. A similar program is the Economic Development Administration's Assistance to Coal Communities (ACC) program, which has awarded $30 million to support 35 projects in 16 states. The awarded projects are locally driven efforts to create programs that support job creation, capital investment, economic diversification, workforce development, and re-employment opportunities.[5]

In addition to federal support for worker compensation and workforce development, community-led programs can fill gaps felt in the workforce caused by plant closures. One example is the $55 million Centralia Coal Transition Fund supported by TransAlta that was an outcome of a collaboration with environmental groups, the state, and community groups.[6] The investment is designed to fund businesses, nonprofit organizations, and local governments in Washington State. The fund supports weatherization, economic and community development, and energy technology development projects. Most notably, the economic and community development fund provides up to $20 million for projects that retrain workers and enhance economic opportunities, with a special emphasis on communities that have recent, or are soon to have, coal plant closures.[7] Operating utilities or plant owners may also financially aid communities in worker compensation efforts, like the Arizona Public Service payout to Navajo workers after the Navajo Generation Station closure, as described in Section 3.

4.4.2 Community Entities Designed to Oversee Decommissioning

As described in Section 3, the Lansing Town Council has appointed an advisory board to oversee the decommissioning of the Cayuga Coal Plant in order to engage community stakeholders in decision-making processes. Similarly, the Fisk and Crawford Reuse Taskforce was created in Chicago to gather community input and devise a shared vision for the

[1] The Washington Post. In small towns across the nation, the death of a coal plant leaves an unmistakable void. March 2019.
[2] CNN Politics. Small Ohio town counts on Trump to stave off plant closures. February 2017.
[3] U.S. EPA. Building vibrant communities: Community benefits of land revitalization. October 2009.
[4] World Resources Institute. Steps to aid US fossil fuel workers in the clean energy transition. January 2021.
[5] U.S. EDA. Assistance to coal communities (ACC). October 2017.
[6] NW Energy Coalition. How a community, a company, and environmental groups are building the future. November 2018.
[7] Centralia Coal Transition Grants. Economic and community development.

redevelopment of the Fisk coal plant site in Pilsen and the Crawford coal plant site in Little Village.[1] The Little Village Environmental Organization and Pilsen Environmental Rights and Reform Organization community groups advocated for the closure of the plants and led the efforts in devising the Task Force's Guiding Principles.[2] Community-led decommissioning requires meaningful engagement with community and place-based organizations. Such collaboration is likely to lead to the best outcome for all involved. The key learnings from the Task Force's guiding principles include the following:

- Broad-based stakeholder input on the redevelopment of the sites should be encouraged.
- During site redevelopment, pollution and waste should be minimized, with an emphasis on sustainability.
- Redevelopment should create quality, living-wage jobs for residents of the communities.
- Potential sources of public and private resources for reclamation and redevelopment should be identified early and actively pursued.
- Parties involved in future redevelopment should be aware of what the communities prefer as replacement assets for the sites.

5.0 Conclusions

Coal-fired power plants across the United States are retiring at gigawatt scales, and the pace of plant decommissioning is accelerating.[3] This report highlights the drivers and common options for the decommissioning and repurposing of coal power plant sites, whether driven by policy and regulations, competition with other fuels, or stakeholder pressure. An overview of the types of plant decommissioning is provided, along with the associated processes and costs related to regulated and deregulated markets, and sources of funding for decommissioning.

In addition to the need for uniform data on plant decommissioning efforts, the effects of decommissioning on the communities in which the plants to be retired are located give rise to needs for workforce and economic redevelopment. The analysis found that coal-dependent communities have limited-to-no role in plant decommissioning processes. They do not know what and how the energy transition future will unfold for their local economy and livelihoods. Hence, best practices for equitable decommissioning of plants might be needed to guide the process. Decommissioning processes are expected to be enhanced by experience, lessons learned, and insights increasingly gained in the field.

Future research areas in this field may include a more comprehensive tracking system surrounding coal plant decommissioning, planned and post decommissioned sites, and redevelopment. This can foster understanding of the scope of the communities affected by retired plants and can initiate further study of the effects of those retirements. In addition, research can support in identifying best practices in engaging with community stakeholders about coal plant decommissioning plans and economic transition.

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[1] Pace University School of Law. Transition support mechanisms for communities facing full or partial coal power plant retirement. March 2017.
[2] Fisk & Crawford Reuse Task Force. Fisk and Crawford Generating Stations: Process, principles and recommendations. September 2012.
[3] Interagency Working Group. Initial Report to the President on Empowering Workers Through Revitalizing Energy Communities. April 2021.

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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 3-04
June 2026 Coal Recommissioning and Modernization

An official website of the United States government Here's how you know

U.S. DEPARTMENT of ENERGY

Project Selections for Broad Agency Announcement DE-FOA-0003605, Restoring Reliability: Coal Recommissioning and Modernization (Topic 1)

Project Selections for Broad Agency Announcement DE-FOA-0003605, Restoring Reliability: Coal Recommissioning and Modernization (Topic 1)

AES Puerto Rico, L.P. Life Extension and CCUS Feasibility — **AES Puerto Rico, L.P.** (Guayama, Puerto Rico) plans to retrofit and modernize the Guayama plant, an existing coal-fired plant with a total capacity of 510 megawatts (MW), to ensure continued operation. The effort also includes a carbon capture and utilization system front-end engineering design study for a post-combustion carbon dioxide capture system.

DOE Funding: $164,500,000
Non-DOE Funding: $655,400,000
Total Value: $819,900,000

AES Warrior Run Generating Plant — **AES Warrior Run** (Cumberland, Maryland) plans to recommission the Warrior Run Generating Plant, a 205 MW clean-coal facility that ceased operations in 2024. The project focuses on reactivating existing equipment through routine maintenance and repairs needed to resume operations. The effort will also assess the feasibility of adding a carbon capture, utilization, and storage component to the plant.

DOE Funding: $78,000,000
Non-DOE Funding: $78,000,000
Total Value: $156,000,000

Alaska Carbon Capture, Utilization, and Storage Coal Commissioning Project — **Terra Energy Center Corporation** (Anchorage, Alaska) will assess the viability for commissioning a new, 1,250 MW coal-fired generation facility with an integrated carbon capture technology system.

DOE Funding: $89,000,000
Non-DOE Funding: $101,375,155
Total Value: $190,375,155

TerraSpark WV Energy Campus — **TerraPurus Inc. DBA "TerraSpark Inc."** (Mt. Storm, West Virginia) will undertake scoping and design efforts for a 1,600 MW next-generation, coal-fired power plant with a fully integrated carbon capture system at the West Virginia Energy Campus.

DOE Funding: $18,500,000
Non-DOE Funding: $21,462,500
Total Value: $39,962,500

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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 3-05
Public Interest Organizations' April 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. 202-26-21

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

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 a new and 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. 202-26-21 ("Order") renews the Department's Order No. 202-25-14 ("December Order"). Public Interest Organizations previously requested rehearing of the December Order 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 the December Order. *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).

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, and battery resources. Replacing dirty, expensive, and unreliable plants 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 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, 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 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.

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 & 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*

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.

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.").

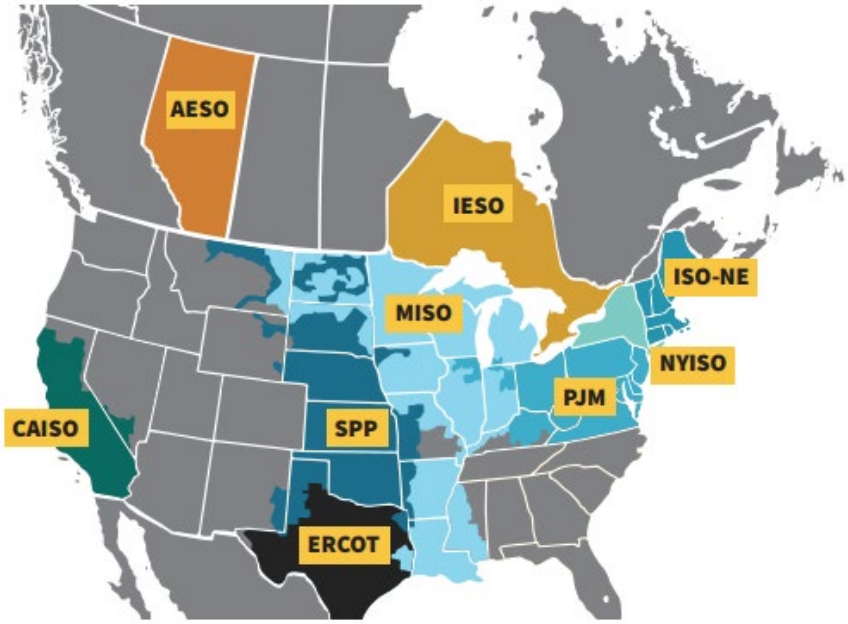
As part of its regulatory oversight, FERC has promoted the role of nonprofit entities, known as Independent System Operators or Regional Transmission Organizations. *See Fed. Energy Regul. Comm'n v. Elec. Power Supply Ass'n*, 577 U.S. 260, 267 (2016); *Regional Transm. Orgs.*, Order No. 2000, 65 Fed. 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.

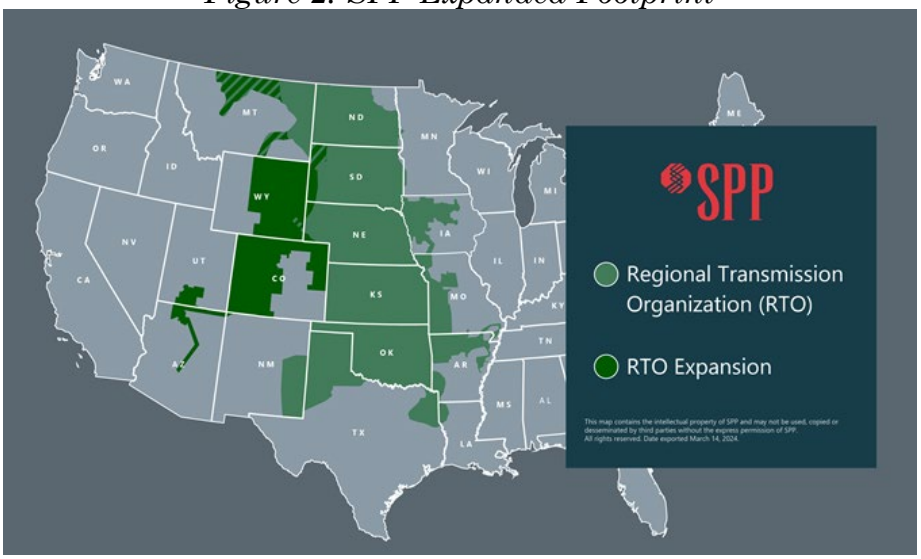
Figure 1: Boundary Areas of RTOs and ISOs



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

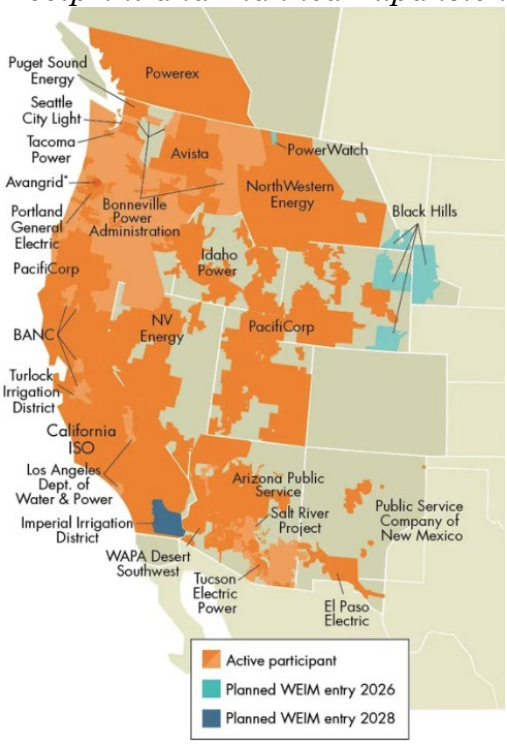
River Project and Xcel participate in the Northwest Power Pool Reserve Sharing Group:

> 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

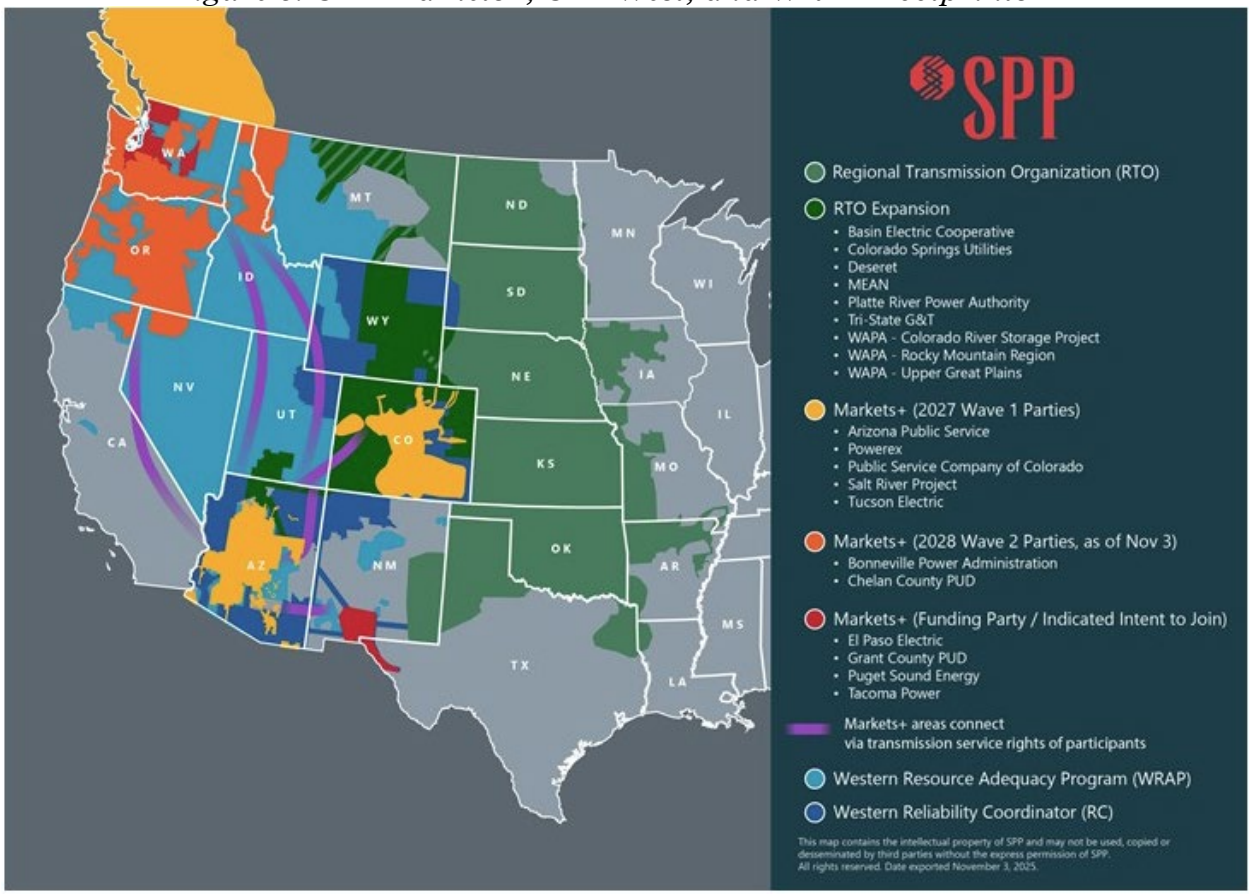


Source: Ex. 2-111 at 2 (Western Energy Imbalance Market Webpage).

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).

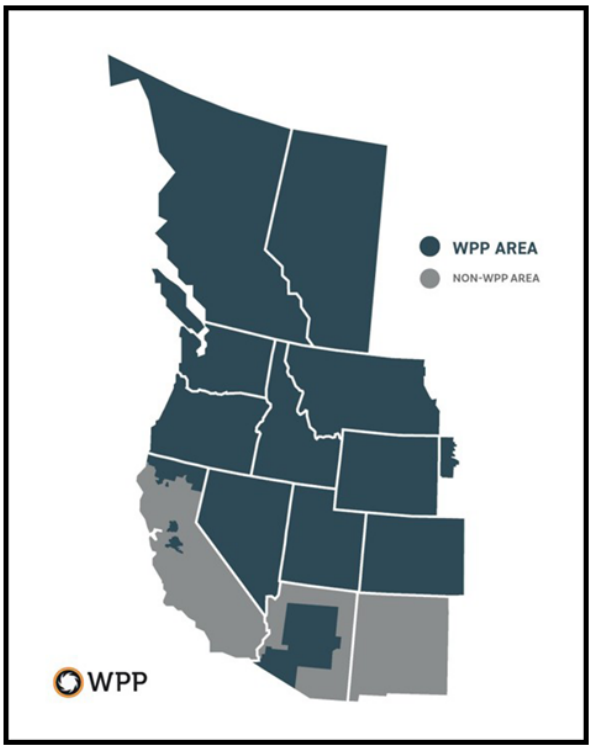
4. State and Regional Regulatory Bodies Protect Resource Adequacy Through Integrated Resource Planning and Annual Capacity Demonstration Requirements.

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).

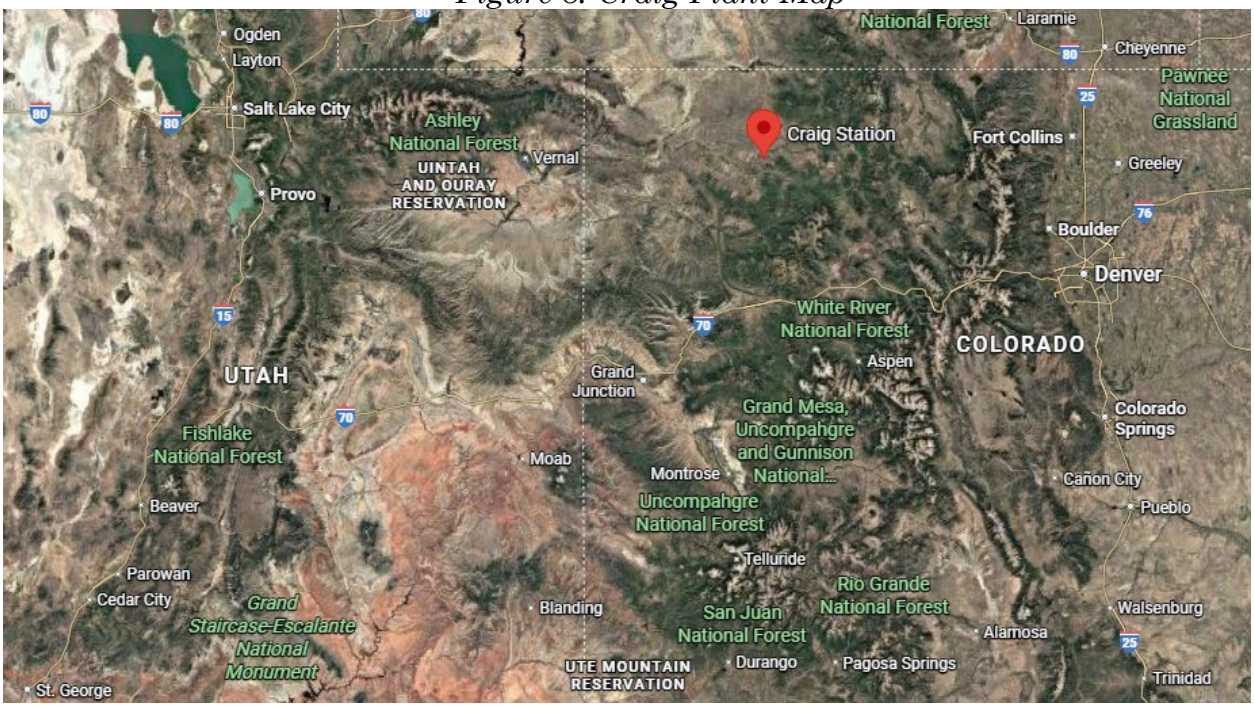
WECC also performs a yearly assessment of resource adequacy in its footprint, which is a useful resource for system planners. *E.g.*, WECC, *Western Assessment of Resource Adequacy: 2024* (last visited April 21, 2026), https://feature.wecc.org/wara/; Ex. 2-09 (2024 Western Assessment of Resource Adequacy). 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. 2-08 at 4 (NERC 2025-26 Winter 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. 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.).

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 Petition for Rehearing) (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 Request for Rehearing) (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.). 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 explained in their Request for Rehearing of the December Order, "Craig Unit 1's closure was announced a decade ago, and numerous steps, such as deferring maintenance, reducing staffing, and redirecting capital expenditures, have been undertaken since." Ex. 2-175 at 22. 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.

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 Request for Rehearing) (emphasis added). 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 will exacerbate 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. 2-175 at 30 (Tri-State and Platte River Rehearing Request); *see also id.* at 20 ("Ongoing operations at the site will also require continual maintenance and staffing readiness, with the potential for further equipment failures that require 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 Request for Rehearing). Tri-State avers that "the order will likely require additional investments 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." 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 Request for Rehearing) (describing operational, maintenance, and staffing 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' lawful 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, and 202-26-16; Indiana, Order Nos. 202-25-12, 202-25-13, 202-26-19, and 202-26-20; Washington, Order No. 202-25-11 and 202-26-18, and in Pennsylvania, Order Nos. 202-25-4, 202-25-8, 202-25-10, and 202-26-17.

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 that Can Come Within 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]

1. Legal Framework: Section 202(c) Empowers the Department to Respond Only to Imminent, Certain, and Unexpected Shortfalls in Electricity Supply.

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,

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

> 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 over-ride state and private decision-making must be an event that is imminent, certain, and unexpected. 16 U.S.C. § 824a(c). 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, Certain, and Unexpected Events

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 imminent, unexpected, and certain events. 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 "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 shortfalls: 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 specific and imminent supply 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 (emphasis added). 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.* 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 provision allows only a temporary fix for a temporary problem.

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) to mandate generation the

[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).

Department viewed as necessary to ensure long-term resource sufficiency, or in response to generalized regional risks that had not produced any 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 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 1–5.

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 longer term 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.").

ii. The Order Does Not Demonstrate Any Long-Term Resource Adequacy Concerns that Are Not Already Being Addressed Through the Appropriate Processes Under the Federal-State Balance of Responsibilities.

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 section of the Order titled "Continuing Emergency Conditions" discusses five sources touching on long-term issues: (1) the 2025 Long-Term Reliability Assessment; (2) the 2025 Western Assessment of Resource Adequacy; (3) data from the Energy Information Administration concerning generating capacity in Colorado; (4) executive orders; and (5) DOE's July Resource Adequacy Report. Order at 3-5. 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.

The Order's first basis for finding a continuing, long-term emergency is 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).

The Order's second basis for finding a continuing, long-term emergency is WECC's 2025 Western Assessment of Resource Adequacy. The Order references isolated statements from this document, 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 undermines 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." 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" —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.

Nor does WECC's 2024 Western Assessment of Resource Adequacy, which the December Order cited as its second basis for finding a long-term emergency, provide evidence of a long-term shortfall in electricity or generating supplies in the Rocky Mountain region. 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).

The Order's third basis for finding a long-term emergency is data from the Department's Energy Information Administration. The Department here 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.

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 state or states have 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 insubstantial.

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.

The Order's fourth basis for finding a long-term emergency is executive orders. 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).

Neither executive order 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 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 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 the executive orders' unsupported, generalized conclusions 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.[4] Congress explained that the National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the 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).[5] 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.

The Order's fifth basis for finding a long-term emergency is the Department's July Resource Adequacy Report. Order at 5 (citing Ex. 2-35 at 1 (July Resource Adequacy Report)). But the Order's claim that there is an emergency in the WECC Rocky Mountain assessment area does not appear to be based on or informed by the

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[4] 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.").

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

Department's July 2025 Report, notwithstanding the Order's citation to that report. 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[6] 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 emergency 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 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. *S*ee 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

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[6] 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).

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.

Additionally, 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 are engaged in ongoing efforts to procure new resources to come online in future years to meet customer demand. For example, Xcel currently has two proceedings pending before the Colorado Commission to acquire new utility-scale resources: the Near Term Procurement, in which it has 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 a separate procurement in Proceeding No. 24A-0442E in which 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 soon issue Requests for Proposals for additional resources that can come online by the end of 2031. Xcel's 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 long-term emergency is 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.*

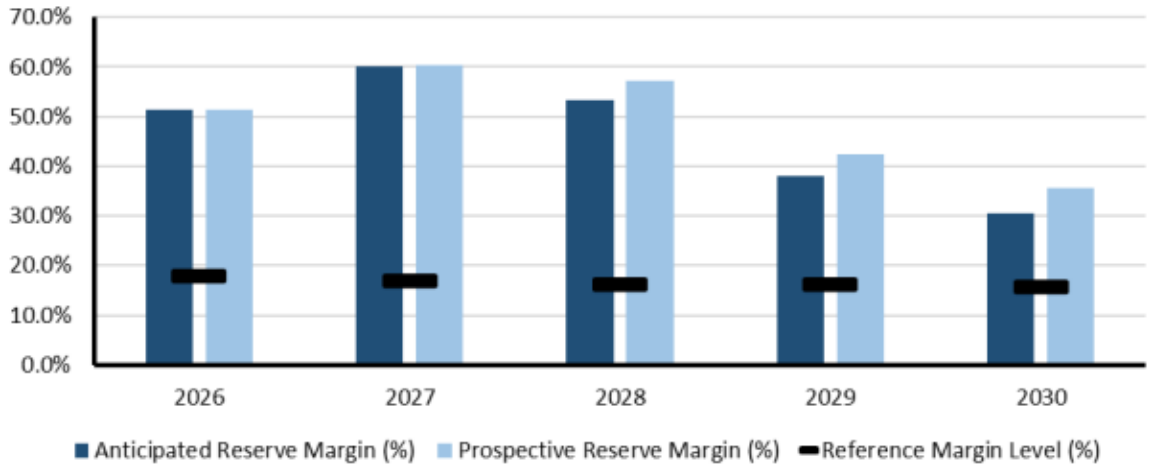
In a single sentence, the Order claims that Colorado Public Utilities Commissioners "have expressed concerns about the ability of certain utilities to meet projected summer 2026 loads." Order at 4–5. The Order references Commissioner discussions of only a single utility in Colorado, Xcel, not multiple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

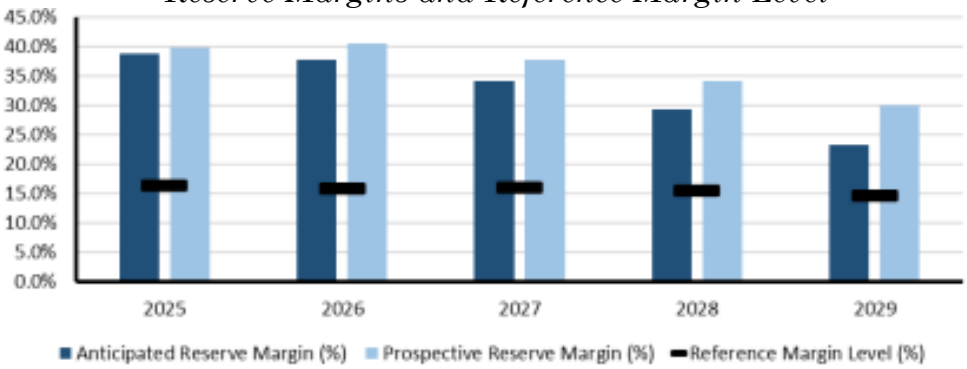
Base Case Summary of Results			
	2026*	2026	2028
EUE (MWh)	1,722	0	1
EUE (PPM)	4	0	0
LOLH (hours per year)	0.04	0	0
Operable On-Peak Margin	37.6%	36.1%	27.8%

* 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.

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.[7] 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 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

[7] 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.

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 Is Not Based on Reasoned Decision-Making and Substantial Evidence in Imposing Requirements 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 6–7. 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.[8]

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 includes "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "available imports, demand response, and

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[8] 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.

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).

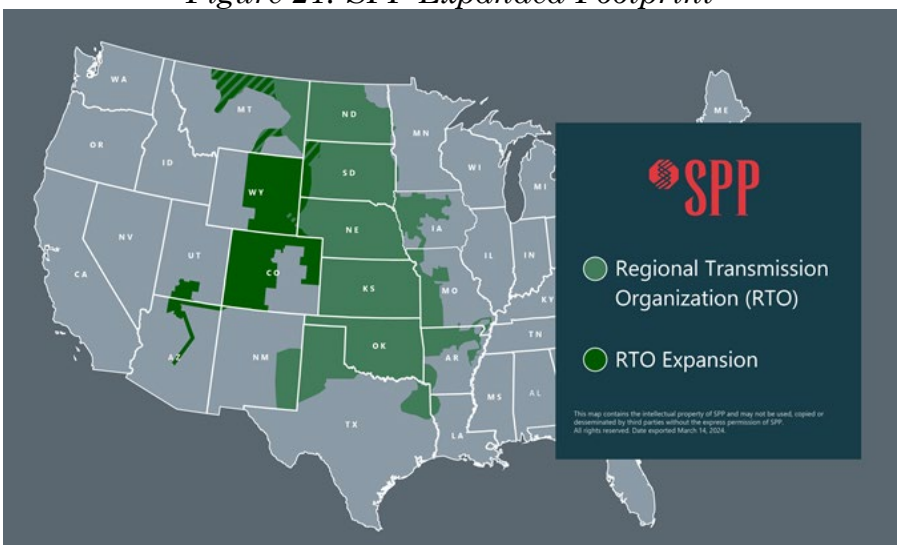
Figure 20: Boundary Areas of WECC Subregions



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 6–7. 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 facilit[ies]." Order at 1 n.6.[9] 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

[9] To be sure, the Order does not offer any evidence for the premises in footnote 6. The footnote's conclusion—continuous operation is required so long as the Secretary determines a shortage exists and is likely to persist—is unreasoned and is not based on any substantial evidence in the footnote or the Order.

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 Request for Rehearing). 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.

> 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*.

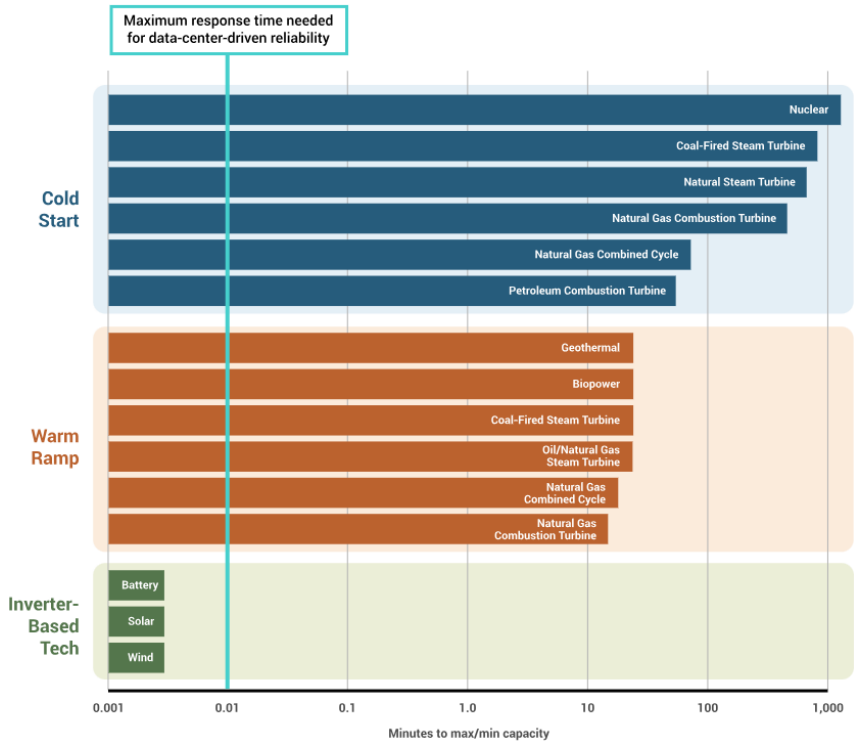
Ex. 2-44 at PDF 2–3 (RMI Analysis of Coal Plants' Threats to Reliability).

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 5. 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 Request for Rehearing) (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.

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 6, 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

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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).

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 Petition for Rehearing) (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.

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

[11] A utility that takes steps subject to state authority cannot point to a Section 202(c) order as the basis for a right to recover associated costs. *See* 16 U.S.C. § 824a(c)(1) (providing for compensation or reimbursement to be paid based on just and reasonable terms for carrying out an authorized order).

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).

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.").

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

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]

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

[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).

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 7. 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's Terms Fail 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-

[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

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 B," 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.

> [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 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

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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).

extent feasible," but fails to specify *who* bears that responsibility or *what* such operation entails. Order at 7. It imposes no further conditions.[16] 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 the Order's "paragraph A and paragraph B." Order at 7. But Paragraph A contains only a command lasting a single day that the Craig Co-Owners "take all measures necessary to ensure that Craig Unit 1 is available to operate" at the direction of the Western Area Power Administration

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[16] Unlike the order it renews, the Order does not expressly state that "This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators." *See* Order at 7; December Order at 4. The Order does not, however, state that the Order provides such relief, that any such relief is necessary to meet the emergency, or otherwise that the agency is changing its position. There is, therefore, no reason to believe that the agency is changing its position.

or SPP West. *Id.* at 6.[17] Paragraph B, meanwhile, requires SPP and the Craig Co-Owners to ensure Craig's availability and requires SPP to employ economic dispatch of the plant. *Id.* at 6–7. 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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[17] To the extent the Order allows the Western Area Power Administration or SPP West 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 to "ensure that Craig Unit 1 is available to operate," Order at 6–7, 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 December Order; it claims an emergency exists in the Rocky Mountain assessment area and that "[t]he emergency conditions that necessitated the issuance of Order No. 202-25-14 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.[18] 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

[18] 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 Request for Rehearing) (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 (describing the costs to Tri-State's members and Platte River's communities); 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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GLOSSARY OF TERMS

Shortened Term	Long Description
Department	Department of Energy or DOE
Order	Department of Energy Order No. 202-26-21
December Order	Department of Energy Order No. 202-25-14
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
2-07	NERC 2024 Long-Term Reliability Assessment	N. Am. Electric Reliability Corp., *2024 Long-Term Reliability Assessment* (July 11, 2025)	

No.	Exhibit Name	Document Name	URL and Notes
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
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

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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
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

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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
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:

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			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/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf

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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
2-34	Secretary Wright's West Virginia Remarks	Charles Young, *Energy Secretary Chris Wright: Future of U.S. Coal is 'long and bright'*, West	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

No.	Exhibit Name	Document Name	URL and Notes
		Virginia News (July 5, 2025)	
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
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.*	https://sustainableferc.org/wp-content/uploads/2025/08/2025-08-06_NRDC-et-al-Request-for-Rehearing-DOE-Resource-Adequacy-Report.pdf

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		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)	
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 Flexible Loads in US Power Systems*, Duke University Nicholas Institute for Energy,	https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf

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		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

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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)	

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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)	
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
2-65	CDPHE Regulation No. 3	Colorado Department of Public Health and Environment,	

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		Colorado APCD, *Regulation No. 3, Part F, Sec. VI.D* (adopted December 15, 2016)	
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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 & Transmission Association Craig Station Units 1 and 2*	

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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/

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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)	

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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)	

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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
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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

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 3-06
Tri-State and Platte River April Rehearing Request

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY

In re Craig Order No. 202-26-21	)	Order No. 202-26-21
	)	

REQUEST FOR REHEARING OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION AND PLATTE RIVER POWER AUTHORITY

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Pursuant to Section 313(a) of the Federal Power Act (FPA),[1] and Rule 713 of the Rules and Regulations of the Federal Energy Regulatory Commission (FERC or Commission),[2] and the applicable rules of practice and procedure,[3] Tri-State Generation and Transmission Association, Inc. (Tri-State) and Platte River Power Authority (Platte River) (together, Petitioners) file this Request for Rehearing of Order No. 202-26-21 dated March 30, 2026 (the Order) requiring Petitioners and their co-owners to keep coal-fired Unit 1 of the Craig Generating Station in Craig, Colorado (Craig Unit 1) open and available to operate notwithstanding its long-planned retirement. Craig Unit 1 was originally scheduled to shut down by December 31, 2025.[4]

SUMMARY

Section 202(c) provides that "during" an emergency, the U.S. Department of Energy (DOE) is authorized to require extraordinary steps be taken to serve the public interest. 16 U.S.C. § 824a(c)(1). The Order finds that such an emergency exists—but indicates that the claimed energy shortages DOE has identified are not likely to occur, if ever, until ***2034***—more than seven years—or ***thirty-one*** 90-day

[1] 16 U.S.C. § 825l.

[2] 18 C.F.R. § 385.713 (2026).

[3] U.S. Dep't of Energy, DOE Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited Jan. 15, 2026); *see also* 18 C.F.R. §§ 385.214 (2026), 385.713.

[4] Petitioners are co-owners of Craig Unit 1, and named recipients of the Order. Under the Commission's rules and regulations they are parties to this proceeding. However, if necessary to give them party status, out of an abundance of caution, Petitioners ask that this filing also be treated as a motion to intervene under Rule 214 of the Commission's Rules and Regulations. Petitioners' position on the Order and the nature of their interest are set forth in detail in this filing.

Section 202(c) renewal cycles in the future. That emergency, should it ever come to pass, cannot be solved by requiring that Craig Unit 1, a more than 45-year-old coal plant, continue operating today. It cannot be solved by allowing dispatch of Craig Unit 1 during the period of the current Order. While Petitioners raised many of these and other concerns in their request for rehearing and clarification responding to DOE's initial Section 202(c) order targeting Craig Unit 1,[5] this second Order provides little response.

Petitioners again request rehearing to bring to DOE's attention the myriad constitutional, procedural, and evidentiary defects of the Order. Regardless of whether the Order survives such scrutiny, it effects an uncompensated physical and regulatory taking of Petitioners' property interests in Craig Unit 1 and associated fuel and transmission resources. This taking does not come with just compensation, because (1) the processes by which Petitioners could potentially obtain recovery are insufficient and unclear; (2) and these processes fail to provide *compensation* from the taking party—the federal government—rather than facilitating potential compensation from private third parties (including Petitioners).

The Order is also defective on the merits. It fails to articulate a valid emergency, and its chosen remedy—keeping Craig Unit 1 open and available for dispatch—does not respond to the emergency it purports to identify. Because the

[5] *In re Craig Order No. 202-25-14*, Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority (Jan. 29, 2026), https://www.energy.gov/documents/request-clarification-and-rehearing-tri-state-generation-and-transmission-association-and (the First Rehearing Request).

contemplated "emergency" does not occur until 2034, the Order fails to provide constitutionally adequate due process before deprivation of Petitioners' property interests. Similarly, the Order is procedurally defective; it fails to incorporate statutorily mandated consultation between DOE and other agencies and neglects to consider any alternatives to its proposed plan. Finally, the Order does not align with the statutory objectives of the Federal Power Act (FPA), and DOE never explains how it could.

Petitioners seek to work with all levels of government to provide consumers with reliable and affordable electricity. But Petitioners cannot fulfill this mission when agencies impede years of concerted planning and mandate disruptive and costly changes that do not promote reliability or affordability. This is not what Section 202(c) was intended for. Petitioners urge DOE to reconsider its approach.

STATEMENT OF ISSUES

Pursuant to FPA Section 313(a), Petitioners request clarification and, in the alternative, rehearing based on the following issues:

1. By mandating Craig Unit 1's availability to operate and the terms under which it shall operate, and requiring related changes to Petitioners' physical property, the Order constitutes both a physical and regulatory taking. Because the Order does not provide "just compensation" from the government, this is an uncompensated taking in violation of the Fifth Amendment to the United States Constitution. *United States v. Pewee Coal Co.*, 341 U.S. 114, 116 (1951); *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015); *Ruckelshaus v. Monsanto Co.*, 467 U.S. 986, 1011 (1984).

2. Because DOE failed to establish the existence of an emergency, and, because of the temporal and geographic disconnect between the energy reliability concerns described by the Order and the means DOE directs for addressing those concerns as compared to alternatives, DOE failed to establish that the purported emergency here is addressed by the continued operation and dispatch of Craig Unit 1 or that the Order "best meet[s] the

emergency and serve[s] the public interest." 16 U.S.C. § 824a(c); 10 C.F.R. § 205.373 (2026). It is, therefore, contrary to law and arbitrary and capricious.

3. Because DOE predicated the Order on long-term concerns, and not an existing emergency, and reissued the Order notwithstanding the due-process objections Petitioners raised in their prior request for rehearing, Petitioners were denied any meaningful opportunity to be heard, notwithstanding time and notice permitting such process. This violates the Due Process Clause of the Fifth Amendment and is contrary to the procedural protections contemplated by the Administrative Procedure Act and the FPA. *Pa. Gas & Water Co. v. FPC*, 427 F.2d 568, 576 (D.C. Cir. 1970); *S. Allegheny Pittsburgh Restaurant Enterprises, LLC v. City of Pittsburgh*, 806 F. App'x 134, 139–41 (3d Cir. 2020).

4. The Order fails to incorporate any statutorily required consultation between DOE and the agency "with expertise in the environmental interest protected by" the laws or regulations waived by a renewed order. 16 U.S.C. § 824a(c)(4)(B). It is, therefore, contrary to law and arbitrary and capricious.

5. The Order does not align with the statutory objectives of the FPA, because it requires the operation and availability for dispatch of an uneconomic resource, and disrupts ordinary and orderly planning, development, and investment in generation resources. It is, therefore, contrary to law and arbitrary and capricious.

BACKGROUND

A. The Petitioners

Tri-State is a wholesale generation and transmission cooperative operating on a not-for-profit basis with its principal place of business in Westminster, Colorado. Organized and existing pursuant to the Colorado Cooperative Act,[6] Tri-State is a public utility subject to FERC jurisdiction under Part II of the FPA.[7] Tri-State is wholly owned by its electric distribution cooperative and public power district

[6] COLO. REV. STAT. § 7-55-101 *et seq.* (2019) (Cooperatives- General); Articles of Incorporation (2020).

[7] Tri-State Generation and Transmission Ass'n, 170 FERC ¶ 61,221, at P 37 (2020).

members (Utility Members) and three non-Utility Members (Non-Utility Members)[8] and was formed by its Utility Members for the purpose of providing the Utility Members with transmission services and wholesale power for resale to their retail customers.

Tri-State has 11 Utility Members with retail customers located in New Mexico and three Utility Members with retail customers in Nebraska,[9] all of which are outside the 2025 Western Electricity Coordinating Council (WECC) Rocky Mountain region that DOE identified as the region experiencing an emergency in the Order. The retail service territories of Tri-State's Utility Members cover approximately 182,000 square miles and their customers include rural residences, farms and ranches, and large and small businesses and industries, serving approximately 522,000 retail electric meters. Tri-State's Utility Members are the sole state-certificated providers of electric service to retail (residential and business) customers within their designated service territories.

Tri-State owns, directly or indirectly, or controls the output of, various power generation facilities, and purchases wholesale power within both the Western and Eastern Interconnections. Among other generation facilities, Tri-State is a partial owner of Craig Unit 1, with a 24% ownership share. Tri-State's generating facilities

[8] Tri-State's Non-Utility Members are: (i) MIECO, Inc., a wholesale supplier of natural gas in the United States; (ii) Olson's Greenhouses of Colorado, LLC, a grower/distributor of plants throughout the western United States that has a contract to purchase thermal energy from Tri-State; and (iii) Ellgen Ranch Company, which leases property from a Tri-State subsidiary.

[9] Tri-State has six Utility Members that maintain headquarters in Nebraska, three of which operate outside the emergency assessment area.

are included in the Western Power Pool reserve sharing program. This program facilitates sharing of generation reserves to be activated during a system emergency, such as loss of a generating unit or transmission line. Tri-State began participating in the Southwest Power Pool's (SPP) expanded regional transmission organization (RTO) in the Western Interconnection in April 2026.[10]

Platte River is a not-for-profit, municipally-owned power utility and joint action agency that generates reliable, financially sustainable, and environmentally responsible electricity for its owner communities of Estes Park, Fort Collins, Longmont, and Loveland, Colorado. Platte River is a political subdivision of the State of Colorado and a government-owned utility under FPA Section 201(f), 16 U.S.C. § 824(f). Headquartered in Fort Collins, Colorado, Platte River furnishes cost-of-service wholesale electrical power and energy to its four owner communities.

Platte River is a partial owner of Craig Units 1 and 2, with an 18% ownership share in the Craig units. Platte River's share of the total net capacity from both Craig units is 151 MW. Platte River also owns and operates an integrated transmission system of high-voltage aerial and underground power lines that deliver electricity to the electric utilities of Platte River's owner communities in Northern Colorado. Like Tri-State, Platte River began participating in SPP's expanded RTO in April 2026.

[10] As used herein, SPP refers to the SPP RTO's western expansion. It does not include SPP Markets+.

B. The Craig Generating Station

Craig Generating Station is a three-unit, coal-fired power plant located in Craig, Colorado. Craig Units 1 and 2 were built by and are jointly owned by several utilities through what is known as the Yampa Project. Tri-State operates those two units on behalf of all the co-owners, including Platte River, PacifiCorp, Public Service Company of Colorado, and Salt River Project. Tri-State separately owns and operates Craig Unit 3. In April 2026, the owners of Craig Units 2 and 3 became market participants in SPP—the culmination of a multi-year planning process—and began to bid those units into SPP's market. Craig Unit 1 is currently participating as a resource in SPP solely because of the Order.

As a result of changed market conditions and regulatory requirements, the retirement of the Craig units has been planned, reviewed, and integrated into state-approved resource portfolios, and the owners have planned for their closure for nearly a decade—beginning with Craig Unit 1 by December 31, 2025, followed by Craig Unit 3 by January 1, 2028, and Craig Unit 2 by September 30, 2028. Colorado Air Quality Control Commission Regulation No. 23 on Regional Haze Limits now specifies a retirement date for each Craig unit.[11] Unit 1's retirement date was adopted in 2016, in a revision of what was then Colorado Air Quality Control Commission Regulation No. 3, which was approved by the Environmental Protection Agency

[11] COLO. CODE REGS. 1001-27.

(EPA) in 2018.[12] Retirement dates for Craig units were later codified into Regulation No. 23.

The Craig units have been fueled primarily by coal from the nearby Colowyo and Trapper mines. The Colowyo Mine has ceased active mining and transitioned to full reclamation, with two pits in final reclamation and the third transitioned to reclamation on October 15, 2025. Similarly, the Trapper Mine is scheduled to cease active mining and convert to site remediation in calendar year 2026. Before the closure of the Colowyo Mine, Tri-State stockpiled sufficient coal to meet Tri-State's projected demand for Craig Units 2 and 3 through their respective planned retirement dates. Before the Trapper Mine closes, Platte River will have stockpiled sufficient coal to meet its projected demand for Craig Unit 2 through its planned retirement date.

As part of its multi-year resource plan, which incorporated the long-planned retirement of Craig Unit 1, Tri-State has placed into service the 145 MW Axial Basin generating facility. This facility, approximately 26 miles from the Craig facility, relies on much of the same transmission infrastructure. Absent the retirement of Craig Unit 1, this interconnection faces transmission constraints such that, when Craig Unit 1 remains interconnected and available to operate, Tri-State may be required to

[12] *See* Approval and Promulgation of Implementation Plans; Colorado; Regional Haze 5-Year Progress Report State Implementation Plan, 84 Fed. Reg. 47884 (Sept. 11, 2019); Co. Air Pollution Control Div., Colorado Visibility and Regional Haze State Implementation Plan for the Twelve Mandatory Class I Federal Areas in Colorado (Dec. 15, 2016), https://oitco.hylandcloud.com/POP/DocPop/DocPop.aspx?docid=3303135.

curtail output from Axial Basin (particularly when all facilities are generating at or near full output) due to limited transmission capacity.

C. Craig Unit 1

Craig Unit 1 can produce up to 427 MW of electricity and has been running since 1980. Over the last ten years, the operations and maintenance cost (without consideration of coal cost or depreciation expense) to run Craig Unit 1 has totaled in the millions of dollars annually. By the standards of an older coal plant, Craig Unit 1 has generally provided reliable performance when called upon. However, in the last three years (due primarily to economic factors and some forced outages), Craig Unit 1 has run well below half of its capacity for Petitioners, without compromising Petitioners' ability to meet their generation demands reliably.

Operation and maintenance of Craig Unit 1 have been undertaken prudently to reflect the scheduled 2025 retirement. Since 2019, the Craig Unit 1 owners scheduled and performed only that maintenance appropriate for a unit that planned to cease operation at the close of 2025. On December 19, 2025, the unit suffered a valve failure that rendered Craig Unit 1 inoperable, although the unit is now available to operate following repairs.[13]

D. DOE Order No. 202-25-14

On December 30, 2025, DOE issued Order No. 202-25-14, declaring that "an emergency exists within the [WECC-NW] assessment area due to a shortage of

[13] Tri-State Generation & Transmission Ass'n, Inc., *U.S. DOE Orders Tri-State to Keep Craig Generating Station Unit Operating Next 90 Days*, TRI-STATE (Dec. 31, 2025), https://tristate.coop/us-doe-orders-tri-state-keep-craig-generating-station-unit-operating-next-90-days.

electric energy, a shortage of facilities for the generation of electric energy, and other causes." DOE Order No. 202-25-14 at 1 (Dec. 30, 2025). Petitioners sought rehearing and clarification of Order No. 202-25-14, raising multiple legal issues, including DOE's denial of Petitioners' constitutionally protected due process rights, the lack of an appropriate mechanism for just compensation, and DOE's failure to consider alternatives for what the order itself recognized was not an immediate, time-sensitive emergency. DOE denied the First Rehearing Request by operation of law pursuant to 16 U.S.C. § 825l(a) by failing to substantively respond to the request within 30 days, and issued a notice to this effect on March 2, 2026.

This initial order expired on March 30, 2026.

E. DOE Order No. 202-26-21

On March 30, 2026, DOE issued Order No. 202-26-21, continuing Order 202-25-14. The Order declared that "an emergency exists within the Western Electricity Coordinating Council (WECC) Rocky Mountain assessment area due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes." DOE Order No. 202-26-21 at 1 (Mar. 30, 2026). The Order further declared that "[t]he availability of electricity from Craig Unit 1 will continue to be critical to maintain reliability in the WECC Rocky Mountain assessment area." *Id.* at 3. Its emergency was predicated on (1) "increasing demand" and (2) "shortage from accelerated retirement of generation facilities [that] will continue in the near term and are also likely to continue in subsequent years." *Id.* at 6. DOE stated, "[t]his could lead to the loss of power to homes, and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety." *Id.*

DOE predicated its energy reliability concerns on the 2025 Long-Term Reliability Assessment (2025 LTRA) from the North American Electric Reliability Corporation (NERC) for the WECC-Rocky Mountain assessment area, which does not anticipate any shortfalls in supply before Summer 2034. *Id.* at 3. DOE also pointed to the 2025 WECC Western Assessment of Resource Adequacy. The concerns included (1) projected regional load growth; (2) planned retirement of generation facilities fueled by coal and natural gas; and (3) the "prolific growth of data centers" constituting a "new and unexpected source of load growth." *Id.* at 3–5.[14]

The Order requires Petitioners and the other co-owners of Craig Unit 1 to:

1. From March 31, 2026, take all measures necessary to ensure that Craig Unit 1 is available to operate at the direction of either Western Area Power Administration (WAPA)—Rocky Mountain Region, Western Area Colorado Missouri (WACM), in its role as Balancing Authority, or SPP West in its role as the Reliability Coordinator, as applicable.
2. From April 1, 2026, take all measures necessary to ensure that Craig Unit 1 is available to operate, with SPP directed to take every step to employ economic dispatch of Craig Unit 1 to minimize costs to ratepayers, with Tri-State and the co-owners directed to comply with all orders from SPP related to the availability and dispatch of Craig Unit 1.
3. Limit operation of Craig Unit 1 to the times and within the parameters established *supra* in order to minimize adverse environmental impacts, and to provide a daily notification to the Department reporting whether Craig Unit 1 has operated in compliance with the Order.
4. Comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the

[14] The Order placed these concerns in the broader context of Executive Orders 14156 and 14262. Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https:// www.federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency; Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www.federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

maximum extent feasible while operating consistent with the emergency conditions.

5. By April 14, 2026, provide DOE with information concerning the measures each has taken and is planning to take to ensure the operational availability of Craig Unit 1 consistent with the Order, as well as additional information regarding the environmental and operational impacts of the Order and its compliance with the conditions of the Order, in each case as requested by DOE.
6. File tariff revisions or waivers with FERC to effectuate the Order, as needed.

The Order is effective from March 31 through June 28, 2026. Tri-State has submitted and continues to submit daily notifications to DOE as the Order requires.

ARGUMENT

Petitioners seek rehearing on two fronts. *First*, the Order effectuates a taking of Petitioners' property under the Fifth Amendment to the United States Constitution without an adequate process to obtain constitutionally required compensation. *Second*, the Order does not meet either the Constitution's or Section 202(c)'s requirements for a reasoned, procedurally adequate finding of a valid emergency that compels operation of Craig Unit 1.

I. THE ORDER CONSTITUTES AN UNCOMPENSATED TAKING OF PETITIONERS' PROPERTY INTERESTS

Petitioners chose to close Craig Unit 1 to meet reliability targets and achieve regulatory goals, and have taken numerous steps over the years to prepare for its closure. The Order nevertheless requires Tri-State to operate the facility beyond that planned retirement date, effecting an uncompensated taking of Petitioners' property in violation of the Fifth Amendment of the United States Constitution. By compelling continued operational availability of Craig Unit 1, DOE took effective control over the

facility itself and mandated changes to Petitioners' infrastructure and business operations, constituting both a *per se* physical and regulatory taking.

The Order's taking comes with no constitutionally adequate avenue for just compensation. FERC cost recovery shifts compensation onto ratepayers; it does not assure compensation *from the government*. And, due in part to the broad scope of the declared energy emergency, FERC cost recovery related to the Order will be procedurally and substantively novel and could leave material costs unrecovered from the Order's putative beneficiaries.

A. The Order Constitutes a Physical Taking

The Fifth Amendment provides, "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. "When the government physically acquires private property for a public use, the Takings Clause imposes a clear and categorical obligation to provide the owner with just compensation." *Cedar Point Nursery v. Hassid*, 594 U.S. 139, 147 (2021) (citation omitted).

Physical takings can take various forms, including intermittent or limited-value intrusions. *Id.* at 149–55; *see also Loretto v. Teleprompter Manhattan CATV Corp.*, 458 U.S. 419 (1982). Moreover, "[i]f government action would qualify as a taking when permanently continued, temporary actions of the same character may also qualify as a taking." *Ark. Game & Fish Comm'n v. United States*, 568 U.S. 23, 26 (2012). This is true even when the government has not seized title to property but rather directed it to operate in a particular way. Temporary seizures of property to operate are takings "in as complete a sense as if the Government held full title and

ownership." *See Pewee Coal Co.*, 341 U.S. at 116 (quoting *United States v. United Mine Workers of Am.*, 330 U.S. 258, 285–86 (1947)).

The Order operates as a physical taking in two interrelated ways. *First*, by directing Petitioners to maintain and operate Craig Unit 1, on a prolonged basis, and in clear departure from Petitioners' own planned retirement of the facility, the Order falls within a near-century-old tradition of classifying mandatory operations—even under wartime and emergency authorities—as takings requiring compensation. *Second*, the Order constitutes a physical taking by compelling Petitioners to make material physical changes to the plant, including repairing out-of-service equipment like feedwater heater tubes, ash blowers, and side stream filter pumps, for example, requiring additional staff onsite, and physically diverting coal allocated for Craig Units 2 and/or 3 to fuel Craig Unit 1. Reduction of these stockpiled reserves requires Petitioners to obtain replacement coal that will be compatible for use in Units 2 and 3, from uncertain sources and at uncertain future prices, creating an additional uncompensated cost. And because of transmission constraints, Craig Unit 1's operations could limit the circumstances where SPP can dispatch the nearby Axial Basin generating facility.

1. The Order's Direction of Prolonged Operations at Craig Unit 1 Contrary to Petitioners' Plan to Retire the Facility Constitutes a Physical Taking

Section 202(c) was enacted to address energy shortages that occurred during the First World War,[15] making it particularly suitable for analysis under post-war interpretations of the Takings Clause. These cases show that, even in the context of an emergency, where the government takes control of part or all of a business's facilities to use and operate for the government's purposes, a compensable taking occurs, *see*, *e.g.*, *United States v. Gen. Motors Corp.*, 323 U.S. 373 (1945) (government seizure of part of leased warehouse space for military purposes was a compensable taking). Similarly, where the government requires a private business to operate in the public interest, this too constitutes a *per se* physical taking. *Pewee Coal Co.*, 341 U.S. at 116 (taking occurred when government responded to work stoppages and strikes at coal mines by directly operating them or arranging for their continued operation). Finally, these cases illustrate that a taking is particularly likely to occur where the imposition of government control extends over a lengthy period of time. *See Gen. Motors Corp.*, 323 U.S. at 375 (warehouse seized for more than a year); *Pewee Coal Co.*, 341 U.S. at 115 (government-directed operation of coal mine continued for more than 160 days).[16]

[15] Benjamin Rolsma, *The New Reliability Override*, 57 Conn. L. Rev. 789, 789–846, 800–02 (2024) ("Rolsma (2024)").

[16] Indeed, the federal government recently recognized that where the government appropriates the right to control operation of a facility and deprives owners of their freedom to dispose of their property, a taking has occurred. *See* EPA-R08-OAR-2024-0607-0067, Regional Haze Round 2 at 19–21 (Jan 9, 2026), https://www.regulations.gov/document/EPA-R08-OAR-2024-0607-0067 (describing how the "unconsented closure" of a coal-fired power

In that light, the Order constitutes a taking of Petitioners' property. The Order requires Petitioners to, in relevant part: (1) take all measures necessary to ensure that Craig Unit 1 is available to operate; (2) limit operation of Craig Unit 1 to certain times and parameters; and (3) make Craig Unit 1 available for dispatch at the direction of SPP, a non-governmental actor. Compliance with these requirements has compelled Petitioners to take significant steps, steps they would not otherwise take, for a prolonged period of time. DOE's renewed Order extends the period of compelled availability to roughly six months, and nothing in the Order suggests this control will be temporary rather than renewed through successive emergency declarations. This closely resembles the mandate to operate that the *Pewee Coal* Court held was a taking.[17] By requiring Petitioners to involuntarily keep Craig Unit 1 available for operations according to SPP's instructions—for not hours or days but months—DOE enacts a taking.

2. The Order Mandates Physical Changes to Petitioners' Property That Constitute a Physical Taking

The physical changes to Petitioners' property mandated by the Order also constitute a *per se* physical taking of Petitioners' property rights in Craig Unit 1 and other related property, such as fuel. *First*, operations require fuel, which compels

station constituted a per se taking of the facility owner's property) (citing *Cedar Point Nursery v. Hassid*, 594 U.S. 139 (2021) and *Horne v. Dep't of Agric.*, 576 U.S. 351 (2015)).

[17] The *Pewee Coal* Court did not enjoin the government's actions—the wartime emergency justified the government's effort to keep coal mines operational in 1943, the heat of the war. The fact of a justified emergency, however, did nothing to abate the Takings Clause requirement that the government compensate the plaintiff. *See Pewee Coal Co.*, 341 U.S. at 118 (holding that government is "entitled to the benefits and subject to the liabilities" of operating a facility it takes over).

Petitioners to make use of the Craig facility's limited fuel reserves intended exclusively for Craig Units 2 and/or 3 as operations at Unit 1 continue; these reserves were acquired and measured for the anticipated operation of two specific coal units and based on the assumption that Craig Unit 1 would retire at the end of 2025. Because the Order forces Petitioners to surrender coal inventory for the government's chosen public purpose—coal that Petitioners acquired, allocated, and reserved for other units—it effects a *per se* physical taking of that property. *Second*, transmission capacity limitations for Petitioners' facilities at and near Craig Unit 1—the other Craig units and Axial Basin—mean that requiring Craig Unit 1 to remain interconnected and possibly operating constrain the ability of these resources to fully access the grid. And *third*, mandating that Petitioners make Craig Unit 1 ready for operations has compelled Petitioners to make material physical changes to Craig Unit 1, including repairing out-of-service equipment that would otherwise remain unused.

a. The Craig Facility's Fuel Reserve

All three Craig Units were designed to run on coal obtained from the now-shuttered Colowyo Mine and the soon-to-be-shuttered Trapper Mine.[18] Before closing the Colowyo Mine, Tri-State stockpiled reserves sufficient to operate its share of the Craig Units until their respective retirements. The only readily available source of

[18] Tri-State believes that co-owners supply their share of Craig Units 1 and 2 through Trapper or other mines.

fuel for Craig Unit 1 to maintain readiness, and to make use of in the event of a dispatch, are the reserves acquired and allocated for Craig Units 2 and 3.[19]

This too constitutes a taking. *See Horne*, 576 U.S. at 357–65 (USDA requirement that a percentage of a grower's crop be set aside for public use constituted a *per se* physical taking). Just as the government in *Horne* effected a *per se* taking by requiring raisin growers to surrender a specific, identifiable portion of their crop for public use, by mandating that Petitioners consume coal inventory purchased and reserved for Craig Units 2 and/or 3, DOE appropriates that property for a public objective. Under *Horne*'s reasoning, forced depletion of a utility's fuel reserves—no less than forced surrender of raisins—constitutes a physical taking of personal property requiring just compensation.

b. Axial Basin

The 145 MW Axial Basin generating facility, located near the Craig Generating Station, relies on much of the same transmission infrastructure. There is insufficient transmission capacity to move all electricity generated by the three Craig units and Axial Basin to the broader power grid. The Order thus constitutes appropriation of Tri-State's transmission infrastructure (including transmission infrastructure allocated to Axial Basin), a clear physical intrusion. This transmission limitation may

[19] Diverting this coal will require Petitioners to purchase replacement fuel at uncertain cost, imposing an additional, uncompensated expenditure that independently constitutes a taking. Use of an alternative source of supply not only results in additional costs, but also requires Petitioners to negotiate new contracts and alter operations at the Craig facility to account for variances between the physical qualities of different coal supplies. Meanwhile, using coal with different physical qualities could also require expensive and time-consuming modification of one or more Craig Units to allow such coal to be burned.

trigger additional physical intrusion, as ensuring sufficient transmission capacity for Craig Unit 1's compliance with the Order may require curtailment of one or more other generation facilities (especially when the system is operating near capacity).

c. Physical Changes to Craig Unit 1

Ongoing operations at Craig Unit 1 will require continual maintenance and staffing readiness, with further equipment failures requiring repair and staffing (including overtime). Compelling a property owner to make improvements to their property constitutes a physical taking when the mandated improvement benefits others—particularly the public at large—but do not benefit the property owner. "Put in general terms, government may not force a landowner to make an improvement that, while valuable to others, is useless to him" without it constituting a compensable taking. *Furey v. City of Sacramento*, 780 F.2d 1448, 1454 (9th Cir. 1986) (discussing *Norwood v. Baker*, 172 U.S. 269 (1898) and *Myles Salt Co. v. Bd. of Comm'rs*, 239 U.S. 478 (1916)), *abrogated on other grounds, Cumbre Inc. v. State Compensation Ins. Fund*, 403 F. App'x 272 (9th Cir. 2010). The Order requires Petitioners to continue to maintain and operate Craig Unit 1, and to replace equipment and material, even though they had planned to imminently retire the unit for good and Unit 1 is not needed to serve the reliability needs of their respective systems. This is the kind of physical taking described in *Furey*.

B. The Order Constitutes a Regulatory Taking

In addition to being a *per se* physical taking, the Order constitutes a regulatory taking. Regulatory takings occur where the government "imposes regulations that restrict an owner's ability to use his own property" but goes too far. *Cedar Point*

Nursery, 594 U.S. at 148. The property rights implicated by the Takings Clause can include contract rights, *see Lynch v. United States*, 292 U.S. 571, 579 (1934), and government-created entitlements with economic value, *Ruckelshaus*, 467 U.S. at 1001–1004 (trade secrets constituted property for takings purposes). When evaluating whether a regulatory burden constitutes a taking, courts look to the test established in *Penn Cent. Transp. Co. v. N.Y.C.*, 438 U.S. 104, 124 (1978), which evaluates regulatory takings based on: (1) the regulation's economic impact; (2) its interference with reasonable investment-backed expectations; and (3) the character of the government action. The Order constitutes a regulatory taking under this analysis.

1. Economic Impact

In requiring Petitioners to "take all measures necessary to ensure that Craig Unit 1 is available to operate," the Order places a heavy economic burden on Petitioners. Petitioners incur various operations and maintenance costs to ensure Craig Unit 1 is ready and able to operate at SPP's direction. Moreover, because of limited capacity over common transmission facilities, dispatching Craig Unit 1 while the other Craig Units are operating can impede SPP's ability to dispatch the nearby Axial Basin generating facility. This, in turn, prevents Petitioners from gaining the benefit of a margin on more economic resources, including renewable energy credits (which themselves have tangible economic value).

2. Investment-Backed Expectations

"[T]he regulatory regime in place at the time the claimant acquires the property at issue helps to shape the reasonableness of [investment-backed]

expectations." *Palazzolo v. Rhode Island*, 533 U.S. 606, 633 (2001) (O'Connor, J., concurring). Where a change in regulation dramatically disrupts the economic basis for a property owner's choices, it constitutes unreasonable interference with reasonable investment-backed expectations. *See Petworth Holdings, LLC v. Bowser*, 308 F. Supp. 3d 347, 356–58 (D.C. Cir. 2018). An explicit government guarantee forms the basis of a reasonable investment-backed expectation. *See Ruckelshaus*, 467 U.S. at 1011.

The Order disrupts Petitioners' reasonable investment-backed expectations on several fronts. DOE's use of Section 202(c) authority to address potential long-term shortages or grid reliability problems is a substantial and novel change to prior uses of Section 202(c) emergency authority.[20] The Order fundamentally alters DOE's longstanding approach in a novel, untested way that could not be predicted from DOE's previous actions, and certainly not when Petitioners decided a decade ago to retire Craig Unit 1 in 2025. Petitioners could not have fairly anticipated DOE's novel approach to Section 202(c) when it engaged in business planning and made investment decisions; thus, the Order upsets Petitioners' reasonable expectations. Diverting coal from Craig Unit 1 to comply with the Order, moreover, depletes Craig Unit 2 and 3's fuel reserves and hinders Petitioners' right and ability to freely use those facilities consistent with their investment-backed expectations.[21]

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[20] *Rolsma* (2024) at 802–09, 839–46 (discussing paucity of involuntary Section 202(c) orders since WW2).

[21] The Order also upsets Petitioners' delicate contractual relationships. Even if Section 202(c) provides protection from enforcement action by Colorado under "environmental" laws, disruption to these longstanding relationships disturbs Petitioners' ability to manage risk,

Finally, the electrical generation and transmission industry operates on a long time horizon. 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. Disruption of these long-term plans upsets Petitioners' reasonable investment-backed expectations. The seizure of a facility eight years in advance of a potential emergency upsets a reasonable expectation that long-term resource planning will be the mechanism by which utilities address resource adequacy needs.

3. Character of the Taking

The character of a governmental action is defined by "the purpose and importance of the public interest underlying [the] regulatory imposition, by obligating the court to inquire into the degree of harm created by the claimant's prohibited activity, its social value and location, and the ease with which any harm stemming from it could be prevented." *Maritrans, Inc. v. United States*, 342 F.3d 1344, 1356 (Fed. Cir. 2003) (internal quotation and citation omitted). "A 'taking' may more readily be found when the interference with property can be characterized as a physical invasion by government . . . than when interference arises from some public program adjusting the benefits and burdens of economic life to promote the common good." *Penn Cent.*, 438 U.S. at 124 (citations omitted).

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engage in long-term planning, and maintain their reputations as reliable counterparties. Petitioners have made commitments to stakeholders and planned their businesses around complying with existing environmental laws, which form part of their reasonable investment-backed expectations.

The character of the Order's action further aligns with a regulatory taking. As discussed above in Section (I)(A), the Order effectively commandeers Craig Unit 1, its fuel, the potential dispatch of the nearby Axial Basin facility, and related infrastructure owned by Petitioners. It places Craig Unit 1 under the control of SPP, a non-governmental actor, and requires Petitioners to comply with "all orders" that SPP issues "related to the availability and dispatch of Craig Unit 1." Order at 7. The Order does not merely adjust the benefits and burdens of economic life, but rather directs operational control for a public reliability aim that could—and should—be solved through other means, and by other electrical utilities.

C. Just Compensation

The Takings Clause provides that "private property [shall not] be taken for public use, without just compensation." U.S. Const. amend. V. Whether compensation is "just" is measured by relation "both to an owner whose property is taken and to the public that must pay the bill[.]" *United States v. Commodities Trading Corp.*, 339 U.S. 121, 123 (1950). "The owner's loss is measured by the extent to which governmental action has deprived him of an interest in property." *Wheeler v. City of Pleasant Grove*, 833 F.2d 267, 270 (11th Cir. 1987). Petitioners cannot obtain constitutionally sufficient compensation for the costs the Order imposes for several reasons.

First, SPP's existing market structures do not assure Petitioners they can recover both their variable and fixed costs of continued operation of Craig Unit 1. Under SPP's existing market structure, generators like Petitioners participate by bidding their output into SPP's real-time and day-ahead energy and ancillary services

market. SPP's markets assure generators recovery of only their marginal, variable costs—not fixed costs.[22] As a long lead-time reliability resource, Craig Unit 1 is offered for selection within a multi-day resource assessment. In the event SPP selects the resource for reliability purposes, the resource is compensated for energy costs. SPP does not operate a mandatory all-resource capacity market, a mechanism by which generators recover their non-variable (fixed) costs.[23] And, in any event, the Order instructs that Craig Unit 1 "shall not be considered a capacity resource[,]" Order at 7.

Second, while Section 202(c) and its implementing regulations suggest recovery may be possible through FERC rate-making processes, that suggestion is not a promise of constitutional recovery.[24] The scope of the purported emergency, covering the entire WECC–Rocky Mountain region, is broader than just SPP's market. Public Service Company of Colorado's (PSCo) Balancing Authority Area, for example, falls within the WECC–Rocky Mountain region identified as experiencing

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[22] *See* Market Protocols—SPP Integrated Marketplace, at 39 ("SPP committed Resources are assured recovery of their Start-Up Offer, No-Load Offer and actual incremental Energy costs as defined in the Energy Offer Curve subject to certain eligibility criteria[.]").

[23] *See* Federal Energy Regulatory Commission, Office of Energy Policy and Innovation, *Energy Primer: A Handbook for Energy Market* Basics 72 ("[C]apacity markets are intended to provide more certainty for investment in new capacity resources while including an opportunity for all resources to recover their fixed costs over time.").

[24] The terms of the Order, moreover, could have substantive impact on Tri-State's ability to make energy sales at market-based rates through authority granted to it by FERC. *See, e.g.*, *Tri-State Generation and Transmission Ass'n,* 170 FERC ¶ 61,220, at PP 1, 22 and ordering para. (A) (2020) (generally providing Tri-State with authorization to transact at market-based rates). The circumstances are analogous for Platte River. Platte River also makes energy sales at market rates, but, as a government utility exempt under FPA Section 201(f), Platte River does not need market-based rate authority from FERC.

the "emergency" and thus PSCo presumably benefits from Craig Unit 1's continued operations, but PSCo does not participate in SPP, the mechanism for potential compensation identified in the Order. DOE sets forth no mechanism for navigating these complexities, much less an assurance of just recovery notwithstanding these issues; at minimum DOE should clarify the entities from which it intends to provide Petitioners the right to seek recovery.[25] And conflating recovery from SPP with constitutional just compensation is particularly inappropriate here because recovery from SPP, of which Petitioners are a part, means that "cost recovery" would in significant part come from the pockets of ***Petitioners themselves***.[26] The Takings Clause does not permit the federal government to appropriate control and use of property while leaving the owner without a mechanism to obtain just compensation from the government itself.

[25] As such, Petitioners request clarification of which "ratepayers" DOE is referring to in the Order, such as SPP ratepayers, all ratepayers within the WECC–Rocky Mountain region, or ratepayers for all co-owners of Craig Unit 1.

[26] For example, Tri-State comprises approximately 52% of the SPP West load but owns only 24% of Craig Unit 1. Additionally, there are co-owners of Craig Unit 1 that are not participants in SPP, who will bear costs without any apparent mechanism of recovery through SPP. If costs are allocated in proportion to load, and recovery in proportion to ownership, Tri-State and other co-owners who do not participate in SPP stand to lose. Routing recovery through SPP may obligate these co-owners to fund more than half of the costs imposed by the Order, effectively compelling them to subsidize purported reliability benefits for others without any showing that Craig Unit 1's co-owners required the Unit's continued operation to address any identified resource shortfall. *See* Tri-State 2026 Resource Adequacy Annual Report (2026), https://tristate.coop/sites/default/files/PDF/resourceplan/Resource%20Adequacy_2026.pdf (showing excess resources in Tri-State's footprint through 2035); Platte River Power Authority Resource Adequacy Report 2025 (2025), https://prpa.org/wp-content/uploads/2025/04/PRPA_RA2025_-signed.pdf (showing excess resources in Platte River's footprint through 2030).

Petitioners raised these problems in their initial request for rehearing but the Order fails to resolve them. DOE's refusal to bridge this gap is especially problematic given that the renewed Order altered the geographic framing of the asserted emergency. Having adjusted the relevant assessment area and introduced new evidence, DOE had ample opportunity to explain how Petitioners could obtain just compensation or to offer just compensation. DOE failed to do so. This is no small matter. If Petitioners 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.

Moreover, even if Petitioners can and do recover some costs through this process, it is still not *just compensation* within the meaning of the Takings Clause. "[O]nce the government executes a taking, the Constitution does not permit it to shift the public's burden of just compensation to third parties. When property is taken for public use under the Fifth Amendment, the public—and not specific individuals or groups at the order of the government—must pay." *Carson Harbor Village, Ltd. v. City of Carson*, 353 F.3d 824, 831 (9th Cir. 2004) (O'Scannlain, J., concurring); *see also U.S. Bank, Nat'l Assoc. v. SFR Invests. Pool 1, LLC*, Case No. 15-cv-00287-APG-GWF, 2016 WL 1248704, at *5 (D. Nev. Mar. 28, 2016) ("[A] takings claim requires just compensation from the government, not from a private third party."); *Baker v. City of McKinney*, 608 F. Supp. 3d 457, 465–67 (E.D. Tex. 2022) (plaintiff was entitled to full compensation for a taking by police even though she obtained additional money from donations).

This is particularly true where, as here, at least some of Petitioners' relief will come from Tri-State's members and Platte River's ratepayers, even if FERC orders some level of cost recovery.[27] DOE cannot simply transfer the constitutional obligation to provide just compensation onto private parties—including, here, rural communities and the residents of four small Colorado municipalities—through regulatory mandates without satisfying its own Takings Clause obligations.

II. THE ORDER DISRUPTS PETITIONERS' RELIABILITY PLAN AND FAILS TO ACCOUNT FOR VIABLE ALTERNATIVES

Separate from whether DOE must compensate Petitioners for the impact of the Order on their property and operations, the Order suffers from statutory and constitutional defects.

First, the Order fails to identify an emergency that meets the requirements of Section 202(c), or that is addressable by keeping Craig Unit 1 open. The issues articulated by the Order are fundamentally mismatched—temporally and geographically—with the Order's methods. Forcing Craig Unit 1 to remain open is counterproductive, disrupting a considered resource planning effort aimed at addressing the very concerns DOE raises in the Order. This analytical failure renders the Order arbitrary and capricious.

[27] As noted in the Order, a significant driver of the growth in the demand for energy nationwide is data center demand. *See* Order at 5. To the extent the alleged emergency has been caused by the demands of data centers, shifting the costs of Craig Unit 1 onto Petitioners and their ratepayers is contrary to President Trump's pledge to protect ratepayers from these effects. *See* Ratepayer Protection Pledge, Proclamation No. 11014, 91 F.R. 11439 (Mar. 4, 2026).

Second, the rote invocation of an "emergency" does not waive Petitioners' constitutional due process rights to pre-deprivation notice and a hearing. The materials relied upon in the Order demonstrate that the alleged resource-adequacy concerns are not sudden or unforeseen but instead involve long-term conditions projected to arise years in the future. And where, as here, DOE had ample time to deliberate—and was already informed in Petitioners' prior rehearing request that its proposed action raised serious due process concerns—the asserted need to address an emergency eight years in the future does not excuse DOE's failure to provide notice and an opportunity for Petitioners to be heard before imposing the Order.

Third, the Order does not meet the requirements of Section 202(c). It does not limit the Orders to a remedy necessary to address the emergency, and it does not consider reasonable alternatives as required by Section 202(c) (including Petitioners' carefully calibrated reliability planning, using both thermal and renewable resources based on findings supported by objective, industry-leading forecasting methods). And *fourth*, the Order is inconsistent with the FPA's objectives. The Order is, therefore, contrary to law and arbitrary and capricious.[28]

[28] As DOE is aware, Petitioners have already taken and will continue to take steps to comply with the Order. This includes incurring compensable costs and expenses. Although the Order is improper under Section 202(c), Petitioners are nonetheless entitled to cost recovery under Section 202(c) and as a compensable taking. Petitioners note that Section 202(c) is an emergency provision, and, for that reason, recovery pursuant to its terms should not turn on an ultimate determination of the lawfulness of the Order. Further, the Order provided notice to all potential ratepayers that rights to recovery would accrue to Petitioners (and the other co-owners) beginning on December 30, 2025. To bar Petitioners from recovering these already-incurred costs would be inconsistent with Section 202(c)'s purpose to respond to emergency conditions and would violate constitutional protections. Petitioners' position is based on currently available facts and information. Petitioners reserve all rights.

A. The Order Describes Speculative Energy Shortfalls in 2034, and Therefore Does Not Establish the Existence of an Emergency Addressed by Requiring Continued Operation and Dispatch of Craig Unit 1

Section 202(c)(1) provides that DOE may issue an order when it determines "an emergency exists," and that the emergency was caused by "a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes[.]" 16 U.S.C. § 824a(c)(1). DOE's regulations define an emergency as an "unexpected inadequate supply of electric energy" and envision use of Section 202(c) to address a "specific inadequate power supply situation." 10 C.F.R. § 205.371 (2026). These regulations acknowledge that "inadequate planning or the failure to construct necessary facilities" may lead to an emergency—but also indicate that 202(c)'s role is to provide short-term relief. As DOE explained in its rulemaking:

> The DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[29]

As DOE admits, Section 202(c) is focused on short-term problems with specific solutions. *Accord* 10 C.F.R. § 205.371 (where inadequate planning causes an emergency, DOE expects that "the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a

[29] Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984 (Aug. 6, 1981).

continuing emergency order is not needed"). DOE's longstanding regulations confirm that Section 202(c) authority is not intended as a substitute for long-term planning or resource development, but as a temporary tool to address unexpected shortfalls—the opposite of the long-horizon concerns cited in the Order.[30]

A speculative "emergency" occurring eight years or more in the future is not a "specific inadequate power supply situation" as required by DOE's regulations for a Section 202(c) order, nor is it an example of a "sudden increase in the demand for electric energy." Structural changes in electricity markets are precisely the kind of issue addressed by long-term collaborative planning by utilities, communities, and state governments. And while the Order alludes to potential future shortages in the WECC–Rocky Mountain region, it fails to specify where within the WECC–Rocky Mountain area a shortage is expected to arise, how Craig Unit 1's output would be deliverable to the locations of concern, or why existing reserves, imports, or market mechanisms would be inadequate to address the risk. The Order is therefore contrary to law and arbitrary and capricious.

1. Keeping Craig Unit 1 Open Does Not Address Long-Term Concerns

DOE rests the Order on concerns that, as mentioned *supra*, are predicted to occur at least 31 90-day renewal cycles in the future, yet the Order requires Petitioners to take action now. To justify the Order, DOE relies principally on: (1) NERC's 2025 LTRA; (2) the 2025 WECC Western Assessment of Resource

[30] Notably, DOE has not attempted to update these definitions to conform the agency's defined causes of an "emergency" with the novel approach of its Section 202(c) orders.

Adequacy; and (3) expressions of concern by two Colorado Public Utilities Commissioners concerning the ability of a separate utility, PSCo, to meet summer 2026 loads. Order at 4–5. None of these justifications rationally support the Order, let alone establish that requiring Craig Unit 1 to operate now will address the asserted emergency.

The 2025 LTRA expressly provides—and DOE acknowledges—that there is no elevated risk for energy shortfalls over the next five years. As the LTRA shows, actual reserve margin and planning reserve margin are above the reference margin level through 2033, and NERC anticipates ***no*** loss-of-load hours (LOLH) through 2029 for the WECC-Rocky Mountain region. To the contrary, the materials DOE relies on show that in the WECC-Rocky Mountain subregion, the number of projected LOLHs will remain comfortably below DOE's benchmark for reliability over the next decade (so long as planned resource additions roughly approximate current expectations).[31] Indeed, even if actual resource additions fall *well* below projections, it will be more than six years until the number of LOLH hours in a year *may* exceed DOE's own standards.[32] Put plainly, the WECC-Rocky Mountain Region is expected to meet

[31] WECC's analysis indicates that if 85% of planned generation is built, there will be only four LOLH hours in the Rocky Mountain region in the next 10 years (20 LOLHs below DOE's threshold). *See 2025 Western Assessment Supplemental Information*, WECC [https://feature.wecc.org/warasupplemental/index.html] (last visited April 29, 2026); U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid 4 (July 2025), https://www.energy.gov/ sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY %207%29.pdf.

[32] Even in a scenario where only 67% of currently planned generation is built, it is not until 2032 that WECC projects a possibility of more than 2.4 LOLH hours in a single year. *See 2025 Western Assessment Supplemental Information*, WECC ([https://feature.wecc.org/warasupplemental/index.html] (last visited April 29, 2026).

DOE's reliability benchmark for years to come without Craig 1. The region is projected to add sufficient generating capacity to meet demand, and NERC does not expect any hours—now or in the next several years—when there will not be enough electricity to serve customers. The evidence DOE relies upon confirms that no resource adequacy concerns are likely to appear in the region until well into the 2030s.

Keeping 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. Moreover, given that operating Craig Unit 1 ***now*** depletes the fuel stockpile for Craig Units 2 and 3, the Order's actions today may ***create*** reliability concerns that would not exist were Craig Unit 1 to shut down as originally scheduled.[33]

2. Keeping Craig Unit 1 Open Does Not Best Address Concerns in DOE's Targeted Regions

The Order also cites reliability concerns specifically for the WECC Basin and Northwest subregions on one hand, and for the United States as a whole on the other. Order at 3–5. Even if those speculative future conditions could constitute an

[33] DOE also predicates its emergency in part on the WECC-Rocky Mountain subregion's alleged "challenges from an aging thermal resource fleet, which can lead to unplanned outages, exacerbated by supply chain issues, and vendor availability." Order at 3 (citation omitted). DOE's citation, however, is incorrect: the 2025 LTRA does not cite the age of the subregion's thermal fleet as an operational and planning issue. Rather, the LTRA identifies supply chain issues, unplanned discovery work, and vendor availability for repairs at both thermal and hydropower sites as a concern for the region. 2025 LTRA at 161. Moreover, 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.

"emergency" under Section 202(c)—they cannot—Craig Unit 1 is located in the WECC-Rocky Mountain region, and its continued operations cannot reasonably be expected to resolve reliability concerns (also years away) in far-flung locations. As noted, over a dozen of Tri-State's rate-paying Utility Members in New Mexico and Nebraska are located outside of the WECC-Rocky Mountain emergency area, but as owners of Tri-State remain obligated to pay for the costs of compliance despite no emergency being identified in the regions they serve.

DOE's failure to bridge this gap is especially problematic given that the renewed Order altered the geographic framing of the asserted emergency. Having adjusted the relevant assessment area, DOE had ample opportunity to explain how Craig Unit 1 is best suited to address locations of concern, yet it did not.

B. The Order is Procedurally Inadequate on Both Constitutional and Statutory Grounds

Agencies must abide by both constitutional and statutory procedural safeguards before they act. The Fifth Amendment's Due Process Clause guarantees that no person shall be "deprived of life, liberty or property" by the federal government "without due process of law." U.S. Const. amend. V. At its core, due process requires notice and an opportunity to be heard before the government takes action affecting protected interests. *Memphis Light, Gas & Water Division v. Craft*, 436 U.S. 1, 19 (1978). This principle applies across regulatory regimes where hearings are generally required before agencies impose obligations or alter rights. Similarly, where a statute creates specific procedural requirements before it can take action, failure to follow these requirements renders the agency action arbitrary and

capricious. *See Safari Club International v. Zinke*, 878 F.3d 316, 325 (D.C. Cir. 2017) ("A disputed action also may be set aside as arbitrary and capricious if the agency has acted 'without observance of procedure required by law.'") (citing 5 U.S.C. § 706(2)(D)).

The Order violates both constitutional due process and the procedural requirements of Section 202(c)(4)(B)'s consultation and condition-incorporation requirements. These procedural failings render the Order unlawful.

1. The Order Violates Petitioners' Constitutional Due Process Rights

Under the FPA, most Commission (*i.e.*, FERC or DOE) actions—such as rate changes or interconnection orders—cannot take effect without a prior hearing. *See generally* 16 U.S.C. §§ 824a(b), 824a(e), 824a-1(a), 824a-3(f), 824a-4, 824b(a)(4), 824c(b), 824d, 824e, 824f, 824i(b), 824j, 824j-1, 824k, 824m, 824o, and 824p. Section 202(c) orders are unusual in that they may be issued without any prior hearing, reflecting their purpose as a short-term emergency tool meant to address fast-moving and unexpected situations. *See Fuentes v. Shevin*, 407 U.S. 67, 90–91 (1972) (holding that to justify postponing notice and opportunity for a hearing before deprivation of a property interest on basis of an "extraordinary situation," the situation must be "truly unusual.").

However, "[t]here is a relation between the kind of emergency and nature of the solution." *Pa. Gas & Water Co.*, 427 F.2d at 577. Where a hearing is feasible, its absence deprives Petitioners of due process. *See South Allegheny Pittsburgh Restaurant Enterprises, LLC v. City of Pittsburgh*, 806 Fed. Appx. 134, 139–41 (3d

Cir. 2020) (holding that the manifest lack of a qualifying emergency meant that order shutting down under-21 nightclub violated plaintiff's procedural due process rights); *Chalkboard, Inc. v. Brandt*, 902 F.2d 1375 (9th Cir. 1989) (suspension of daycare employees' licenses without pre-deprivation process because of asserted categorical emergency violated procedural due process rights); *Miller v. Campbell Cnty.*, 945 F.2d 348, 353 (10th Cir. 1991) (finding emergency insufficient to avoid need for pre-deprivation hearing when two months elapsed between notice that plaintiff's homes were uninhabitable and date of planned evacuation, but concluding that sufficient pre-deprivation hearing opportunities had occurred).

The Order's emergency does not rest on an urgent and immediate need for additional generation to address a specific incident or event such as unusually extreme weather. Rather, the Order's purported emergency is based on broader concerns about the sufficiency of generation capacity and reliability in the WECC–Rocky Mountain assessment area over time and in the future. Because the Order does not demonstrate an immediate crisis, it cannot justify dispensing with the pre-deprivation hearing requirement. Petitioners, however, have received no such process. Thus, they were deprived of their constitutional right to notice and a hearing before the Order came into effect.

Petitioners identified this Constitutional deficiency in their prior request for rehearing. But rather than accord Petitioners due process, DOE simply issued this new Order with no additional process and with no explanation for why no process was required. Even if the initial order could be defended as emergent, the second cannot.

Having received notice of the due-process defect and having had ample time to address it, DOE's decision to reissue a materially identical order without any procedural safeguard constitutes a discrete constitutional violation and is itself arbitrary and capricious.

2. DOE's Failure to Engage with the EPA Renders the Order Invalid

Section 202(c)(4)(B) mandates that DOE "consult with the primary Federal agency with expertise in the environmental interest protected by" the laws or regulations waived by a renewed order and include any conditions mandated by that agency in the order, which must be "made available to the public." 16 U.S.C. § 824a(c)(4)(B). Similarly, while DOE "may exclude such a condition from the renewed or reissued order if it determines that such condition would prevent the order from adequately addressing the emergency necessitating such order[,]" DOE must provide a public explanation of this lack of condition in the order. *Id.*

This consultation requirement is both mandatory and substantive. After all, Congress empowered DOE to take extraordinary action by extending a Section 202(c) order only *after* DOE has been made aware of the environmental impacts of renewing an order. *Cf. Center for Biological Diversity v. Zeldin*, --- F.4th ---, 2026 WL 850257, at *17–18 (D.C. Cir. Mar. 27, 2026) (holding that programmatic consultation did not alleviate burden of EPA to directly consult with National Marine Fisheries Service under Endangered Species Act because planned action could affect species under NMFS's jurisdiction). The FPA's direction to "consult" with relevant stakeholders obligates DOE to engage in a "meaningful exchange of information[.]" *California*

Wilderness Coal. v. U.S. Dep't of Energy, 631 F.3d 1072, 1086 (9th Cir. 2011) (finding DOE failed to "consult" with the states as required by FPA Section 216).[34]

DOE does not identify ***any*** agency it consulted in promulgating the Order. At the very least, EPA, the entity that administers the Clean Air Act and other statutes most directly relevant to Craig Unit 1 and which approved Colorado's Regional Haze State Implementation Plan (of which the closure of Craig Unit 1 was a part), should have been consulted. The Order, however, does not describe any consultation with EPA and thus contains no indication that DOE complied with an explicit statutory element of a lawfully renewed Section 202(c) order. That alone renders it unlawful. And the defect is not just procedural, but substantive. Meaningful consultation with the EPA, for instance, would inform DOE about the incompatibility of keeping Craig Unit 1 open with Colorado's federally-approved emissions plans and the impact of regulatory uncertainty on utilities' long-term planning around the country, as well as inform how DOE balances different options, and help identify the best alternative as required by Section 202(c).

C. The Order Failed to Limit Emergency Relief to What Is Necessary to Address the Asserted Emergency and Did Not Consider Reasonable Alternatives

Section 202(c) authorizes only those extraordinary measures that are necessary to resolve the emergency at hand, and it requires the Secretary to exercise

[34] The District Court for the District of Columbia recently held that a "late Friday afternoon, three-sentence email exchange between staffers" was insufficient to qualify as "consulting" another agency. *Miot v. Trump*, No. 25-cv-02471 (ACR), 2026 WL 266413, at *22 (D.D.C. Feb. 2, 2026), *cert. granted before judgment*, No. 25-1084, 2026 WL 731087 (U.S. Mar. 16, 2026).

judgment in selecting the course of action that will best meet that emergency and serve the public interest. 16 U.S.C. § 824a(c)(1)–(2). Those requirements impose meaningful limits on DOE's authority, including an obligation to confine any order to what is actually required to address the asserted emergency. The Order fails this threshold requirement. Rather than identifying a specific, imminent reliability problem that necessitates continued operation of Craig Unit 1, DOE imposes a sweeping mandate—of significant scope, duration, and operational rigidity—without explaining why that measure is necessary to address the conditions it cites. By failing to limit emergency relief to what is demonstrably required, the Order exceeds the narrow authority Section 202(c) confers and is arbitrary and capricious.

Lack of necessity is confirmed by DOE's failure to consider reasonable alternatives. Section 202(c) requires the Secretary to exercise "judgment" and select only those measures that "will *best* meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1) (emphasis added). Implicit in this mandate is the recognition that alternatives be considered and ruled out. Having been on notice—both in Petitioners' prior rehearing request and in the intervening months—that alternatives existed, DOE's failure to evaluate them in reissuing the Order independently renders the decision arbitrary and capricious.

DOE should have conducted and disclosed an analysis showing why the path selected is the "best" course forward, particularly in light of the potential 2034 time-horizon of the asserted emergency. *See Michigan v. EPA*, 576 U.S. 743, 753 (2015) (holding that "reasonable regulation ordinarily requires paying attention to the

advantages and the disadvantages of agency decisions"). This is consistent with the emergency nature of the powers contained in Section 202(c), which should not be exercised where "alternatives offered a more confined solution" to the emergency at issue.[35] *Pa. Gas & Water Co.*, 427 F.2d at 577 (considering analogous powers under the Natural Gas Act); *see also Farmers Union Cent. Exchange, Inc. v. FERC*, 734 F.2d 1486, 1511 (D.C. Cir. 1984) ("It is well established that an agency has a duty to consider reasonable alternatives to its chosen policy, and to give a reasoned explanation for its rejection of such alternatives.") (citation and footnote omitted).

As with DOE's first order, the Order reflects no consideration of alternatives, let alone justification for mandating that Craig Unit 1 remain active over other options, and is thus contrary to law and arbitrary and capricious. This failure is especially indefensible here because Petitioners specifically identified alternative approaches in their prior request for rehearing.[36] And an "emergency" occurring eight or more years from now can be solved by any number of means: more generation, more efficient use of existing generation, load flexibility, etc. DOE nevertheless

[35] DOE regulations for utilities applying for a Section 202(c) order to override environmental regulations require the utility to provide extensive information related to operations and alternative courses of action. *See* 10 C.F.R. § 205.373(g)–(i) (mandating that applicants provide information concerning "conservation or load reduction actions," "efforts . . . to obtain additional power through voluntary means," and "[a] listing of proposed sources and amounts of power necessary from each source to alleviate the emergency and a listing of any other 'entities' that may be directly affected by the requested order.").

[36] Request for Clarification and Rehearing of Order No. 202-25-14 at 31. Petitioners identified the possible alternatives of: (1) DOE and/or FERC "proceeding through the rulemaking process pursuant to section 403 of the Department of Energy Organization Act, 42 U.S.C. § 7173, to devise a plan to ensure reliability through a more fulsome, consultative process[;]" and (2) DOE "evaluat[ing] whether it had authority to take proactive action to insure that 'new resources' in the region are not 'significantly delayed.'"

reissued a materially identical order months later without assessing those alternatives or explaining why they were inadequate. Whatever urgency DOE might initially claim, it cannot excuse reissuing a materially identical order without engaging with the alternative approaches identified by Petitioners and explaining why mandating that Craig Unit 1 remain active is the "best" measure to address this long-term reliability concern across the region described in the Order.[37]

Moreover, the long-term nature of the "emergency" articulated by DOE reinforces the need to consider alternatives and broadens the scope of what must be considered. While the "menu" of emergency responses to a sudden and unexpected crisis caused by natural disaster may be limited, the menu of policy options to address reliability concerns eight years in the future is not.

Similarly, DOE's need to consider alternatives is particularly important given Craig Unit 1's status. Craig Unit 1 is an older, uneconomic unit. Due to its long-planned retirement, Craig Unit 1 has experienced years of prudently deferred maintenance and therefore faces particularly high costs to restore and maintain operations compared to possible alternatives. The Order further fails to consider how mandating Craig Unit 1's continued operation interferes with Petitioners' ability to invest in or use other, more economic generation capacity and therefore undermines the very ends that it purports to advance. As previously discussed, the Axial Basin

[37] That Craig Unit 1 has been dispatched since Order No. 202-25-14 was issued does not demonstrate that keeping it in operation and available for dispatch either responds to DOE's asserted "emergency" in any way, or that it is the *best* such response when alternatives are considered (none were). SPP's decision to call on the tools in its toolbox is unrelated to whether DOE's decision to mandate that Petitioners place the tool in its toolbox is reasonable or justified by its Order.

generating facility relies on the same transmission infrastructure as the Craig units. That infrastructure is already congested; when all three Craig units are operating, Craig Unit 1's continued operation could interfere with the ability of new alternatives like Axial Basin to provide economic power to the grid.

In the absence of such consideration, and disclosure of a valid rationale, Petitioners and the public "cannot weigh the merits of an agency decision nor compare it to other alternative actions[.]" *Rocky Mountain Wild v. Bernhardt*, 506 F. Supp. 3d 1169, 1187 (D. Utah 2020). The Order does not discuss why Craig Unit 1's continued operation was selected as the "best" solution to the described conditions, or if alternatives were considered, what those alternatives were, and why any considered alternatives were discarded. Thus, it is contrary to law and an arbitrary and capricious exercise of agency authority.

D. The Order Improperly Usurps the Role of State and Local Governments, Utilities, and Markets in Resource Adequacy Planning

Keeping an aging coal plant online, 90 days at a time, cannot resolve resource shortfalls eight years from now. But developing and implementing a plan to build more generation, and executing on that plan, can. This is what Petitioners—along with other utilities and state and local regulators—aim to do, and are doing. Yet, the Order interferes with these efforts: DOE's approach disrupts a complex ecosystem that includes utility-led resource planning and various layers of supervision and market mechanisms. The Order disrupts this process and makes determining and proceeding with the most efficient and effective solution more difficult.

The FPA imposes an express jurisdictional limit on the exercise of Section 202(c). FPA Section 201(b)(1), 16 U.S.C.A. § 824(b)(1), states that FERC—and, here, DOE exercising FERC's authority—has no jurisdiction "over facilities used for the generation of electric energy" unless such jurisdiction is specifically provided for. The "States' reserved authority[,]" *Hughes v. Talen Energy Marketing, LLC*, 578 U.S. 150 (2016), includes the "[n]eed for new power facilities, their economic feasibility, and rates and services," all of which "are areas that have been characteristically governed by the States." *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205 (1983). [38]

Under this framework, deciding whether Craig Unit 1 should remain operational belongs to its owners and subject to oversight by state governmental units. This reflects, among other things, the unique privileges and obligations of public utilities. *See Jackson v. Metro. Edison Co.*, 419 U.S. 345, 357 (1974) ("The nature of governmental regulation of private utilities is such that a utility may frequently be required by the state regulatory scheme to obtain approval for practices a business regulated in less detail would be free to institute without any approval from a regulatory body.").

[38] "Recognizing the careful balance that the FPA strikes between federal and state regulation" FERC recently found that "states retain exclusive authority over . . . the generation mix." *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61217, at P165 (2025). Long-term economic and planning decisions regarding Tri-State's resource mix had been approved by the State of Colorado through the 2020 and 2023 Energy Resource Plans. This jurisdictional division of responsibility and federal respect for state policymaking is also a policy of the FPA. *See Sierra Club v. FERC*, 145 F.4th 74, 81 (D.C. Cir. 2024) (respecting the role of state regulators); *NextEra Energy Res., LLC v. FERC*, 118 F.4th 361, 365 (D.C. Cir. 2024) ("[FERC] may regulate the transmission, but not the generation, of electricity[.]").

Utilities maintain the lead role in planning and constructing systems that ensure resource adequacy: both Tri-State and Platte River engage in reliability planning that balances system operational needs, cost and regulatory requirements.[39] In Colorado, the Colorado Public Utilities Commission (PUC) oversees resource adequacy planning for utilities under its jurisdiction, among other regulation and coordination of the electrical-generation sector.[40] Finally, other entities play a critical role. SPP, for instance, requires load-serving entities to maintain a certain level of Planning Reserve Margin capacity or face financial penalties, discouraging utilities from free-riding on other participants' efforts.[41]

For nearly a decade, Petitioners along with other co-owners have planned to retire Craig Unit 1 in line with resource adequacy planning. The Order attempts to supplant this process by substituting DOE's judgment for utilities' and Colorado's long-term resource planning decisions—all to address an "emergency" so diffuse that

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[39] Colorado's state government also plans around addressing shorter-term concerns. *See* , *e.g.*, Colo. Energy Office, Colorado Energy Assurance Emergency Plan (https://energyoffice.colorado.gov/climate-energy/colorado-energy-assurance-emergency-plan (last visited Apr. 29, 2026). The Colorado Energy Office (CEO) shares responsibility for energy assurance in the state with the Colorado PUC and state Division of Homeland Security and Emergency Management, with the PUC "primarily responsible for electric and natural gas energy emergencies." *Id.* To the extent the "emergency" is premised on shorter-term concerns, it arbitrarily fails to recognize the efforts made by utilities and state and local government to address them,

[40] *See generally* Colo. Dep't of Regulatory Agencies, PUC, Electric Resource Plans / Clean Energy Plan https://puc.colorado.gov/puc-home/energy-and-water/electric-resource-plans/clean-energy-plan (last visited April 29, 2026). The Colorado Energy Office also tracks resource adequacy in the state of Colorado. *See* C.R.S. 40-43-101 (requiring resource adequacy reports from Colorado utilities). The other states in which Tri-State operates also exercise varying degrees of oversight concerning Tri-State resources.

[41] SPP Open Access Transmission Tariff, Att. AA, § 14, https://www.spp.org/spp-documents-filings/?id=18162. SPP will begin imposing financial penalties in 2027.

its existence (or nonexistence) years from now is impossible to anticipate or cure. DOE's regulations recognize the distinction between the need to conduct planning and the existence of an emergency that results from inadequate planning. *See* 10 C.F.R. § 205.371 (an emergency may result "inadequate planning or the failure to construct necessary facilities" but such an emergency can be resolved through "firm arrangements"). The Order's failure to do so renders it contrary to law and arbitrary and capricious.

E. The Order is Inconsistent with the FPA's Statutory Objectives

Courts reject agency action as arbitrary and capricious if it is "inconsistent with the statutory mandate" or "frustrate[s] the policy that Congress sought to implement." *FEC v. Democratic Senatorial Campaign Comm.*, 454 U.S. 27, 32 (1981). The FPA was passed to advance various policy goals, including protecting consumers from "excessive rates and charges," *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 952 (D.C. Cir. 2016) (citation omitted)); "maintaining competition to the maximum extent possible[,]" *Otter Tail Power Co. v. United States*, 410 U.S. 366, 374 (1973); and encouraging the "orderly development of plentiful supplies of electricity . . . at reasonable prices." *NAACP v. FPC*, 425 U.S. 662, 670 (1976).

The Order, by compelling an uneconomic, aging unit to remain operational well beyond its planned retirement, upends Petitioners' ability to plan their systems and act with confidence in a competitive marketplace. Because the Order is at odds with

the statutory objectives of the FPA, it is contrary to law and arbitrary and capricious.[42]

CONCLUSION

Petitioners are committed to providing reliable and affordable electricity to communities across Colorado and the Mountain West, and have planned accordingly by developing a resilient portfolio of generation resources. Petitioners seek to work constructively with DOE and other agencies to advance shared reliability and affordability goals. Actions that unsettle long-standing, state-approved planning processes, however, risk undermining those objectives and imposing unnecessary costs on the very consumers these processes are designed to protect.

For these reasons the Order cannot stand. It effects an uncompensated taking of Petitioners' property, denies them due process, and fails to meet Section 202(c)'s statutory requirements, including that DOE articulate a valid emergency and that DOE's chosen mandate "best meet" the stated emergency. Moreover, the Order does not address the points raised in Petitioners' first rehearing request. Petitioners urge DOE to reconsider the Order.

[42] As discussed *supra*, the Order similarly contradicts President Trump's pledge to protect ratepayers from the effects of DOE's Section 202(c) orders. *See* Proclamation No. 11014.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon all parties below. Dated at Washington, D.C., this 29th day of April 2026.

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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 3-07
NERC 2026 Summer Reliability Assessment

2026 Summer Reliability Assessment

May 2026

RELIABILITY | RESILIENCE | SECURITY

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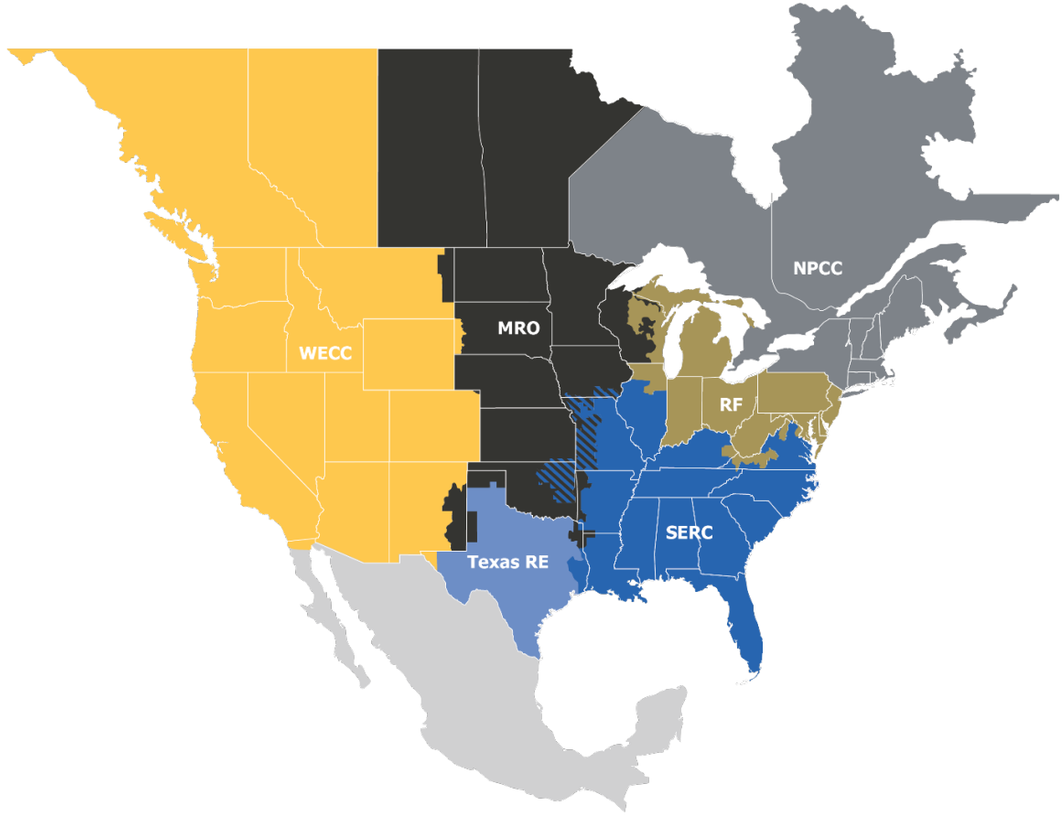
Preface

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 Assessment

NERC's *2026 Summer Reliability Assessment* (SRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the SRA presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment evaluates generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak demand hour and risk hours as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC highlighted in the *2025 Long-Term Reliability Assessment* (LTRA), which covers a 10-year horizon, and other earlier reliability assessments and reports.[1]

The 2026 Summer risk profile is marked by rising demand, significant generation growth in many areas, the prospect of challenging hydrological conditions, and the unpredictability of large loads, from both a forecasting and operational perspective. Multiple assessment areas have revised load forecasts downward from mid-2025 projections to account for the observed rate of completion for large load interconnections and the slower-than-expected pace at which some of those loads are coming on-line. Still, aggregated peak demand across all assessment areas has increased by over 11 GW from Summer 2025 projections that were set earlier in 2025. That level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. As important as the demand growth itself is the timing of the demand. The early arrival of summer heat and high demand in March has highlighted the risks associated with potential overlaps between spring maintenance outages and high demand. The importance of shoulder season supply-demand analysis continues to grow. The BPS has added slightly more than 58 GW of new resources year on year heading into the coming summer. This large resource addition has partly contributed to the improved risk outlook for some areas. The resource additions continue to include a high proportion of variable energy resources, supporting the prioritization of low-wind event preparation and probabilistic analysis of available energy at peak and risk hours.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for Summer 2026.

[1] NERC's long-term, seasonal, and special reliability assessments are published on the Reliability Assessments webpage.

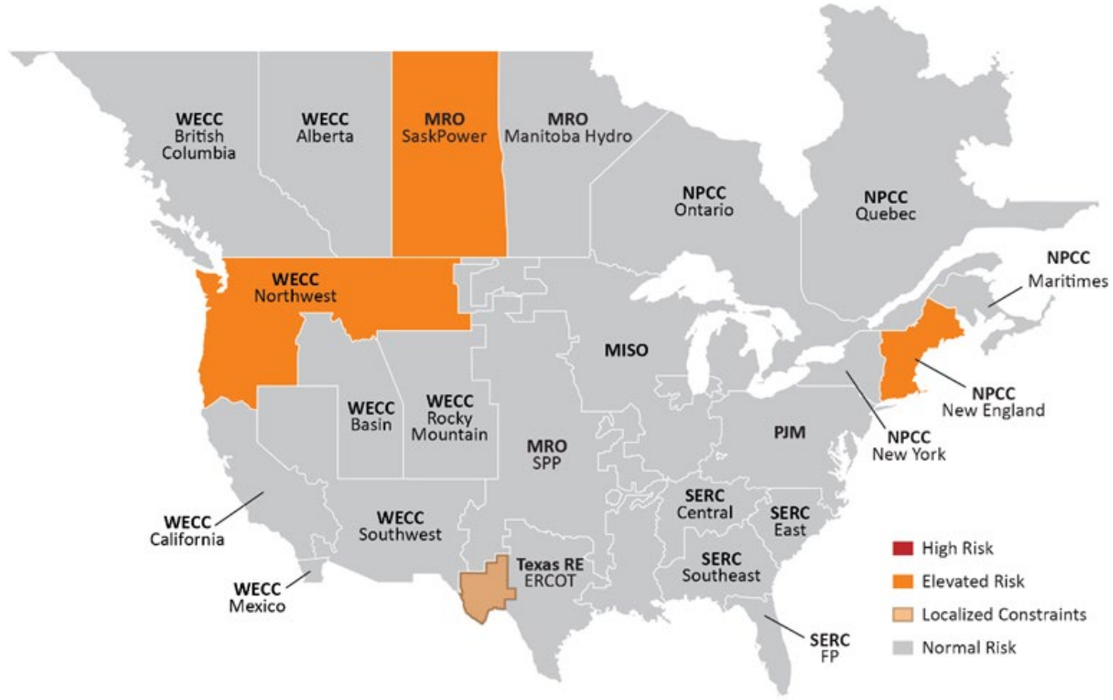
Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load conditions (see **Figure 1**). However, the following areas face elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or are subject to localized constraints that raise the risk levels of certain small areas within the broader system. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historical high outage rates as well as low wind or solar photovoltaic (PV) energy conditions:

- **NPCC-New England:** The New England area expects to have sufficient resources to meet the 2026 Summer peak demand forecast for normal conditions with an Anticipated Reserve Margin of 14%, just above the Reference Margin Level of 13%. New England may rely on non-firm imports to cover shortfalls even as the region has lowered its projected net firm imports by 836 MW from the previous year's projections to just 409 MW for the coming summer season. The decline in firm transfers is the main driver of the 2.6% year-on-year drop in anticipated resources. Non-firm imports, however, received a boost in January with the addition of New England Clean Energy Connect (NECEC), a symmetric monopole +/- 320 HVdc line from the Appalaches substation in Québec to a new substation in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and can import up to 1,200 MW into New England. Total internal demand for the 50/50 peak summer demand forecast is 25,228 MW, up marginally from the demand projections in the *2025 SRA* of 25,202 MW. Expected increases in electrification are the biggest driver in the region's demand forecast as well as slight weather normalization changes. Other resource types have slightly increased from last year within the region. Based on NPCC's most recent energy assessment, some use of New England's operating procedures for mitigating resource shortages is anticipated during Summer 2026 for the base case (50/50 normal demand). For the scenario with the highest peak load and reduced resources, the results were a cumulative loss of load expectation (LOLE) of <0.35 days/period, loss of load hours (LOLH) of <1.2 hours and expected unserved energy (EUE) of 628 MWh/period.
- **MRO-SaskPower:** SaskPower was at elevated risk in the *2025 SRA*, and resource adequacy metrics have declined slightly year on year for the upcoming summer period. Reserves have tightened from 34% to 29% due to a ~1.9% demand growth and no substantial change in resources. While SaskPower does not anticipate capacity constraints or reliability issues under normal conditions, extreme summer conditions may cause SaskPower to require maintenance rescheduling, short-term power transfers from neighboring utilities, and/or available demand-response programs. SaskPower's probabilistic in-house model showed an LOLH for an elevated risk scenario for the 2026 Summer season to be 0.09 hours; the month with the highest LOLH is September (0.05 hours).
- **WECC-Northwest:** The coming summer brings challenging hydrological conditions for regions in which hydropower makes up half or more of the supply fleet. Almost the entire Western Interconnection is in the grips of a persistent drought or in an area where drought development has a greater likelihood through the end of July. In Washington, for example, the snow water equivalent was at 52% of normal levels as of April 1 this year,[2] when snowpack typically reaches its peak. While the total water year supply is forecast to be nearly average in the Columbia River Basin, snowpack peaked at low elevation and melted early in the year. This has implications for the expected resources available to the Northwest, the generation mix for which is 55% hydropower. The region is contending with a nearly 5% increase in net internal demand from the *2025 SRA* and a nearly 2% drop in existing resources as well as a roughly 43% drop in expected Tier 1 resources. Though higher modeled net transfers are projected to contribute double what they were projected to last year (albeit with the increase largely attributable to a modeling change that accounts for economic transfers), this was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year. For this summer's assessment, WECC's study for the Northwest region resulted in small amounts of EUE, increasing from zero in the previous probabilistic assessment. The study also indicated an LOLH of >0.1 hours/period. The hour of greatest risk occurs around 6:00 p.m. in early September.
- **Texas RE:** The Texas Interconnection is widely at a normal risk level for Summer 2026 due to a 12% jump in anticipated resources for the summer period and a 4.5% decline in projected net internal demand. The lower demand forecast is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads. The results of ERCOT's Probabilistic Reserve Risk Model (PRRM) simulation indicate a low risk of declaring an energy emergency alert (EEA) during the risk hour (9:00 p.m. local time). However, the PRRM does not capture the pre-contingency load shedding risk in the Far West region of ERCOT's footprint resulting from rapid growth in both load and resources in this zone. Operational

[2] WSOR-WA

challenges could arise in Far West Texas during periods of high demand combined with low wind output and absence of solar generation. Under these conditions, transmission constraints in the Far West Texas zone may become binding. Price-responsive demand is expected to help reduce transmission congestion and maintain balance with supply during tight conditions. In addition, ERCOT and transmission service providers have developed mitigation measures to address these constraints by incorporating dynamic line ratings that account for solar irradiance along with ambient temperatures. Operating procedures that include involuntary load curtailment are in place to maintain system operating limits when needed. In September 2025, two new thermal cascading Interconnection reliability operating limits (IROL) became effective in the Far West region of ERCOT's footprint.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Normal	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

Other Key Reliability Highlights

- **Weather services are expecting an El Niño weather pattern to influence the weather outlook for the 2026 Summer period.**[3] El Niño weather patterns can suppress Atlantic hurricanes, which are a major reliability consideration for the Gulf Coast and Southeast United States. Temperature and precipitation forecasts for the coming summer show a higher likelihood of hotter-than-normal temperatures in the U.S. South and West and cooler-than-normal temperatures in the upper Midwest and parts of the Northeast (see **Figure 2**). Wetter-than-normal conditions could alleviate drought severity in the Gulf Coast, but the U.S. Northwest is still expected to see drier-than-normal conditions,[4] starting with sub-average snowpack[5] heading into spring that can impact the availability of hydropower units in a region that relies heavily on hydro-fueled electricity generation. In Canada, higher-than-normal temperatures are expected across the country, with the greatest likelihood residing in northeast and southwest Canada. Snowpack in Canada is generally in average conditions. British Columbia has experienced below-average snowpack in the southwest part of the province and above-average snowpack in the Columbia and Peace regions. The **Review of 2025 Capacity and Energy Performance** section describes actual demand and resource levels in comparison with NERC's *2025 SRA* and summarizes 2025 resource adequacy events.

- **A large influx of BPS resources over the past year has outpaced demand and is boosting reserves.** BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural-gas-fired generators. Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

- **Strong load growth continues in nearly all assessment areas.** Load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025. The level of growth exceeds the year-on-year rise of 10 GW that preceded Summer 2025. The largest increases are in parts of the U.S. West. WECC-Southwest saw the largest year-on-year increase in net internal demand at +9.5%, followed by WECC-Northwest with +4.6% and WECC-Basin with 3.8%. Overall, 19 out 23 assessment areas saw demand increases from the *2025 SRA* projections.

- **Large computational and other large loads pose operational challenges for the upcoming summer.** Recent events of unexpected disconnections underscore the need for operational readiness for the upcoming summer. For example, the Eastern and ERCOT Interconnections have observed load-reduction events with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction.[6] The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation, which caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying sizes reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue. NERC issued a Level 3 essential actions alert related to large loads[7] as well as a reliability guideline regarding risk mitigation for emerging large loads.[8]

- **Battery resource additions help maintain stable frequency on the grid.** Since last summer, over 16 GW of nameplate battery storage capacity has been added to the grid. Texas and the Western Interconnection continue to have the strongest growth in these resources. The *2025 State of Reliability* report noted an upward trend in frequency response capability that can be attributed to the addition of battery storage resources.[9] Charged battery storage resources can respond quickly to the abrupt decline in system frequency that occurs during disturbances and sudden imbalances, helping to maintain the nominal 60 Hz system frequency and prevent equipment damage and system instability. NERC's *2026 State of Reliability* report, to be published in June, will report on this continuing trend of improved grid frequency response.

[3] Climate Prediction Center: ENSO Diagnostic Discussion
[4] Climate Prediction Center: Seasonal Drought Outlook
[5] WSOR-WA
[6] *Incident Review: Considering Simultaneous Voltage-Sensitive Load Reductions*, NERC, January 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf
[7] NERC Level 3 Alert: Computational Load Modeling, Studies, Instrumentation, Commissioning, Operations, Protection, and Control
[8] Risk Mitigation for Emerging Large Loads
[9] NERC State of Reliability reports

- **The overlap of early summer heat and spring maintenance outages can lower operating reserves in the shoulder season and early summer.** March 2026 was the warmest March in the 132 years of recordkeeping in the contiguous United States.[10] The average temperature across the country was 9.4°F above the 20th-century average. Raising the average were at least 10 states in the U.S. West that had their warmest March on record. The widespread heat-dome bled across the border and infused unseasonably warm temperatures into British Columbia as well, with at least five communities in the southern part of the province recording their warmest overnight low temperatures ever observed for the month of March.[11] Some assessment areas in the West have reported that extended lead times for hydro unit overhauls and the limited availability of engineering, procurement, and construction contractors are contributing to longer outage durations that complicate maintenance planning. Longer-than anticipated maintenance periods, in turn, can lead to higher-than-expected calls on electricity imports from neighboring regions. In other areas, there are older sites that may require extensive overhauls, such as generator rewinds that can keep resources out of service for extended periods of time, potentially longer than planned, as discovery work manifests into additional maintenance.
- **Impacts of wind drought (i.e., low wind periods) pose a risk to reliability.** Areas of the North American electric grid continue to experience periods of wind drought or steep wind down-ramping, and installed wind capacity across the BPS is up by 3% year on year. It is critical that areas experiencing these events continue to maintain operational awareness, including accurate forecasts and appropriate operating procedures to mitigate these periods. Additionally, the impact of wind ramp events—particularly down ramp—must be anticipated and planned for such that appropriate resources are ready to replace the energy lost during these conditions. It is not uncommon for areas to experience several thousands of megawatts of wind energy coming off-line during these events. For example, in January 2025, MISO experienced a wind reduction event of 1,600 MW per hour, which also coincided with a solar ramping down and evening load ramp up.[12]

[10] Assessing the U.S. Temperature and Precipitation Analysis in March 2026 | News | National Centers for Environmental Information (NCEI)
[11] Blazing hot: 1,000+ records fall in brutal March heat wave - The Weather Network
[12] *Incident Review: Preparing the Grid for Wind Energy Droughts and Down-Ramps*, https://www.nerc.com/globalassets/our-work/reports/event-reports/incident_review_low_wind_event.pdf

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- Reliability Coordinators (RC), Balancing Authorities (BA), and Transmission Operators (TOP) in the elevated-risk areas identified in the key findings should take the following actions:
  - Review seasonal operating plans and protocols for communicating and resolving potential supply shortfalls in anticipation of above-normal demand levels.
  - Consider the potential for higher-than-anticipated forced generator outage rates in operating plans due to plant age, operating patterns, or limited pre-seasonal maintenance availability.
  - Employ conservative generation and transmission outage coordination procedures and operate conservatively commensurate with long-range weather forecasts to ensure adequate resource availability. Past system performance reviews noted that early declaration of conservative operations in advance of extreme conditions helped reduce grid congestion and enhance transfer capability.[13]
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand-side management mechanisms called for in operating plans.
- RCs, TOPs, and BAs should review outage coordination processes and policies and consider if adjustments are needed to account for potential above-normal temperatures to extend beyond the traditional summer season. Those same entities should also be prepared to adjust operating plans in early summer for delayed return-to-service of BPS generation and transmission elements.
- BAs should consider the following steps to reduce risks to system balance from conditions that could affect resources or demand for the upcoming summer:
  - **Wind energy:** In areas with ample wind resources, employ proactive operating plans for low-wind events and wind down-ramping events when weather conditions are developing or are uncertain.
  - **Hydro availability and output:** In areas with a predominance of hydro generation in the supply stack, consider in operating plans the potential for low water conditions to affect hydro generation. Coordinate a sufficient supply of alternative resource types and ready necessary demand-side management mechanisms if needed.
  - **Large computational load disconnects:** Be aware of the potential for load reductions from large computational loads in response to system conditions and include conservative practices in operating plans. Refer to NERC's incident reviews for details of recent events involving voltage-sensitive data centers and cryptocurrency mining facilities.[14]

[13] See notable operations practices in Appendix 2 of the *January 2025 Arctic Events System Performance Review | FERC, NERC, and its Regional Entities: A Joint Staff Report*, April 2025.

[14] See Incident Review section of NERC Event Analysis page.

Risk Highlights

Summer Temperature and Drought Forecasts

During the summer season, heat drives peak electricity demand as consumers use more electricity to cool their homes and businesses. March of this year brought record heat for the month and exacerbated concerns over persisting or worsening drought, concerns that gained even more traction following an underwhelming snowpack peak in the Pacific Northwest in April. Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Peak demand hours may not coincide with the highest risk hours in the summer as the resource mix shifts during a 24-hour cycle, particularly when there are prolonged periods of above-normal temperatures. Coordinating pre-season preparations and maintenance remains critical to avoiding forced outages where possible and mitigating risks to BPS reliability.

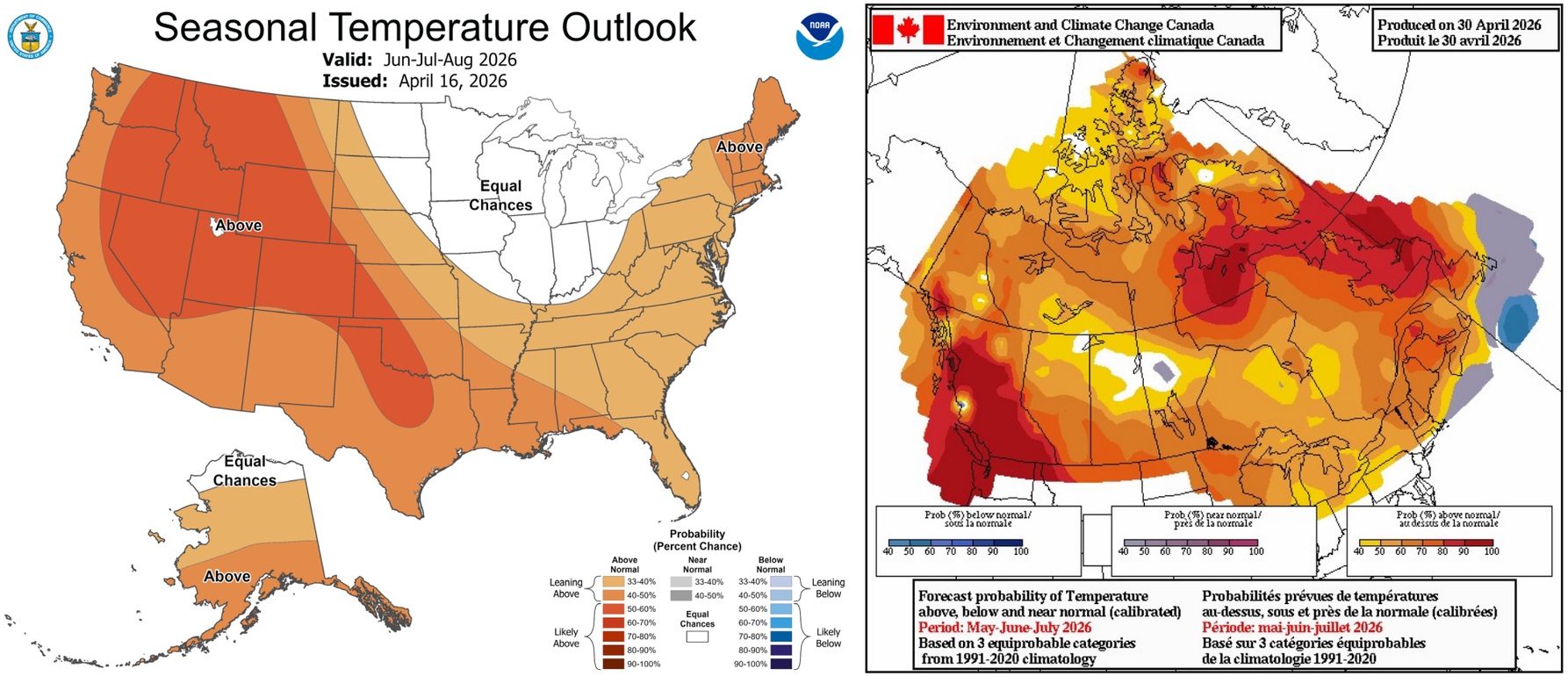


Figure 2: United States and Canada Summer Temperature Outlook[15]

[15] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Demand and Resource Trends

Strong load growth from data centers and large loads continues to propel North American electricity demand forecasts higher, with an increase in peak demand since Summer 2025 exceeding the change observed from the prior summer. Resource additions over the past year have outpaced demand growth, contributing to higher reserves.

Summer Electricity Demand Continues to Rise

Aggregated peak demand across all assessment areas has increased by over 11 GW since 2025, comparing forecasted net internal demand (NID). This measure of peak demand is inclusive of the benefits from demand response, which offset total internal demand (TID) (see **Figure 3**). NID continues to accelerate. The year-on-year increase in peak demand for Summer 2025 was 10 GW—more than double the increase in peak demand from 2023 to 2024.

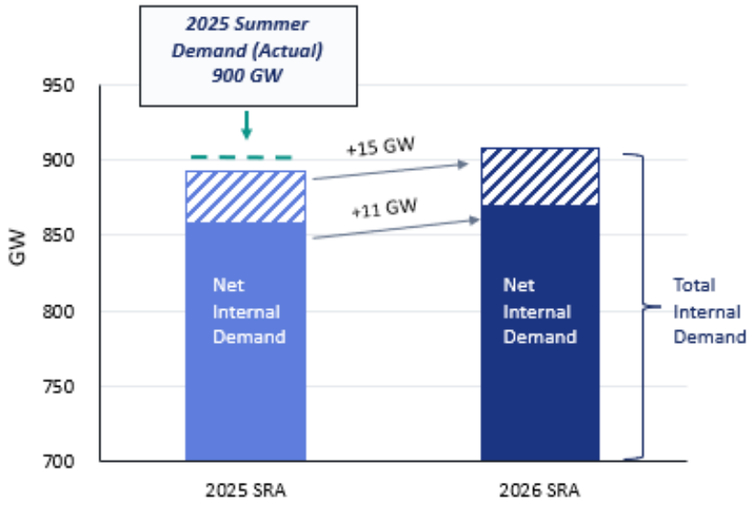


Figure 3: BPS Total and Net Internal Demand
Aggregated Peak Demand from All Assessment Areas

Nearly all assessment areas are experiencing demand growth. Peak demand forecasts have risen since 2025 in 19 of the 23 assessment areas. The largest increases are in parts of the U.S. West. In Canada, all provinces are forecasted to have increases of 2% or more except for Québec, which is forecasting a 1% decline in peak demand. Texas RE-ERCOT is a notable exception to the growth trend this summer. TID in ERCOT declined by 1.9 GW (2.3%), largely driven by updated forecasting that accounts for observed behavior of large computational loads at peak demand. NID, which includes demand response, is 3.7 GW lower (4.6%) compared to last summer because more data centers can be curtailed by grid operators when needed to prevent grid emergencies. A summary of assessment area demand changes is provided in the **Net Internal Demand** section.

More Resources Available for Summer

BPS resources for the upcoming summer have jumped by over 58.5 GW with the addition of substantial amounts of solar PV and battery resources and some new natural gas-fired generators (see **Figure 4**). Sixteen of the 23 assessment areas have increased available capacity ahead of summer. Solar PV is the leading type of new resource (+30.5 GW nameplate additions, contributing an additional 16.4 GW of capacity at peak demand). Battery additions account for 14.7 GW in increased on-peak capacity. These resources also help balance variability in solar PV and wind resources, as well as demand fluctuations. Other capacity changes since 2025 amounting to 19 GW are attributed to resource additions of other types as well as changes to generator availability (e.g., completion of extended nuclear generator outages, changes to maintenance plans). The addition of solar and batteries, which perform well under more hours of the day during summer than they do in winter, is helping to meet escalating demand and increase reserves in many assessment areas.

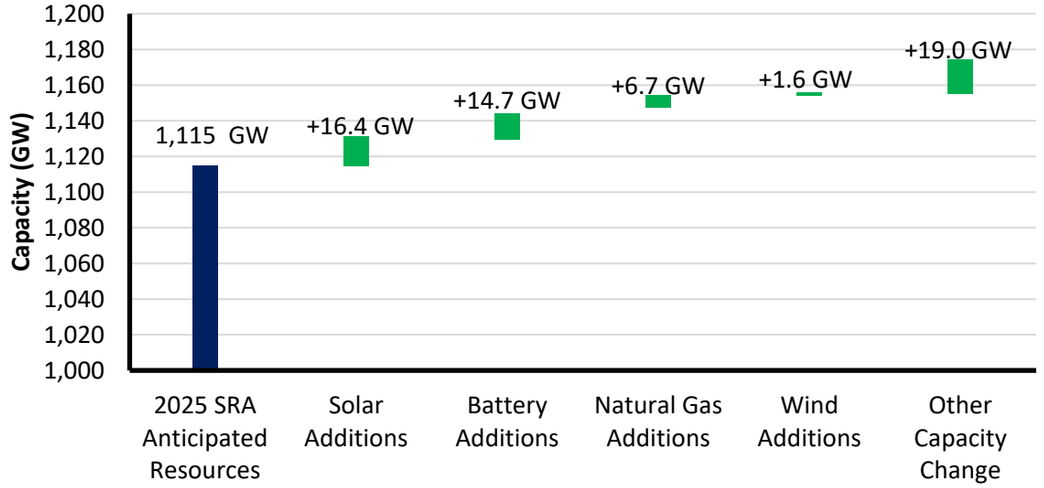


Figure 4: Summer BPS Resource Capacity Change Since 2025

Generators Extended by Federal Power Act Emergency Authority

Starting in 2025, the Department of Energy (DOE) issued emergency orders, pursuant to section 202(c) of the Federal Power Act, requiring that six different power plants maintain operational availability. Thermal generators with diverse fuel sources can be an important electricity resource, especially during winter when solar PV and battery resources are less capable compared to summer months. The DOE has since renewed those emergency orders, extending availability requirements into late May and early June (see **Table 1**). These plants and units were not incorporated into the anticipated resources of their corresponding assessment areas for Summer 2026 but may be called upon within the orders' time frames.

Table 1: Power Plants Impacted by Department of Energy 202(c) Orders in 2025 and 2026

Assessment Area	Plant Name	Nameplate Capacity (MW)	Summer Capacity (MW)	DOE 202(c) Order Expiration
MISO	J.H. Campbell	782	760	5/18/2026
MISO	F.B. Culley Generating Station	104	90	6/21/2026
MISO	Schahfer Generating Station	847	722	6/21/2026
PJM	Eddystone Generating Station	782	760	5/24/2026
WECC-NW	Centralia Generating Station	730	670	6/14/2026
WECC-RM	Craig Station	446	427	6/28/2026

Risk Assessment Discussion

NERC assesses the risk of electricity supply shortfall in each assessment area for the upcoming season by considering Planning Reserve Margins, seasonal risk scenarios, probability-based risk assessments, and other available risk information. NERC provides an independent assessment of the potential for each assessment area to have sufficient operating reserves under normal conditions as well as above-normal demand and low-resource output conditions selected for the assessment. A summary of the assessment approach is provided in **Table 2**.

Table 2: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels • Probabilistic indices exceed benchmarks (e.g., LOLH of 2 hours or higher across the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with **normal resource scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours across the season) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under extreme peak-day demand with **normal resource scenarios**[2] (i.e., typical or expected outage and derate scenarios for conditions) • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under normal peak-day demand with **reduced resource scenarios**[3] (i.e., extreme outage and derate scenarios)
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible (e.g., LOLH below 0.1 hours across the season) • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1] The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2] **Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the peak demand.
[3] **Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4] Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Assessment of Planning Reserve Margins and Operational Risk Analysis

Anticipated Reserve Margins, which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins for seasonal risk scenarios of more extreme conditions are provided in **Table 3**.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	31.1%	21.6%	3.8%
MRO-Manitoba	13.2%	9.5%	4.3%
MRO-SaskPower	29.2%	23.2%	7.3%
MRO-SPP	26.8%	21.4%	3.8%
NPCC-Maritimes	83.8%	73.4%	53.3%
NPCC-New England	14.0%	4.0%	-0.9%
NPCC-New York	34.2%	15.0%	7.5%
NPCC-Ontario	32.4%	32.4%	12.3%
NPCC-Québec	34.5%	16.4%	7.3%
PJM	26.2%	16.1%	3.8%
SERC-C	18.9%	13.9%	5.6%
SERC-E	26.3%	17.4%	10.3%
SERC-FP	25.8%	20.7%	13.6%
SERC-SE	36.9%	33.1%	24.7%
TRE-ERCOT	67.9%	60.2%	20.4%
WECC-AB	32.3%	28.2%	9.1%
WECC-Basin	37.6%	34.9%	11.5%
WECC-BC	40.5%	40.0%	9.6%
WECC-Cal	55.6%	54.3%	17.0%
WECC-Mex	32.5%	25.5%	11.0%
WECC-NW	26.9%	25.2%	8.8%
WECC-RM	51.9%	49.2%	21.5%
WECC-SW	48.1%	44.7%	25.2%

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario charts in each

dashboard provide potential summer peak demand and resource condition information, as well as risk hour resource condition information for areas where the risk hour differs from the peak demand hour. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; more information about these dashboard charts is provided in the **Data Concepts and Assumptions** section.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 3**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in **orange** are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be on maintenance or forced outage during peak demand conditions. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's summer risk scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are summarized in **Table 4**. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincides with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of an EEA occurrence.

Energy Emergency Alerts

Extreme generation outages, low resource output, and peak loads similar to those experienced in wide-area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for Summer 2026. When forecasted resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ operating mitigations or EEAs to obtain the capacity and energy necessary for reliability. A description of each EEA level is provided below.

EEA Levels

EEA Level	Description	Circumstances
EEA1	All available generation resources in use	• The BA is experiencing conditions in which 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.
EEA2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy-deficient BA. • An energy-deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy-deficient BA is still able to maintain minimum contingency reserve requirements.
EEA3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum contingency reserve requirements.

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Planning Year 2026–2027 LOLE Study Report	MISO's values for LOLH and EUE are taken from the noted assessment report, where the annual LOLE was set at 1 day in 10 years or 0.1 LOLE but equated to 0.076 LOLE for the summer. For Summer 2026, LOLH is 0.235 hrs/year and EUE is 983.8 MWH/year for the Reference Margin Level. Expectations for load loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level.
MRO-Manitoba	2024 and 2025 NERC Probabilistic Assessment (ProbA)	Manitoba Hydro's probability-based resource adequacy risk assessments for the summer season display risk when hydro flow conditions are low and load is higher than expected. Based on the analysis that was conducted for the 2024 and 2025 ProbA, this risk was considered low as normalized EUE was less than 2 parts per million and LOLH was less than 0.2 hrs/year.
MRO-SaskPower	Probability-based capacity adequacy assessment Summer 2026	SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). LOLH equated to 0.09 hrs/season, and the month of highest risk has shifted from June to September, when the system experiences the largest uncertainties in load and generator availability forecasts. September risk makes up over 50% of summer season risk within this assessment area. SaskPower indicated that in extreme conditions, it may have to use short-term power transfers from neighboring utilities, maintenance rescheduling, and/or demand-response programs to prevent energy shortfall.
MRO-SPP	SPP East Assessment Area and 2024 NERC Probabilistic Assessment (ProbA)	Based on SPP East's probabilistic assessment and the 2024 NERC ProbA, risk observed in summer 2026 was minimal. Risk hours that materialized during simulations occurred during late afternoon and early evening periods and were driven by high demand and low wind conditions.
NPCC	NPCC conducted an all-hour probabilistic assessment that consisted of a base case and several more severe scenarios examining low resources and higher loads. The highest peak load scenario has a 7% probability of occurring.	NPCC Regional Entity assesses that there will be an adequate supply of electricity across the Regional Entity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Preliminary results of the probabilistic analysis by assessment area are below. NPCC anticipates releasing the assessment in May.
NPCC-Maritimes		The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes Area is not expected to require use of its established operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. The Maritimes Area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain a balance over the May–September summer period for all the scenarios modeled.
NPCC-New England		The preliminary results[16] of NPCC's probabilistic assessment indicate that use of New England's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages. Preliminary cumulative LOLE (days/season), LOLH (hours/season), and EUE (MWh/season) risks were reported as negligible over the summer May to September period for the expected load with expected resources scenario. Under an extreme scenario, the estimated cumulative LOLE risk is 0.343 days/period, with associated LOLH of1.178 hours/period and EUE of 628 MWh/period with the highest risk occurring in June, with some in July and August.

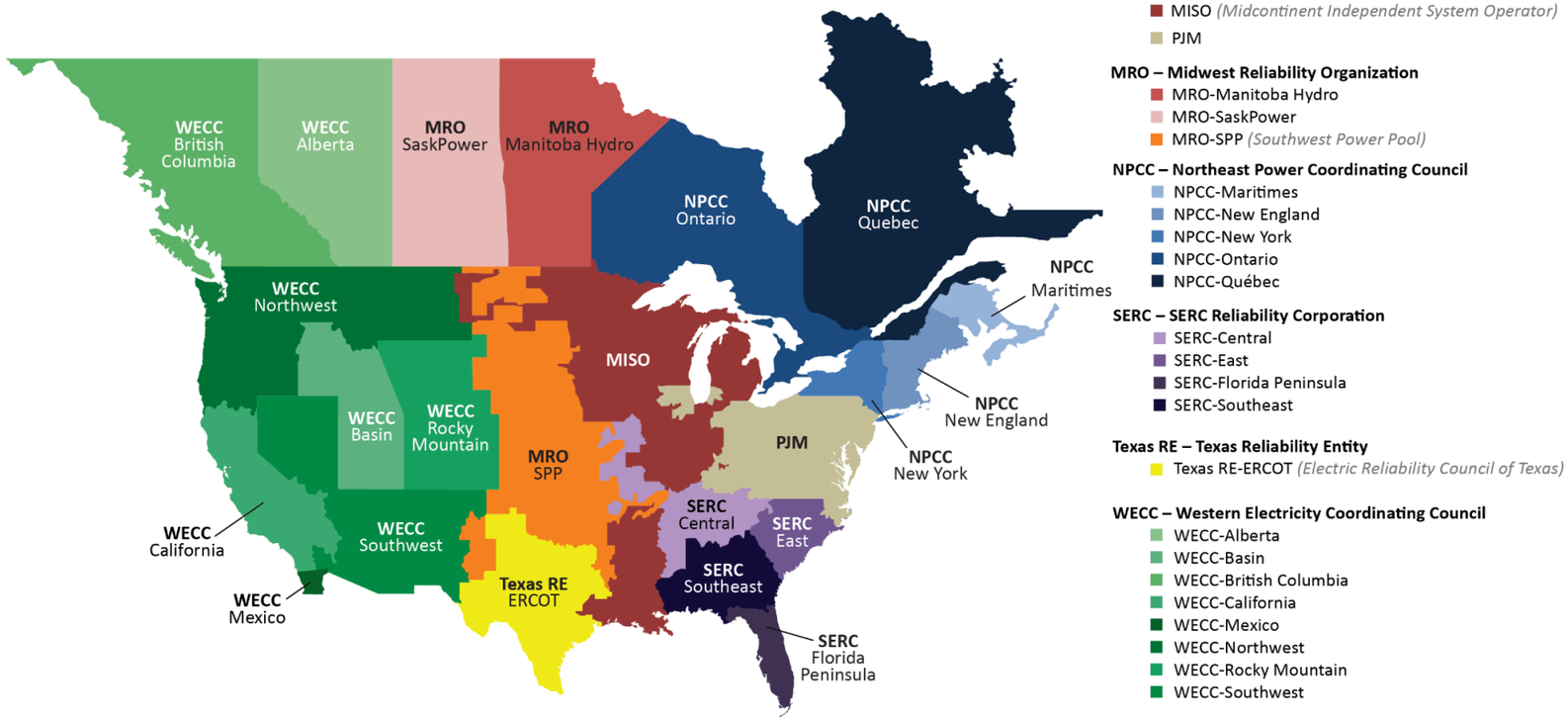
[16] Based on preliminary runs from March 31, 2026

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-New York		The preliminary results of NPCC's probabilistic assessment indicate that use of New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026 with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE, which is below elevated risk criteria under the scenario of highest peak load and reduced resource conditions; the estimated cumulative risk reached 0.655 days of LOLE, 2.004 hours of LOLH, and 1,262 MWh of EUE, with the greatest risks occurring in July and August.
NPCC-Ontario		The preliminary results of NPCC's probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.
NPCC-Québec		The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of its operating procedures designed to mitigate resource shortages during Summer 2026 based on a probabilistic-based assessment. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.
PJM	2023 PJM Reserve Requirement Study (RRS)	The RRS analyzed a wide range of load scenarios (low, regular, and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. During extreme high temperatures that can cause record demand, PJM anticipates the need for demand-response resources to help reduce load at times this summer. PJM is forecasting 26% installed reserves (including expected committed demand response), which is above the reserve requirement margin of 18.6% necessary to meet the 1-day-in-10-years LOLE criterion.
SERC	Probabilistic resource adequacy assessment for the 2026 Summer season	SERC performed a probabilistic resource adequacy assessment for the summer season (June–September) using the PowerGEM SERVM model. The analysis is based on an 8,760 hourly model with 5,375 Monte Carlo simulations per hour and incorporates data across 43 historical weather years (1980–2022), load forecast uncertainty, generator forced outages, power transfer between SERC assessment areas, and variable energy resource performance.
SERC-Central		Results from the summer 2026 probabilistic risk assessment indicate that resources will be sufficient to meet projected demand and do not exhibit any EUE or LOLH.
SERC-East		Simulations performed show that small amounts of EUE materialized in a single summer evening hour under a high-stress scenario involving elevated load, reduced solar output during the evening ramp, and coincident generator outages. The magnitude and frequency of the event are low and do not indicate a broader resource adequacy concern.
SERC-Florida Peninsula		No EUE or LOLH materialized within SERC-Florida Peninsula across all simulations, which resulted in an implied LOLE of approximately zero. These results indicate that available resources are sufficient to meet projected demand under modeled conditions.
SERC-Southeast		The probabilistic assessment did not identify any loss of load events for SERC-Southeast during the Summer 2026 season. EUE and LOLH were both zero across all simulation hours.
Texas RE-ERCOT	ERCOT probabilistic assessment using the PRRM	The simulation indicates low risk of having to declare an EEA for hour 21, the highest risk hour for the peak load day in August (which is also the expected summer peak load day) with a probability of declaring an EEA of 0.43%. This is categorized by ERCOT as "low risk" per its criteria of hourly EEA probability that is equal to or less than 10%. For the *2025 SRA*, ERCOT reported EEA declaration probability for hour ending 21 of 3.1%. The large decrease in EEA probabilities is due to the addition of 8,780 MW of BESS capacity in 2025 and 2,677 MW more as of March 2026.

Table 4: Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC	Probabilistic resource adequacy assessment for the 2026 Summer season	For the 2026 SRA, WECC, for the first time, performed a probabilistic resource adequacy assessment using the PowerGEM SERVM model based on an 8,760 hourly model that incorporates data across 43 historical weather years, load forecast uncertainty, generator forced outages, power transfers, and variable energy resources shapes. With this shift, WECC opted to default to the NERC defined Reference Margin Level and change its reporting to reflect the different data construct and reporting of results.
WECC-AB		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC–Basin		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-BC		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-CA		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-Mex		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-RM		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.
WECC-NW		WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
WECC-SW		WECC's probabilistic analysis showed no LOLH or EUE under a range of demand and energy availability conditions.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-peak reserve margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that is established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left **blue** column shows anticipated resources (from the **Demand and Resource Tables** section), and the **orange** column at the right shows the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables** section) and the extreme summer peak demand determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.





MISO

The Midcontinent Independent System Operator, Inc. (MISO) is a not-for-profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local Balancing Authority and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

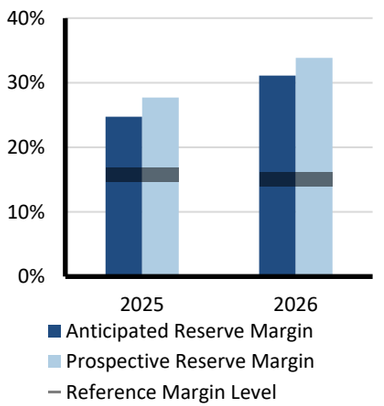
Highlights

- Although MISO's peak load has increased by 2.5 GW from the *2025 SRA*, MISO is not anticipating operational or reliability issues for the 2026 Summer season. Load growth is driven by increased projections of data center load and is expected to accelerate in 2027 and beyond, which may lead to increased reliability risk in the future if resource additions cannot keep pace with rising load forecasts.
- MISO's capacity resources have improved since Summer 2025, and new additions are made up of predominantly solar resource installations, along with smaller amounts of natural gas, wind, and battery storage resources. Solar resources are helping the system serve peak load but are shifting risk hours to later in the day where intermittent resource capabilities are low and temperatures are above expected conditions.
- MISO benefits from transmission connections with neighbors to meet extreme weather conditions, and reliance may increase when extreme conditions arise.

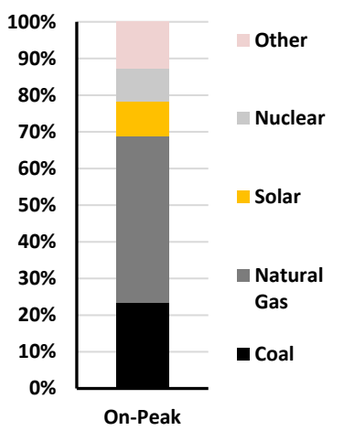
Risk Scenario Summary

Expected resources meet operating reserve requirements for assessed scenarios. Above-normal summer peak load combined with low resource conditions could result in the need to employ operating mitigations (e.g., load-modifying resources) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access demand-response resources when operating reserve shortfalls are projected.

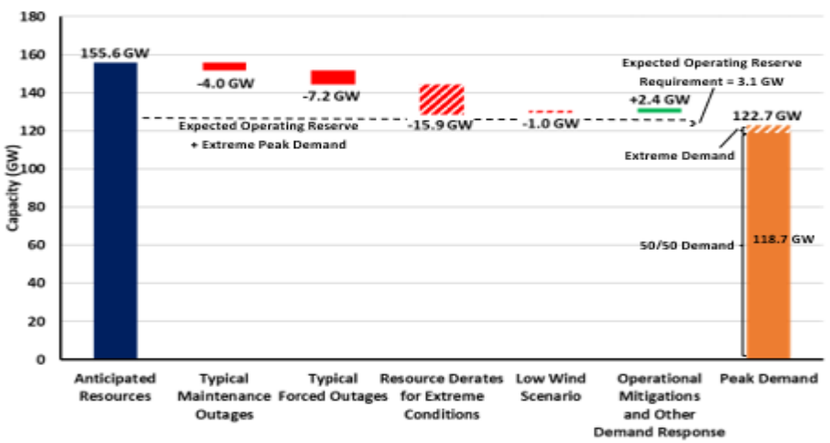
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand forecast (50/50) plus transmission losses.

Maintenance Outages: Rolling three-year average of maintenance outages that occurred during the summer (June-September) peak hour.

Forced Outages: Rolling three-year average of forced outages that occurred during the summer (June–September) peak hour.

Extreme Derates: Rolling three-year average of maintenance and planned outages that occurred across thermal resources during the summer (June-September) peak hour, plus a reduction in solar resource performance during the risk hour.

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme conditions.



MRO-Manitoba Hydro

Manitoba Hydro provides electricity to approximately 601,000 electric customers in Manitoba and provides approximately 291,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is a provincial crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

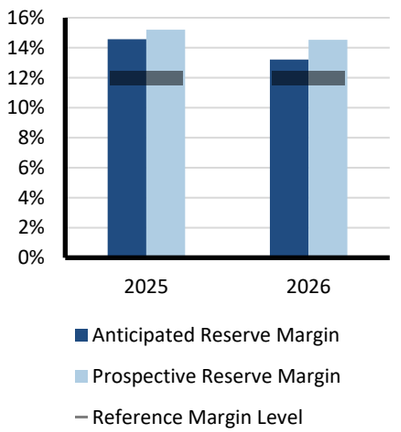
Highlights

- Manitoba Hydro is not anticipating any operational challenges or emerging reliability issues in its assessment area for Summer 2026.
- Manitoba Hydro's demand increase of 2.5% is driven primarily by population and economic growth, including electrification of a large industrial customer to reduce carbon emissions. Currently, new cryptocurrency operations cannot connect in Manitoba due to a moratorium.
- The 2024 ProbA for the 2026 load year shows an EUE of 4 MWh and an LOLH of 0.05 hours.
- Manitoba Hydro's reservoir storage conditions are below average, but winter snowfall has been above average, which should favorably impact spring runoff. The Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought. Manitoba Hydro expects to reliably supply its internal demand and export obligations, even if extreme drought develops through 2026–2027.
- Manitoba Hydro continues to monitor summer resource adequacy in the MISO area but does not believe that there are significant seasonal reliability issues in MISO or in other neighboring assessment areas that have potential to impact Manitoba Hydro operations for Summer 2026.
- The Anticipated Reserve Margin for Summer 2026 exceeds the 12% Reference Margin Level.

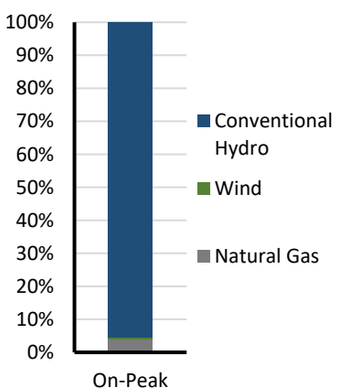
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

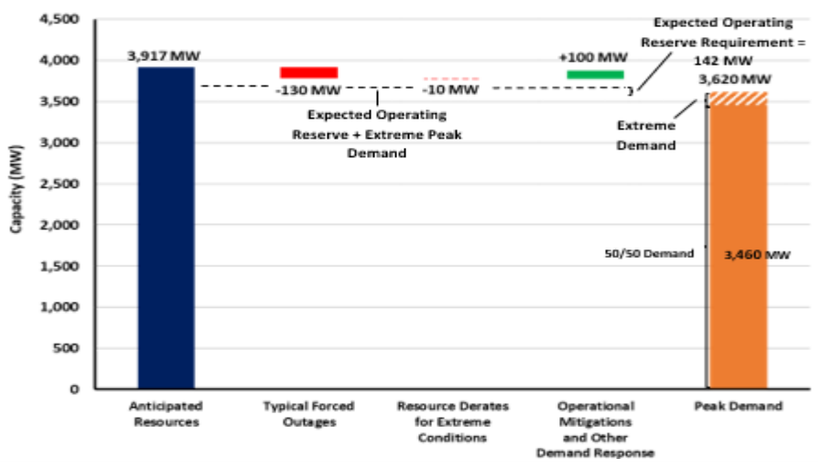
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: 50/50 Demand with allowance for extreme demand based on a 90th percentile extreme weather scenario of 36.0 C (96.8 F).

Forced Outages: Typical forced outages.

Extreme Derates: Summer wind capacity accreditation of 18.2% of nameplate rating based on MISO seasonal analysis. No further wind output derates based on experience; wind farms constitute less than 1% of Manitoba Hydro's available capacity.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; assume 100 MW of non-firm imports available.



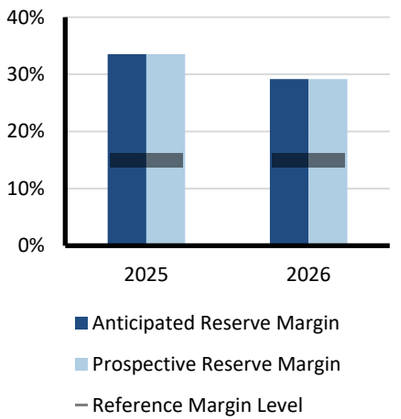
MRO-SaskPower

MRO-SaskPower is an assessment area that covers the Canadian province of Saskatchewan. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of just over 1.1 million people. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial Crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections. Overall, SaskPower operates nearly 14,816 circuit-km of transmission lines, 65 high-voltage switching stations, and 191 distribution substations. Peak electricity demand on the SaskPower system currently occurs during the winter season.

Highlights

- Although Saskatchewan is mainly a winter-peaking region, summer can also bring high electricity demand due to extreme heat.
- There is a 1.9% increase in TID from the *2025 SRA* projection. This growth is mainly driven by population growth in the province, expansion projects, reduced self-generation in the industrial sector, and increased electrification.
- SaskPower conducted a probability-based capacity adequacy assessment for the 2026 Summer season. This assessment considered uncertainties in load forecasts, wind forecasts, and forced generation outages to calculate the expected number of hours with energy deficiencies (LOLH). According to probabilistic in-house model, the LOLH for an elevated risk scenario for the 2026 Summer season is 0.09 hours, which is nearly in line with the 0.1 LOLH risk criteria NERC sets for the elevated-risk level. The month with the highest LOLH is September (0.05 hours).
- Based on the planned maintenances, typical forced outages from historical data, and expected renewable generation under the normal and extreme demand conditions, SaskPower does not anticipate any reliability issues during Summer 2026. Under extreme conditions, however, SaskPower may have to use short-term power transfers from neighboring utilities, maintenance outage deferrals, and/or demand-response programs to maintain sufficient supplies.

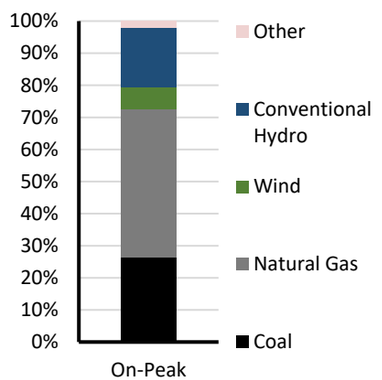
On-Peak Reserve Margin



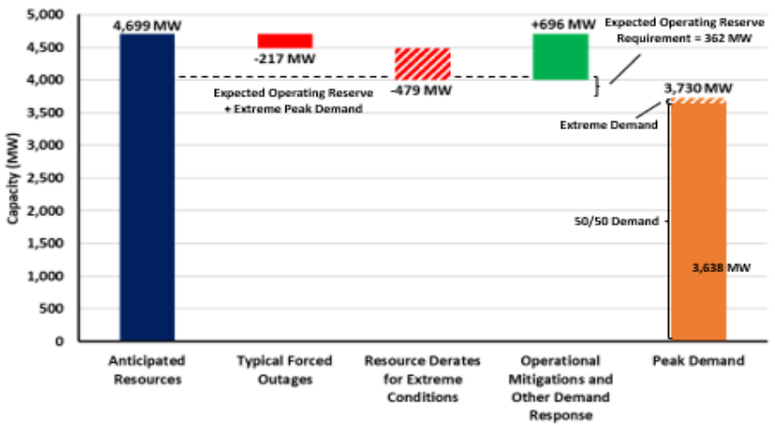
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand and outage conditions. During extreme summer conditions causing above-normal demand or generator outages, SaskPower can experience operating reserve shortfalls that it would mitigate using rescheduled planned maintenance, short-term power transfers from neighboring utilities, and/or available demand-response programs.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads.

Forced Outages: Based on historic generation stats and SaskPower's forced outage rate models.

Extreme Derates: Based on the wind turbines datasheet and the percentage of the total available wind that will be cut off when the temperature is extremely high (40 degrees and higher).

Operational Mitigations: Estimated non-firm imports and standby generators on 2–7 days' notice. In addition, 176 MWs of demand response can be called upon during operating emergencies.



MRO-SPP

The Southwest Power Pool (SPP) PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the PC footprint, which touches parts of the MRO Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

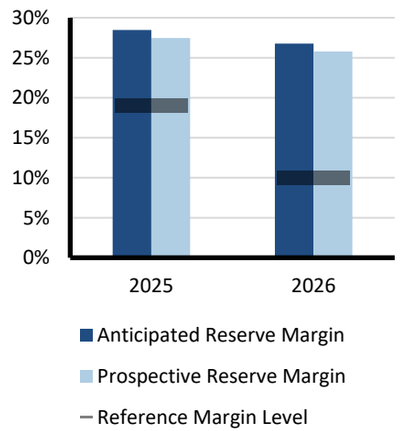
Highlights

- At this time, SPP does not anticipate any operational challenges that would result in reliability risk under normal conditions.
- SPP has operational procedures in place to manage generation outages taken over the summer to ensure appropriate generation is in place for high load. These procedures utilize probabilistic forecasts on factors such as load, generation, and outages to prepare for upcoming peak conditions.
- With heavy reliance on wind generation, SPP's greatest summer risk periods are when wind availability is low. If these low wind periods correspond to peak load conditions, then the combination presents extra risk for the area.
- SPP is projecting a 1.5% increase in forecasted 2026 Summer peak load vs. 2025 Summer peak actuals. Solar PV and energy storage continue to grow rapidly.

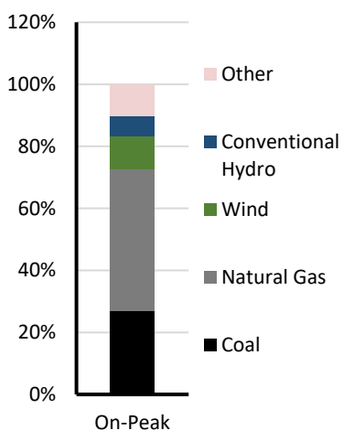
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. A combination of higher-than-average demand or lower-than-expected wind generation could result in the need for operating mitigations (e.g., demand response and transfers from neighboring systems), including resource advisories and EEAs, where appropriate.

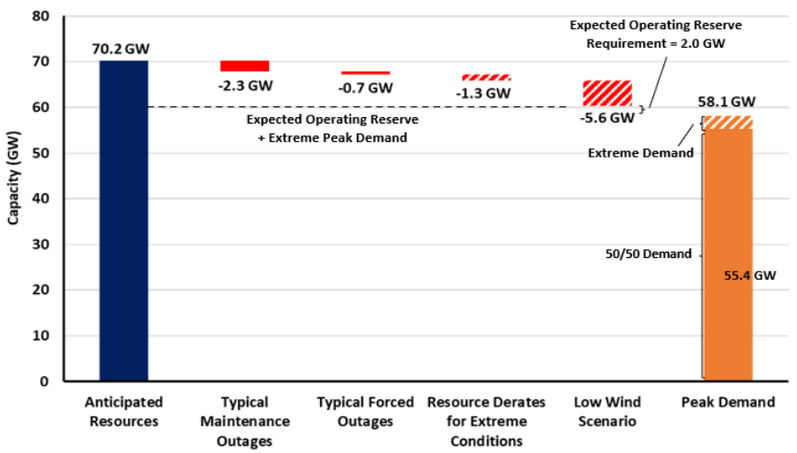
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 4.9% increase from net internal demand.

Maintenance and Forced Outages: Represent five-year historical averages; calculated from SPP's generation assessment process.

Extreme Derates: Additional unavailable capacity from operational data at high-demand periods.

Low Wind Scenario: Derates reflecting an average low-wind day in the summer.



NPCC-Maritimes

NPCC-Maritimes is an assessment area that covers the Canadian Maritime provinces—New Brunswick, Nova Scotia, and Prince Edward Island—and the northernmost portion of the U.S. state of Maine. The area covers approximately 150,000 square kilometers (58,000 square miles) and has a total population of nearly 1.9 million people. The New Brunswick Power Corporation (NB Power) is the BA for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the BA for Nova Scotia. NB Power's system is electrically interconnected with NPCC-Québec and NPCC-New England, and the electric systems in the provinces of Nova Scotia and Prince Edward Island have ties with New Brunswick but no direct ties with other assessment areas. Peak electricity demand in NPCC-Maritimes occurs during the winter season.

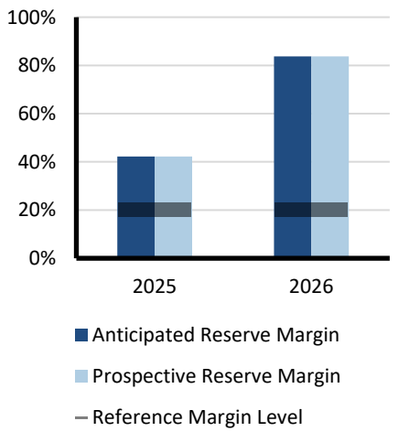
Highlights

- There are no anticipated issues for the Maritimes in the upcoming summer assessment period with sufficient firm capacity to meet the forecast peak demand.
- The Maritimes has not identified any operational issues that are expected to impact system reliability. Emergency operations and planning procedures are in place to mitigate operational events.
- Maritimes summer on-peak reserve margin is largely driven by resource maintenance outages. As a result of fewer planned outages (~1,000 MW) at peak, the 2026 on-peak reserve margin doubled from the 2025 SRA (84% compared to 42%).
- The preliminary results of NPCC's probabilistic assessment indicate that the Maritimes area is not expected use their operating procedures during the Summer of 2026 to maintain sufficient supply. The Maritimes area did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks, and established operating procedures were sufficient to maintain an energy balance over the May–September summer period for all the scenarios.
- Although margins can go negative in May under the high load (above 90:10) scenario, there are opportunities to purchase non-firm energy through the interconnections with neighboring control areas as this scenario does not coincide with either the Maritimes or the NPCC summer peaks.
- Dual-fueled units will have sufficient supplies of heavy fuel oil (HFO) on site to enable sustained operation in the event of natural gas supply interruptions.

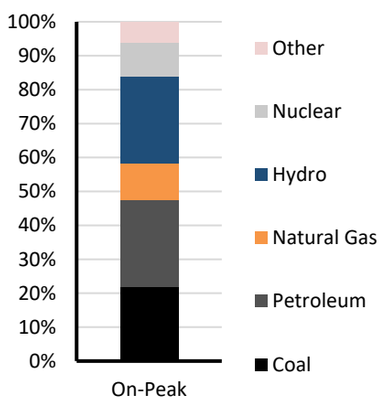
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

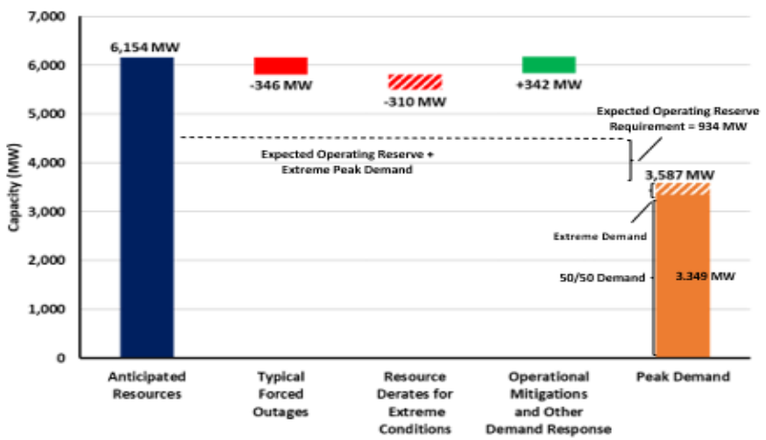
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and above 90/10 extreme demand forecast.

Forced Outages: Based on historic operating experience.

Extreme Derates: A low-likelihood scenario comprising a 100% derate of solar and storage, a 50% derate of wind (calm weather), and a 50% derate to natural gas (fuel supply issue).

Operational Mitigations: Changes to system operating conditions in the Maritimes area (i.e., transmission and/or generator outages) will be managed using short-term operating procedures (STOP), which would outline any special operating conditions for the operators.



NPCC-New England

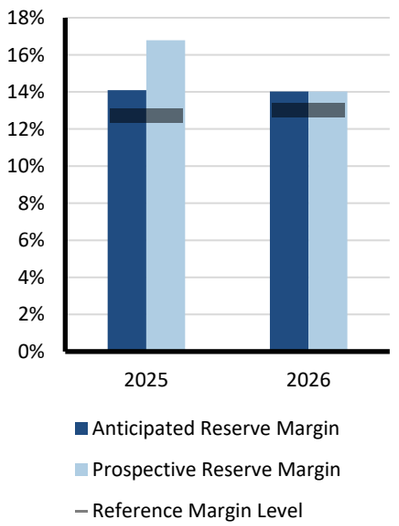
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- The New England area Anticipated Reserve Margin of 14% marginally exceeds the Reference Margin Level of 13%, avoiding a shortfall between anticipated resources and the reference level for reserves. There is, however, a 41 MW shortfall if resource additions are not included.
- ISO-NE assumes a net interchange of 409 MW, which is capacity-backed; however, ISO-NE typically imports around 3,000 MW during summer peak load conditions.
- ISO-NE does not anticipate any operational challenges or reliability issues for the upcoming 2026 Summer assessment period and forecasts adequate transmission capability and manageable capacity margins to meet the expected peak demand and operating reserves.
- Since January 2026, New England has added NECEC, a symmetric monopole +/- 320kV HVdc line from the 735 kV Appalaches substation in Québec to a new 345 kV substation, Merrill Road in Lewiston, Maine. NECEC will be used as an "import-only" tie with Hydro Québec and is capable of importing up to 1,200 MW into New England, but only on a non-firm basis for the coming summer.
- A probabilistic assessment was conducted for New England, modeling both NPCC and its neighboring regions. The analysis simulated a base case (50/50 normal demand) alongside a highest peak load scenario, which has a 7% probability of occurrence. The preliminary results of the probabilistic assessment indicate that use of New England's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. Under the scenario of highest peak load levels and reduced resource conditions, the estimated cumulative risk reached 0.343 days of LOLE, 1.178 hours of LOLH, and 628 MWh of EUE, with the greatest risks occurring in June and July. The final NPCC 2026 Summer Reliability Assessment will be approved in May 2026.

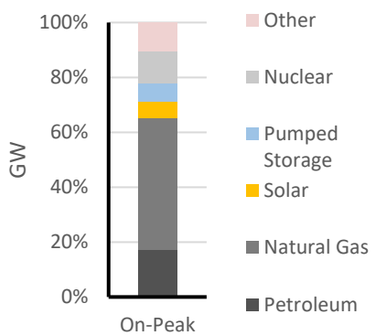
On-Peak Reserve Margin



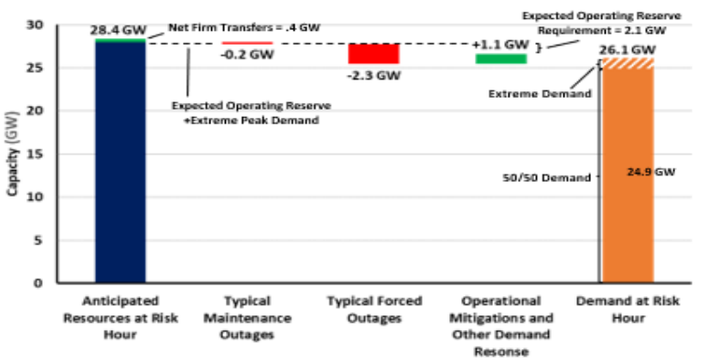
Risk Scenario Summary

The New England area expects to have sufficient resources to meet the 2026 summer peak demand forecast through the use of its established operating procedures and significant imports over its many ties to its neighbors that have historically been able to provide up to 3,000 MW during summer peak load conditions.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Forecasted risk hour demand (50/50) and (90/10) extreme demand adder.

Maintenance Outages: Historical average of maintenance outages.

Typical Forced Outages: Based on historical average of forced outages for summer period.

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures.



NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. NYISO is the only BA within the state of New York. The BPS in New York encompasses over 11,000 miles of transmission lines and 760 power generation units and serves 20.2 million customers. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an installed reserve margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. The council approved the 2026–2027 IRM at 24.5%.

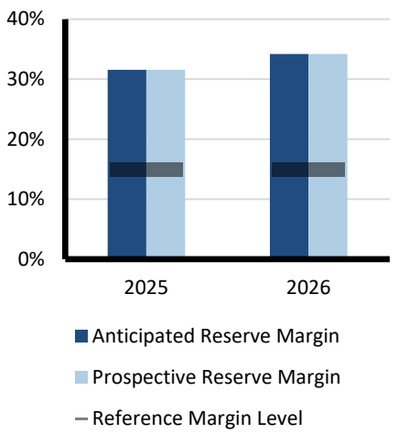
Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer.
- Adequate capacity margins are projected for the summer peak, and prospective transactions with neighbors should mitigate reliability concerns. Operating procedures should be sufficient to handle any issues that may occur.
- The preliminary results of the NPCC probabilistic assessment indicate that use of New York's established operating procedures is sufficient to maintain a balance between electricity supply and expected 50/50 demand if needed to mitigate resource shortages during Summer 2026. The expected load and resource scenario resulted in negligible risks over the May to September summer period, with less than 0.017 days of LOLE, 0.042 hours of LOLH, and 20 MWh of EUE.
- In contrast, under the scenario of highest peak load and reduced resources, the estimated cumulative risk reached 0.655 days of LOLE, 1.996 hours of LOLH, and 1,255 MWh of EUE, with the greatest risks occurring in July and August.
- to coordinate extensively with neighboring RCs and BAs to improve situational awareness and vet needs for firm or non-firm transfers to address extreme system conditions

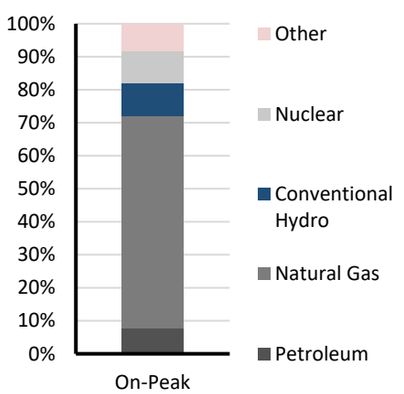
Risk Scenario Summary

The preliminary results of NPCC's probabilistic assessment indicate that New York's established operating procedures are sufficient to maintain a balance between electricity supply and expected demand, if needed, to mitigate shortages during Summer 2026.

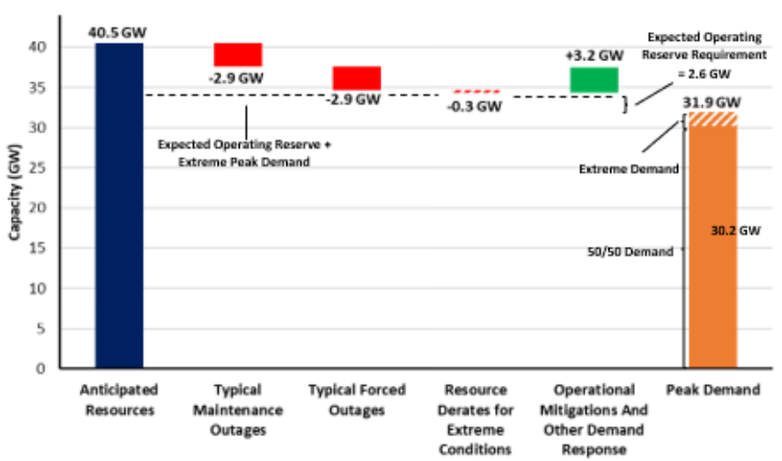
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: The risk period is at the time of peak demand.

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast. **Maintenance Outages:** Based on historical performance and the new NYISO capacity accreditation process.

Forced Outages: Based on historical five-year averages.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational Mitigations: A total of 3.2 GW based on operational/emergency procedures in area emergency operations manual.



NPCC-Ontario

NPCC-Ontario is an assessment area that covers the Canadian province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of over 16 million people. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. NPCC-Ontario is electrically interconnected with NPCC-Québec, MRO-Manitoba, MISO, and NPCC-New York. Peak electricity demand in NPCC-Ontario occurs during the summer season.

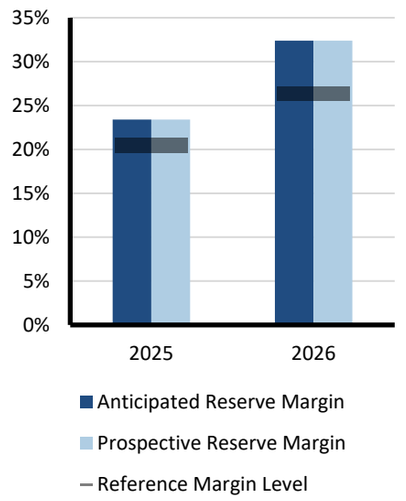
Highlights

- Ontario is well prepared for Summer 2026, and the IESO expects that the electricity system will remain reliable.
- Demand increased 2.7% over last year, driven in part by a rise in certain economic indicators, such as higher total employment, across the forecast horizon. However, uncertainty persists in the current economic environment with Ontario's largest trading partner.
- Existing-certain capacity is 8.4% higher than last year, reflecting the addition of new units. Established resource adequacy policy sets out a competitive strategy for securing new resources in the short, medium, and long terms. Also, Darlington G4 nuclear refurbishment was completed early and will be available for the summer period.
- Net firm capacity transfers increased 30.6% from Summer 2025. Although the capacity auction secured fewer imports for Summer 2026 compared to Summer 2025, IESO has chosen to utilize 300 MW of the 2015 Capacity Sharing Agreement with Hydro-Québec for the period commencing June 1, 2026, and ending September 30, 2026.
- Anticipated resources are projected 9% higher than Summer 2025 due to upgrades at existing natural gas facilities and new energy storage facilities anticipated to be coming on-line this summer.
- The preliminary results of NPCC's probabilistic assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. Even under peak load and low-resource conditions, the risk of LOLE remained negligible. This stability is supported by nearly 1,100 MW of new capacity from recent gas facility upgrades and storage projects. Consequently, no emergency operating procedures were required to maintain the balance between supply and demand.

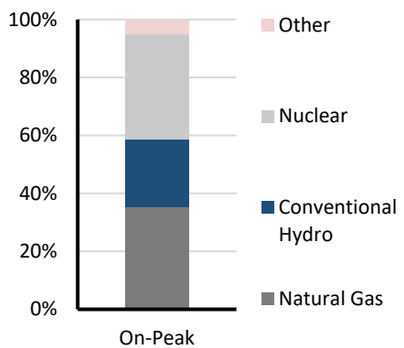
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

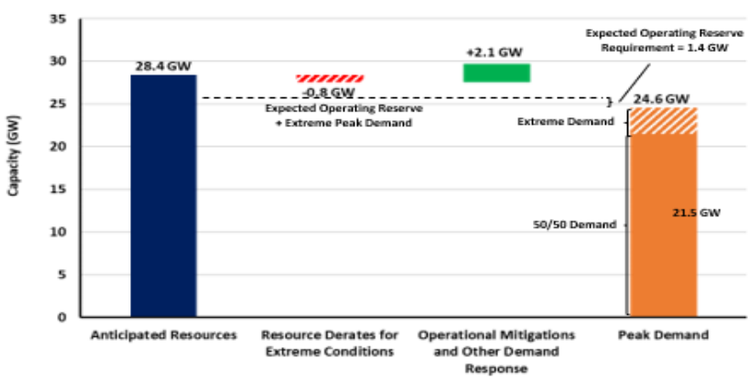
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50 forecast) and highest weather-adjusted daily demand based on 31 years of demand history, and extreme weather represents a 97/3 distribution of probabilistically modeled data.

Extreme Derates: Derived from weather-adjusted temperature ratings of thermal units and adjustments to expected hydro production for low water conditions.

Operational Mitigations: The operational procedures used to mitigate extreme conditions total approximately 2,100 MW for the On-Peak Risk Scenario, consisting of Imports, Public Appeals, and voltage reductions.



NPCC-Québec

NPCC-Québec is an assessment area that covers the Canadian province of Québec. The province of Québec covers over 1.5 million square kilometers (nearly 600,000 square miles) and has a population of nearly 9 million people. Hydro-Québec is the BA for the province of Québec. The Québec BPS is one of the four electric Interconnections in North America. It is a predominantly hydroelectric-generation-based system that is electrically interconnected with NPCC-Ontario, NPCC-New York, NPCC-New England, and NPCC-Maritimes. Peak electricity demand in NPCC-Québec occurs during the winter season.

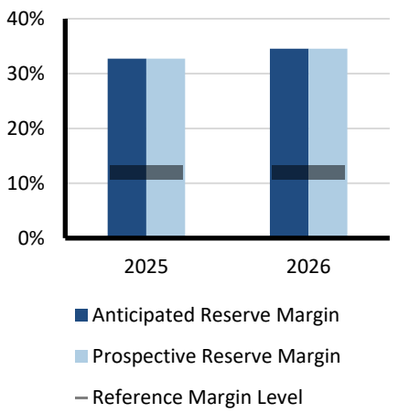
Highlights

- Québec is a winter-peaking hydroelectric system. Despite reduced generation because of reduced runoff in northern Québec since 2023, the Québec area expects no issues in meeting its operational needs this summer.
- Load (NID) is projected to decrease by 1% with respect to 2025.
- Net firm capacity exports have significantly increased (+1,018 MW) this year, as the CHPE is positioned to provide firm capacity to New York for the summer.
- There is a significant change to existing-certain capacity (3.7% or +1,192 MW). Hydro-Québec includes its planned outages in its certain capacity. This year, Hydro-Québec improved its modeling of its outages partially to account for its flexibility in managing outages; notably, the ability to recall certain outages to improve margins during peak events is highlighted.
- The preliminary results of NPCC's probabilistic assessment indicate that Québec area is not expected to require use of operating procedures designed to mitigate resource shortages during Summer 2026. Québec did not demonstrate any measurable amounts of cumulative LOLE, LOLH, or EUE risks over the May–September summer period for all the scenarios modeled since the system is winter peaking. The Québec area expects to be able to help other areas if needed.

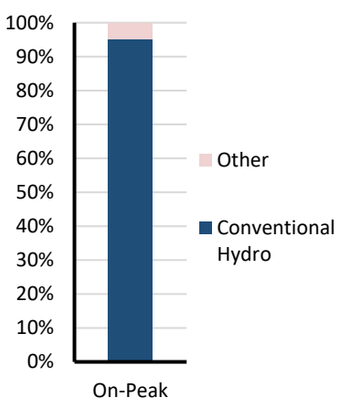
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

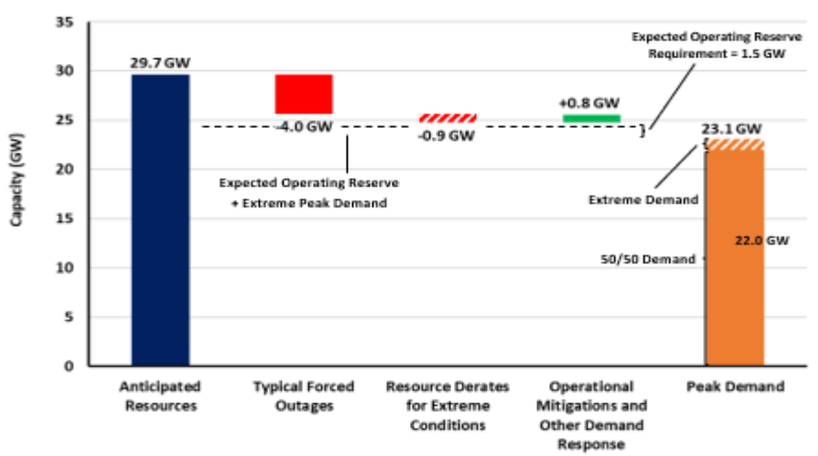
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Based on historical data and trending.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational mitigations: An operational procedure used to mitigate extreme conditions and not already included in margins is the depletion of some operating reserves by 750 MW.



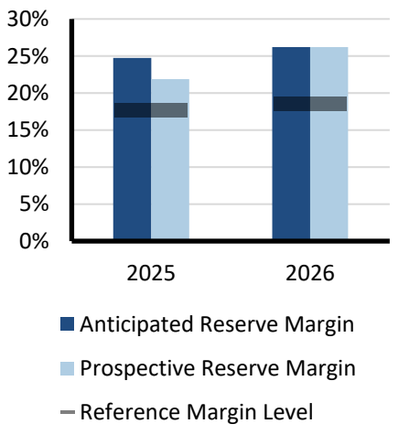
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM's footprint covers approximately 369,054 square miles and serves more than 67 million people. PJM is the area's BA, Transmission and Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC. PJM is electrically interconnected with MISO, NPCC-New York, SERC-Central, and SERC-East. Peak electricity demand in PJM occurs during the summer season.

Highlights

- PJM is expecting a low risk of resources falling below the required reserve requirement during Summer 2026.
- PJM is forecasting ~26% installed reserves (including expected committed demand resources), which is above the PJM reserve requirement margin of 18.6% that is necessary to meet the 1-day-in-10-years LOLE criterion. The highest risk for unserved energy is at peak demand hour.
- If extreme high temperatures are experienced, PJM anticipates the need for demand-response resources to help reduce load.
- New and better load forecasts and advancement of planned resources have improved PJM's reserve margin looking into this summer over previous assessments.
- The LOLH and EUE values reported in the 2024 LTRA for 2026 were 0.12 hours/year and 537.52 MWh/year, respectively. These values corresponded to a 17.8% operable margin (also reported in the 2024 LTRA). Since the expected actual reserve margin for the PJM system is 26% in 2026, the LOLH and EUE values associated with a 26% reserve margin are expected to be lower than those reported in the 2024 LTRA.

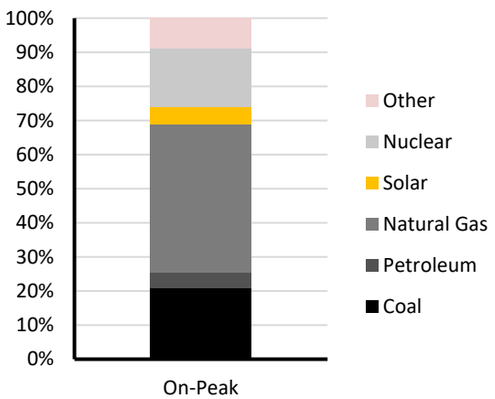
On-Peak Reserve Margin



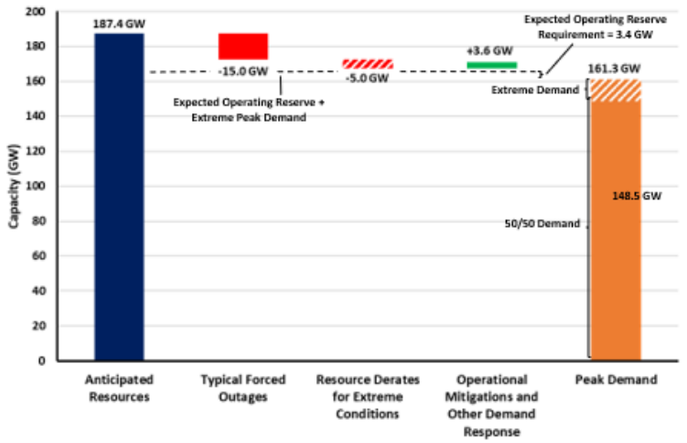
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Based on historical data and trending.

Extreme Derates: Accounts for thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 3.6 GW estimated based on operational/emergency procedures. This includes 500 MWs of additional demand response that can be called upon during operating emergencies.



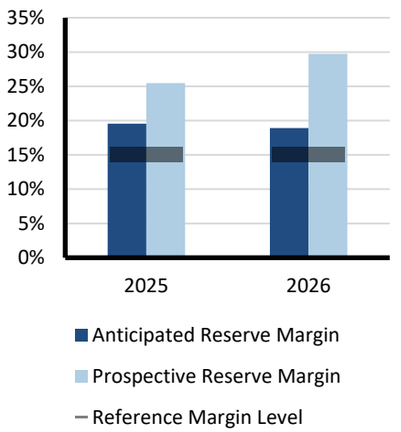
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Georgia, Iowa, Kentucky, Mississippi, Missouri, North Carolina, Oklahoma, Tennessee, and Virginia. SERC-Central is a dual-peaking assessment area, experiencing peak electricity demand during both the summer and winter seasons. The PCs in this subregion include Associated Electric Cooperative Inc., Louisville Gas & Electric/Kentucky Utilities, Owensboro, KY Municipal Utilities, and the Tennessee Valley Authority. Other SERC member entities in this subregion include Brookfield/Smoky Mountain, Memphis Light, Gas and Water Division, and Nashville Electric Service.

Highlights

- No significant reliability concerns were identified.
- Modest load growth (~1–3%) is driven by residential, industrial, and emerging data center demand.
- Increased demand response (DR) results from new demand-side management (DSM) programs and large industrial load enrollments.
- Adequate capacity, transfers, resource assumptions and reserve margins remain sufficient to support reliability.
- Robust operational planning and coordination, with DSM/DR programs providing additional flexibility during peak conditions.
- ProbA results show negligible risk for this summer.

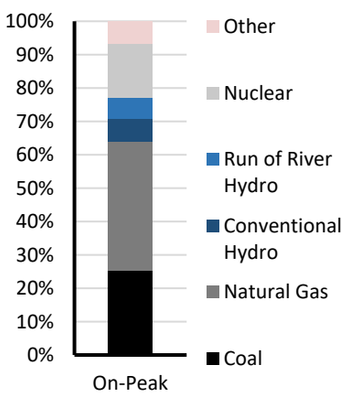
On-Peak Reserve Margin



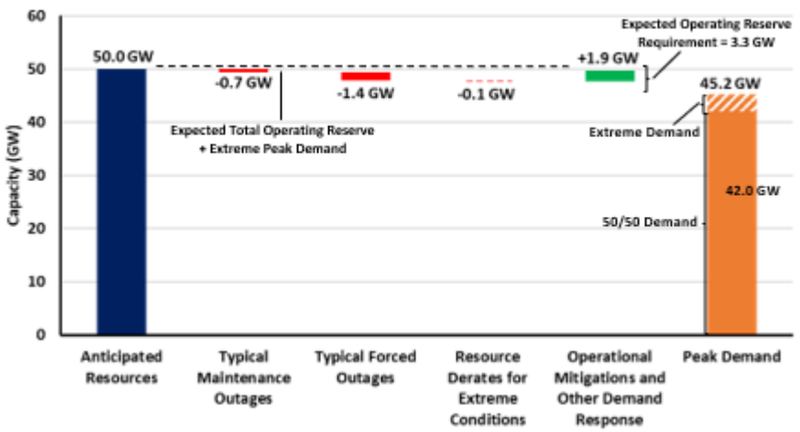
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: 1.9 GW based on operational/emergency procedures.



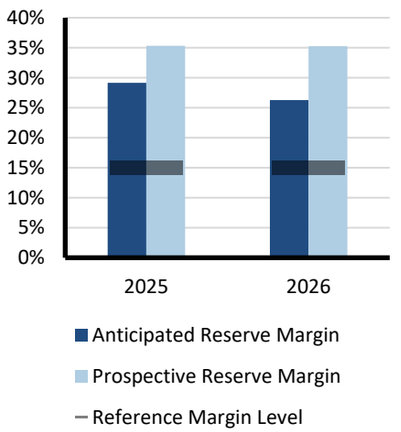
SERC-East

SERC-East is an assessment area within the SERC Regional Entity and includes North Carolina and South Carolina. SERC-East is a winter-peaking assessment area. The PCs in this subregion include Cube Hydro Carolinas LLC, Dominion Energy South Carolina Inc., Duke Energy Carolinas LLC, Duke Energy Progress LLC, and the South Carolina Public Service Authority (Santee Cooper). Other SERC member entities in this subregion include the Cube Hydro Carolinas-Yadkin Division and Southeastern Power Administration.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain adequate for Summer 2026.
- Fuel supply, generation availability, and transmission operations are expected to be adequate, with no major outages anticipated to impact reliability.
- Minimal changes are expected in demand and resource mix; reserve margins remain above planning targets despite updated solar/storage accreditation.
- Strong coordination processes and established operating procedures support reliable peak demand management.
- ProbA results show negligible risk for this summer.

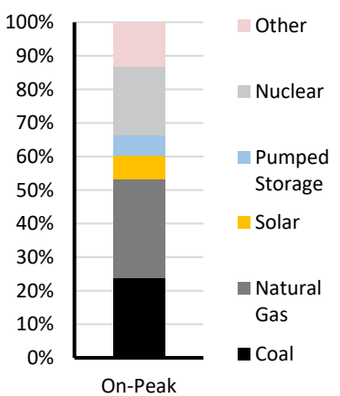
On-Peak Reserve Margin



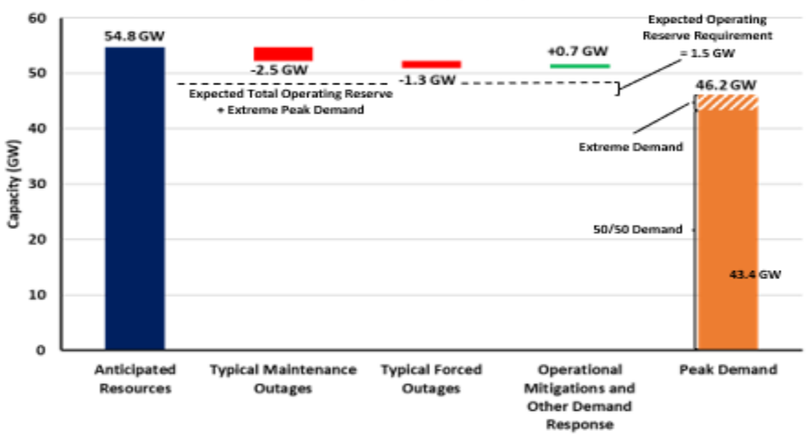
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 728 MW based on operational/emergency procedures.



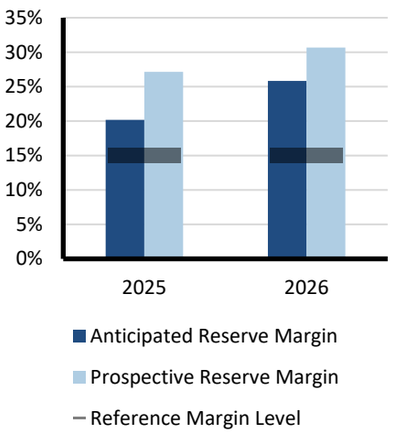
SERC-Florida Peninsula

SERC-Florida Peninsula is an assessment area within the SERC Regional Entity and includes all of Florida. SERC-Florida Peninsula is a summer-peaking assessment area. The PCs in this subregion include Duke Energy Florida LLC, the Florida Municipal Power Agency, Florida Power & Light Company, Florida Reliability Coordinating Council Inc., Gainesville Regional Utilities, the City of Homestead, JEA, Lakeland Electric, the Orlando Utilities Commission, Seminole Electric Cooperative, the City of Tallahassee, and Tampa Electric Company.

Highlights

- No significant operational challenges or emerging reliability issues were identified; system conditions remain stable for Summer 2026.
- There is an adequate demand and capacity outlook, with minimal year-over-year changes and no significant operational risks.
- There is strong resource adequacy, with projected reserve margins (~26%) well above the 15% reference margin.
- DR (~3,350 MW available) and established coordination practices support peak demand and emergency preparedness.
- ProbA results show negligible risk for this summer.

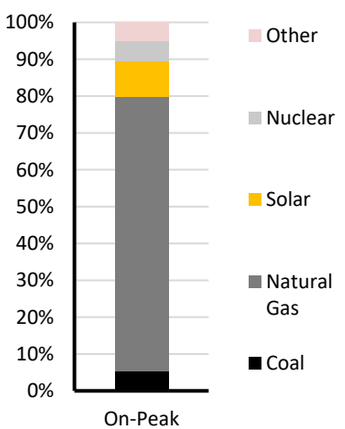
On-Peak Reserve Margin



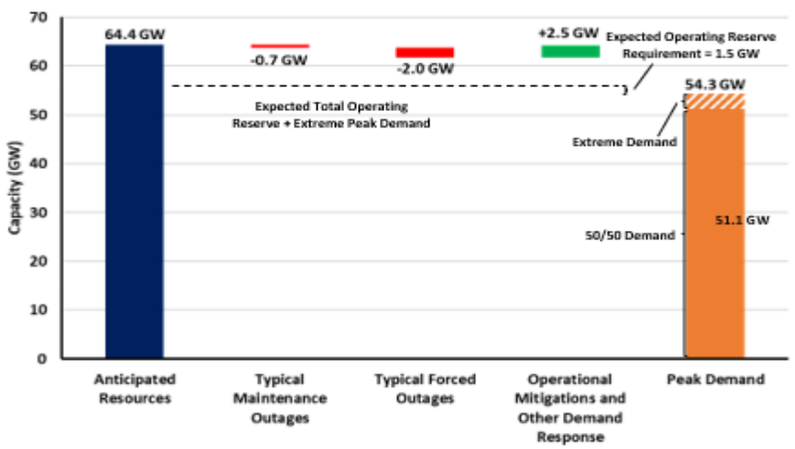
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures.



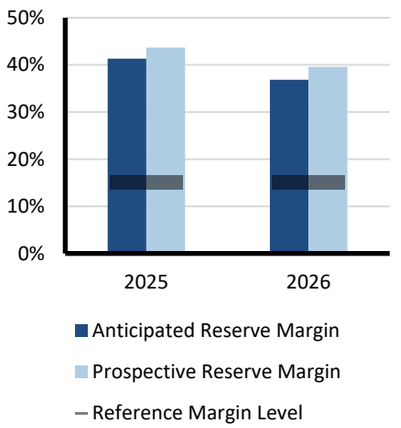
SERC-Southeast

SERC-Southeast is an assessment area within the SERC Regional Entity and includes all or portions of Alabama, Florida, Georgia, and Mississippi. SERC-Southeast is a summer-peaking assessment area. The PCs in this subregion include Georgia Transmission Corporation, the Municipal Electric Authority of Georgia, PowerSouth Energy Cooperative, and Southern Company Services, Inc. - Trans.

Highlights

- No significant reliability risks were identified; fuel supply and generation portfolios remain diverse and adequate.
- Natural gas pipeline constraints and increasing solar penetration present manageable operational considerations, not reliability threats.
- Moderate load growth (~1–3%), driven by economic conditions, residential and commercial expansion, and emerging data center load.
- Limited reliance on DR; existing operating practices and planning processes are sufficient to meet peak demand.
- ProbA results show negligible risk for this summer.

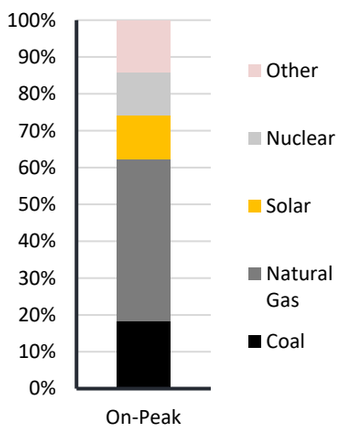
On-Peak Reserve Margin



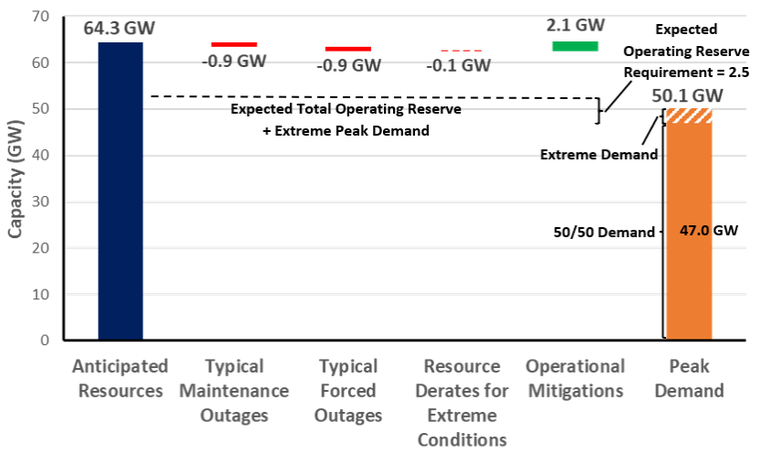
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast).

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level.

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions.

Extreme Derates: Estimated resources unavailable in extreme conditions.

Operational Mitigations: A total of 2.1 GW based on operational/emergency procedures.



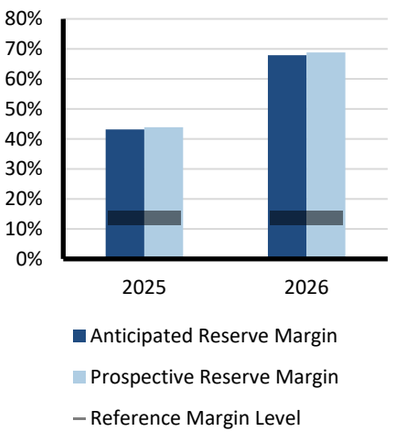
Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator (ISO) for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer peaking, and the forecasted summer peak load month is August. It covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,460 generation units, and serves more than 26 million customers. Texas RE is responsible for the Regional Entity functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the reliability monitor for the Texas grid.

Highlights

- Given an Anticipated Reserve Margin of 67.9% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves for the August peak load hour given expected normal system summer conditions.
- Continued growth in load and intermittent resources drives a higher risk of emergency conditions in the evening hours when solar generation ramps down and loads are high.
- The probability of an EEA during the expected August (and summer) peak load day continues to drop relative to previous SRAs due to continued robust growth in battery energy storage capacity (up 2,677 MW year-on-year as of March 2026). The EEA probability for the highest-risk hour—hour ending 9:00 p.m.—is 0.43%, down from 3.1% previously.
- The projected EEA risk does not account for regional constraints in Far West Texas, which may lead to a reliance on price-responsive demand in certain low-generation scenarios.
- An identified risk is the potential of newly interconnected large loads (mainly data centers and crypto-mining facilities) to trip and potentially cause grid stability problems. ERCOT has implemented mandatory ride-through capabilities and requires dynamic model submissions, among other solutions, to address this risk.
- The risk assessment process for this SRA will be the same as ERCOT's upcoming August 2026 Monthly Outlook of Resource Adequacy (MORA) to be released on June 5.

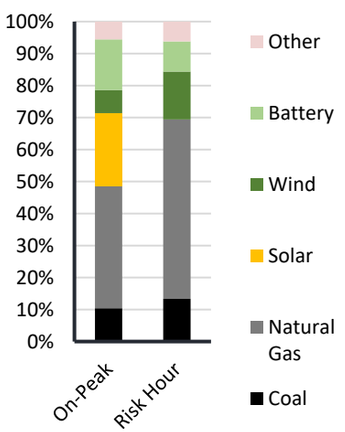
On-Peak Reserve Margin



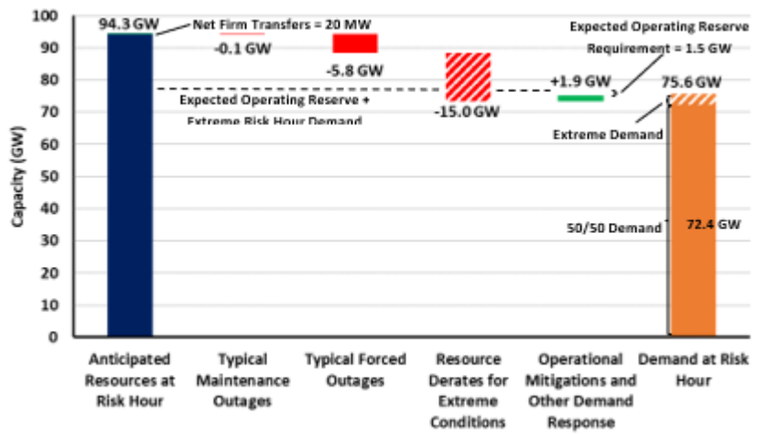
Risk Scenario Summary

The risk of having to declare an EEA for hour 21 is low (0.43%), according to ERCOT's probabilistic reserve risk model (PRRM) simulation results. The highest risk hour for the peak load day in August (which is also the expected summer peak load day).

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Hour: The highest risk hour, HE 2100 (9:00 pm CDT).

Demand Scenarios: Net internal demand, and an adjustment to extreme demand based on the 95th percentile of the PRRM's distribution of load simulation outcomes for the highest-risk hour (HE 2100).

Forced Outages: The adjustment is the 95th percentile of 10,000 daily thermal forced outage values generated by the PRRM, less the 50th percentile value.

Low-Wind Scenario: The adjustment is the 50th percentile of 10,000 wind generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Extreme Derates: The adjustment is the 50th percentile of 10,000 solar generation values for hour ending 2100 generated by the PRRM, less the 0th percentile value.

Operational Mitigations: Additional capacity from switchable generation and additional imports.



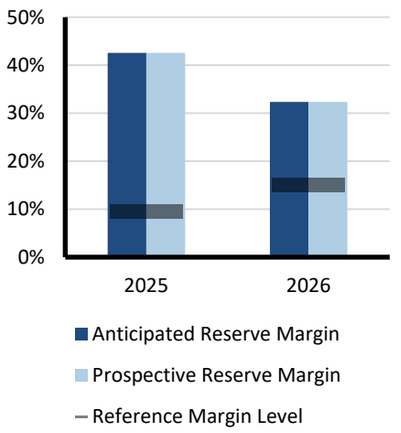
WECC-Alberta

WECC-Alberta is an assessment area that covers the Canadian province of Alberta. The province has a geographic area of 661,848 square kilometers (255,541 square miles) and a population of almost 5 million people. The Alberta Electric System Operator (AESO) is the province's planning entity and RC responsible for safe, reliable, and economic operation of the Alberta Interconnected Electric System. AESO is a non-profit corporation that operates a system that includes approximately 26,000 kilometers of transmission lines and connects approximately 426 qualified generating units and nearly 250 market participants through a wholesale market. Alberta's transmission system has three interties with neighboring areas—Saskatchewan (see MRO-SaskPower), British Columbia (see WECC-British Columbia), and Montana (see WECC-Northwest). Peak electricity demand on the AESO system currently occurs during the winter season.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. Additionally, WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak demand is projected to increase by 2.1% over last summer's forecast.
- Wide-area heat events and wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.

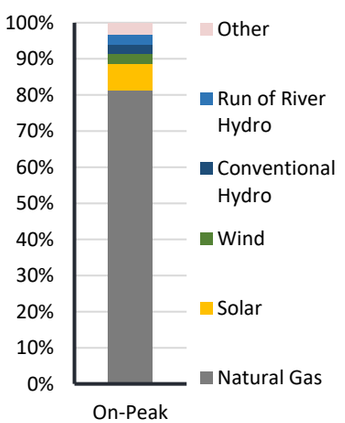
On-Peak Reserve Margin



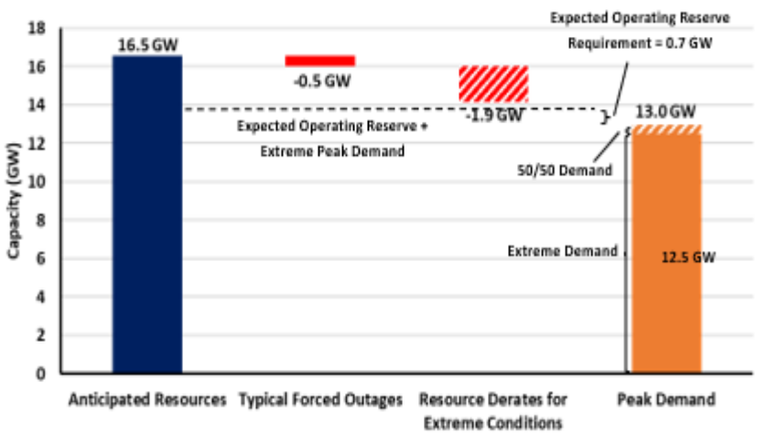
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



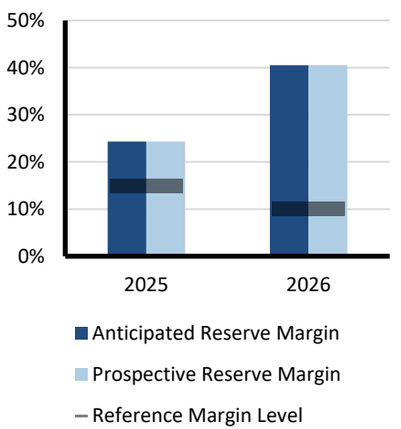
WECC-Basin

WECC-Basin is a summer-peaking assessment area in the WECC Regional Entity that includes Utah, southern Idaho, and a portion of western Wyoming, covering Idaho Power and PacifiCorp's eastern Balancing Authority Area. The population of this area is approximately 5.4 million. It has 15,910 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- WECC-Basin has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Wildfires remain a reliability concern for the region, particularly in areas with remote generation such as remotely located hydro. Mitigation programs such as hardening and public safety shutoff programs are in place.
- Extreme temperatures pose a risk to the area, impacting load levels and renewable variability. WECC-Basin is positioned to rely on imports during such conditions, which also poses a risk of concurrent impacts should neighbors experience similar conditions.
- Load forecasts for the area are projected to be 2.5% higher than 2025 Summer actuals.
- Wind, solar, and energy storage resources continue to grow.
- Reserve margins are not anticipated to fall below the 15% Reference Margin Level for 2026 Summer. Both Anticipated and Prospective Reserve Margins are expected to be adequate at 37.6%

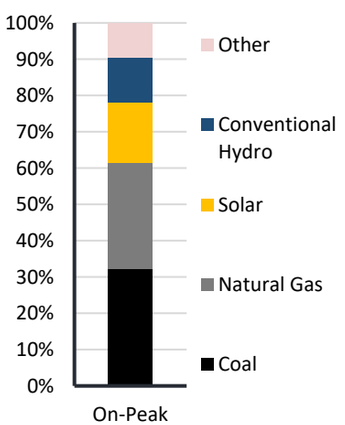
On-Peak Reserve Margin



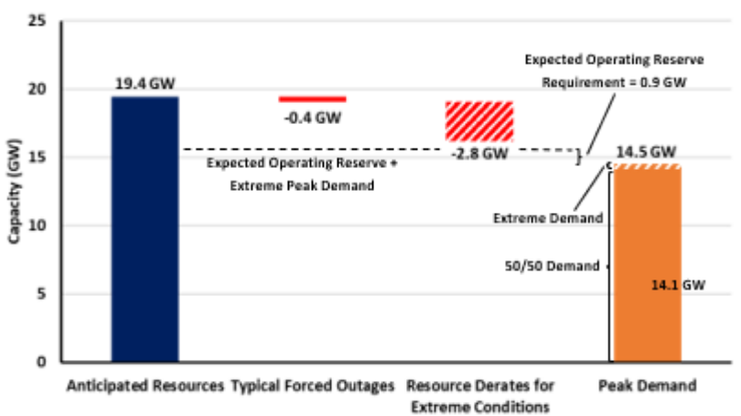
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



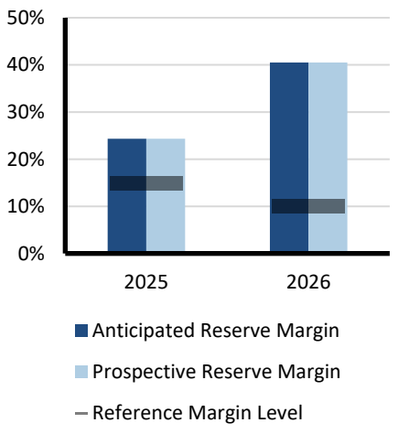
WECC-British Columbia

WECC-British Columbia is an assessment area that covers the Canadian province of British Columbia. The province has a geographic area of 944,735 square kilometers (364,764 square miles) and a population of just over 5 million people. BC Hydro is the Planning Entity and RC for the province of British Columbia and is the principal supplier of electricity for the province. BC Hydro is a provincial Crown corporation and, under provincial legislation, is responsible for the oversight of the British Columbia BES and its interconnections. BC Hydro operates an integrated system supported by 32 hydroelectric plants, approximately 80,000 kilometers of transmission and distribution lines, and 125 contracts with independent power producers. BC Hydro's transmission system has two interties with neighboring areas—the U.S. state of Washington (see WECC-Northwest) and Alberta (see WECC-Alberta). Peak electricity demand on the BC Hydro system currently occurs during the winter season.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- WECC's probabilistic analysis shows no LOLH nor EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to increase 2.4% over last summer's forecast while anticipated resources increase by 15.7%.
- Wide-area heat events or wildfires that affect resource and transmission availability across the Western Interconnection are a reliability concern. Energy imports may be limited at this time if neighboring areas are also experiencing peak loads, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.

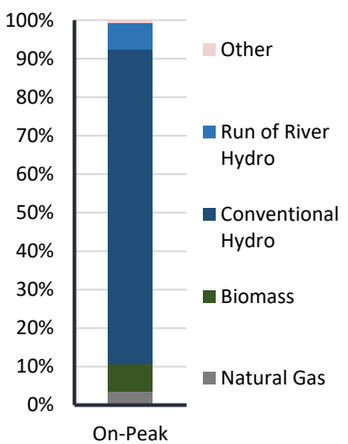
On-Peak Reserve Margin



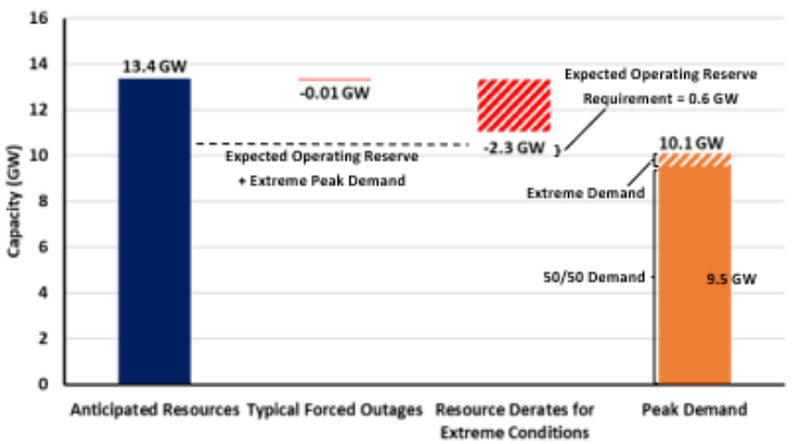
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



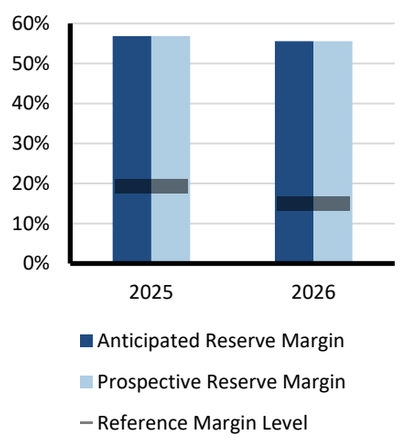
WECC-California

WECC-California is a summer-peaking assessment area in the Western Interconnection that includes most of California and a small section of Nevada. The assessment area has a population of over 42.5 million people. The area includes the California ISO, the Los Angeles Department of Water and Power, the Turlock Irrigation District, and the Balancing Area of Northern California. It has 32,712 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Extreme heat and wildfires exacerbated by continued climate change may impact generation and transmission resources and remain a reliability concern.
- Cyber attacks pose significant reliability concerns for the area.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Inverter-based resource (IBR) output variability remains a concern, such as from the evening ramp requirements from declining solar and Santa Ana winds, which can overspeed wind turbines, requiring them to curtail.

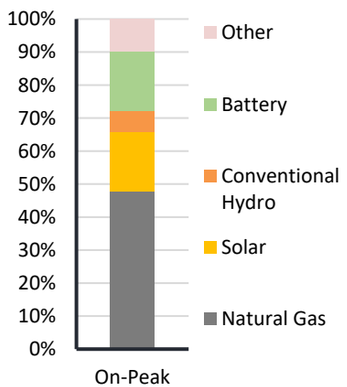
On-Peak Reserve Margin



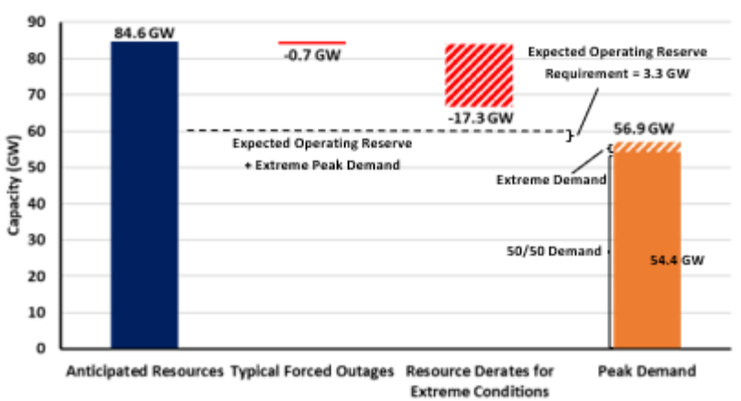
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: On-peak risk scenario.

Demand Scenarios: 50/50 and 90/10. Significant difference in delta from 2025. May be from switch to SERVM and weather year adjustment taken out.

Forced Outages: Based on historical average of forced outages for a specified period/conditions (e.g., average of forced outages for June through September weekdays, over the past three years), or area-specific methodology for determining anticipated forced outages for non-intermittent resources (e.g., thermal, hydro).

Extreme Derates: Capacity derate for resources for extreme conditions. The derate accounts for reduced capacity contributions due to performance in extreme conditions for thermal, wind, PV, storage, and other.



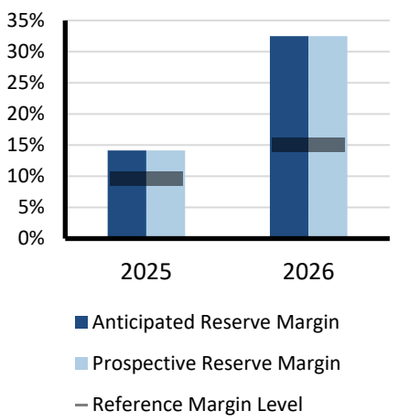
WECC-Mexico

WECC-Mexico is a summer-peaking assessment area in the Western Interconnection that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people and includes Centro Nacional de Control de Energía (CENACE). It has 1,568 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- WECC-Mexico has added an additional 1 GW of natural-gas-fired resources since last summer, greatly improving its outlook from the *2025 SRA*.
- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions. Anticipated resources are projected to be 15.5% higher.
- Operating reserves are a concern in this region during periods of extreme heat and elevated demand. High loading on Path 45 (See: WECC Path Rating Catalog) coupled with outages or derates to large thermal assets in this region can result in the declaration of an EEA and a request for assistance from RC West.
- Some generating units have reached advanced operational age, resulting in an observable increase in the forced outage rate. This condition increases the risk of capacity shortfalls and may compromise system reliability during peak seasonal demand.

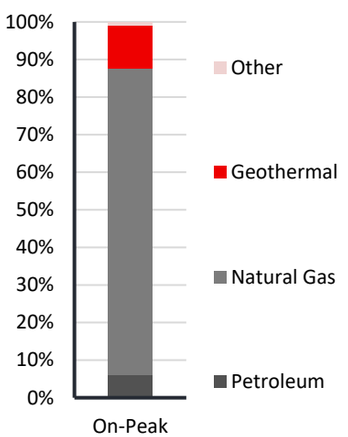
On-Peak Reserve Margin



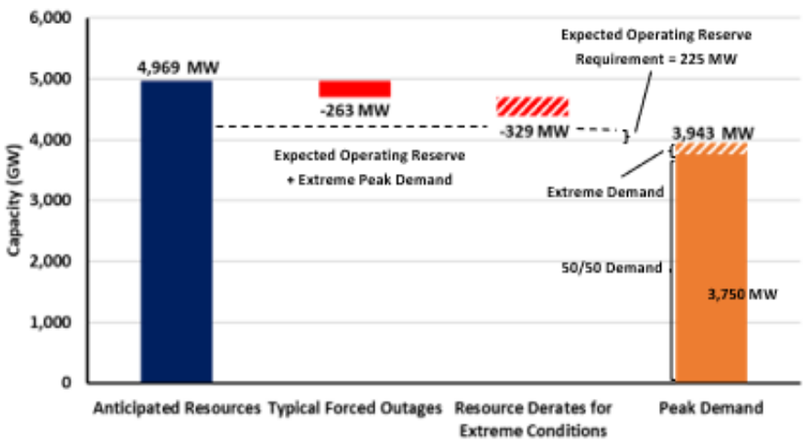
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: Using (90/10) resource performance distribution at peak hour.



WECC-Northwest

WECC-Northwest is a winter-peaking assessment area in the WECC Regional Entity. The area includes Montana, Oregon, and Washington and parts of northern California and northern Idaho. The population of the area is approximately 13.6 million. It has 32,751 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

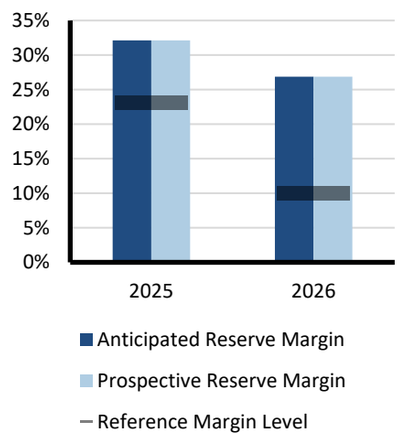
Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions.
- The EUE and LOLH occurs in hours 17 and 18 in August and September, with the vast majority September hour 18.
- Peak net internal demand is projected to grow 4.6% over last summer's forecasts; however, anticipated resources are showing just a 1.5% increase in energy availability, leading to tighter margins.
- Wide-area heat events, wildfires, and low snow-water equivalents due to a changing climate impact generation resource and transmission availability and remain a continued reliability concern. Firm imports may be limited at this time if neighboring areas are also experiencing peak loads or derates, limiting energy availability.
- Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- There have been instances where operators had difficulty maintaining frequency due to sudden disconnection of large loads necessitating additional regulation capability.

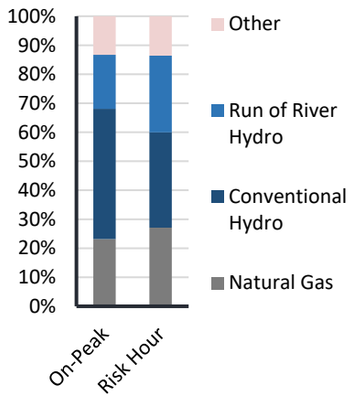
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under the assessed extreme scenarios. WECC's probabilistic analysis showed EUE at 2.7 MWh and LOLH of 0.1 hours weighted average under a range of weather scenarios for demand and energy availability conditions, placing the area at risk of shortfall during extreme conditions.

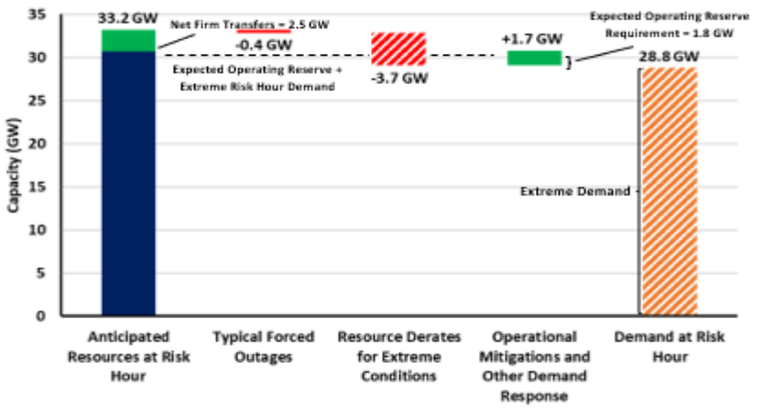
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Modeled output depicting load-loss event from the probabilistic model.

Risk Period: Off-peak highest risk hour is primarily 6 p.m. in September.

Demand Scenarios: Modeled load for the risk hour during load-loss event.

Typical Forced Outages: Based on historical average of forced outages for the period.

Extreme Derates: Modeled outage and derates to account for underperformance of resources at the risk hour.

Operational Mitigations: An operational procedure used to mitigate extreme conditions not already included in the margins is the depletion of operating reserves by 1.7 GW. WECC did not use an operational model prior to this year's report, and it the first time the model includes operating reserves of 6% withheld through unserved energy.



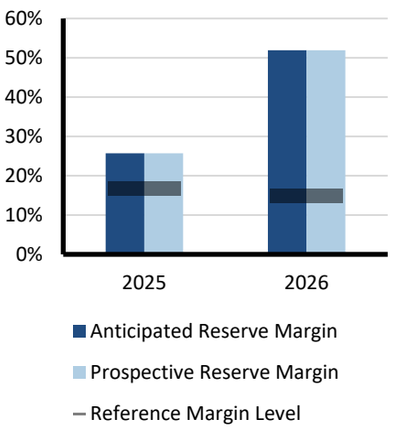
WECC-Rocky Mountain

WECC-BC (British Columbia) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 Balancing Authorities, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- WECC-Rocky Mountain has established a 15% Reference Margin Level for the 2026 Summer assessment period.
- Anticipated Reserve Margins for the summer exceed the NERC-recommended Reference Margin Level.
- Wildfires in the region, along with extreme heat conditions for the summer, pose the greatest reliability risk scenario for the Rocky Mountains. These conditions can impact rural co-ops disproportionately.
- The existing certain and Anticipated Reserve Margins are projected to be at 43% and 52%, respectively, above the established 15% for the summer. Projections for summer load indicate minimal growth from 2025 and are 0.6% higher than 2025 Summer peak load conditions.

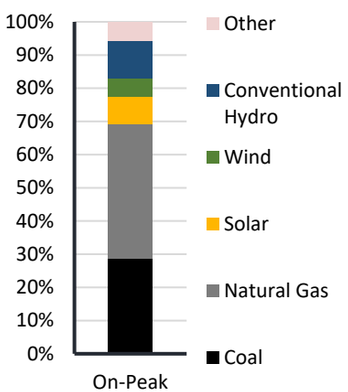
On-Peak Reserve Margin



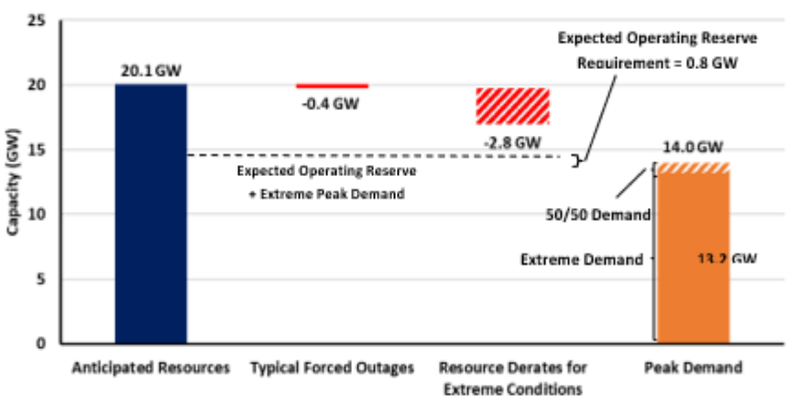
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios with imports.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand.

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.



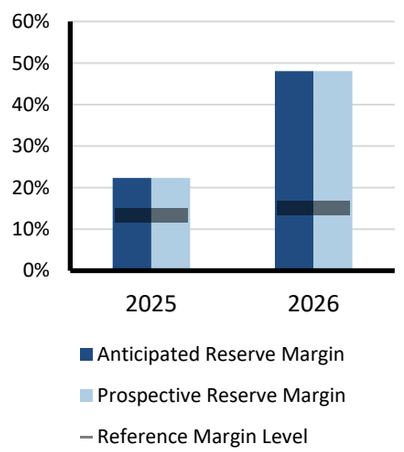
WECC-Southwest

WECC-Southwest is a summer-peaking assessment area in the Western Interconnection that includes all of Arizona and New Mexico, most of Nevada, and small parts of California and Texas. The area has a population of approximately 13.6 million. It has 23,084 miles of transmission. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 40 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 84.5 million customers, it is geographically the largest and most diverse Regional Entity.

Highlights

- Anticipated Reserve Margins for the summer exceed the NERC-prescribed Reference Margin Level. WECC's probabilistic analysis shows no LOLH or EUE under a range of demand and energy availability conditions.
- Peak net internal demand is projected to grow 9.5% over last summer's forecasts. DR availability has also increased from 199 MW to 364 MW.
- Anticipated resource capacity is expected to be 32.5% higher than last summer, mostly due to methodological changes to capacity of incoming future resources. Supply chain constraints and economic uncertainty may impact Tier 1 resources.
- Elevated forced outage rates due to the amount of aging generation capacity along with extensive overhaul requirements can keep resources out of service for extended periods of time.
- Extreme heat events can result in prolonged periods of elevated demand, derates to thermal generation, and—given the large area that heat waves cover—drastically reduced import capability from neighboring areas. The area also faces significant wildland fire potential this summer. Wildfires have the potential to interrupt large numbers of customers by damaging generation, transmission, and distribution assets.

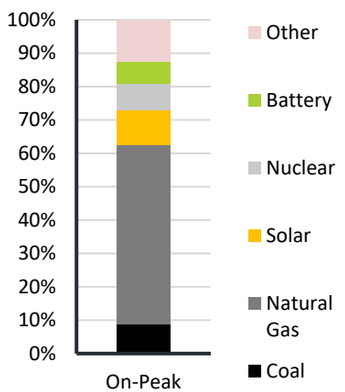
On-Peak Reserve Margin



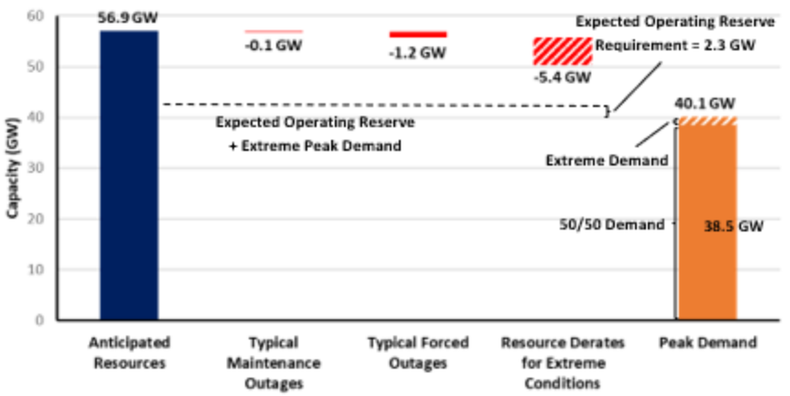
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local).

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: Using (90/10) scenario.

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions
• Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
▪ Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
▪ Operating reliability is the ability of the electric system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
• The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
• All data in this assessment is based on existing federal, state, and provincial laws and regulations.
• Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
• A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.
Demand Assumptions
• Electricity demand projections, or load forecasts, are provided by each assessment area.
• Load forecasts include peak hourly load[17] or total internal demand for the summer and winter of each year.[18]
• Total internal demand projections are based on normal weather (50/50 distribution)[19] and are provided on a coincident[20] basis for most assessment areas.
• Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

[17] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[18] The summer season represents June–September and the winter season represents December–February.

[19] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.

[20] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC calculates total internal demand on a noncoincidental basis.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity**: Included in this category are commercially operable generating units or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or, where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions**: This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports)**: This category includes transfers with firm contracts.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss-of-load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecast. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Level s may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominantly thermal systems and 10% for predominantly hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the **Regional Assessments Dashboards**. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left **blue** column shows anticipated resources, and the two **orange** columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle **red** or **green** bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[21] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for Summer 2026 as shown in **Figure 5**.

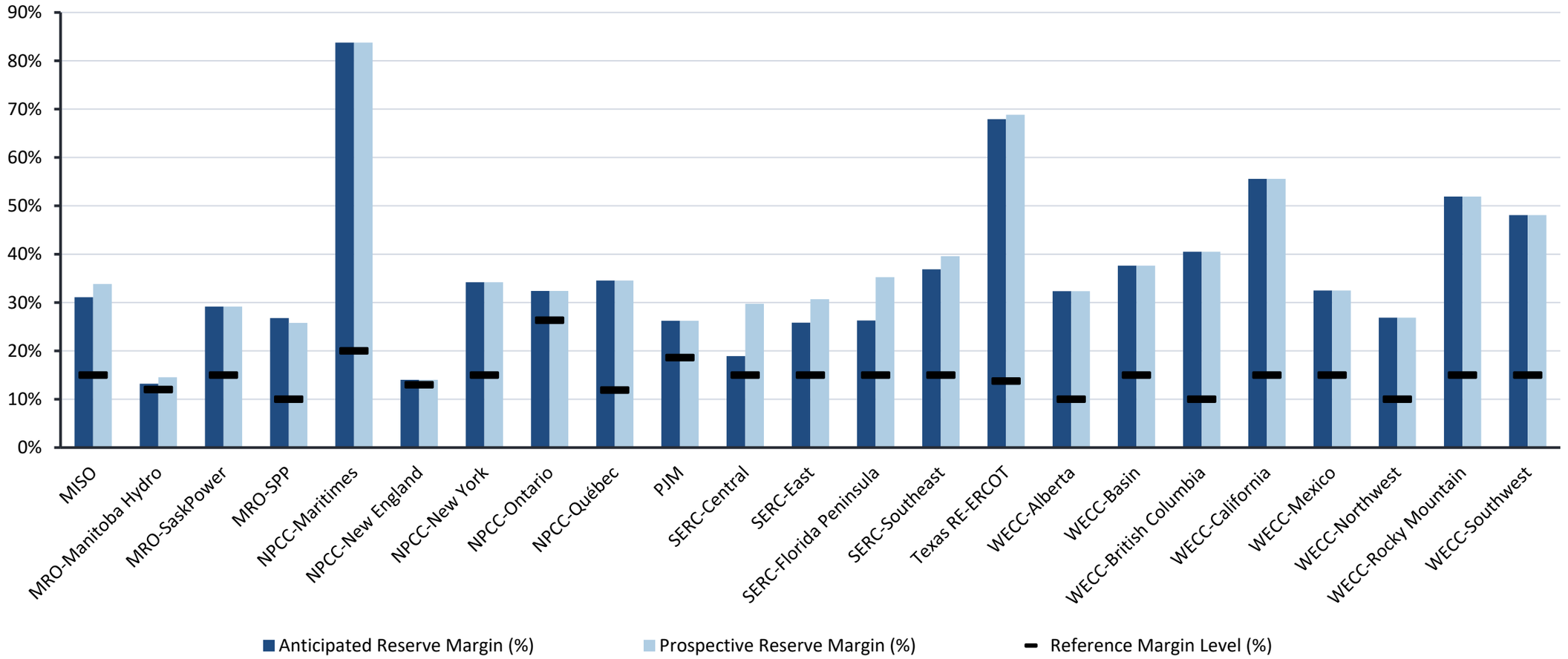


Figure 5: Summer 2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[21] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year to Year

Figure 6 provides the relative change in the forecast Anticipated Reserve Margins from the 2025 Summer to the 2026 Summer. A significant decline can signal potential operational issues for the upcoming season. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.

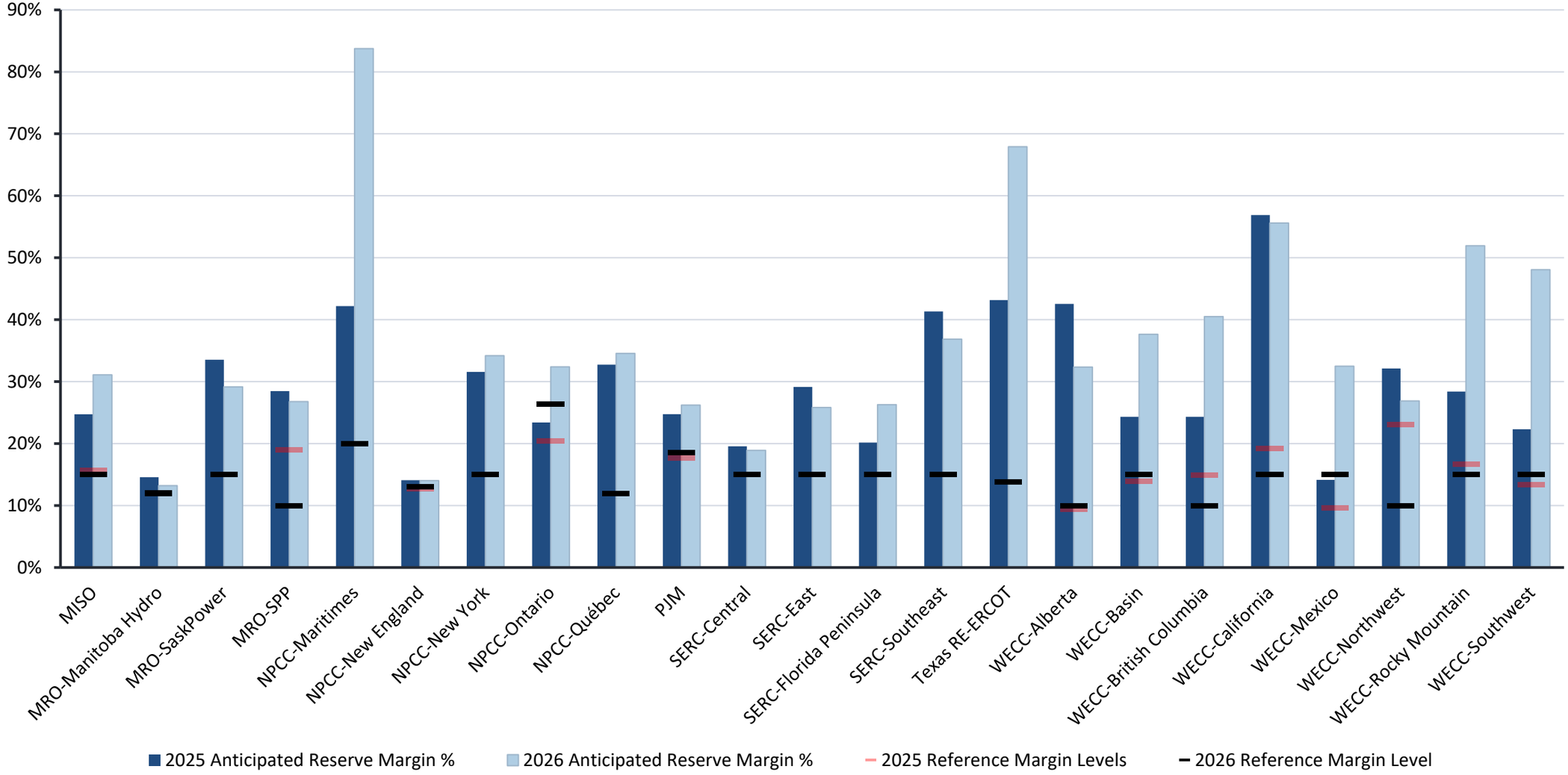


Figure 6: Summer 2025 and Summer 2026 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted net internal demand for each assessment area are shown in **Figure 7**.[22] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

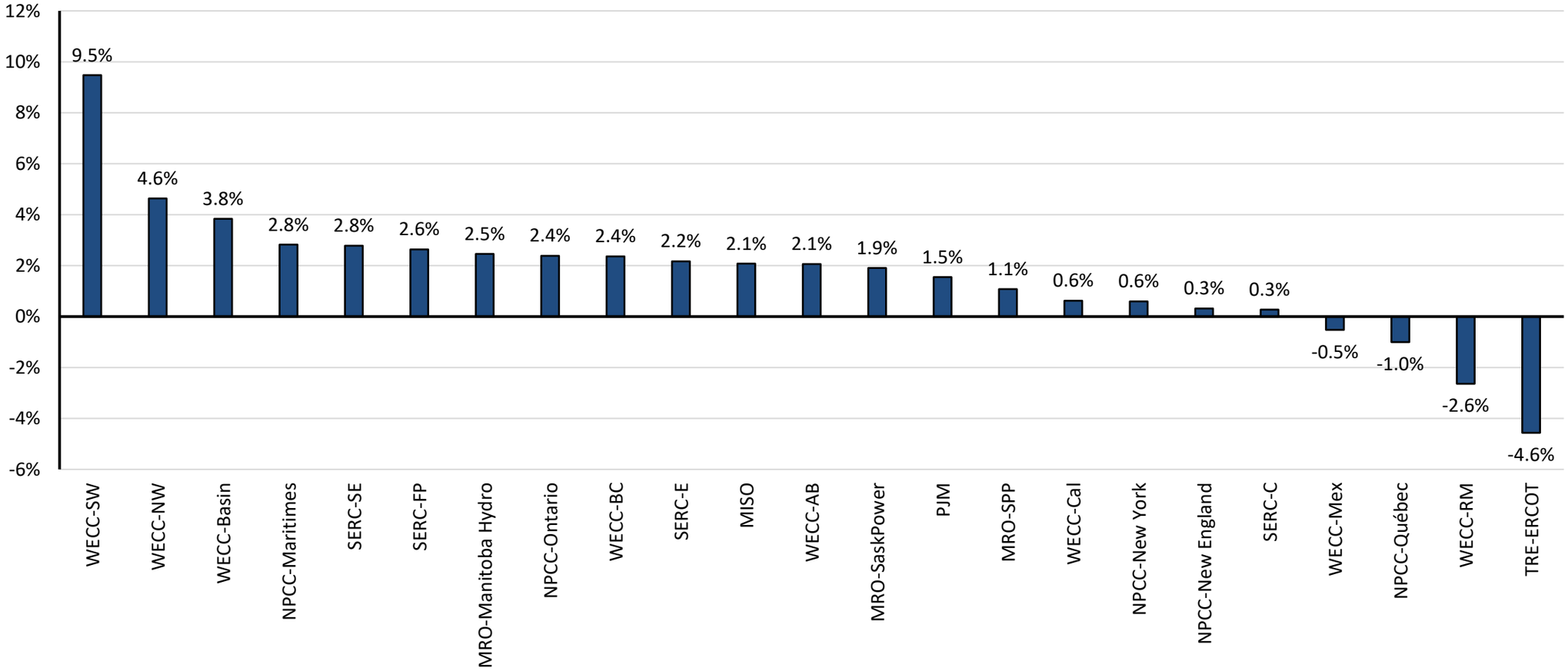


Figure 7: Changes in Net Internal Demand—Summer 2025 Forecast Compared to Summer 2026 Forecast

[22] The lower demand forecast in Texas RE-ERCOT is the result of updated load modeling that reflects the observed behavior of load during peak periods and more demand response from large computational loads.

Demand and Resource Tables

The tables in this section contain peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area.

MISO			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	125,313	127,824	2.0%
Demand Response: Available	9,004	9,100	1.1%
Net Internal Demand	116,309	118,725	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	142,793	152,382	6.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,280	3,259	42.9%
Anticipated Resources	145,073	155,641	7.3%
Existing-Other Capacity	1,190	0	-100.0%
Prospective Resources	148,543	158,900	7.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	31.1%	6.4
Prospective Reserve Margin	27.7%	33.8%	6.1
Reference Margin Level	15.7%	15.0%	-0.7

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,377	3,611	6.9%
Demand Response: Available	0	151	-
Net Internal Demand	3,377	3,460	2.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,583	5,631	0.9%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-1,714	-1,714	0.0%
Anticipated Resources	3,869	3,917	1.2%
Existing-Other Capacity	21	46	114.6%
Prospective Resources	3,890	3,963	1.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.6%	13.2%	-1.4
Prospective Reserve Margin	15.2%	14.5%	-0.7
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,620	3,688	1.9%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,570	3,638	1.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,477	4,409	-1.5%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,767	4,699	-1.4%
Existing-Other Capacity	0	0	-
Prospective Resources	4,767	4,699	-1.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	33.5%	29.2%	-4.4
Prospective Reserve Margin	33.5%	29.2%	-4.4
Reference Margin Level	15.0%	15.0%	0.0

MRO-SPP			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	56,168	57,122	1.7%
Demand Response: Available	1,408	1,772	25.8%
Net Internal Demand	54,760	55,350	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	70,549	69,317	-1.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-201	851	-524.0%
Anticipated Resources	70,348	70,168	-0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	69,801	69,621	-0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.5%	26.8%	-1.7
Prospective Reserve Margin	27.5%	25.8%	-1.7
Reference Margin Level	19.0%	10.0%	-9.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,584	3,691	3.0%
Demand Response: Available	327	342	4.6%
Net Internal Demand	3,257	3,349	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,348	5,721	31.6%
Tier 1 Planned Capacity	220	280	27.3%
Net Firm Capacity Transfers	63	153	142.9%
Anticipated Resources	4,631	6,154	32.9%
Existing-Other Capacity	0	0	-
Prospective Resources	4,631	6,154	32.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.2%	83.8%	41.6
Prospective Reserve Margin	42.2%	83.8%	41.6
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,471	31,578	0.3%
Demand Response: Available	1,487	1,415	-4.8%
Net Internal Demand	29,984	30,163	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,682	37,324	-1.0%
Tier 1 Planned Capacity	0	210	-
Net Firm Capacity Transfers	1,769	2,941	66.3%
Anticipated Resources	39,451	40,475	2.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,451	40,475	2.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	31.6%	34.2%	2.6
Prospective Reserve Margin	31.6%	34.2%	2.6
Reference Margin Level	15.0%	15.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,202	25,228	0.1%
Demand Response: Available	399	346	-13.3%
Net Internal Demand	24,803	24,882	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	27,054	27,667	2.3%
Tier 1 Planned Capacity	0	295	-
Net Firm Capacity Transfers	1,245	409	-67.1%
Anticipated Resources	28,299	28,371	0.3%
Existing-Other Capacity	668	0	-100.0%
Prospective Resources	28,967	28,371	-2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	14.0%	-0.1
Prospective Reserve Margin	16.8%	14.0%	-2.8
Reference Margin Level	12.7%	13.0%	0.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,955	22,545	2.7%
Demand Response: Available	998	1,088	9.1%
Net Internal Demand	20,957	21,457	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	24,760	26,837	8.4%
Tier 1 Planned Capacity	413	670	62.2%
Net Firm Capacity Transfers	689	900	30.6%
Anticipated Resources	25,862	28,407	9.8%
Existing-Other Capacity	0	0	-
Prospective Resources	25,862	28,407	9.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	23.4%	32.4%	9.0
Prospective Reserve Margin	23.4%	32.4%	9.0
Reference Margin Level	20.5%	26.3%	5.9

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,283	22,490	-3.4%
Demand Response: Available	1,020	450	-55.9%
Net Internal Demand	22,263	22,040	-1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	32,132	33,324	3.7%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,582	-3,670	42.1%
Anticipated Resources	29,550	29,655	0.4%
Existing-Other Capacity	0	0	-
Prospective Resources	29,550	29,655	0.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.7%	34.5%	1.8
Prospective Reserve Margin	32.7%	34.5%	1.8
Reference Margin Level	11.9%	11.9%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,765	44,369	3.8%
Demand Response: Available	864	2,354	172.3%
Net Internal Demand	41,900	42,016	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	46,949	47,603	1.4%
Tier 1 Planned Capacity	592	202	-66.0%
Net Firm Capacity Transfers	2,554	2,158	-15.5%
Anticipated Resources	50,095	49,962	-0.3%
Existing-Other Capacity	2,475	4,546	83.7%
Prospective Resources	52,570	54,508	3.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	19.6%	18.9%	-0.6
Prospective Reserve Margin	25.5%	29.7%	4.3
Reference Margin Level	15.0%	15.0%	0.0

PJM			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	154,144	156,373	1.4%
Demand Response: Available	7,898	7,864	-0.4%
Net Internal Demand	146,246	148,509	1.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	186,638	188,854	1.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-4,200	-1,427	-66.0%
Anticipated Resources	182,438	187,427	2.7%
Existing-Other Capacity	0	0	-
Prospective Resources	178,238	187,427	5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.7%	26.2%	1.5
Prospective Reserve Margin	21.9%	26.2%	4.3
Reference Margin Level	17.7%	18.6%	0.9

SERC-East			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	44,015	44,765	1.7%
Demand Response: Available	1,558	1,387	-11.0%
Net Internal Demand	42,457	43,378	2.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,665	54,637	0.0%
Tier 1 Planned Capacity	17	23	36.9%
Net Firm Capacity Transfers	150	119	-20.7%
Anticipated Resources	54,832	54,780	-0.1%
Existing-Other Capacity	2,628	3,890	48.1%
Prospective Resources	57,459	58,670	2.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.1%	26.3%	-2.8
Prospective Reserve Margin	35.3%	35.3%	0.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	52,987	54,477	2.8%
Demand Response: Available	3,158	3,335	5.6%
Net Internal Demand	49,829	51,142	2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	59,395	64,163	8.0%
Tier 1 Planned Capacity	102	58	-43.4%
Net Firm Capacity Transfers	381	131	-65.6%
Anticipated Resources	59,878	64,352	7.5%
Existing-Other Capacity	3,482	2,481	-28.7%
Prospective Resources	63,360	66,833	5.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.2%	25.8%	5.7
Prospective Reserve Margin	27.2%	30.7%	3.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	85,151	83,224	-2.3%
Demand Response: Available	3,292	5,100	54.9%
Net Internal Demand	81,859	78,124	-4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	112,321	125,975	12.2%
Tier 1 Planned Capacity	4,854	5,189	6.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	117,195	131,184	11.9%
Existing-Other Capacity	0	0	-
Prospective Resources	117,770	131,903	12.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	43.2%	67.9%	24.8
Prospective Reserve Margin	43.9%	68.8%	25.0
Reference Margin Level	13.75%	13.75%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	47,049	48,625	3.3%
Demand Response: Available	1,338	1,642	22.7%
Net Internal Demand	45,711	46,983	2.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	64,111	64,391	0.4%
Tier 1 Planned Capacity	0	375	-
Net Firm Capacity Transfers	489	-467	-195.5%
Anticipated Resources	64,600	64,299	-0.5%
Existing-Other Capacity	1,077	1,277	18.7%
Prospective Resources	65,676	65,576	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	41.3%	36.9%	-4.5
Prospective Reserve Margin	43.7%	39.6%	-4.1
Reference Margin Level	15.0%	15.0%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,246	12,499	2.1%
Demand Response: Available	0	0	-
Net Internal Demand	12,246	12,499	2.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,176	16,179	-5.8%
Tier 1 Planned Capacity	281	323	15.1%
Net Firm Capacity Transfers	0	40	-
Anticipated Resources	17,457	16,542	-5.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,457	16,542	-5.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.6%	32.3%	-10.2
Prospective Reserve Margin	42.6%	32.3%	-10.2
Reference Margin Level	9.4%	15.0%	5.6

WECC-BC			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	9,309	9,529	2.4%
Demand Response: Available	0	0	-
Net Internal Demand	9,309	9,529	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	11,313	12,307	8.8%
Tier 1 Planned Capacity	260	469	80.3%
Net Firm Capacity Transfers	0	612	-
Anticipated Resources	11,573	13,388	15.7%
Existing-Other Capacity	0	0	-
Prospective Resources	11,573	13,388	15.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	40.5%	16.2
Prospective Reserve Margin	24.3%	40.5%	16.2
Reference Margin Level	14.9%	10.0%	-4.9

WECC-California			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	54,797	55,073	0.5%
Demand Response: Available	746	685	-8.2%
Net Internal Demand	54,051	54,388	0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	75,726	78,788	4.0%
Tier 1 Planned Capacity	8,470	2,085	-75.4%
Net Firm Capacity Transfers	598	3,751	527.2%
Anticipated Resources	84,794	84,623	-0.2%
Existing-Other Capacity	0	0	-
Prospective Resources	84,794	84,623	-0.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	56.9%	55.6%	-1.3
Prospective Reserve Margin	56.9%	55.6%	-1.3
Reference Margin Level	19.2%	15.0%	-4.2

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	35,321	38,814	9.9%
Demand Response: Available	199	364	82.9%
Net Internal Demand	35,122	38,451	9.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,300	46,476	15.3%
Tier 1 Planned Capacity	1,966	6,667	239.1%
Net Firm Capacity Transfers	695	3,791	445.4%
Anticipated Resources	42,961	56,934	32.5%
Existing-Other Capacity	0	0	-
Prospective Resources	42,961	56,934	32.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	22.3%	48.1%	25.8
Prospective Reserve Margin	22.3%	48.1%	25.8
Reference Margin Level	13.3%	15.0%	1.7

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	29,157	30,479	4.5%
Demand Response: Available	30	2	-93.3%
Net Internal Demand	29,127	30,477	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	36,388	35,708	-1.9%
Tier 1 Planned Capacity	844	477	-43.5%
Net Firm Capacity Transfers	1,249	2,483	98.8%
Anticipated Resources	38,481	38,668	0.5%
Existing-Other Capacity	0	0	-
Prospective Resources	38,481	38,668	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	32.1%	26.9%	-5.2
Prospective Reserve Margin	32.1%	26.9%	-5.2
Reference Margin Level	23.1%	10.0%	-13.1

WECC-Basin			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	14,214	14,564	2.5%
Demand Response: Available	620	448	-27.7%
Net Internal Demand	13,594	14,116	3.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	14,923	16,759	12.3%
Tier 1 Planned Capacity	704	1,382	96.3%
Net Firm Capacity Transfers	1,274	1,288	1.1%
Anticipated Resources	16,901	19,429	15.0%
Existing-Other Capacity	0	0	-
Prospective Resources	16,901	19,429	15.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	24.3%	37.6%	13.3
Prospective Reserve Margin	24.3%	37.6%	13.3
Reference Margin Level	14.0%	15.0%	1.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	13,848	13,516	-2.4%
Demand Response: Available	284	310	9.1%
Net Internal Demand	13,564	13,206	-2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	17,312	18,363	6.1%
Tier 1 Planned Capacity	104	1,206	1059.6%
Net Firm Capacity Transfers	0	495	-
Anticipated Resources	17,416	20,063	15.2%
Existing-Other Capacity	0	0	-
Prospective Resources	17,415	20,063	15.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	28.4%	51.9%	23.5
Prospective Reserve Margin	28.4%	51.9%	23.5
Reference Margin Level	16.7%	15.0%	-1.7

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2025 SRA**	**2026 SRA**	**2025 vs. 2026 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,770	3,750	-0.5%
Demand Response: Available	0	0	-
Net Internal Demand	3,770	3,750	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,303	4,761	10.6%
Tier 1 Planned Capacity	0	765	-
Net Firm Capacity Transfers	0	-557	-
Anticipated Resources	4,303	4,969	15.5%
Existing-Other Capacity	0	0	-
Prospective Resources	4,303	4,969	15.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	32.5%	18.4
Prospective Reserve Margin	14.1%	32.5%	18.4
Reference Margin Level	9.6%	15.0%	5.4

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (VER) (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution (MW) of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (e.g., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area

	Wind			Solar PV			Hydro			Energy Storage Systems (ESS)		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Run-of-River Hydro	Expected Run-of-River Hydro	Expected Share of Nameplate (%)	Nameplate ESS	Expected ESS	Expected Share of Nameplate (%)
MISO	32,066	5,611	17%	20,419	12,322	60%	1,294	770	60%	3,560	3,457	97%
MRO-Manitoba Hydro*	259	47	18%	-	-	0%	202	-	0%	-	-	0%
MRO-SaskPower	816	319	39%	30	9	28%	121	74	61%	-	-	0%
MRO-SPP	35,760	8,114	23%	3,926	2,139	54%	113	66	59%	1,318	1,113	84%
NPCC-Maritimes	1,341	423	32%	148	80	54%	1,316	1,316	100%	162	106	65%
NPCC-New England	2,431	424	17%	3,609	1,728	48%	584	287	49%	723	686	95%
NPCC-New York	2,598	417	16%	661	283	43%	914	354	39%	23	-	0%
NPCC-Ontario*	4,943	735	15%	478	66	14%	-	-	0%	451	226	50%
NPCC-Québec*	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
PJM	13,855	4,570	33%	16,852	9,951	59%	2,505	2,505	100%	256	238	93%
SERC-Central	1,324	370	28%	2,303	1,446	63%	4,979	3,213	65%	100	100	100%
SERC-East	-	-	0%	7,843	4,205	54%	3,096	3,033	98%	323	235	73%
SERC-Florida Peninsula	-	-	0%	13,502	6,276	46%	-	-	0%	1,177	1,145	97%
SERC-Southeast	-	-	0%	9,412	8,087	86%	3,326	3,374	101%	164	141	86%
Texas RE-ERCOT	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC-AB	5,684	455	8%	1,870	1,271	68%	896	481	54%	261	222	85%
WECC-Basin	5,959	360	6%	3,773	2,605	69%	884	386	44%	655	557	85%
WECC-BC*	753	60	8%	17	12	71%	1,871	888	47%	-	-	0%
WECC-Cal	7,985	907	11%	27,495	14,278	52%	1,120	628	56%	16,711	14,204	85%
WECC-Mexico	296	3	1%	350	35	10%	-	-	0%	-	-	0%
WECC-NW*	9,941	1,016	10%	1,729	1,051	61%	14,086	8,303	59%	547	461	84%
WECC-RM	5,684	1,034	18%	2,920	1,551	53%	117	61	52%	342	291	85%
WECC-SW	4,848	1,473	30%	11,112	4,868	44%	376	270	72%	3,691	3,137	85%
EASTERN INTERCONNECTION	94,474	21,180	22%	78,714	46,528	59%	18,892	15,435	82%	7,805	7,220	92%
QUÉBEC INTERCONNECTION	4,024	885	22%	10	1	12%	444	444	100%	-	-	0%
TEXAS INTERCONNECTION	40,586	9,450	23%	40,279	29,682	74%	579	447	77%	21,979	20,688	94%
WECC INTERCONNECTION[23]	41,150	5,308	13%	49,266	25,670	52%	19,350	11,017	57%	22,207	18,872	85%
All INTERCONNECTIONS	**181,153**	**36,673**	**20%**	**168,736**	**101,946**	**60%**	**38,822**	**26,899**	**69%**	**52,442**	**47,005**	**90%**

*On peak contributions from conventional hydro are not represented in this table, and in certain areas those contributions are significant.

[23] Some areas in the Western Interconnection re-categorized their hydro resources for the 2026 SRA from run-of-river hydro to conventional hydro

Review of 2025 Capacity and Energy Performance

The summer of 2025 was the 12th hottest on record for the contiguous United States[24] during the meteorological summer period (June–August) and the 11th warmest summer in Canada.[25] Cooler-than-normal temperatures were observed in the eastern U.S., whereas most of Canada experienced slightly above-normal temperatures. Despite the comparatively temperate 2025 Summer (summer of 2024 was the fourth-hottest on record in both the United States[26] and Canada[27]), U.S. electricity generation reached a record high for the assessment summer period (June – September) at 1,628 TWh[28], topping the prior year's summer electricity generation total of 1,603 TWh. The month of July in the U.S. set a new monthly generation record at 446 TWh. In Canada, the comparatively cooler summer appears to have brought electricity generation down from the 2024 summer high of 192 TWh to the 2025 total of 188 TWh[29]. Actual peak demand exceeded normal demand forecasts across 19 assessment areas and exceeded extreme demand projections from the *2025 SRA* in three assessment areas. Despite a lower average summer temperature in 2025, a widespread heatwave[30] in early summer impacted much of the central and eastern U.S., bringing record-setting temperatures across several hundred counties.

Canada experienced its second-worst wildfire year on record[31] (2023 being the worst) with fires burning an area larger than New Brunswick and Prince Edward Island combined. Saskatchewan and Manitoba comprised nearly half of the total area impacted by the fires. Drought that began in 2021 has also deepened across Canada, resulting in reduced hydroelectric power generation for a third straight year in British Columbia.

Eastern Interconnection–Canada and Québec Interconnection

In Ontario, grid operators utilized demand response resources on 10 different occasions during the summer period,[32] culminating in demand reductions of 316 MW during the time of peak demand (24,862 MW) on June 24, 2025, the single highest peak in 12 years. Other demand-side management programs further reduced peak demand by 1,800 MW, contributing to 7% total reduction in demand stemming from consumer programs.

Québec saw electricity generation of roughly 52 TWh during the summer period,[33] down from 56 TWh for Summer 2024 amid relatively cooler temperatures and a year beset by low runoff levels that have persisted since 2023.[34] The Maritimes saw a slight increase in electricity generation to 5.8 TWh for Summer 2025, up from 5.3 TWh the prior summer. Nova Scotia Power realized nearly a 20% reduction in annual 2025 power outages from the year before but still fell short of targets set by the Nova Scotia Energy Board relating to power-outage duration and frequency.

Saskatchewan saw severe storms and large hail in late August that damaged infrastructure, triggering emergency operating conditions and power outages.[35]

[24] Assessing the U.S. Temperature and Precipitation Analysis in August 2025 | News | National Centers for Environmental Information (NCEI)
[25] Climate Trends and Variations Bulletin - summer 2025 - Canada.ca
[26] U.S. sweltered through its 4th-hottest summer on record | National Oceanic and Atmospheric Administration
[27] Climate Trends and Variations Bulletin - Summer 2024 - Canada.ca
[28] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis
[29] Electric power generation, monthly generation by type of electricity
[30] Assessing the U.S. Climate in June 2025 | News | National Centers for Environmental Information (NCEI)
[31] Canada's top 10 weather stories of 2025 - Canada.ca
[32] 2025 Year in Review
[33] Electric power generation, monthly generation by type of electricity
[34] Hydro-Québec - Quarterly Bulletin - Third Quarter 2025
[35] SaskPower crews still working to restore power after weekend outages - WestCentralOnline: West Central Saskatchewan's latest news, sports, weather, community events.

Eastern Interconnection–United States

New York and New England saw region-wide heat waves in June and July. ISO-NE saw peak-hour demand in June exceed its extreme demand projections from the *2024 SRA*, a significant step up from the prior year's summer peak (+7%). Heat and humidity, high demand, and some unexpected generation reductions and outages left the region short of the resources needed to maintain required operating reserves for more than three hours around the evening peak on June 24,[36] though electricity supply was not interrupted. NYISO declared an EEA Level 1 on June 24, June 25, and July 29 due to limited capacity availability,[37] resulting in the deployment of emergency DR programs and other special-case resources. Both the New York and New England ISOs saw peak loads that exceeded their demand projections.

PJM saw their third-highest all-time summer peak[38] of more than 160 GW. This exceeded extreme demand projections for the summer (159 GW). The system operator was able to manage load by calling on customers who were enrolled in financially incentivized DR programs.

MISO declared an EEA Level 1[39] on June 23 to access emergency capacity. At the time of the event, more than 4 GW of generation was trapped in the south due to transmission constraints. MISO was able to dispatch 565 MW of emergency capacity in the Midwest, but only 45% performed. MISO has been engaged in efforts to highlight the need for non-performance penalties. On June 24, when neighboring areas were experiencing peak demand, MISO had to curtail non-firm exports to avoid going into EEA. In late July, MISO experienced a shortage of operating reserves due to errors in forecasting load and renewables. This was one of 24 total instances of operating reserve shortage, double the amount from the previous year.

In SERC, an EEA Level 2 was declared in the Carolinas amid high load conditions and generation resources that were unavailable[40] during the peak of the June heat wave affecting the broader Eastern Interconnection – a precautionary reliability measure to support system operations during peak demand and generation outages. During this event, the affected service territory recorded a new all-time peak demand of 21,931 MW on June 25.

Texas Interconnection–ERCOT

Texas saw a relatively mild summer and above-average rainfall in 2025 with the June–July period ranking as the 43rd hottest out of 131 historical years. But even so, Summer 2025 load levels were comparable to the 2023 Summer load levels when the summer was far hotter.[41] Forced outages of thermal resources outstripped such forced outages from the summer of 2024, prompting a larger discharge of energy storage resources (ESR) some evenings. Texas set a new solar generation record in July at 29.3 GW, and solar contributed just under 17 GW at the hour of peak demand on August 18 (hour ending at 6:00 pm). Wind generation was relatively high at the peak demand hour and also set records in the spring. Energy storage also reached a new discharge record at 7.2 GW on August 20.

Western Interconnection

The Western Interconnection saw summer peak demand decrease slightly from the previous year's summer peak, reaching 163,140 MW in 2025, down from 168,206 MW the prior summer. Operators and RCs were able to maintain the flow of electricity through the summer months.

[36] Summer 2025 recap: Reliability maintained as grid sees highest peak in over a decade - ISO Newswire
[37] NYISO Summer 2025
[38] 2025 in Review: Operations Improvements See PJM Through Record Peaks, Growing Demand | PJM Inside Lines
[39] Microsoft PowerPoint - IMM Quarterly Report, Summer 2025
[40] DOE grants Duke Energy authority to exceed power plant permit limits during extreme heat | Utility Dive
[41] 12 Summer 2025 Operational and Market Review.pptx

Western Interconnection–Canada

Western Canada experienced a heat wave from late August and through early September, breaking daily records in British Columbia and the Yukon and exacerbating the ongoing drought in western Canada. Wildfire activity also increased due to heat and dry conditions. The same period brought generation outages that triggered emergency operations in parts of western Canada.

Western Interconnection–United States

The western United States overall navigated last summer with the BPS experiencing relatively few emergency events, and demand in western assessment areas never reached or exceeded the projections for extreme demand from the *2025 SRA.* Variable resources performed as expected with the exception of California seeing much less solar generation than anticipated, 65% less solar than was projected ahead of the prior year's assessment. California's lower-than-expected solar did not result in energy shortfalls.

In Mexico, generation losses in late August triggered Level 3 EEAs, but the overall number of Level 3 EEAs was down year-on-year and on par with the number of Level 3 EEAs triggered in 2023 for the same seasonal period.

Despite the moderation in summer heat when compared to 2024, certain Rocky Mountain states saw record temperatures with Utah and Nevada recording their warmest years on record. The Rocky Mountain region saw peak demand surpass the projected normal demand conditions but remained under extreme demand projections.

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	Actual Peak Demand[1] (GW)	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)
MISO	121.6	116.3 121.6	1,105	6,039	12,323	9,123	8,856
MRO-Manitoba Hydro	3.5	3.4 3.6	0	48	0	0	252
MRO-SaskPower	3.6	3.6 3.8	232	310	26	9	0
MRO-SPP	54.5	54.8 57.5	8,130	5,556	810	492	4,370
NPCC-Maritimes	3.6	3.3 3.5	151	314	69	0	33
NPCC-New England	26.6	24.7 26.4	566	142	180	1,412	1,963
NPCC-New York	32	30.0 31.7	1,256	446	164	243	1,372
NPCC-Ontario	24.9	21.0 24.5	607	742	39	66	1,532
NPCC-Québec	23.0	22.3 23.3	790	885	0	0	5,029
PJM	160.7	146.2 158.7	4,515	1,855	7,730	6,244	15,945
SERC-C	43.2	41.9 45.7	84	370	714	1,053	701
SERC-E	44.8	42.5 45.7	0	0	3,200	5,022	2,407
SERC-FP	54.6	49.8 50.8	0	0	8,035	5,749	1,599
SERC-SE	46.4	45.7 55.9	0	0	3,366	7,728	1,380
TRE-ERCOT	83.7	85.2[5] 91.3[5]	14,509	9,396	16,961	22,962	11,095
WECC-AB	12.5	12.2 12.7	2,870	796	32	1,480	**
WECC-BC	9.8	9.3 10.0	293	149	4.8	0	**
WECC-CA	54	54.1 64.3	1,744	1,207	5,064	14,756	1,063

2025 Summer Demand and Generation Summary at Peak Demand							
Assessment Area	**Actual Peak Demand[1] (GW)**	**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)**
WECC-MX	3.5	3.8 4.1	2.5	50	296	227	**
WECC-NW	29.8	29.1 32.7	1,054	3,107	1,398	666	1,825
WECC-RM	13.4	13.8 15.0	2,313	1,359	1,571	1,669	1,954
WECC-Basin	13.8	13.6 15.0	931	911	2,660	2,231	0
WECC-SW	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*.
[4] Values from NERC Generator Availability Data System 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*.
[5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (3.2 GW) to the demand scenarios found on p. 30 of the 2025 SRA.
**Data unavailable - Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.