UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit MMM: Tri-State, Request for Clarification and for Rehearing of Tri-State Generation and Transmission Association and Platte River Power Authority
(Apr. 29, 2026)

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

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[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.

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

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. <u>The Order Mandates Physical Changes to Petitioners' Property That Constitute a Physical Taking</u>

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

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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. <u>Economic Impact</u>

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. <u>Investment-Backed Expectations</u>

"[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. <u>Character of the Taking</u>

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. <u>The Order Violates Petitioners' Constitutional Due Process Rights</u>

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

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[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.").

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[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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UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit NNN: NERC, 2026 Summer Resource Adequacy (May 2026)

2026 Summer Reliability Assessment

May 2026

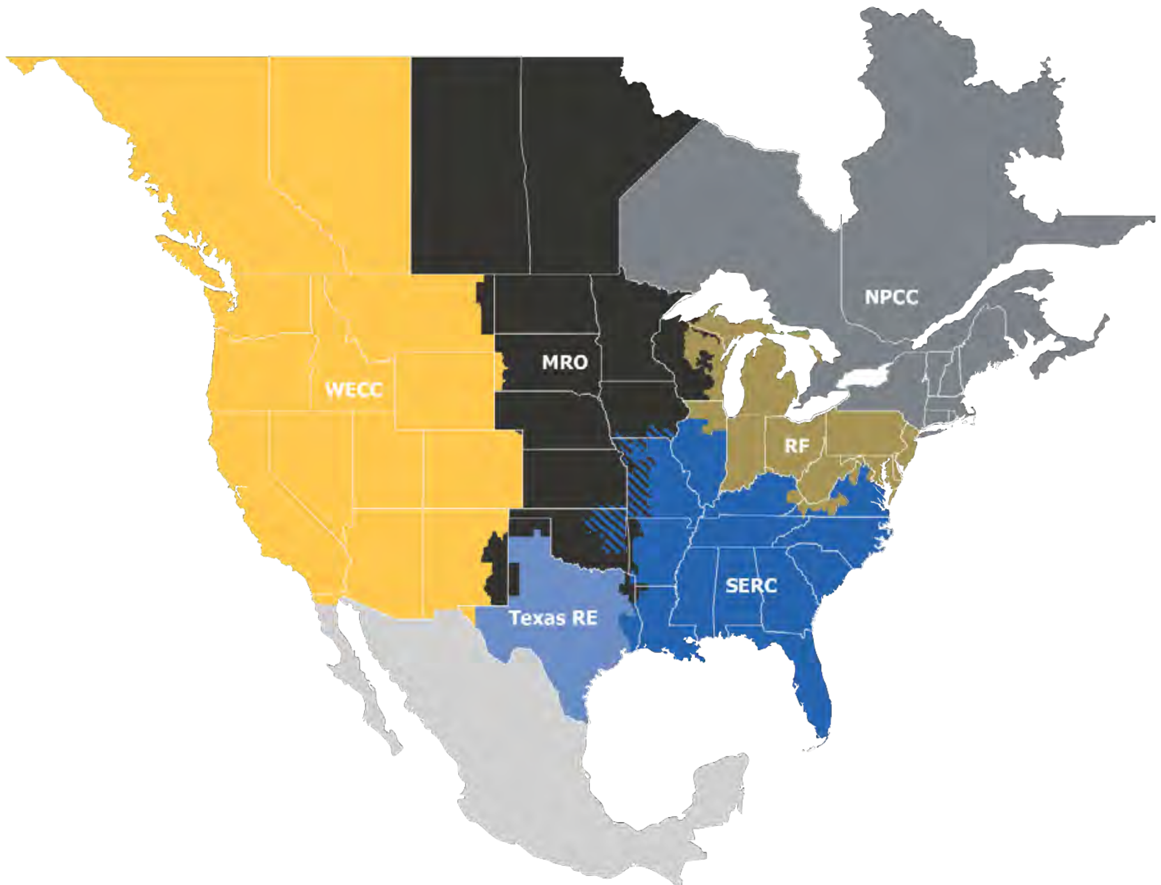
Table of Contents

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.

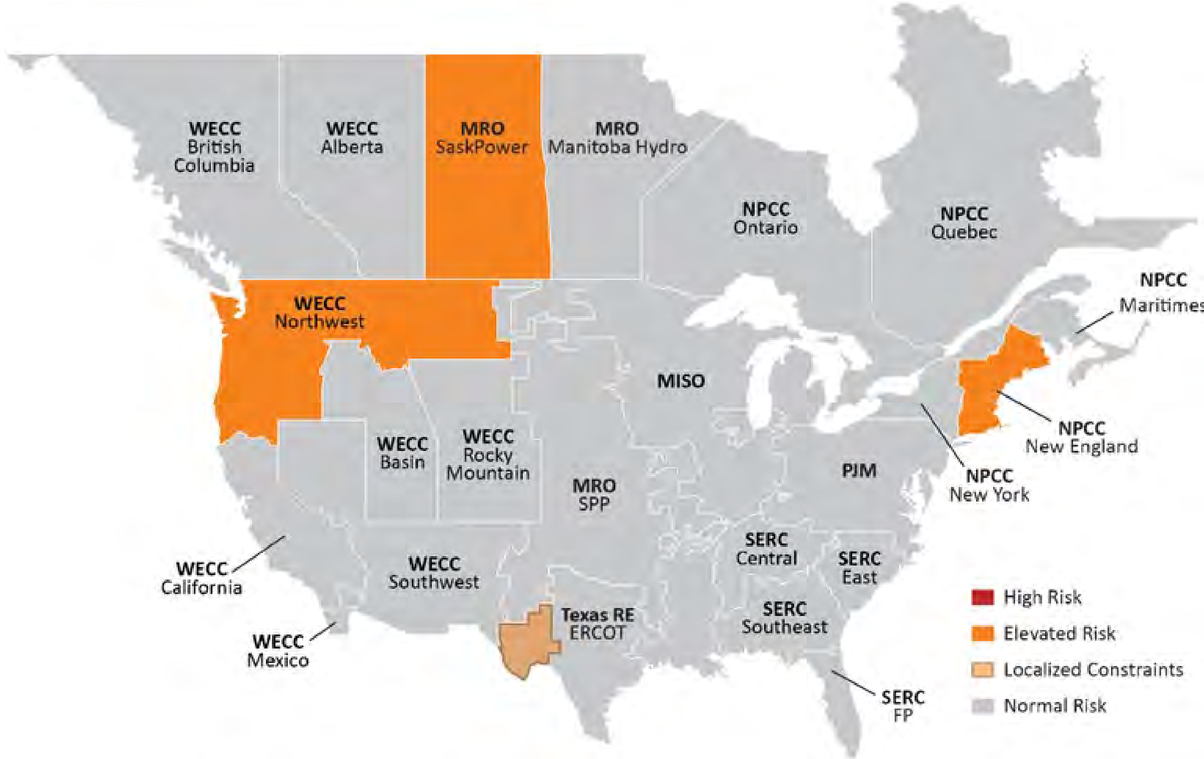
Resource Adequacy Assessment and Energy Risk Analysis

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.

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[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^{o}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.

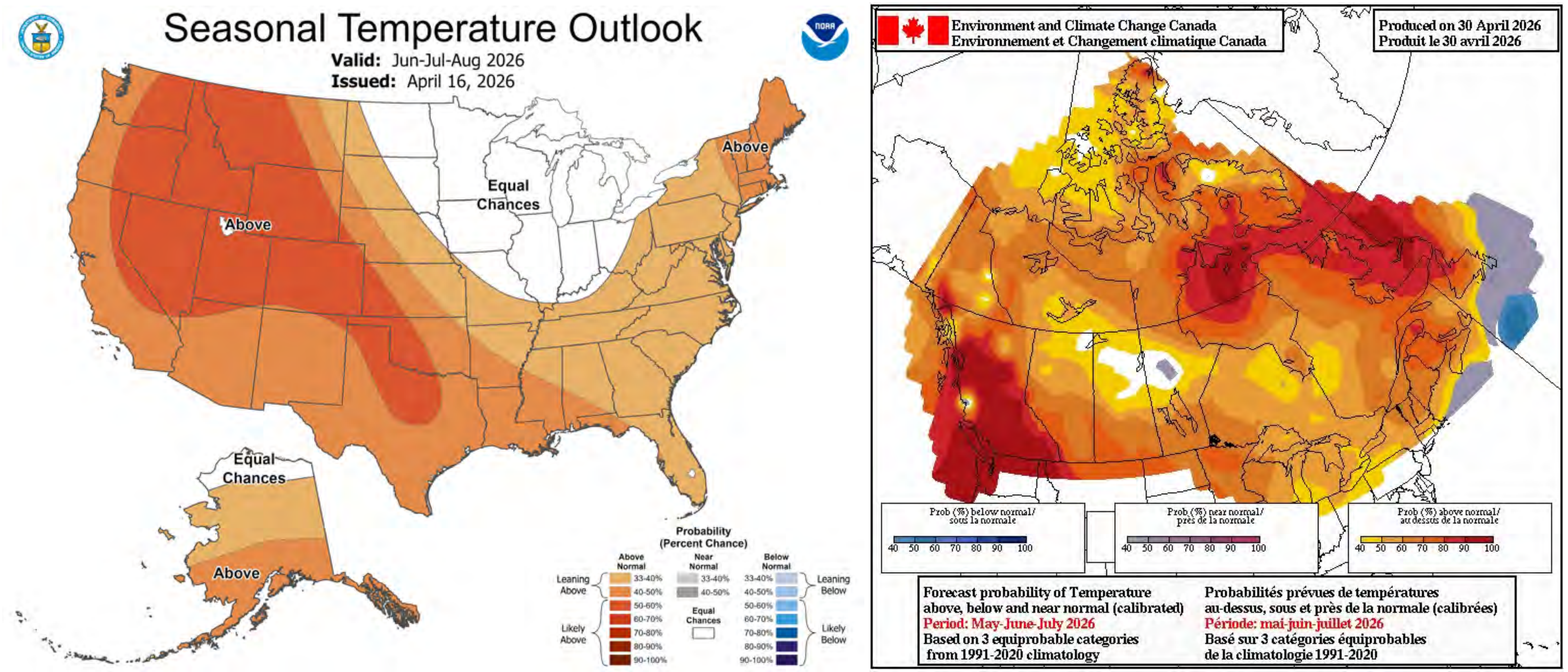


Figure 2: United States and Canada Summer Temperature Outlook[15]

[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.

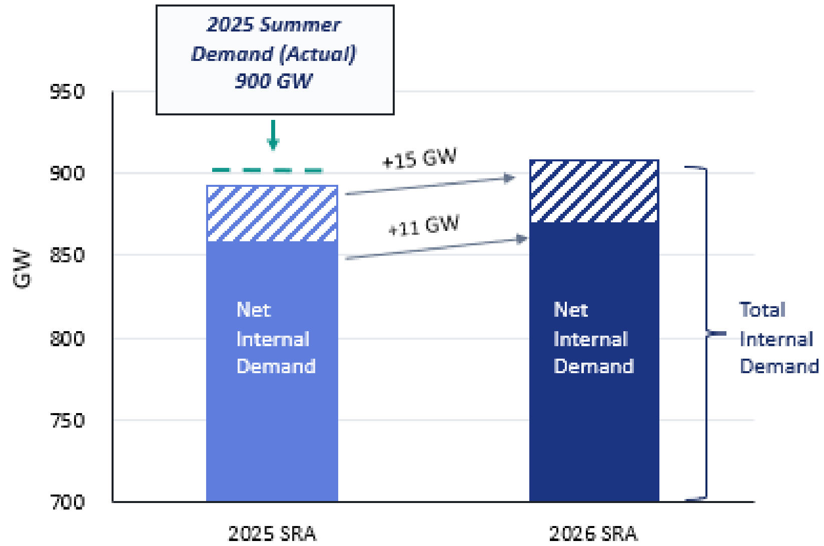


Figure 3: BPS Total and Net Internal Demand
Aggregated Peak Demand from All Assessment Areas

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.

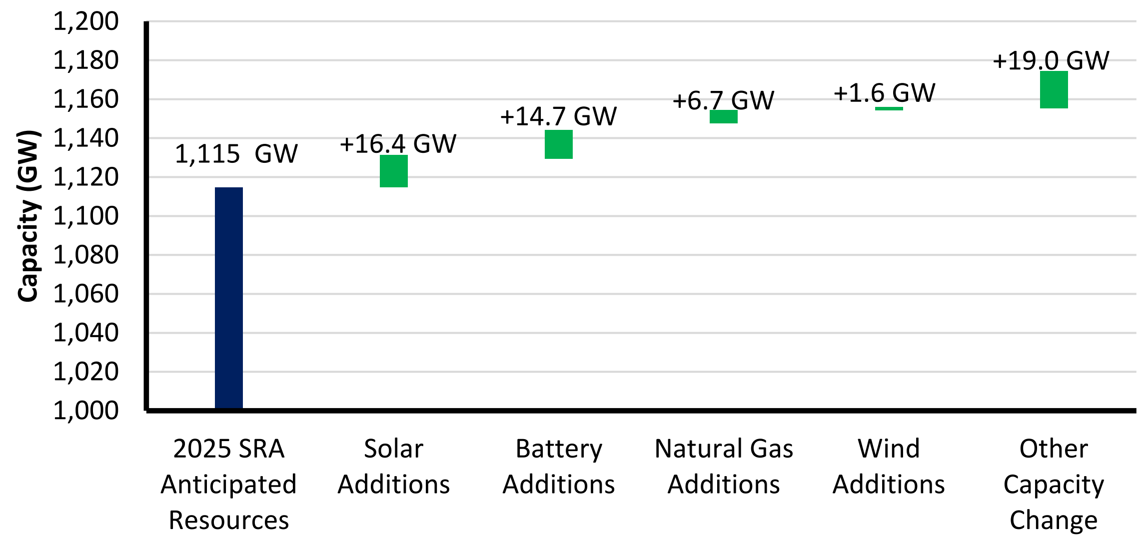


Figure 4: Summer BPS Resource Capacity Change Since 2025

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.

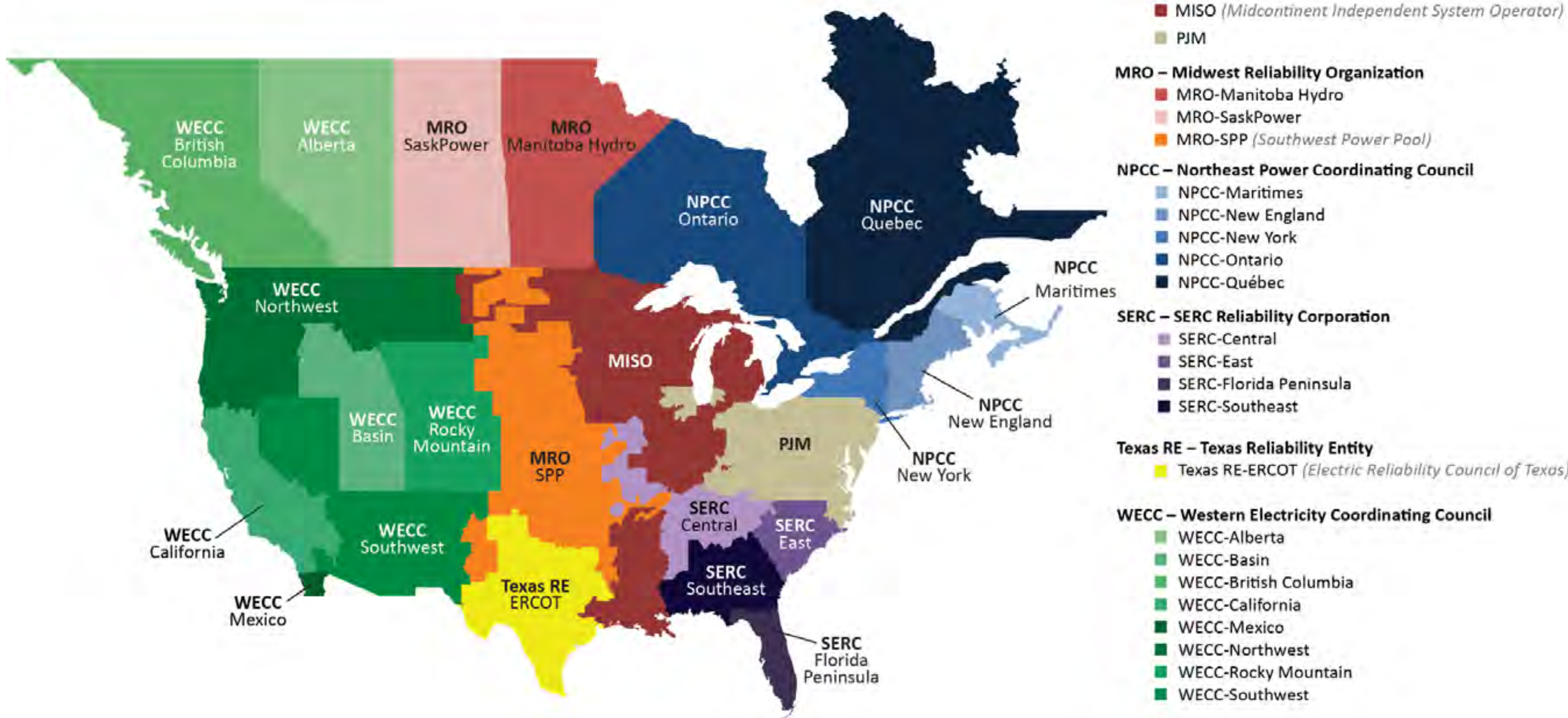
[16] Based on preliminary runs from March 31, 2026

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.

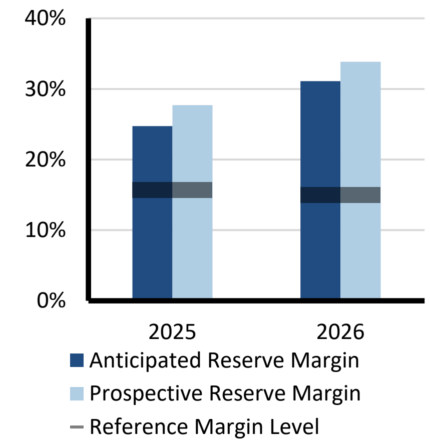
Highlights

- 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.

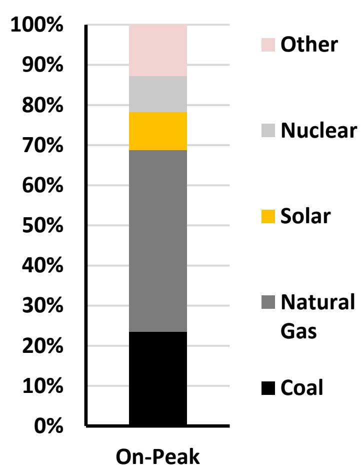
Risk Scenario Summary

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.

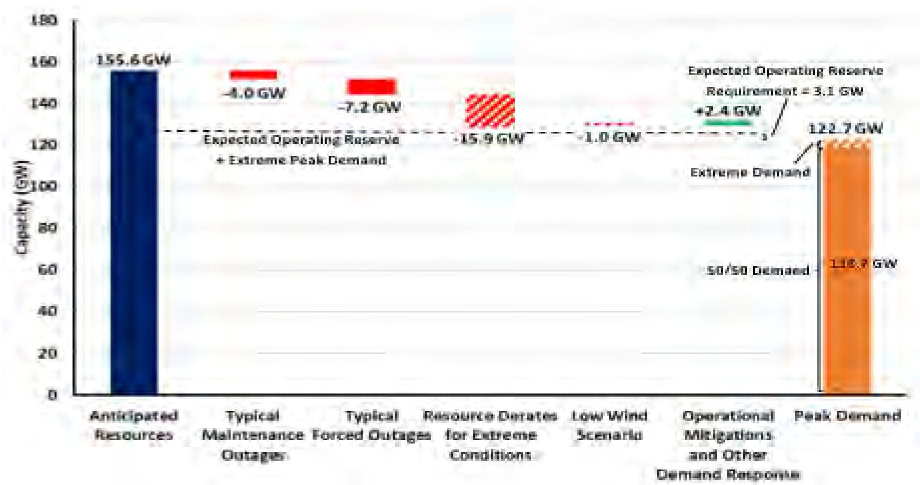
On-Peak Reserve Margin



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.

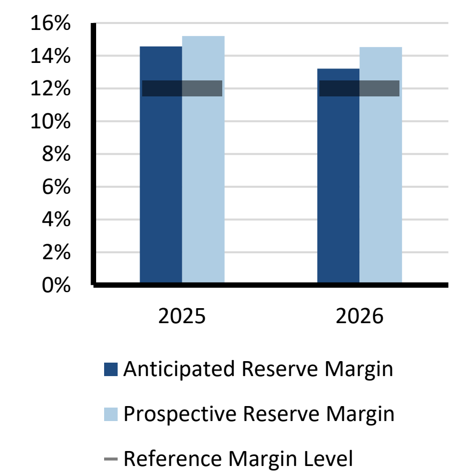
MRO-Manitoba Hydro

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.

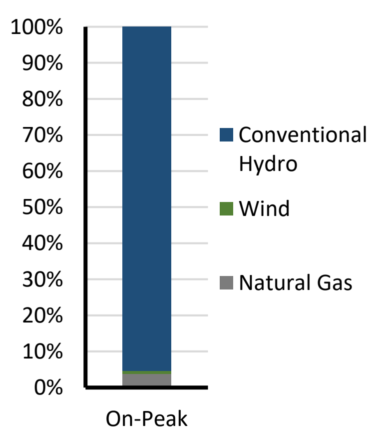
On-Peak Reserve Margin



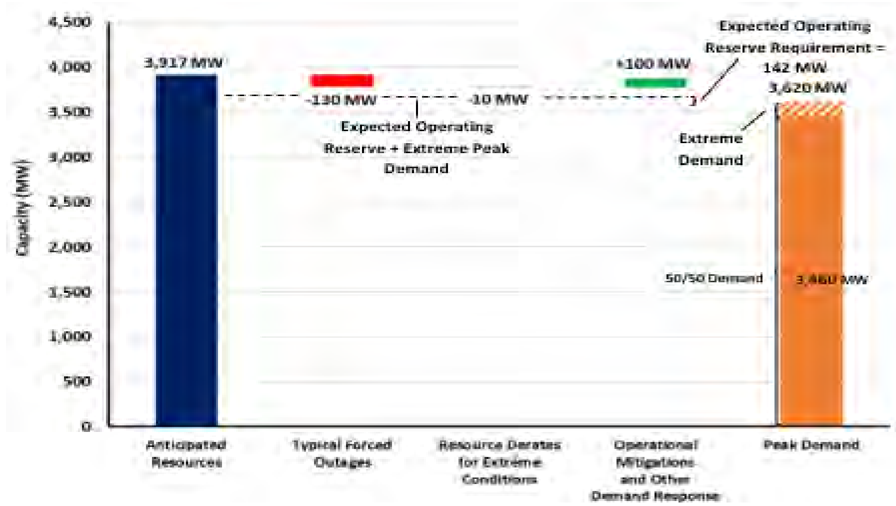
Risk Scenario Summary

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: 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.

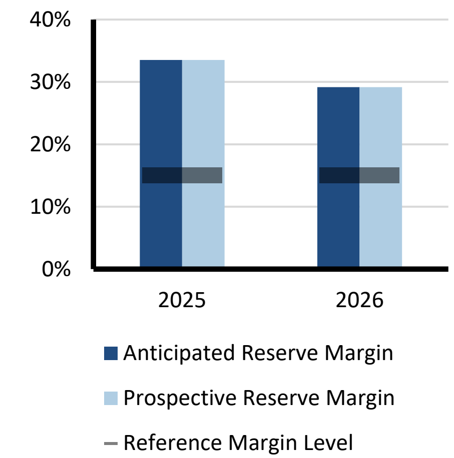
MRO-SaskPower

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.

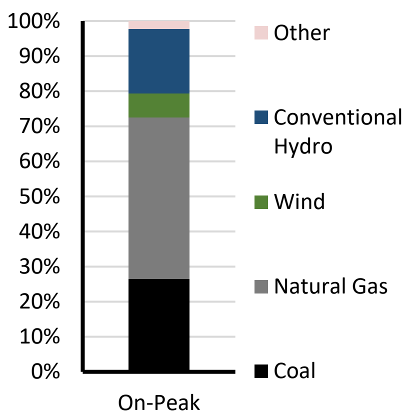
On-Peak Reserve Margin



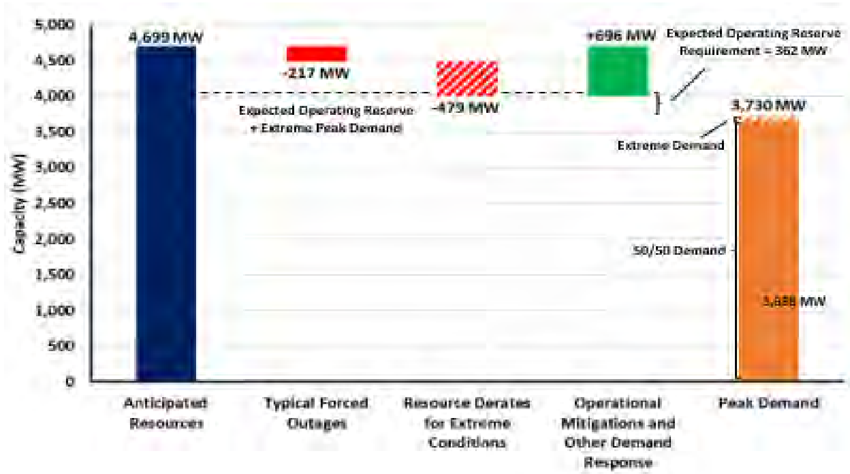
Risk Scenario Summary

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.

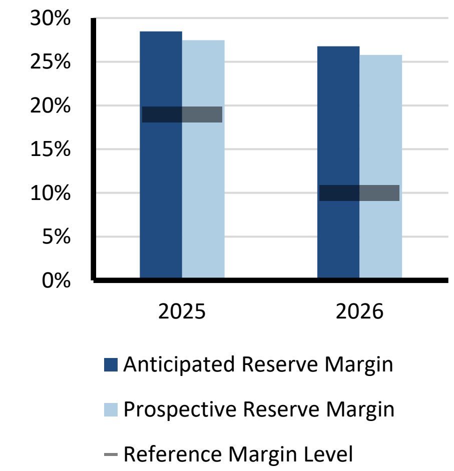
MRO-SPP

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.

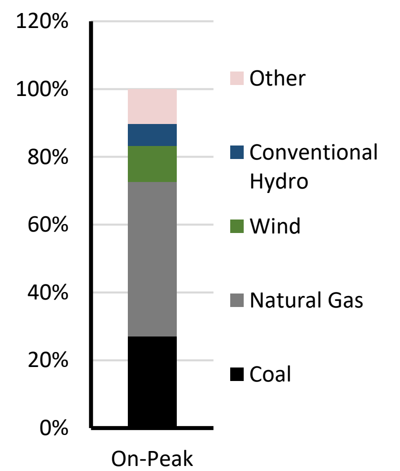
On-Peak Reserve Margin



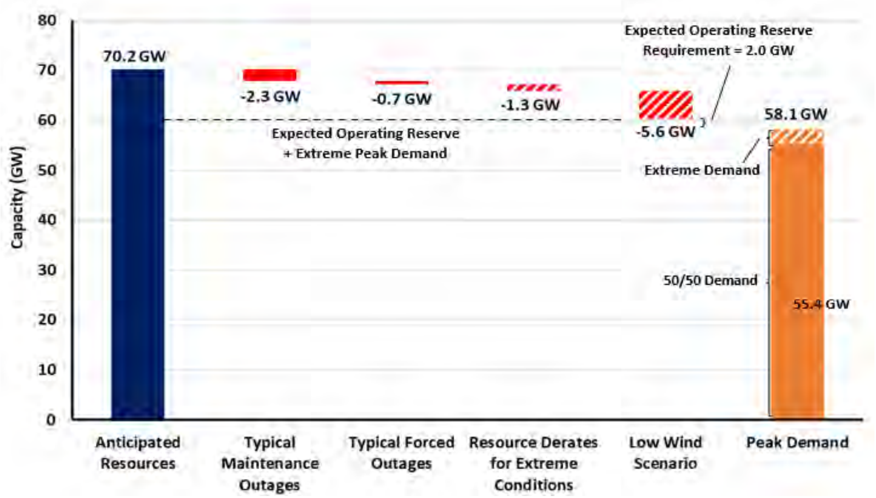
Risk Scenario Summary

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.

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.

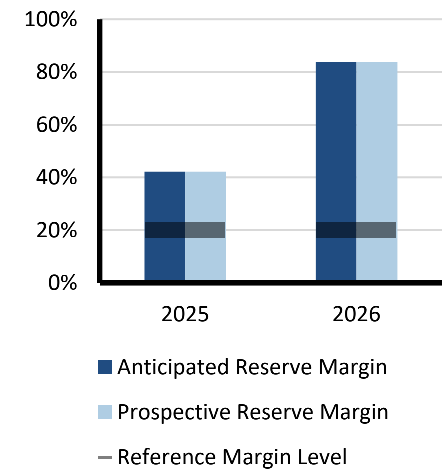
NPCC-Maritimes

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.

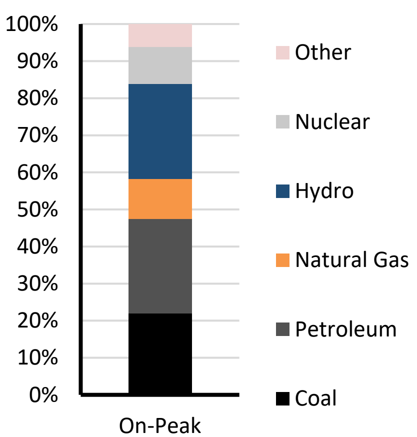
On-Peak Reserve Margin



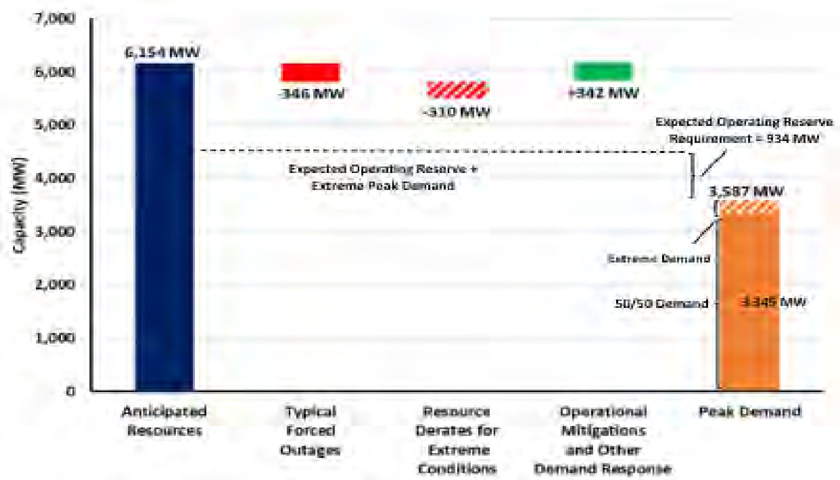
Risk Scenario Summary

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 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

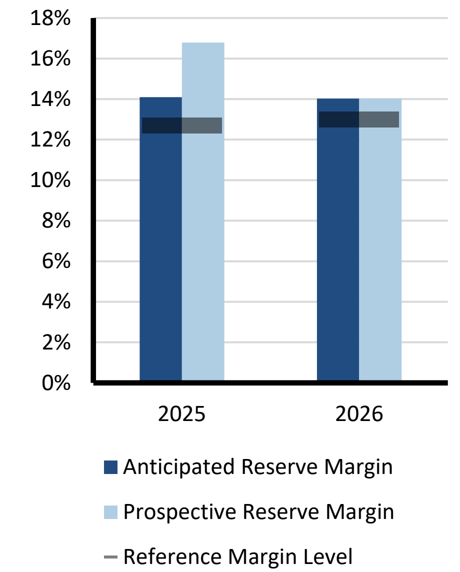
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New 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.

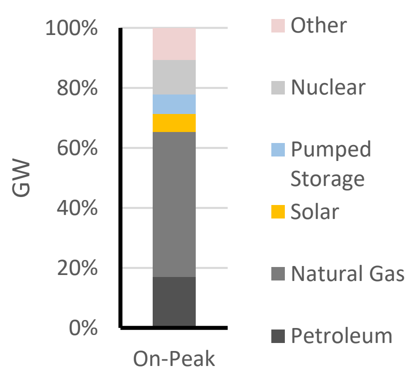
On-Peak Reserve Margin



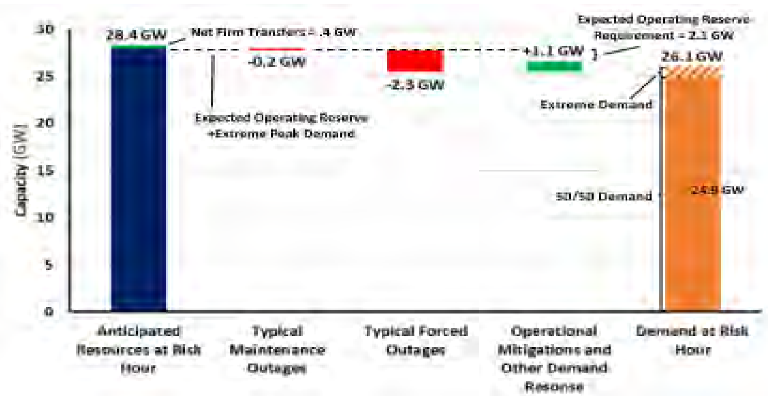
Risk Scenario Summary

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.

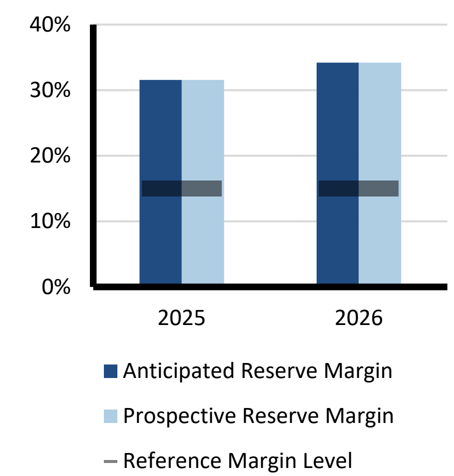
NPCC-New York

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

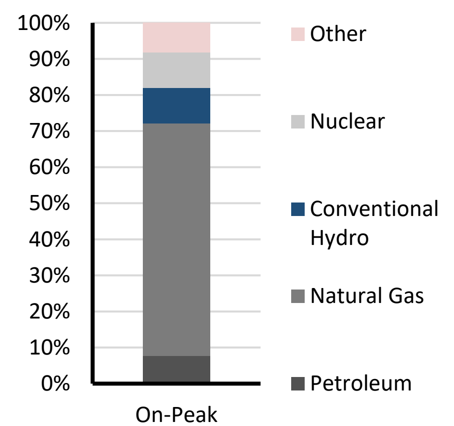
On-Peak Reserve Margin



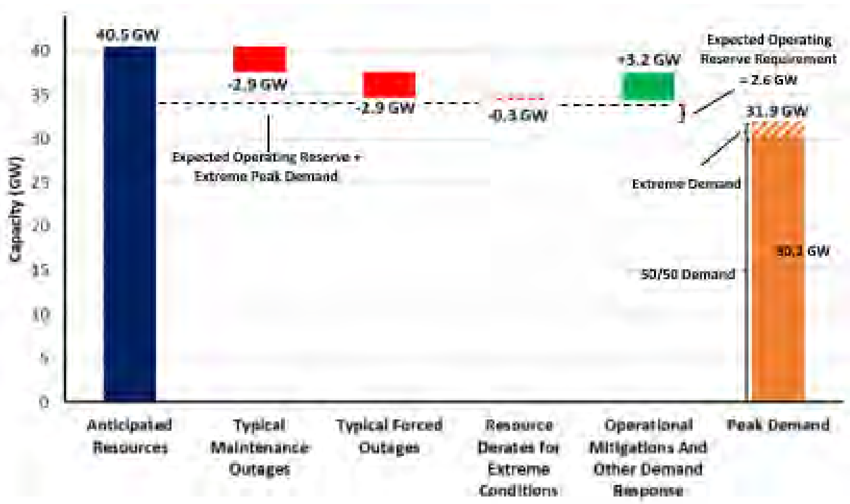
Risk Scenario Summary

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.

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.

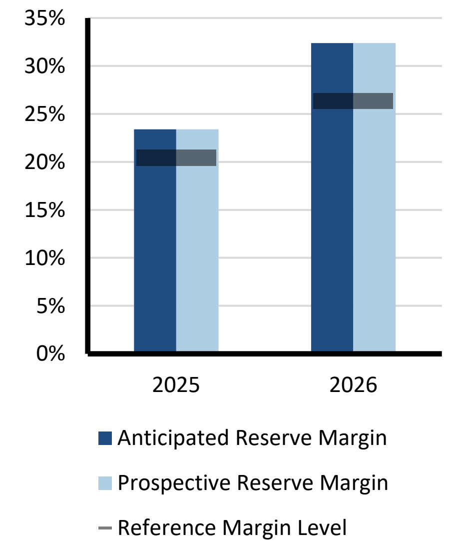
NPCC-Ontario

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.

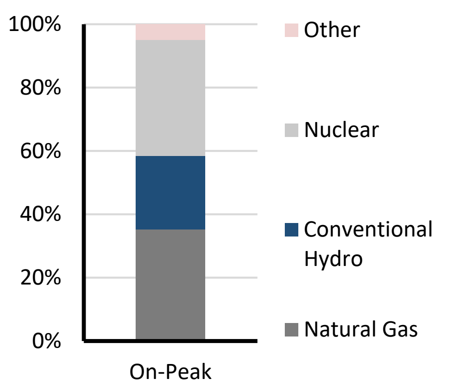
On-Peak Reserve Margin



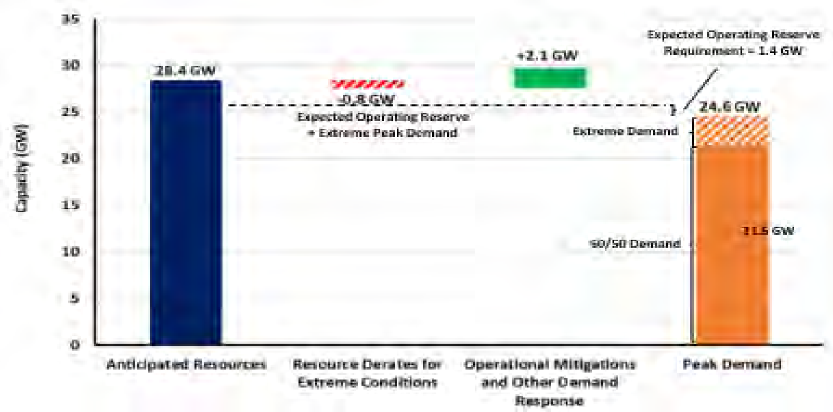
Risk Scenario Summary

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 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.

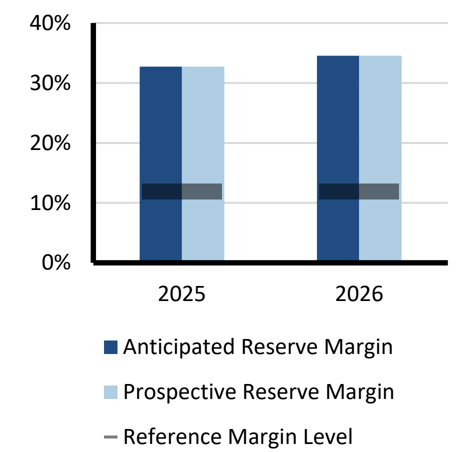
Highlights

- 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.

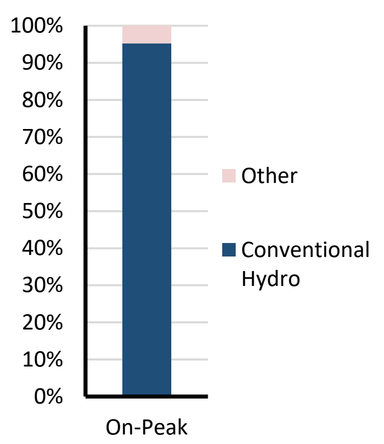
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

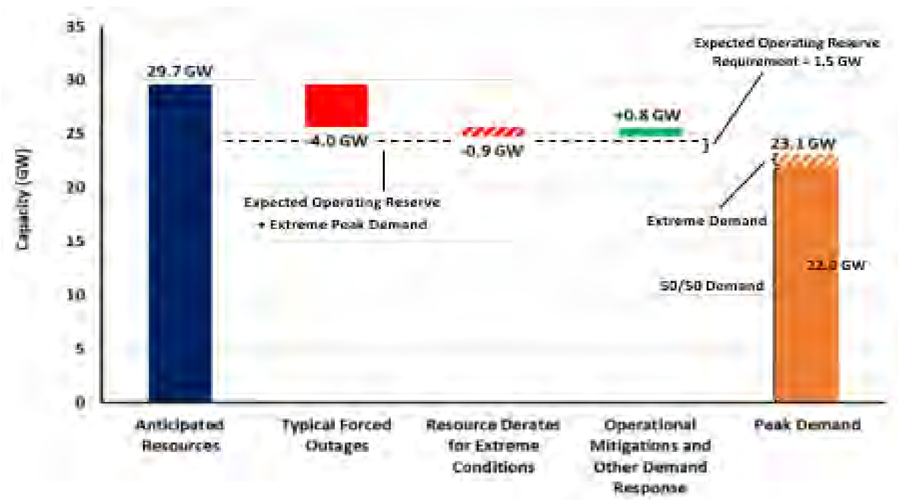
On-Peak Reserve Margin



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.

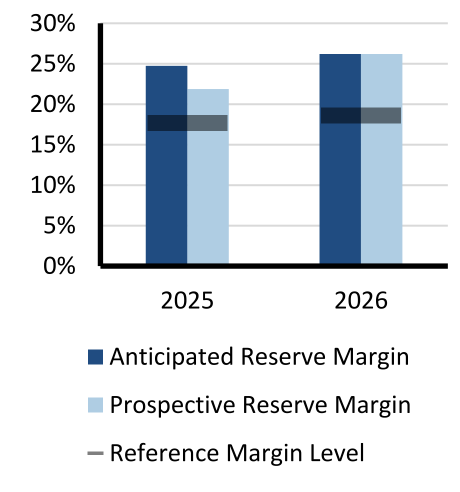
PJM

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.

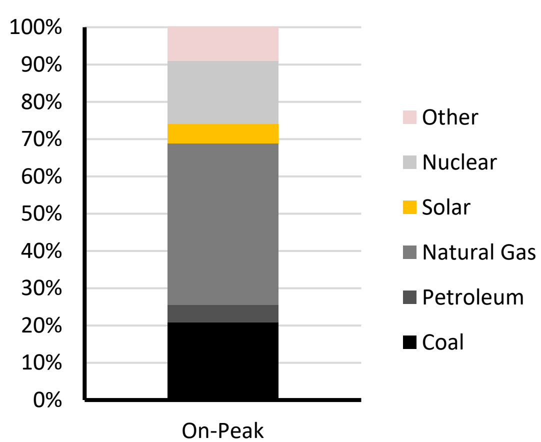
On-Peak Reserve Margin



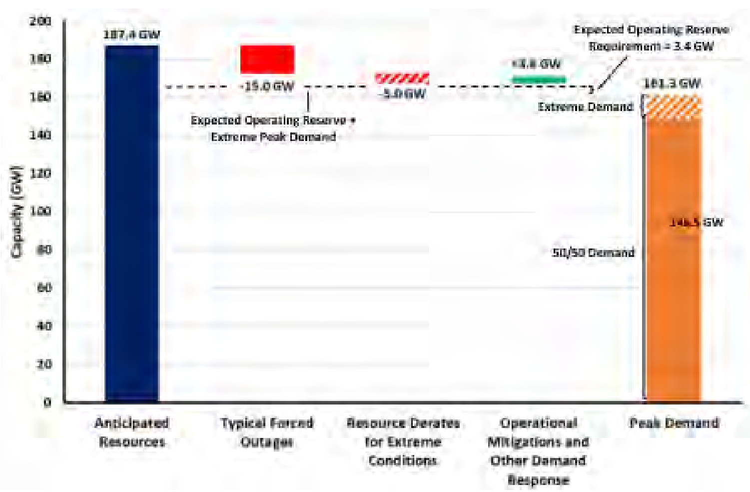
Risk Scenario Summary

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.

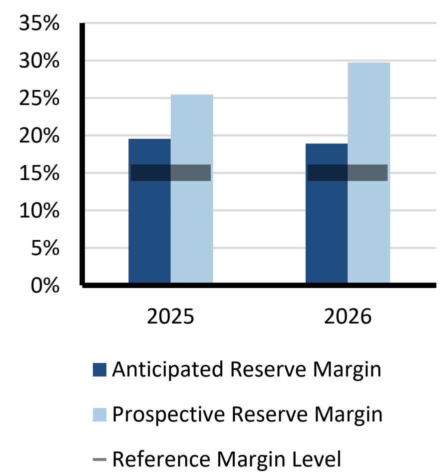
Highlights

- 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.

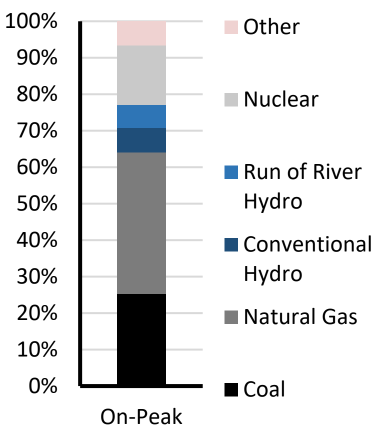
Risk Scenario Summary

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 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.

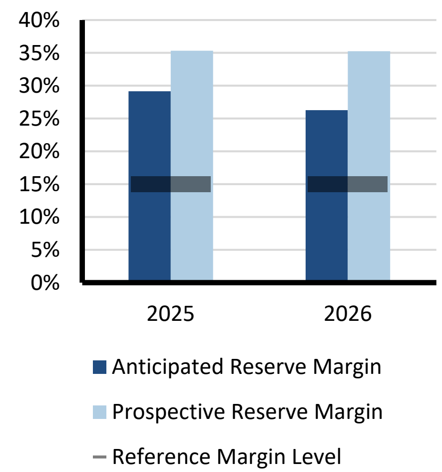
Highlights

- 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.

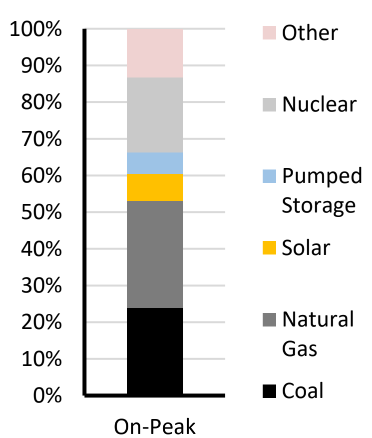
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

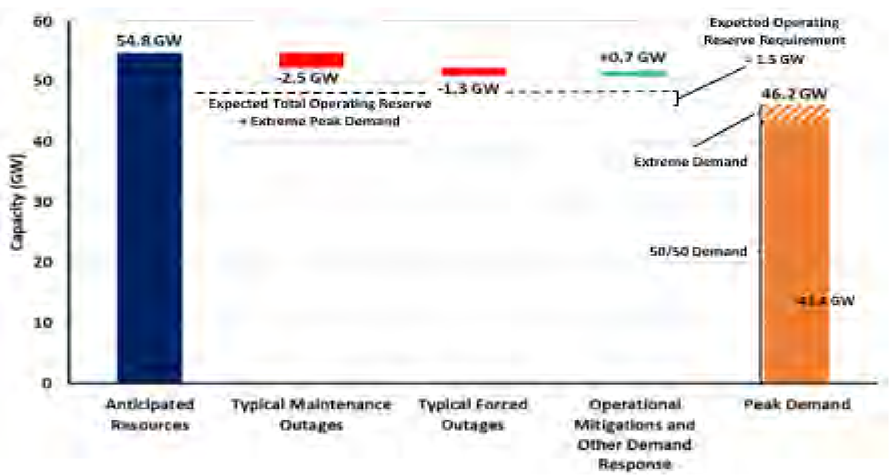
On-Peak Reserve Margin



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 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.

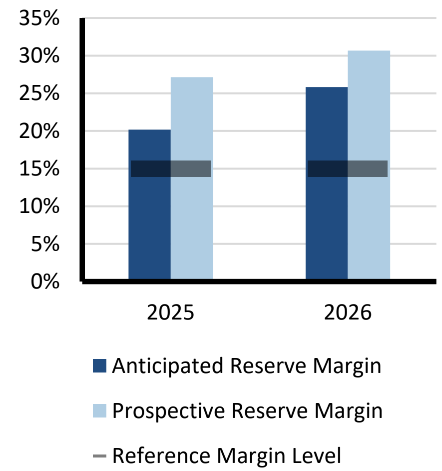
Highlights

- 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.

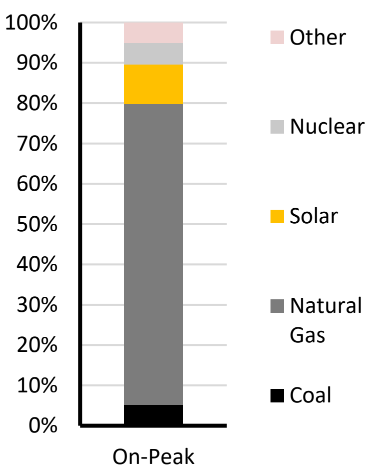
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

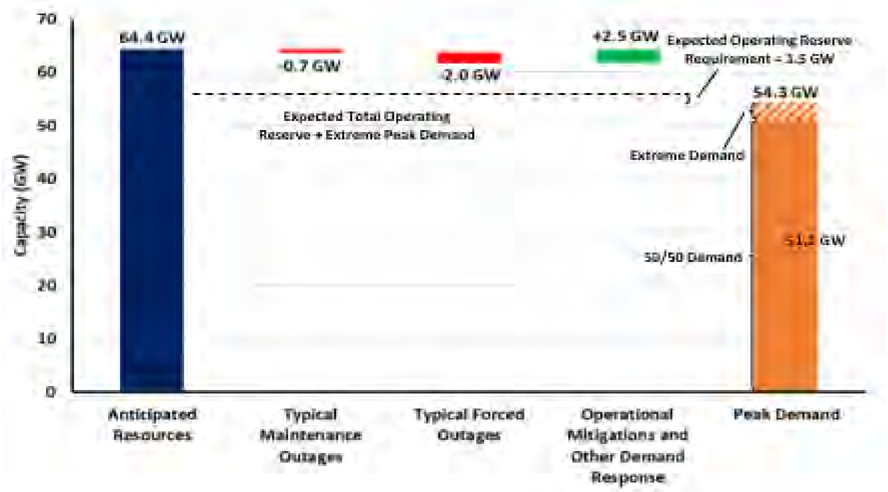
On-Peak Reserve Margin



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 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.

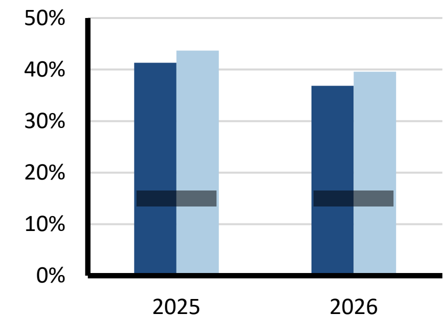
SERC-Southeast

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.

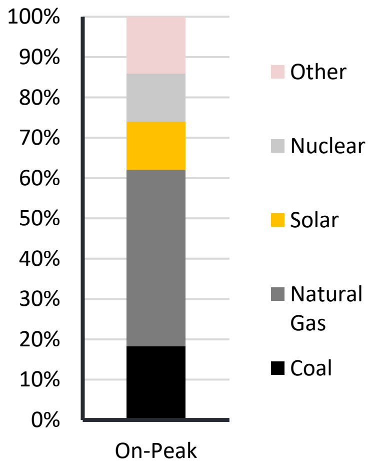
On-Peak Reserve Margin



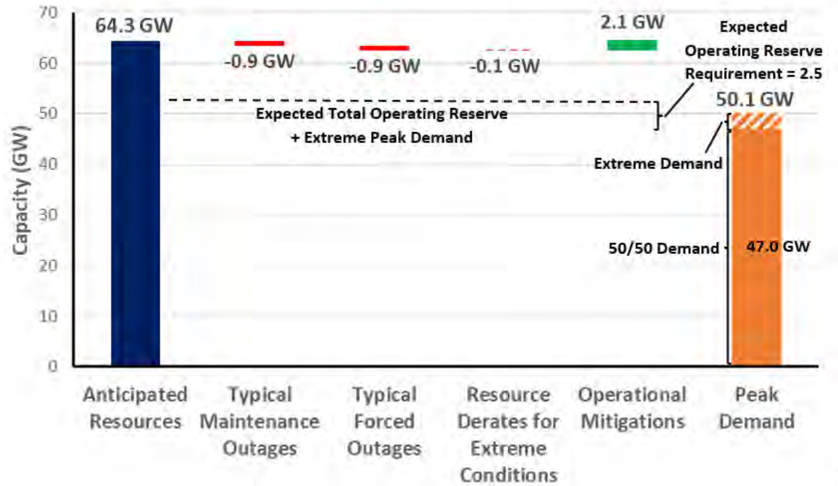
Risk Scenario Summary

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.

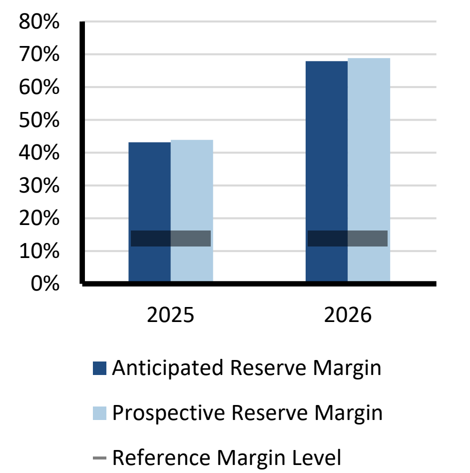
Highlights

- 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.

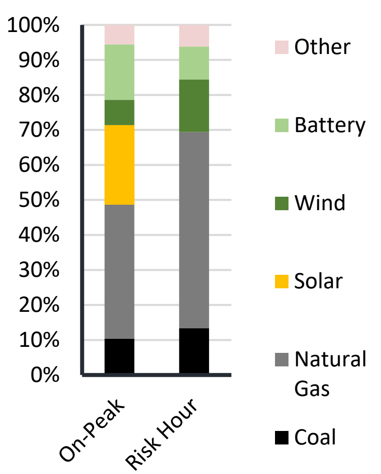
Risk Scenario Summary

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).

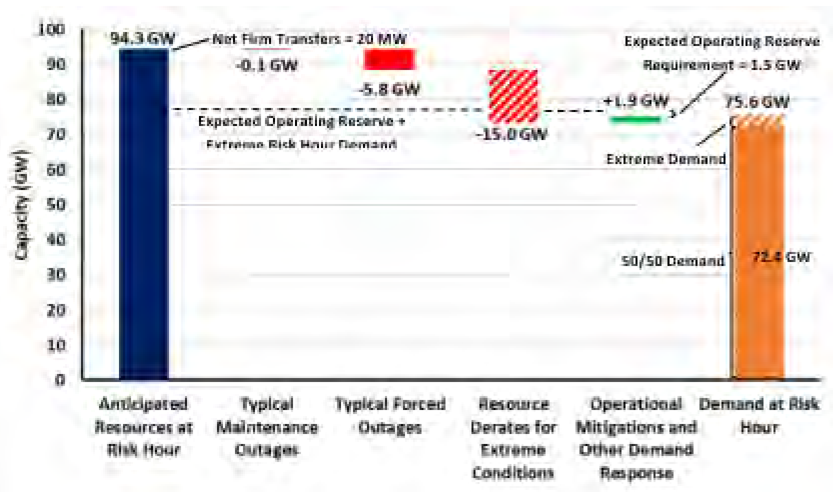
On-Peak Reserve Margin



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.

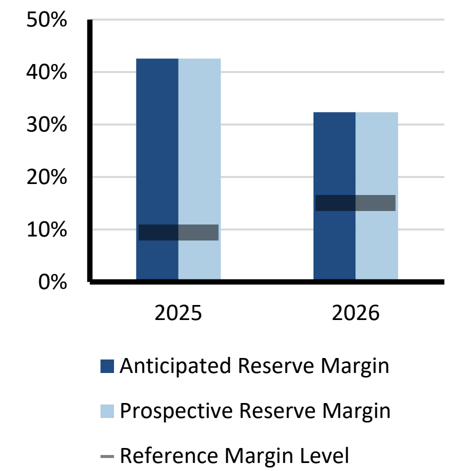
WECC-Alberta

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.

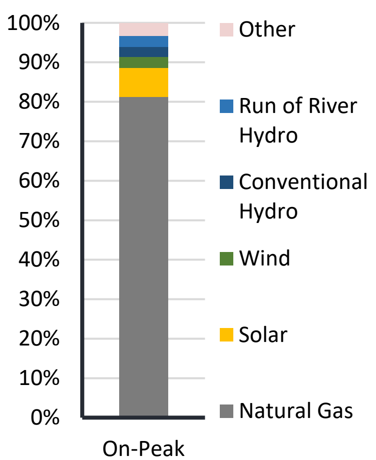
On-Peak Reserve Margin



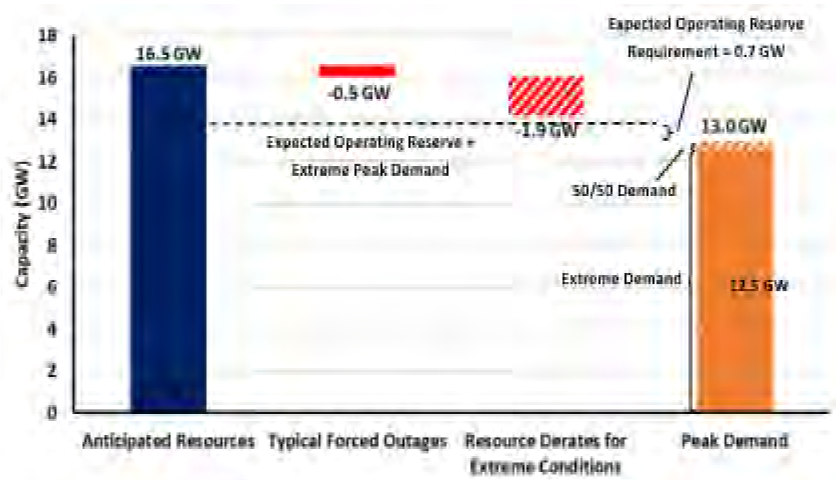
Risk Scenario Summary

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.

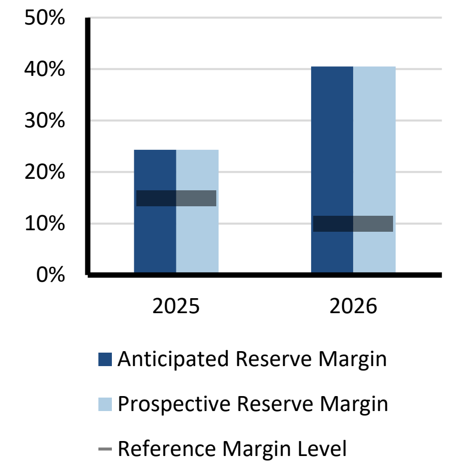
Highlights

- 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%

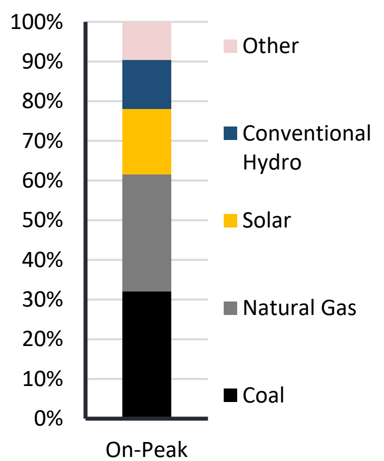
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios with imports.

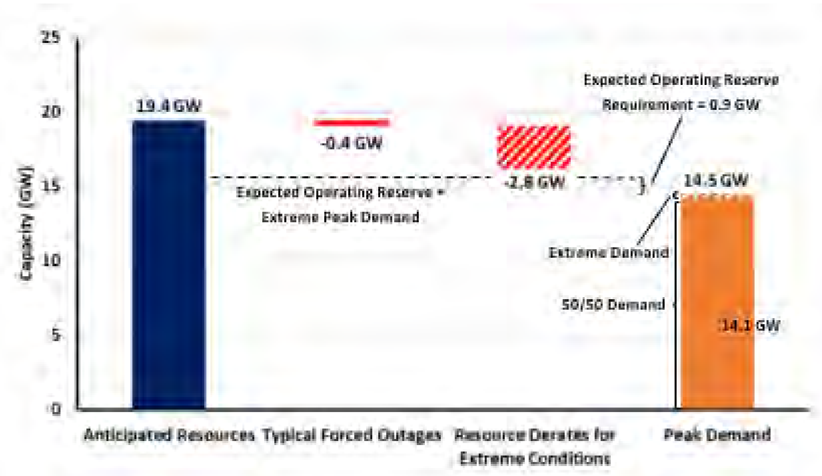
On-Peak Reserve Margin



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 (90/10) demand forecast.

Forced Outages: Average seasonal outages.

Extreme Derates: (90/10) resource performance distribution at peak hour.

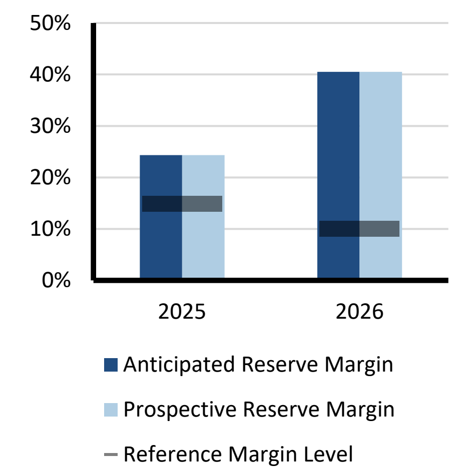
WECC-British Columbia

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.

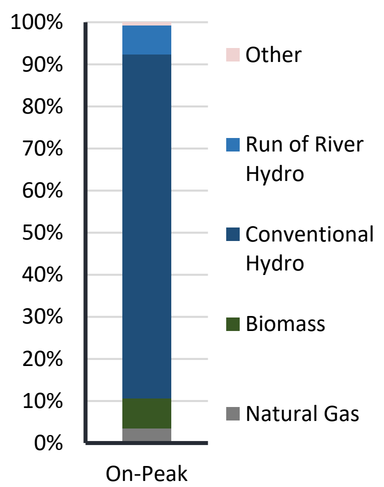
On-Peak Reserve Margin



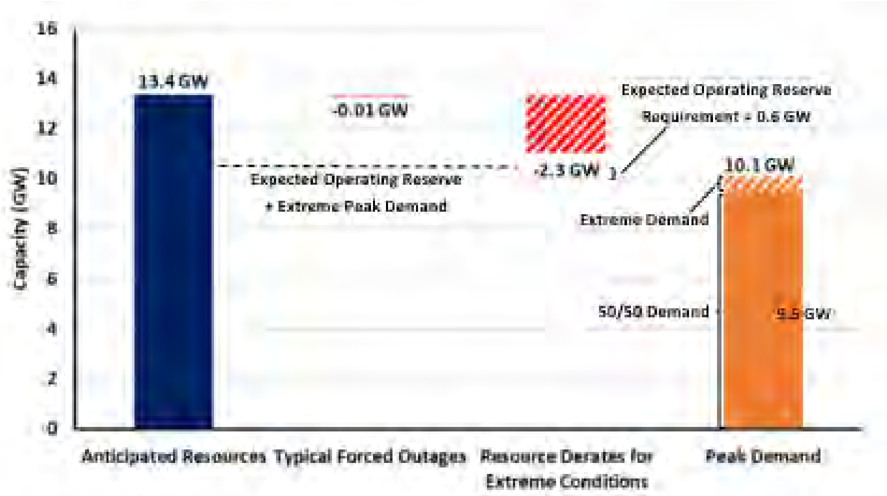
Risk Scenario Summary

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.

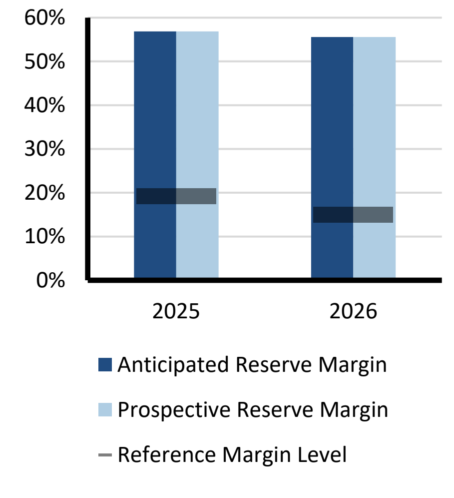
Highlights

- 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.

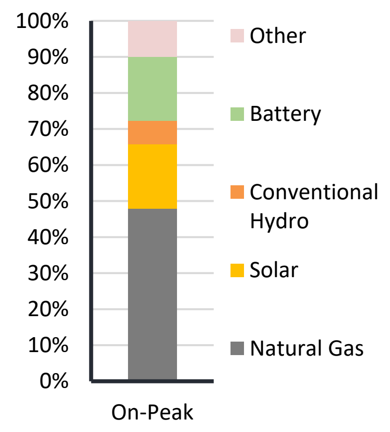
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

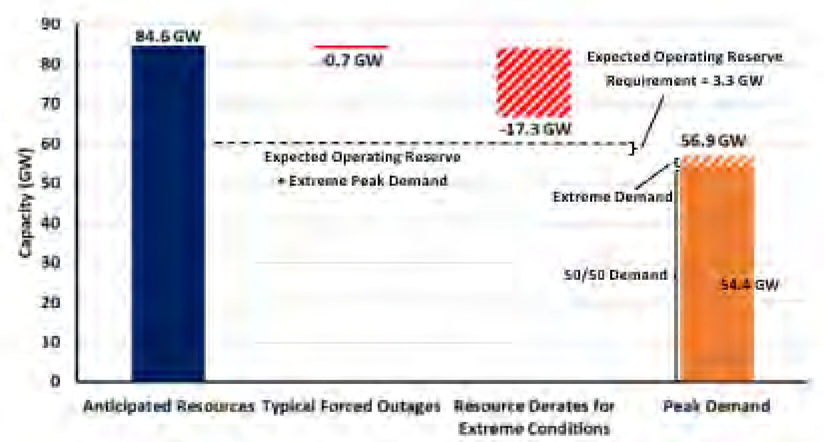
On-Peak Reserve Margin



Fuel Mix



Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: 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.

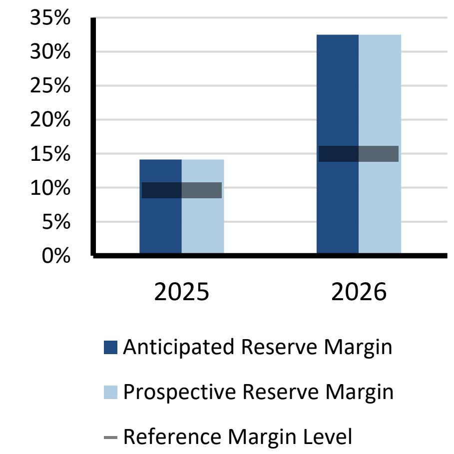
WECC-Mexico

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.

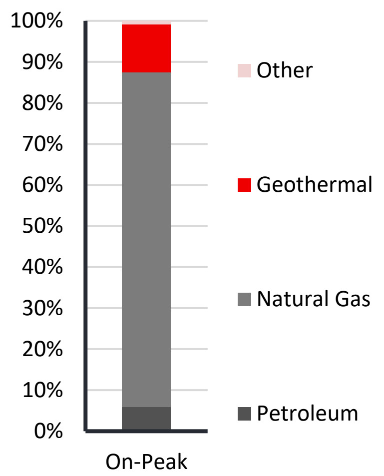
On-Peak Reserve Margin



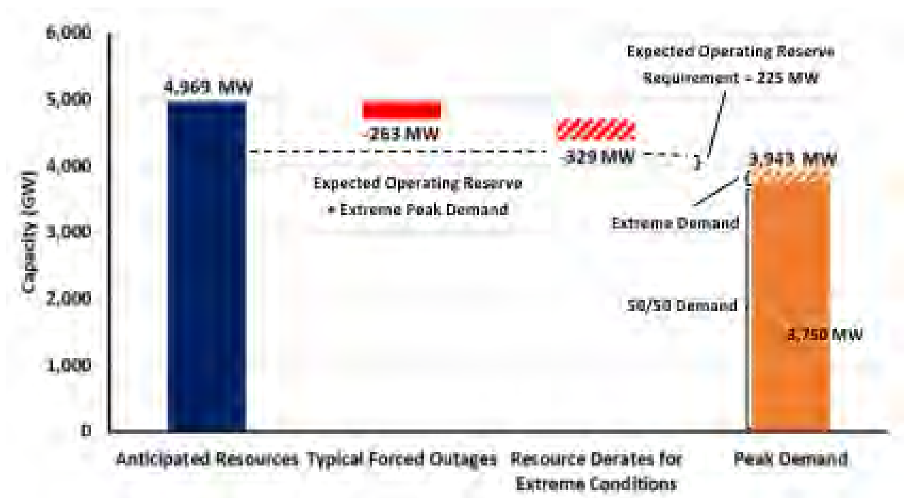
Risk Scenario Summary

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.

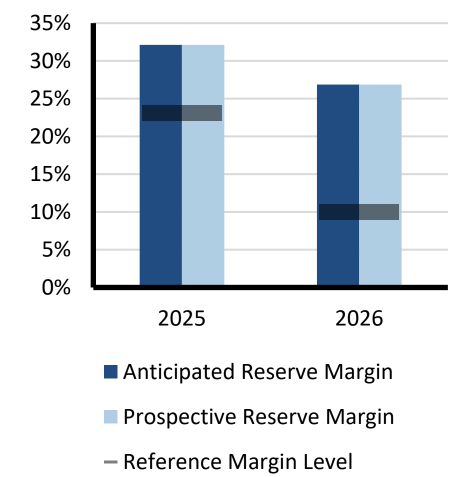
WECC-Northwest

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.

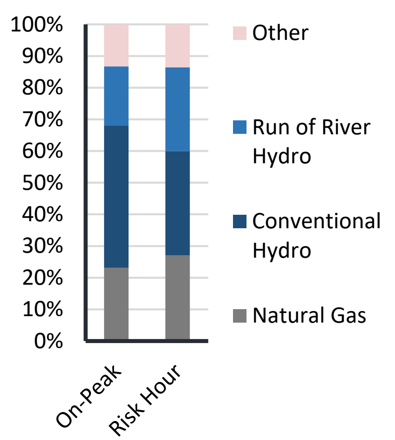
On-Peak Reserve Margin



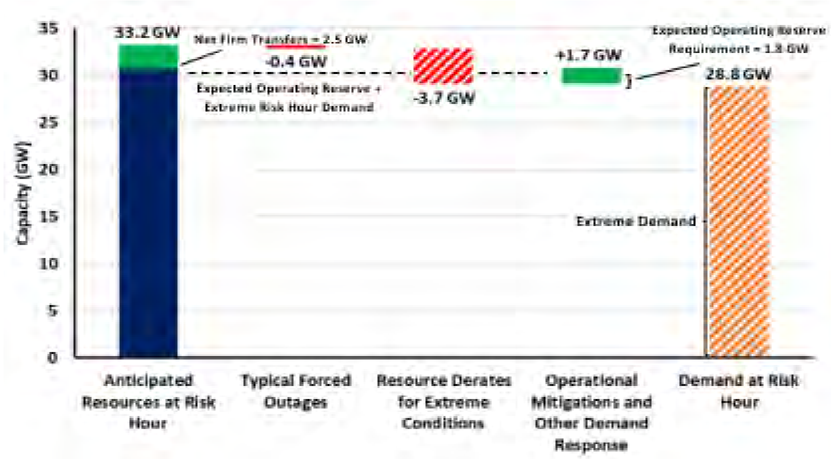
Risk Scenario Summary

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.

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.

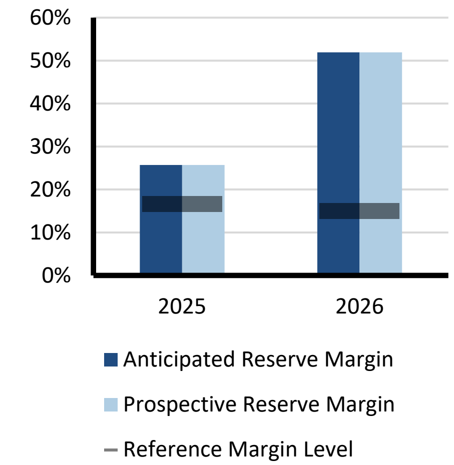
WECC-Rocky Mountain

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.

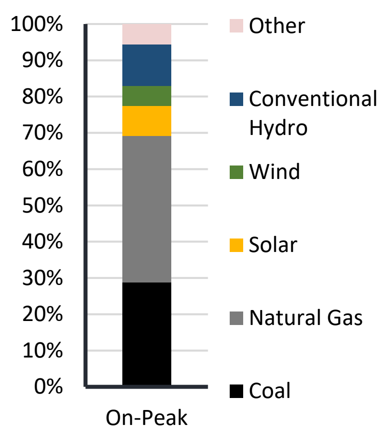
On-Peak Reserve Margin



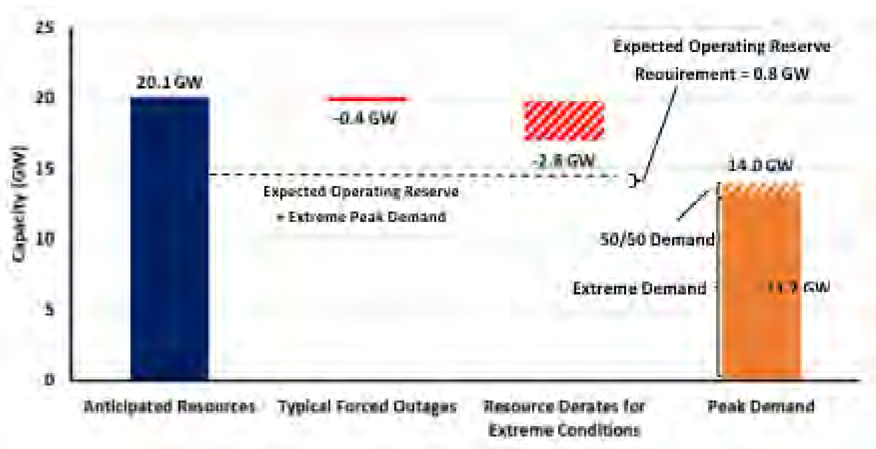
Risk Scenario Summary

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.

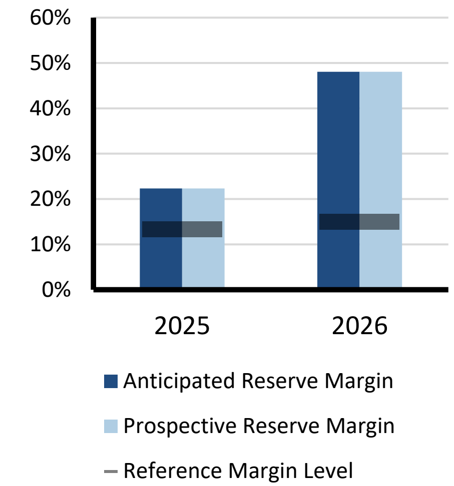
WECC-Southwest

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.

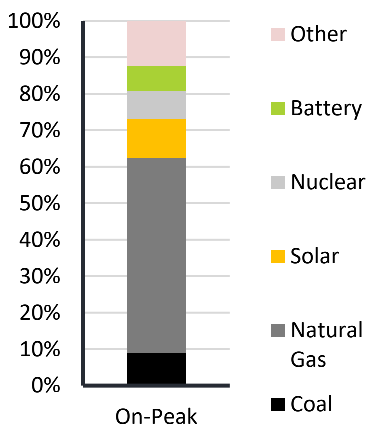
On-Peak Reserve Margin



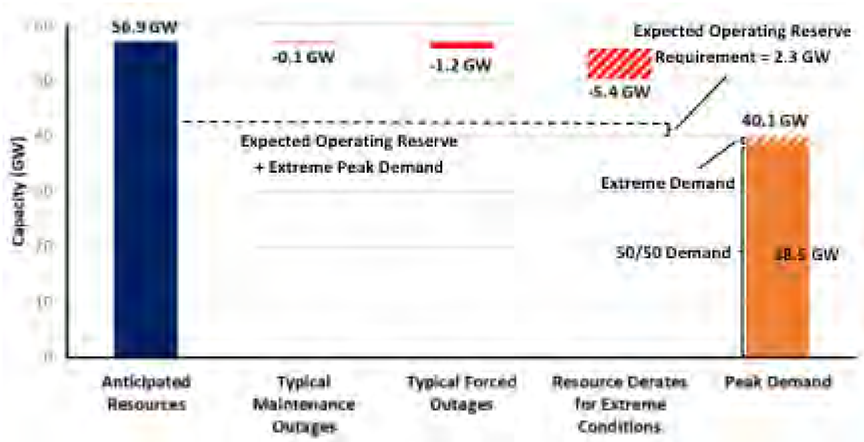
Risk Scenario Summary

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**.

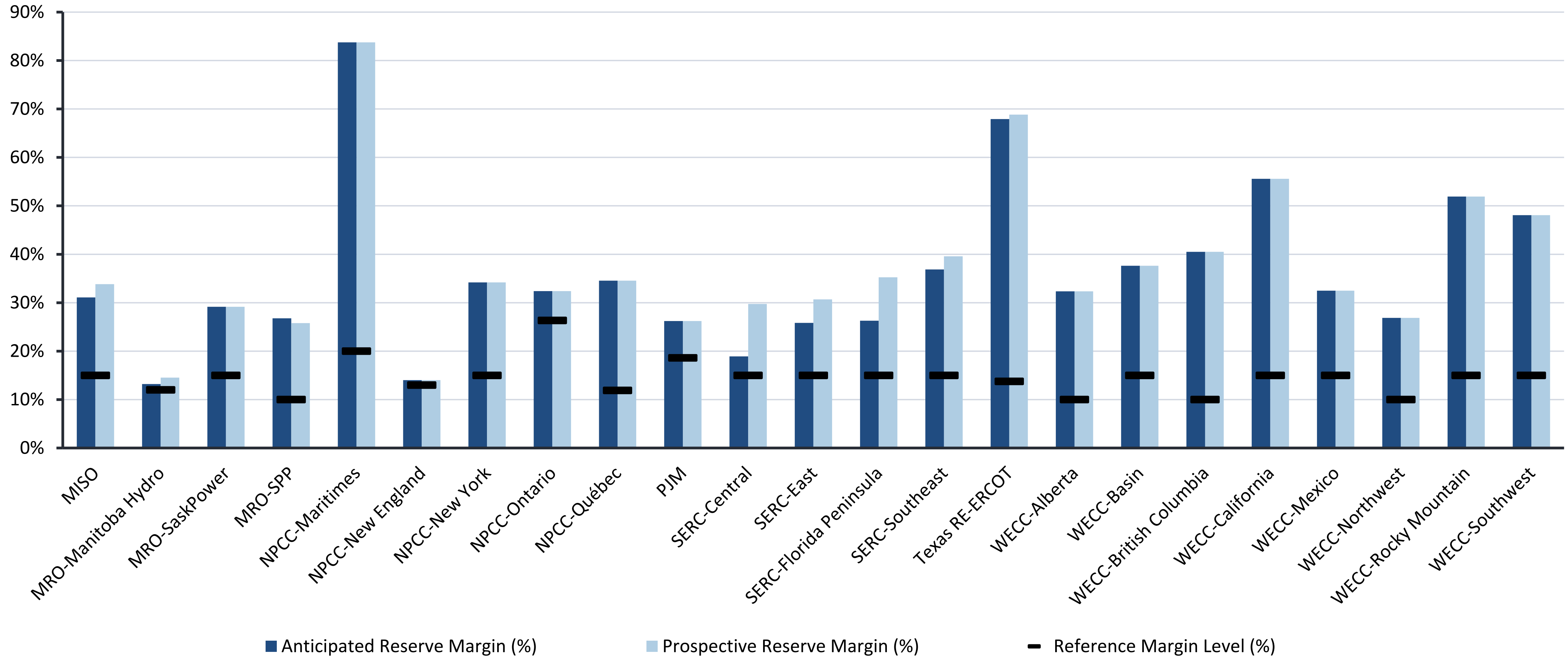


Figure 5: Summer 2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

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[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.

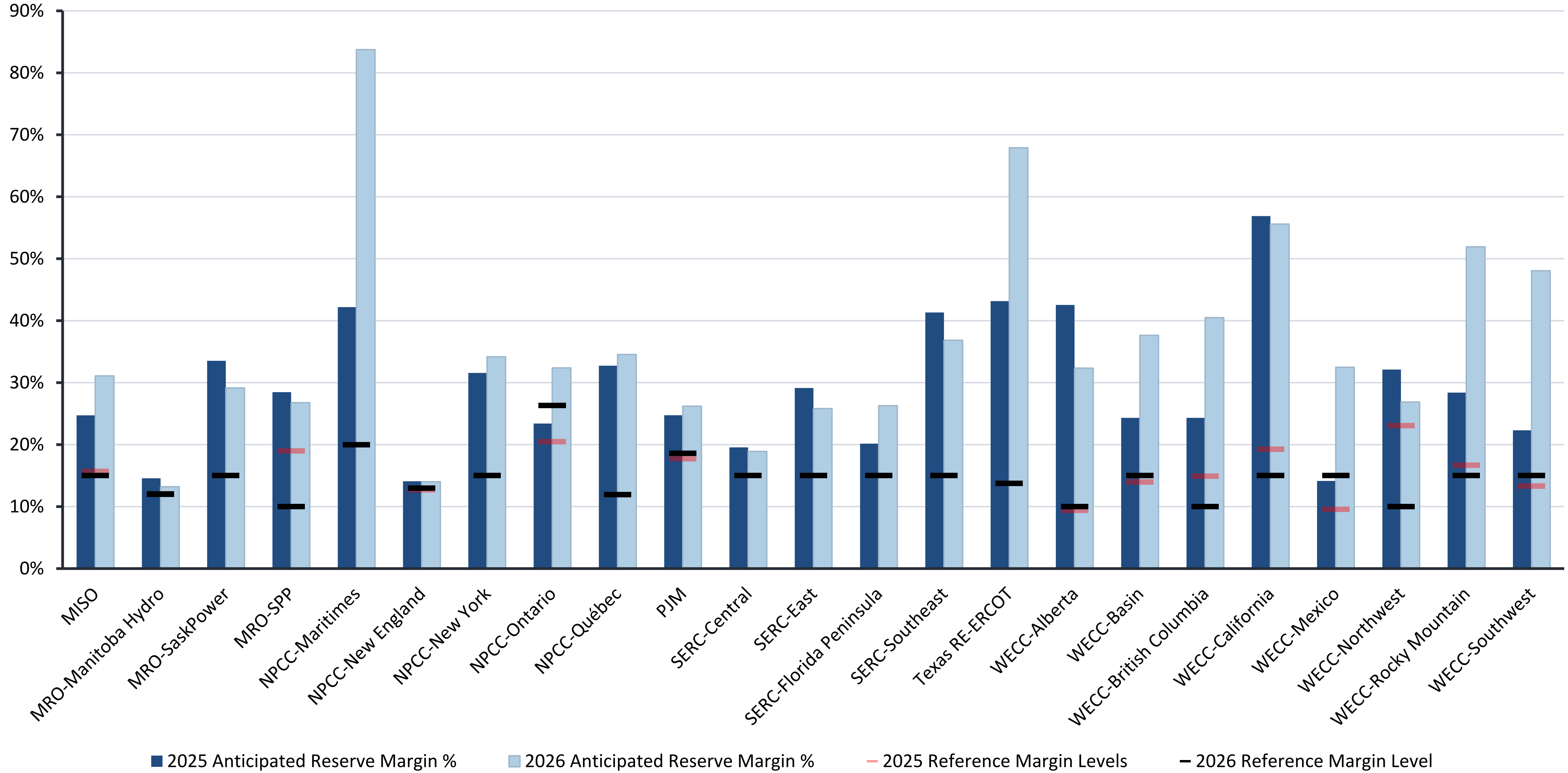

Figure 6: Summer 2025 and Summer 2026 Anticipated Reserve Margins Year-to-Year Change

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.

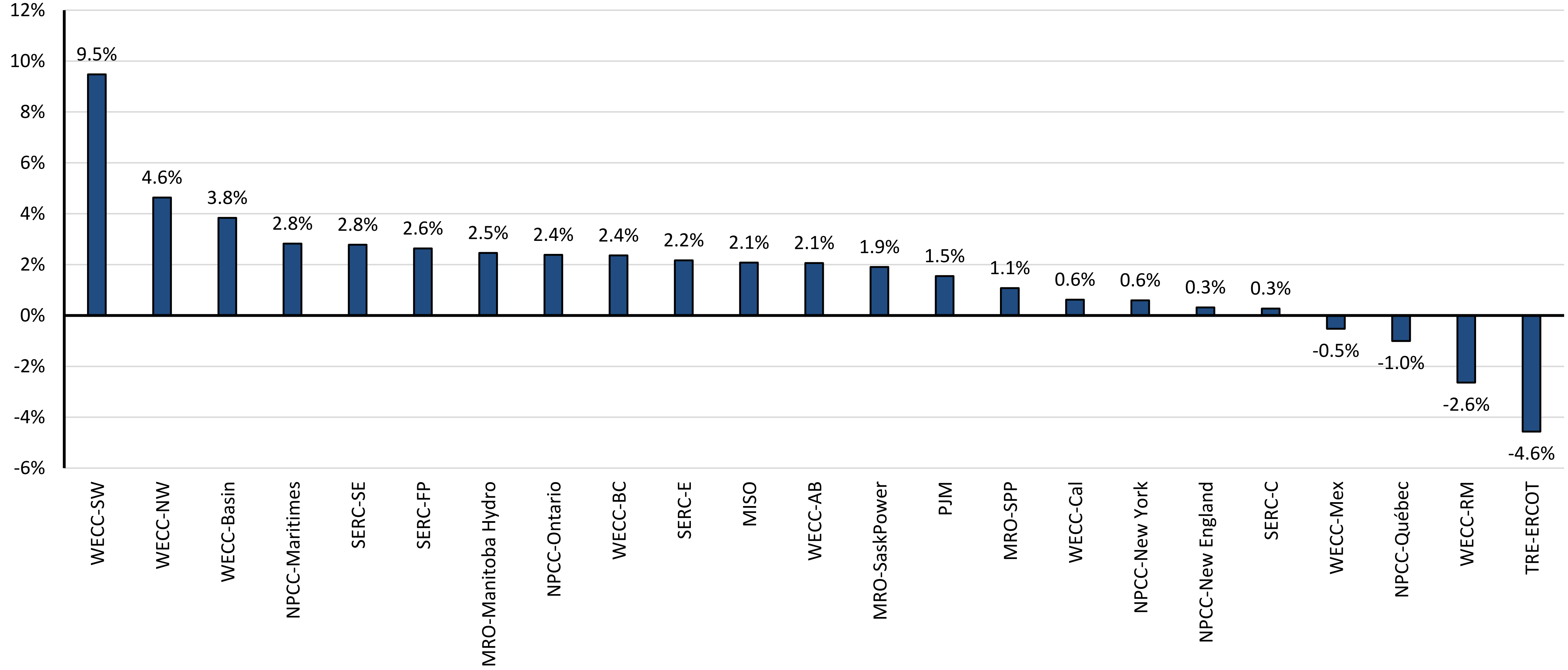

Figure 7: Changes in Net Internal Demand—Summer 2025 Forecast Compared to Summer 2026 Forecast

[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]

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[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.

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[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.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit OOO: Department, Order No. 202-26-22 (May 19, 2026)

Department of Energy
Washington, DC 20585

Order No. 202-26-22

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States due to a shortage of electric energy, a shortage of facilities for the generation of electricity, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The J.H. Campbell Generating Plant (Campbell Plant) is a 1,420 MW coal-fired plant primarily owned by Consumers Energy Company (Consumers) and located in West Olive, Michigan. In 2021, Consumers announced that it planned to implement a "speed closure" of the Campbell Plant fifteen years before the end of its scheduled design life.[3] Instead of retiring the Campbell Plant at the end of its design life, Consumers planned to accelerate the Campbell Plant's retirement and discontinue its operations on May 31, 2025.

Order Nos. 202-25-3, 202-25-7, and 202-25-9 issued pursuant to FPA section 202(c), each required that the Campbell Plant remain in operation for 90 days, until August 21, 2025, November 19, 2025, and February 17, 2026, respectively. Subsequently, Order No. 202-26-16, issued pursuant to FPA section 202(c), required that the Campbell Plant remain in operation for 90 days, through May 18, 2026. Those orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO likely faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[4] I determined that the continued operation of the Campbell Plant would provide additional generation capacity during

[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] *See* Consumers Energy, *Consumers Energy Announces Plan to End Coal Use by 2025; Lead Michigan's Clean Energy Transformation* (June 23, 2021), https://www.consumersenergy.com/news-releases/news-release-details/2021/06/23/consumers-energy-announces-plan-to-end-coal-use-by-2025-lead-michigans-clean-energy-transformation.

[4] *See, e.g., Midcontinent Indep. Sys. Operator, Inc., and Consumers Energy Co.*, Order No. 202-25-9, at 1 (Nov. 18, 2025), https://www.energy.gov/sites/default/files/2025-11/Order%20No%20202-25-9.pdf.

these periods, which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[5] I determined that the continued operation of the Campbell Plant was necessary to alleviate immediate and anticipated threats to reliability.[6] My determination was based on a number of facts.

First, the North American Electric Reliability Corporation (NERC) released its 2025 Summer Reliability Assessment on May 14, 2025. In its assessment, NERC stated that "[d]emand forecasts and resource data indicate that MISO is at elevated risk of operating reserve shortfalls during periods of high demand or low resource output."[7] In particular, NERC explained that the retirement of thermal generation capacity increased the likelihood of electricity supply shortfalls. NERC anticipated that the near -term period of greatest capacity shortfall for MISO would likely occur in August.[8]

Second, multiple generation facilities in Michigan have retired in recent years. According to the U.S. Energy Information Administration (EIA), "[s]ince 2020, about 2,700 megawatts of coal-fired generating capacity have been retired and no new coal-fired facilities are planned."[9] Additionally, EIA stated, "Michigan's nuclear power plants typically supplied about 30% of in-state electricity, but the amount of electricity generated by nuclear power plants in Michigan has declined as plants have been decommissioned."[10] The state's Big Rock Point nuclear power plant shut down in 1997, and the Palisades nuclear power plant closed in 2022. The Palisades plant remains unavailable, although the plant will reportedly resume service in 2026.[11]

Third, the Campbell Plant's retirement would have further decreased available dispatchable generation within MISO's service territory, adding to the loss of 1,575 MW of natural gas and coal-fired generation that has retired since the summer of 2024.

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[5] *Id.* at 5; *see also id.* at 1, 8.

[6] *Id.* at 1.

[7] NERC, *2025 Summer Reliability Assessment*, at 16 (May 2025), https://www.nerc.com/globalassets/programs/rapa/ra/nerc_sra_2025.pdf.

[8] *Id.*

[9] EIA, *Mich. State Profile & Energy Estimates* (Nov. 19, 2025), https://www.eia.gov/states/MI/analysis.

[10] *Id.*

[11] *See* Dustin Dwyer, *Palisades nuclear plant restart plans pushed back to "early 2026,"* MICH. PUB. (Dec. 17, 2025), https://www.michiganpublic.org/environment-climate-change/2025-12-17/palisades-nuclear-plant-restart-plans-pushed-back-to-early-2026; Will Wade, *Despite $80-billion commitment, nuclear plants face decadelong timeline to meet AI energy needs*, L.A. TIMES (Nov. 13, 2025), https://www.latimes.com/business/story/2025-11-13/despite-80-billion-commitment-nuclear-plants-face-decade-long-timeline-to-meet-ai-energy-needs.

Although MISO and Consumers have incorporated the planned retirement of the Campbell Plant into their supply forecasts, and Consumers acquired a 1,200 MW natural gas power plant in Covert, Michigan, NERC has noted "[e]scalating demand forecasts and uncertainty around new resource commercialization timing contribute to heightened resource adequacy concerns in the MISO area."[12]

Fourth, MISO's Planning Resource Auction Results for the 2025–2026 Planning Year, released in April 2025, noted that for the northern and central zones, which include Michigan, "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources."[13] While the results "demonstrated sufficient capacity," the summer months reflected the "highest risk and a tighter supply-demand balance."[14] According to MISO, these results "reinforce the need to increase capacity."[15]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-3, 202-25-7, 202-25-9, and 202-26-16 continue, both in the near and long term.[16] The production of electricity from the Campbell Plant will continue to be a critical asset to maintain reliability in MISO. According to the EIA-923 Power Plant Operations Report's monthly generation data for February 2026, the total net generation for the

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[12] NERC, *2025 Long-Term Reliability Assessment*, at 15 (Jan. 2026) (2025 NERC Long-Term Reliability Assessment), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[13] MISO, *Planning Resource Auction—Results for Planning Year 2025–2026*, at 13 (May 29, 2025) (MISO 2025–2026 Planning Resource Auction), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[14] *Id.* at 12.

[15] *Id.* at 2. *See Midcontinent Indep. Sys. Operator, Inc. & Consumers Energy Co.*, Order No. 202-25-7 (Aug. 20, 2025) (determining that emergency conditions existed), https://www.energy.gov/sites/default/files/2025-08/MISO%20Order%20No.%20202-25-7.pdf.

[16] Further, as noted in Order No. 202-25-7, as a coal-fired facility, it would be difficult for the Campbell Plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. If Consumers were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Order No. 202-25-7 at 1 n.1.

Campbell Plant was 394,703 MWh and from June 2025 through December 2025 the plant generated an average of approximately 520,670 MWh per month.[17] The historic data of consistent generation indicates the Campbell plant is providing vital generation capacity to the region. From June 11, 2025, through November 5, 2025, MISO issued dozens of alerts to manage grid reliability in its Central Region in response to hot weather, severe weather, high customer load, forced generation outages, and transfer capability limits.[18]

MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when it operated under a cold weather alert and declared conservative operations from January 23 through February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generational outages, high demand, and transfer capability limits.[19]

MISO's year-round resource adequacy concerns are well documented. In 2021, MISO requested that the Federal Energy Regulatory Commission (FERC) approve its revised resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[20] MISO justified this revision by explaining that "Reliability risks associated with resource adequacy have shifted from 'Summer only' to a year-round concern."[21] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[22]

In December 2023, MISO released its *Attributes Roadmap*, in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a

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[17] *See* EIA, Form EIA-923 detailed data with previous form data (EIA-906/920), February 2026 Data (Mar. 2026), https://www.eia.gov/electricity/data/eia923/. On the "Page 1 Generation and Fuel Data" tab, Plant Name filtered for J H Campbell, Rows 533–535.

[18] MISO *Operations Report* (Sept. 16, 2025) cdn.misoenergy.org/20250916%20Markets%20Committee%20of%20the%20BOD%20Item%2005%20MISO%20Operations%20Report717458.pdf

[19] Midcontinent ISO, @MISO_energy, X (Jan. 24, 2026, 9:39 AM), https://x.com/MISO_energy/status/2015072060876140805.

[20] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, Docket No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[21] MISO Transmittal Letter at 3.

[22] *Id.* at 3–4.

rapidly transforming energy landscape."[23] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023–2024 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons.[24] MISO also projected that the risk of loss of load in the winter and spring seasons will nevertheless increase over time, although not as high as in the summer or fall.[25]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative*.[26] In a section of that report labeled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season.

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[27]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In its 2025 Long-Term Reliability Assessment, NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years,[28] stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[29] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[30] Moreover, the 2025 NERC Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and

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[23] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[24] *Id.* at 11.

[25] *Id.*

[26] MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

[27] *Id.* at 12.

[28] 2025 NERC Long-Term Reliability Assessment at 6.

[29] *Id.* at 8.

[30] *Id.* at 43.

retirements."[31] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[32] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[33]

While the 2025–2026 NERC Winter Reliability Assessment found the MISO region to be at normal risk in 2026 and elevated risk in 2027, two earlier winter studies were more critical. The 2023–2024 NERC Winter Reliability Assessment characterized MISO as a region at elevated risk with the "[p]otential for insufficient operating reserves in above-normal conditions."[34] These findings were echoed in NERC's 2024–2025 Winter Reliability Assessment, which noted that "[g]enerating capacity is 10 GW lower (-6.8%) compared to the prior winter as generators have retired, withdrawn from MISO's capacity market, or received lower winter accredited capacity."[35]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–2026 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Michigan.[36]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[37] The 2025 OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[38] The 2025 OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for

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[31] *Id.* at 15.
[32] *Id.*
[33] *Id.*
[34] NERC, *2023–2024 Winter Reliability Assessment*, at 5 (Nov. 2023), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2023.pdf.
[35] NERC, *2024–2025 Winter Reliability Assessment*, at 15 (Nov. 2024), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2024.pdf.
[36] MISO 2025–2026 Planning Resource Auction at 13.
[37] OMS & MISO, *OMS-MISO Survey Results* (updated June 6, 2025) (2025 OMS-MISO Survey), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.
[38] *Id.* at 2.

electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[39] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[40]

The primary reasons for these projected deficits also are shown on the 2025 OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[41] Although the 2025 OMS-MISO Survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[42]

MISO has been taking steps to address these projected deficits. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[43] MISO's ERAS should help expedite the construction of needed new capacity; however, resources studied under the ERAS will have commercial operation dates that are at least three years away and are provided an additional three-year grace period to commence commercial operations.[44] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[45] Consequently, the

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[39] *Id.* at 7.

[40] *Id.* at 9.

[41] *Id.* at 7, 9.

[42] *Id*.

[43] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025), https://cdn.misoenergy.org/2025-07-21_192%20FERC%20%C2%B6%2061,064_Docket%20No.%20ER25-2454-000709770.pdf.

[44] *Id.* P 84.

[45] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply. ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts.").

new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-3, 202-25-7, 202-25-9, and 202-26-16 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[46] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[47] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[48]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[49] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. This growth is illustrated by the fact that there are more than twenty AI companies operating in Michigan alone.[50] In addition, as just one example, Consumers

[46] Exec. Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025), https://www.whitehouse.gov/presidential-actions/2025/01/declaring-a-national-energy-emergency/.

[47] *Id*.

[48] 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/.

[49] U.S. Dep't of Energy, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[50] Ekku Jokinen, *Top 21 A.I. Cos. in Mich.* (last accessed Aug. 13, 2025), https://www.inven.ai/company-lists/top-21-artificial-intelligence-companies-in-michigan.

has announced an additional 1 GW of new power to a planned hyperscale data center and "continue[s] to see positive momentum with data centers within the 9 GW pipeline . . . ."[51]

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[52] Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected demand for energy-hungry data centers to support artificial intelligence."[53] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[54]

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

<u>*ORDER*</u>

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

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[51] *See* Data Center Dynamics, *Michigan utility Consumers Energy to provide 1GW of power to new hyperscale data center* (Aug. 5, 2025) (quoting Consumers CEO Garrick Rochow), https://www.datacenterdynamics.com/en/news/michigan-utility-consumers-energy-to-provide-1gw-of-power-to-new-hyperscale-data-center/.

[52] *Keeping the Lights On: Examining the State of Regional Grid Reliability; Hearing Before the House Committee on Energy and Commerce, Subcommittee on Energy*, 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Independent System Operator), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

[53] *Id.* at 6

[54] *Id.* at 7.

interest."[55] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Campbell Plant when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

As described above, the emergency conditions resulting from the combination of increasing demand for electricity and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-3, 202-25-7, 202-25-9, and 202-26-16, will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Campbell Plant is necessary to best meet the increased demand for electricity and mitigate the observed shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Campbell Plant will be available if needed to address emergency conditions, it shall remain in operation through August 16, 2026.[56]

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

A. From May 19, 2026, MISO and Consumers shall take all measures necessary to ensure that the Campbell Plant is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of the Campbell Plant to minimize costs to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. Consumers is directed to comply with all orders from MISO related to the availability and dispatch of the Campbell Plant.

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

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

[56] 16 U.S.C. § 824a(c)(4).

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

D. By June 2, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Campbell Plant consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

E. Consumers is directed to file with FERC tariff revisions or waivers to effectuate this Order, as needed. Rate recovery is available pursuant to 16 U.S.C. § 824a(c).

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

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

H. This Order shall be effective on May 19, 2026, through August 16, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 19th day of May 2026.

____

Chris Wright
Secretary of Energy
cc:

<u>FERC Commissioners</u>

Chairman Laura V. Swett
Commissioner David Rosner
Commissioner Lindsay S. See
Commissioner Judy W. Chang
Commissioner David A. LaCerte

Michigan Public Service Commissioners

Chairman Dan Scripps
Commissioner Katherine Peretick
Commissioner Shaquila Myers

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit PPP: Department, Order No. 202-26-24 (May 21, 2026)

Department of Energy
Washington, DC 20585

PJM Interconnection, L.L.C. and
Constellation Energy Corp.
Regarding Eddystone Unit 3 and Unit 4

Order No. 202-26-24

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

BACKGROUND

The Eddystone Generating Station is a power plant owned by Constellation Energy Corporation (Constellation Energy) and located in Eddystone, Pennsylvania. Units 3 and 4 (Eddystone Units), each with 380 MW of generation capacity, are subcritical steam boiler-turbine generator units that run on either natural gas or oil, depending on market conditions. The Eddystone Units were initially scheduled for retirement on May 31, 2025.

Order Nos. 202-25-04, 202-25-08, and 202-25-10, issued pursuant to FPA section 202(c), each required that the Eddystone Units remain available to operate for 90 days, until August 28, 2025, November 26, 2025, and February 24, 2026, respectively. Subsequently, Order No. 202-26-17, issued pursuant to FPA section 202(c), required the Eddystone Units to remain available to operate for 90 days, through May 24, 2026. Those orders were based on my determination that emergency conditions existed in the PJM region. Specifically, I explained that there was a potential shortage of electric energy and a shortage of facilities for the generation of electric energy.[3] I stated that the potential loss of power to homes and local businesses presents a risk to public health and safety.[4] I determined that continued operation and economic dispatch of the Eddystone

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] *See, e.g., PJM Interconnection, L.L.C.*, Order No. 202-25-10, at 7 (Nov. 25, 2025).
[4] *Id.* at 9.

Units was necessary to best meet the emergency and serve the public interest.[5] My determination was based on a number of different facts.

First, in congressional testimony, PJM's President and CEO stated that its system faces a "growing resource adequacy concern" due to load growth, the retirement of dispatchable resources, and other factors.[6] Through 2030, PJM anticipates reliability risk from increasing electricity demand, generator retirement outpacing new resource construction, and characteristics of resources in PJM's interconnection queue.[7] Upcoming retirements, including the planned retirement of the Eddystone Units, would exacerbate these resource adequacy issues.

Second, PJM indicated that resource constraints could exist within its service territory under peak load conditions, stating that "available generation capacity may fall short of required reserves in an extreme planning scenario."[8] In its February 2023 assessment, *Energy Transition in PJM: Resource Retirements, Replacements & Risks*, PJM highlighted increasing reliability risks in the coming years due to the "potential timing mismatch between resource retirements, load growth and the pace of new generation entry" under "low new entry" scenarios for renewable generation.[9]

Third, in December 2024, PJM filed revisions with the Federal Energy Regulatory Commission (FERC) to Part VII of its Open Access Transmission Tariff, known as the Reliability Resource Initiative (RRI), to address near-term resource adequacy concerns. In a February 2025 order, FERC accepted the revisions and found "the possibility of a

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[5] *Id.* at 9 & Ordering Paragraph A.

[6] *Keeping the Lights On: Examining the State of Reg'l Reliability; Hearing Before the House Comm. on Energy & Com., SubComm. on Energy*, 119th Cong. 4–5 (2025) (testimony of Mr. Manu Asthana, President and CEO, PJM) [hereinafter Asthana Test.], https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-AsthanaM-20250325.pdf.

[7] *Id.*; *see also PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 15 (2025) ("PJM states . . . that, in 2023, it found that generator retirements, load growth, the pace of new entry, and the operating characteristics of the intermittent and limited duration resources that make up a large part of PJM's interconnection queue pose increasing reliability risks through 2030.").

[8] *PJM Summer Outlook 2025: Adequate Resources Available for Summer Amid Growing Risk*, PJM INSIDE LINES (May 9, 2025), https://insidelines.pjm.com/pjm-summer-outlook-2025-adequate-resources-available-for-summer-amid-growing-risk/.

[9] PJM, *Energy Transition in PJM: Res. Rets., Replacements & Risks*, at 1 (Feb. 24, 2023) [hereinafter Four Rs Report], https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx.

resource adequacy shortfall driven by significant load growth, premature retirements, and delayed new entry."[10]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-04, 202-25-08, 202-25-10, and 202-26-17 continue, both in the near and long term.[11] The production of electricity from the Eddystone Units will continue to be a critical asset for maintaining reliability in PJM. According to data from the U.S. Environmental Protection Agency (EPA), the Eddystone Units generated 26,971 MWh between June 2025 and December 2025,[12] providing vital generation capacity to the region. Over the summer of 2025, PJM took action to manage grid operations, issuing Hot Weather Alerts and/or Maximum Generation Alerts (i.e., an Energy Emergency Alert (EEA) 1) to manage grid reliability covering a total of 20 days, including days in June, July, and August.[13]

PJM's resource adequacy concerns were recently demonstrated during Winter Storm Fern, when PJM operated under a cold weather alert and declared conservative operations from January 24 to February 2, 2026. Additionally, on January 27, 2026, PJM declared a Maximum Generation Emergency/Load Management Alert and an EEA 1.[14]

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[10] *PJM Interconnection*, 190 FERC ¶ 61,084 at P 14.

[11] Further, it likely would be difficult for these units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if Constellation Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. Thus, continued operation is required in such cases so long as the Secretary determines that an emergency exists. The costs and time of decommissioning a coal plant are extensive and includes various components. Therefore, restarting such decommissioned plants could have significant costs in terms of dollars and time. *See* Section 4 in Lessick, Jennifer, et al. *Business Models for Coal Plant Decommissioning*. www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

[12] *See* EPA, *Custom Data Download, EPA CAMPD (Clean Air Mkts. Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from Data Type dropdown; choose "Monthly Emissions" from Data Subtype dropdown; choose "Unit (No Aggregation)" from Aggregation dropdown; then click "Apply"; then type "2025" into "Time Period" filter and click "June, July, August, September, October, November, December"; then click "Apply Filter"; then click "Facility" filter and type "Eddystone Generating Station (3161)"; then click ""Eddystone Generating Station (3161)"; then click "Apply Filter"; then click "Preview Data").

[13] *See* PJM, *Emergency Procs.*, https://emergencyprocedures.pjm.com/ ep/pages/dashboard.jsf (search Effective From 06/01/2025 Effective To 08/31/2025).

[14] *See id.* (search Effective From 01/20/2026 Effective To 02/07/2026).

Due to concerns about resource adequacy from the high demand driven by the extreme cold, PJM also applied for an order pursuant to FPA section 202(c) "that broadly authorizes all electric generating units located within the PJM Region to operate up to their maximum generation output levels, notwithstanding air quality or other permit limitations or fuel shortages during the pendency of this emergency."[15] DOE granted PJM's application and issued Order No. 202-26-02 on January 25, 2026.[16]

On January 29, 2026, PJM applied for an extension of Order No. 202-26-02, which was designated as Order No. 202-26-02A, which was granted by the Department on the same day.[17] Furthermore, on March 17, 2026, in his testimony to the House Committee on Energy and Commerce, North American Electric Reliability Corporation (NERC) Chief Executive Officer Jim Robb stated that "PJM and other grid operators indicated that 202(c) facilities made material contributions" with regard to reliability during Winter Storm Fern.[18]

PJM's resource adequacy concerns are well documented. In January 2025, PJM reached a new record peak for winter demand, exceeding the previous winter peak set in 2015.[19] PJM notes that the "20-year annualized growth rate in the 2025 Long-Term Load Forecast for the winter peak is up to 2.4%."[20] Further, PJM's risk profile continues to shift from the summer season to the winter season. For example, in a March 2025 presentation, PJM estimated that 87.8% of the expected unserved energy for the 2025/2026 delivery year falls in the winter season.[21]

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[15] Letter from Michael E. Bryson, Senior Vice Pres., Operations, PJM, to Hon. Chris Wright, Sec'y, DOE, at 2 (Jan. 4, 2026) (requesting emergency order under FPA section 202(c)), https://www.energy.gov/documents/pjm-202c-application-2026-01-24.

[16] *PJM Interconnection, L.L.C.*, Order No. 202-26-02 (Jan. 25, 2026).

[17] *PJM Interconnection, L.L.C.*, Order No. 202-26-02A (Jan. 29, 2026).

[18] *Winter Storm Fern Lessons: Supplying Reliable Power to Meet Peak Demand; Hearing Before the House Comm. on Energy & Com., Subcomm. On Energy*, 119th Cong. 8 (2026) (statement of James B. Robb, President and CEO, NERC), https://www.congress.gov/119/meeting/house/119077/witnesses/HHRG-119-IF03-Wstate-RobbJ-20260317.pdf.

[19] *Jan. 22 Update: Extreme Cold Produces PJM Record for Winter Elec.y Demand*, PJM INSIDE LINES (Jan. 22, 2025), https://insidelines.pjm.com/jan-22-update-extreme-cold-produces-pjm-record-for-winter-electricity-demand/.

[20] *2025 Long-Term Load Forecast Rep. Predicts Significant Increase in Elec. Demand*, PJM INSIDE LINES (Jan. 30, 2025), https://insidelines.pjm.com/2025-long-term-load-forecast-report-predicts-significant-increase-in-electricity-demand/.

[21] PJM Res. Adequacy Planning Special Planning Comm., *2026/27 BRA IRM, FPR, & ELCC Class Ratings: Shift Towards More Winter Risk*, at 8 (Mar. 13, 2025), https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250313-special/2026-2027-irm-fpr-elcc-and-winter-risk.pdf.

Recognizing the need for and importance of additional generation resources, on April 20, 2026, a Consent Decree between the Commonwealth of Pennsylvania and Keystone-Conemaugh Projects, LLC (KEY-CON) authorized operations to continue at two coal-fired steam electric generating plants that were slated for permanent cessation. The Consent Decree explained that "[d]ue to recent changes in the long-term electricity market outlook based on recent projections by PJM Interconnection LLC and the U.S. Department of Energy, including the need for electricity generators to cover projected increased electrical demand driven by build-out of data centers, particularly within the Mid-Atlantic Area Council, a portion of the PJM Interconnection LLC regional transmission organization that the [Conemaugh Generating Station and Keystone Generating Station] CON has recently reevaluated its 2021 decision to achieve [permanent cessation of coal combustion] at the [Conemaugh Generating Station and Keystone Generating Station] by December 31, 2028."[22]

In the fall of 2025, Pennsylvania Governor Josh Shapiro recognized the need for and importance of securing more electricity generation for the grid. Governor Shapiro stated that "[c]hange is needed to keep energy costs low, bring new energy generation onto the grid more quickly, and meet the needs of the 67 million Americans who rely on this grid for everything from running a business to keeping the lights on at home."[23] Furthermore, PJM expressed support for Order No. 202-25-04, since it has "repeatedly documented and voiced its concerns over the growing risk of a supply and demand imbalance driven by the confluence of generator retirements and demand growth. Such an imbalance could have serious ramifications for reliability and affordability for consumers."[24]

PJM has indeed voiced these concerns for years. In its February 2023 Four Rs Report, PJM cautioned that 40 GW of thermal generation are at risk of retirement

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[22] Commonwealth of Pennsylvania, Dep't of Env't Prot. v. Keystone-Conemaugh Projects, LLC, No. 2169-CD-2025-1, slip op. at 4 (Apr. 20, 2026) (Unopposed Motion to Enter Consent Decree), https://www.pa.gov/content/dam/copapwp-pagov/en/governor/documents/motion%20to%20enter%20cd-as%20filed.pdf.

[23] *How Josh Shapiro wants to reshape the region's power grid operator as prices rise*, Spotlight PA (Oct. 14, 2025), https://www.spotlightpa.org/news/2025/10/electricity-prices-shapiro-grid-operator-pjm-data-centers-environment/.

[24] *PJM Statement on the U.S. Dept. of Energy 202(c) Order of May 30*, PJM INSIDE LINES (May 31, 2025), https://insidelines.pjm.com/pjm-statement-on-the-u-s-department-of-energy-202c-order-of-may-30/. Further, PJM concluded, "In light of these concerns, PJM supports the U.S. Department of Energy's Order, issued May 30, pursuant to Section 202(c) of the Federal Power Act, to defer the retirements of certain generators operating in PJM's footprint." *Id*.

by 2030.[25] PJM also noted that, while there were then 290 GW of renewable generation capacity in the PJM interconnection queue, historically, the rate of completion for renewable projects is approximately 5%.[26] PJM determined that the pace of new capacity additions "would be insufficient to keep up with expected retirements and demand growth by 2030."[27] PJM estimated that, depending on the pace of new capacity additions, reserve margin erosion would occur between 2026 and 2028.[28]

In its December 2024 Reliability Resource Initiative (RRI) filing with FERC, PJM stated that "[c]oncerns about resource adequacy . . . have only increased since the Four Rs Report."[29] PJM warned that its "resource adequacy concerns are increasing at an extraordinary pace."[30] PJM went on to explain that its "resource adequacy concerns are driven in large part by significant load growth caused by, among other things, large data centers" and that its preliminary analysis shows "substantial increases [in load additions] since the 2024 forecast" for both the summer and winter seasons.[31] According to PJM, "load growth and generator retirements are significantly outpacing the entry of new generation in the PJM Region with this trend expected to continue unabated based on all available evidence."[32] Although the RRI process will help expedite the construction of needed new capacity, it is unlikely to result in the addition of any new generation capacity in the next few years.[33]

In support of the RRI filing, PJM submitted an affidavit from Donald Bielak, PJM's Director, Interconnection Planning. Mr. Bielak characterized the increase in forecasted load growth throughout PJM as "extraordinary" and "unprecedented," stating that it "could not have been foreseen as recently as a year ago."[34] Mr. Bielak expressed the opinion that the "rapid" retirement of thermal generation resources, "extreme"

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[25] Four Rs Report, *supra* note 9, at 2.

[26] *Id*.

[27] *Id.* at 16 tbl. 1.

[28] *Id*.

[29] PJM, Filing, , Dkt. No. ER25-712-000, at 10 (Dec. 13, 2024).

[30] *Id*.

[31] *Id.* at 10-11; *see also id.* at 13 (stating that "the exponential load growth resulting from development of new data centers and the intense energy needs of Artificial Intelligence technology overshadows any relaxation in the pace of fossil fuel generation retirements").

[32] *Id.* at 14.

[33] *See id.* attach. C (Affidavit of Mr. Donald Bielak), at 18–19 (explaining that projects studied in Transition Cycle #2, which includes RRI projects, "could be constructed and in commercial operation by the 2029/30 Delivery Year or sooner").

[34] Bielak Aff. at 10.

forecasted load growth, and "delays in new generation resources achieving commercial operation," would adversely affect resource adequacy throughout PJM's electricity grid.[35]

On February 11, 2025, FERC accepted PJM's proposed tariff revisions in its RRI filing.[36] In its order on rehearing, FERC concluded that "PJM identified increasing reliability risks arising in the next few years and significant resource adequacy issues anticipated by the 2030/31 delivery year. The record supports that these resource adequacy concerns are likely to manifest."[37]

The NERC has raised similar concerns. In its 2025 Long-Term Reliability Assessment, released in January 2026, NERC observed that the PJM region is at high risk of energy shortfalls over the next five years[38] and faces significant reliability challenges as "[c]urrent projections for resource additions do not keep pace with escalating demand forecasts and expected generator retirements."[39] The assessment notes that "[d]emand for electricity in PJM is growing at its fastest pace in years, driven primarily by data centers, followed by electrification and manufacturing loads;" however "[a]t the same time, PJM faces an extreme and rapid tightening of capacity resources in the near term because of generator retirements and project delays."[40] Overall, the assessment concludes that "[b]ased on the load increase and generation decrease, PJM is projecting potential reserve margin shortages during peak operating periods. As a result, there is an increased risk that emergency procedures may be required to meet load and reserve requirements."[41]

Order Nos. 202-25-04, 202-25-08, 202-25-10, and 202-26-17 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national

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[35] *Id.*at 12.

[36] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 (2025); *see also, e.g., id.* P 263.

[37] *PJM Interconnection, L.L.C.*, 192 FERC ¶ 61,085, at P 25 (2025).

[38] NERC, *2025 Long-Term Reliability Assessment*, at 7 fig. 1 (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[39] *Id.* at 8.

[40] *Id.* at 16.

[41] *Id.* at 91.

security, and foreign policy."[42] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[43] In a subsequent Executive Order 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[44]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[45] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth. For example, PPL Electric Utilities has 11.7 GW of advanced data center requests in Pennsylvania through to 2030.[46] As of December 2024, Dominion Energy has 40.2 GW of contracted data center capacity, which is an 18.2 GW increase over the amount from July 2024, an approximately 88% increase.[47] In collaboration with the national labs, the Department modeled the effects of approximately 25 GW of load growth in PJM, of which 15 GW came from data centers, as well as approximately 17 GW of announced

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

[43] *Id*.

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

[45] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025) [hereinafter Resource Adequacy Report], https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[46] *See* PPL Corporation, *PPL Corporation Q2 2025* Investor *Update*, at 7 (July 31, 2025), https://filecache.investorroom.com/mr5ir_pplweb2/1245/PPL_2025_Q2_Investor_Update_vFINAL.pdf.

[47] *See* Dominion Energy Virginia, *Q4 2024 Earnings Call*, at 18 (Feb. 12, 2025), https://s2.q4cdn.com/510812146/files/doc_financials/2024/q4/2025-02-12-DE-IR-4Q-2024-earnings-call-slides-vTCII.pdf.

coal, gas, and oil generation retirements.[48] Under these assumptions, the model estimated approximately 430.3 loss of load hours in an average weather year. Under worst weather year assumptions, the model estimated 1,052 loss of load hours and a maximum unserved load of approximately 21.335 GW.[49]

Grid operators, including PJM, have likewise acknowledged the Nation's current energy crisis. For instance, during a hearing before the United States House of Representatives Committee on Energy and Commerce on March 25, 2025, Manu Asthana, President and CEO, PJM, testified that there was a "growing resource adequacy concern . . . impacting a significant part of our country."[50] Mr. Asthana explained that the "rate of electricity demand is anticipated to increase significantly in the future due to development of large data centers in the PJM service Area . . . [and] increases in demand coming from the transportation and heating sectors and from industrial growth."[51] Mr. Asthana noted that, though various reforms instituted by PJM had succeeded in bringing new generation online and preventing the retirement of existing units, supply conditions within PJM are still tightening.[52] Therefore, Mr. Asthana stated that PJM "encourage[s] all generation owners who have signaled an intent to retire their units to reconsider their decision to support resource adequacy and grid reliability."[53]

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

ORDER

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

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[48] Resource Adequacy Report, *supra* note 44, at 28.
[49] *Id.* at 27.
[50] Asthana Test., *supra* note 6, at 4.
[51] *Id.*
[52] *Id.* at 9–10.
[53] *Id.* at 10.

interest."[54] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of the Eddystone Units when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

As described above, the emergency conditions resulting from the combination of increasing demand and the capacity shortfall stemming from accelerated retirements of generation facilities supporting the issuance of Order Nos. 202-25-04, 202-25-08, 202-25-10, and 202-26-17 will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and local businesses in the areas affected by curtailments or outages, presenting a risk to public health and safety. Given the responsibility of PJM to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of the Eddystone Units is necessary to best meet the increased demand for emergency and mitigate the observed shortage of generation, thus serving the public interest pursuant to FPA section 202(c).

To ensure that the Eddystone Units will be available if needed to address emergency conditions, they shall remain available to operate through August 22, 2026.[55]

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

A. From May 25, 2026, PJM and Constellation Energy shall take all measures necessary to ensure that the Eddystone Units are available to operate. For the duration of this Order, PJM is directed to take every step to employ economic dispatch of the Eddystone Units to minimize cost to ratepayers. Constellation Energy is directed to comply with all orders from PJM related to the availability and dispatch of the Eddystone Units.

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

C. All operations of the Eddystone Units 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

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

[55] 16 U.S.C. § 824a(c)(4).

the emergency conditions. This Order does not provide relief from any obligation to pay fees, or purchase offsets or allowances for emissions that occur during the emergency conditions, or to use other geographic or temporal flexibilities available to generators.

D. By June 8, 2026, PJM is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of the Eddystone Units consistent with this Order. PJM shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department from time to time.

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

F. This Order shall not preclude the need for the Eddystone Units to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, the Eddystone Units shall not be considered capacity resources.

H. This Order shall be effective on May 25, 2026, through August 22, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 21st day of May 2026.

Chris Wright

Chris Wright
Secretary of Energy

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

Pennsylvania Public Utility Commission
Chairman Stephen M. DeFrank
Vice Chair Kimberly M. Barrow
Commissioner Kathryn L. Zerfuss
Commissioner John F. Coleman, Jr.
Commissioner Ralph V. Yanora

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit QQQ: Department, Order No. 202-26-28 (June 12, 2026)

Department of Energy
Washington, DC 20585

TransAlta Centralia Generation LLC and
GridForce Energy Management, LLC and
Southwest Power Pool, Inc. Western RC
Regarding the TransAlta Centralia Generation Facility

Order No. 202-26-28

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists within the Western Electricity Coordinating Council (WECC)–Northwest assessment area[3] due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

TransAlta Centralia Generation Facility (Centralia) is an electric generating facility in Centralia, Washington. Centralia is owned and operated by TransAlta Centralia Generation LLC (TransAlta). Centralia consists of one remaining coal-fired generation unit, Unit 2, with a nameplate capacity of 729.9 MW.[4] Unit 2 began operations in 1973 and was slated to cease operations in December 2025. Unit 1 was retired in 2020. Unit 2 is slated to cease operation based on a 2011 Washington law[5] and

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] The terms “area” and “region” are used interchangeably herein.
[4] U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data (2024)* (Sep. 9, 2025), https://www.eia.gov/electricity/data/eia860m/.
[5] Coal-Fired Elec. Generation Facilities, 2011 Wash. Sess. Laws, Ch. 180, https://lawfilesext.leg.wa.gov/biennium/2011-12/Pdf/Bills/Session%20Laws/Senate/5769-S2.sl.pdf.

a subsequent agreement between TransAlta and the State of Washington.[6] TransAlta has announced plans to convert the unit to natural gas by 2028.[7]

Order Nos. 202-25-11 and 202-25-11B, issued pursuant to FPA section 202(c), required that Centralia remain in operation for 90 days, until March 16, 2026. A subsequent order, Order No. 202-26-18, was issued pursuant to FPA section 202(c), requiring Centralia to remain in operation for 90 days, until June 14, 2026. Those orders were based on my determination that emergency conditions existed in 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.

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[6] *See* Memorandum of Agreement between Christine O. Gregoire, Governor, State of Washington, & Paul Taylor, President, TransAlta Centralia Generation LLC (Dec. 23, 2011), https://ecology.wa.gov/getattachment/858591f6-dd25-47be-ba1d-0f58264ca147/20111223TransAltaMOA.pdf ("D. In exchange for the benefits of entering into an MOA with the State pursuant to RCW 80.80.100, the Company will . . . (5) permanently cease power generation operations of one Boiler in 2020 and the other Boiler in 2025, which dates are prior to the 2035 end of their expected useful lives . . . ."); *see also* First Amendment to Memorandum Of Agreement between Jay Inslee, Governor, State of Washington, & Bob Nelson, President, TransAlta Centralia Generation LLC (July 13, 2017), https://fortress.wa.gov/ecy/ezshare/AQ/PDFs/TransAltaMOAAmend1-20170713.pdf. As a coal-fired facility, it likely would be difficult for the Centralia plant to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30–60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if TransAlta were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. The costs and time of decommissioning a coal plant are extensive and includes various components. Therefore, restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning* 9–12 (DOE, Pac. Nw. Nat'l Lab'y, Report, Aug. 2021), https://www.pnnl.gov/ main/publications/external/technical_reports/PNNL-31348.pdf; *see also* U.S. Energy Info. Admin., *Capital Cost & Performance Characteristics for Util. Scale Elec. Power Generating Techs.* (Jan. 2024), https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf.

[7] TransAlta, *TransAlta Signs Long-Term Agreement for 700 MW at Centralia Facility Enabling Coal to Nat. Gas Conversion* (Dec. 9, 2025), https://transalta.com/newsroom/transalta-signs-long-term-agreement-for-700-mw-at-centralia-facility-enabling-coal-to-natural-gas-conversion/.

Specifically, I determined that the WECC–Northwest region is at an elevated risk of insufficient operating reserves during periods of extreme weather.[8] I determined that the continued operation of Centralia would provide additional generation capacity during these periods, which would help prevent the potential loss of power to homes and local businesses in the areas that might have been affected by curtailments or outages that would otherwise pose a risk to public health and safety.[9] I determined that the continued operation of Centralia was necessary to alleviate immediate and anticipated threats to reliability.[10] My determination was based on a number of facts.

First, in its 2025–2026 Winter Reliability Assessment, the North American Electric Reliability Corporation (NERC) finds that the WECC–Northwest region, which includes Montana, Oregon, Washington, and parts of northern California and northern Idaho, is at elevated risk during periods of extreme weather.[11] The assessment notes that "there is sufficient capacity in the area for expected peak conditions; however, [balancing authorities] are likely to require external assistance during extreme winter weather that causes thermal plant outages and adverse wind turbine conditions for area internal resources. External assistance may not be available during region-wide extreme winter conditions. Winter peak demand for the area is forecast to be 2.9 GW higher (9.3%) compared to last year [i.e., in 2025–2026 compared to 2024–2025]."[12]

Second, in a September 2025 report evaluating Resource Adequacy in the Pacific Northwest, Energy + Environmental Economics (E3) determined that "[a]ccelerated load growth and continued retirements create a resource gap beginning in 2026 and growing to 9 GW by 2030"[13] and that "[l]oad growth and retirements mean the region faces a power supply shortfall in 2026."[14] E3 reported that nearly 9,000 MW of new capacity will be needed in the region by 2030, but currently only 3,000 MW of projects for new capacity are in active development.[15] Overall, E3 found that "[p]referred resources such as wind, solar and batteries make only small contributions to meeting resource adequacy

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[8] *See, e.g.*, *TransAlta Centralia Generation LLC*, DOE Order No. 202-25-11, at 1 (2025) (*Centralia*).

[9] *See, e.g.*, *id.* at 1–3.

[10] *See, e.g.*, *id.* at 3–4.

[11] NERC, *2025–2026 Winter Reliability Assessment*, at 6 (Nov. 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_wra_2025.pdf.

[12] *Id*.

[13] Wash. Utils. & Transp. Comm'n, *Res. Adequacy & the Energy Transition in the Pac. Nw.: Phase 1 Results*, ENERGY+ENV'T ECON. (E3), at 2 (Sept. 22, 2025), https://www.utc.wa.gov/sites/default/files/2025-10/Revised%20V3%20E3%20Presentation%20RA%20Study%20September%2022%20WA%20RA%20Meeting.pdf; *see also id.* (listing E3's study sponsors, which include certain "regional utilities and generation owners").

[14] *Id*. at 10.

[15] *Id*.

needs" and "[t]imely development of all resources is extremely challenging due to permitting and interconnection delays, federal policy headwinds, and cost pressures."[16]

EMERGENCY SITUATION

The emergency conditions that necessitated the issuance of Order Nos. 202-25-11, 202-25-11B, and 202-26-18 continue, both in the near and long term.[17] The production of electricity from Centralia will continue to be an asset to maintain reliability in the WECC Northwest region. According to the U.S. Environmental Protection Agency's data, in 2025,[18] Centralia generated an average of approximately 340,000 MWh per month, providing vital generation capacity to the region.

In its 2025 Long-Term Reliability Assessment,[19] the NERC assessed that the WECC Northwest region is at high risk of energy shortfalls over the next five years,[20] noting that "[r]apid forecasted demand growth is driving the need for more resources" and that "[p]eriods of unserved energy are projected for both summer and winter."[21] The assessment notes that peak load in the region "is forecast to increase by 6.6 GW (19%) over the next 10 years, driven by an influx of data centers into the Pacific Northwest."[22] Additionally, while over 10 GW of new variable resources are in development, the assessment warns that "additional resources will be needed to avoid shortfalls in planning reserves and prevent energy risks from emerging."[23]

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[16] *Id*. at 2.

[17] *See, e.g.*, Order No. 202-25-11 at 1.

[18] *See* U.S. Env't Prot. Agency, *Custom Data Download, EPA CAMPD (Clean Air Mkts. Program Data)*, https://campd.epa.gov/data/custom-data-download (choose "Emissions" from Data Type dropdown; choose "Monthly Emissions" from Data Subtype dropdown; choose "Unit (No Aggregation)" from Aggregation dropdown; then click "Apply"; then type "2025" into "Time Period" filter and click "January, February, March, April, May, June, July, August, September, October, November, December"; then click "Apply Filter"; then click "Facility" filter and type "Centralia (3845)"; then click "Centralia (3845)"; then click "Apply Filter"; then click "Preview Data").

[19] NERC, *2025 Long-Term Reliability Assessment* (Jan. 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[20] *Id.* at 7.

[21] *Id.* at 8.

[22] *Id.* at 19.

[23] *Id.*

NERC's 2026 Summer Reliability Assessment (2026 SRA) classifies the WECC–Northwest region as an Elevated Risk[24] area with highest-risk conditions occurring in early evening hours (around 6 p.m.) in late summer.[25] The region faces "elevated risks of electricity supply shortfalls during periods of more extreme summer conditions or [is] 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."[26] Under typical outage conditions the 2026 SRA forecasts reserve margins to be 25.2% and in a scenario with extreme conditions such as higher demand, outages, and derates, reserve margin is estimated to drop to 8.8%, below the 2026 SRA Reference Margin Level of 10.0%. In normal and typical outages, reserve margins in the 2026 SRA are expected to tighten compared to the 2025 SRA, partly due to net demand growth of 4.6% compared to an increase in energy availability by generation resources of 1.5%. NERC notes that "[t]hermal 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."[27]

In addition, NERC's 2026 Summer Reliability Assessment notes,

> 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 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

[24] Elevated risk refers to the potential for insufficient operating reserves in above-normal conditions. NERC, *2026 Summer Reliability Assessment*, at 2–3 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[25] NERC, *2026 Summer Reliability Assessment*, at 2–3 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

[26] *Id*. at 2.

[27] *Id*. at 9.

> was not enough to prevent the drop in the Anticipated Reserve Margin from 32% last year to 27% this year.[28]
>
> 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. Expected resources do not meet operating reserve requirements under the assessed extreme scenarios.[29]

On March 2, 2026, an amended preliminary injunction was issued by the U.S. District Court for the District of Oregon that imposes operational constraints on the dams that comprise the Federal Columbia River Power System.[30] The restrictions imposed by the amended preliminary injunction will impact power and transmission system reliability, grid stability, and the ability to meet reserve requirements in the WECC–Northwest assessment region.[31] The District Court did not give adequate consideration to the impacts that the preliminary injunction measures will have on the Bonneville Power Administration's (BPA) ability to provide reliable power and transmission services. BPA submitted several declarations detailing the impacts on reliability that would result from the preliminary injunction sought.[32] BPA's modeling of the operational measures in the motion for preliminary injunction concluded that the Columbia River System generation would be greatly decreased in March through November (nine months out of the year) and substantially increase the risk during time periods of high demand such as summer heat waves.[33] Indeed, there is a substantial increased risk that the regional power system will not be able to operate reliably under the ordered spill levels.[34]

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[28] *Id*. at 2.

[29] *Id*. at 36.

[30] *Nat'l Wildlife Fed'n (NWF) v. Nat'l Marine Fisheries Serv. (NMFS),* No. 3:01-cv-00640 (D. Or. Mar. 2, 2026) (granting amended preliminary injunction).

[31] Fed. Def. Response to Minute Order at 4–5, *NWF v. NMFS*, No. 3:01-cv-00640.

[32] *See, e.g.*, Decl. of Rachel Dibble in Supp. of Fed. Def. Opp'n to Pls. Mot. for a Prelim. Inj., *NWF v. NMFS*, No. 3:01-00640, ECF No. 2574; Decl. of Audrey Stevenson in Supp. of Fed. Def. Opp'n to Pls.' Mot. for a Prelim. Inj., *NWF v. NMFS*, No. 3:01- 00640, ECF No. 2582.

[33] *See* Dibble Decl. ¶ 28; *id.* ¶ 42, fig. 3.

[34] *See, e.g.*, Dibble Decl. ¶ 26; Stevenson Decl. ¶ 18.

Order Nos. 202-25-11, 202-25-11B, and 202-26-18 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, *Declaring a National Energy Emergency*, in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[35] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[36] In a subsequent Executive Order No. 14262, *Strengthening the Reliability and Security of the United States Electric Grid*, President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing." [37]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[38] The prolific growth of data centers for the development of AI, as well as their immense energy needs, presents a new and unexpected source of load growth.

In addition, President Trump issued a White House Memo that emphasized the findings of Executive Order No. 14156 stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[39]

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

[36] *Id.*

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

[38] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[39] The White House, *Presidential Determination Pursuant to Sec. 303 of the Defense Product. Act of 1950, as Amended, on Coal Supply Chains & Baseload Power Generation Capacity*, (Apr. 20, 2026), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-

President Trump "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[40]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy . . . or other causes," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[41] This statutory language constitutes a specific grant of authority to the Secretary to require the continued availability of Centralia Unit 2 when the Secretary has determined that such continued availability will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

As described above, the emergency conditions resulting from increasing demand and accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the potential loss of power to homes, businesses, and facilities critical to the national defense in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety.

I have also made the determination 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), Centralia Unit 2 shall be made available for operation through September 12, 2026.

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

A. From June 15, 2025, TransAlta shall take all measures necessary to ensure that Centralia Unit 2 is available to operate at the direction of either Gridforce Energy Management, LLC (in its role as Balancing Authority)[42] or Southwest Power Pool

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production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity.

[40] *Id*.

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

[42] *See* U.S. Energy Info. Admin., *Hourly Elec. Grid Monitor*, EIA-930A 2024 data, https://www.eia.gov/electricity/gridmonitor/about. On EIA-930A 2024 SCH 2, the BA Code for TransAlta Centralia Generation is GRID. *See id.*, EIA-930 data reference tbls., https://www.eia.gov/electricity/gridmonitor/about. On EIA-930 data reference tables, BA Code GRID is associated with Gridforce Energy Management, LLC.

Western RC[43] (in its role as the Reliability Coordinator) or any successors thereto. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices.

B. To minimize adverse environmental impacts, this Order limits operation of Centralia Unit 2 to the times and within the parameters established in paragraph A. TransAlta shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Centralia Unit 2 has operated in compliance with this Order.

[43] *See* Sw. Power Pool, Map (illustrating Regional Transmission Organization and Western Reliability Coordinator footprint with planned expansion), https://www.spp.org/documents/62914/rto%20and%20western%20rc%20footprint%20w%20planned%20expansion.png.

C. All operations of Centralia Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By June 29, 2026, TransAlta is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Centralia Unit 2, consistent with this Order. TransAlta shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

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

F. BPA is directed to facilitate transmission service, as needed, to effectuate this Order.

G. This Order shall not preclude the need for Centralia Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

H. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Centralia Unit 2 shall not be considered a capacity resource.

I. This Order shall be effective from June 15, 2026, through September 12, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 12th day of June 2026.

Chris Wright

Chris Wright
Secretary of Energy

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

<u>Washington Utilities and Transportation Commission</u>
Chairman Brian Rybarik
Commissioner Milt Doumit
Commissioner Ann Rendahl

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit RRR: Department, Order No. 202-26-29 (June 18, 2026)

Department of Energy
Washington, DC 20585

Midcontinent Independent System Operator, Inc. | Order No. 202-26-29
Northern Indiana Public Service Company LLC
Regarding R.M. Schahfer Generating Station

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The R.M. Schahfer Generating Station (Schahfer) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired generation units and two coal-fired generation units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).[3] Unit 17 and Unit 18 began operations in 1983 and 1986, respectively. Unit 17 and Unit 18 were both slated to cease operations in December 2025.[4]

Order No. 202-25-12, issued pursuant to FPA section 202(c), required that Schahfer Unit 17 and Unit 18 remain in operation for 90 days, through March 23, 2026. Subsequently, Order No. 202-26-19, issued pursuant to FPA section 202(c), required the Schahfer Units to remain in operation for 90 days, until June 21, 2026. These orders

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

[3] U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data* (2024), https://www.eia.gov/electricity/data/eia860/.

[4] It likely would be difficult for the coal-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if NIPSCO were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick et al., *Bus. Models for Coal Plant Decommissioning*, at 9-12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

Specifically, I determined that MISO faced tight reserve margins due to well-documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[5] I determined that the continued operation of Schahfer would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Schahfer was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts. First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk, "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[8] Additionally, the LTRA notes that "[t]he departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years."[9]

Second, MISO's year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[10] MISO justified this revision by explaining that "Reliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[11]

[5] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc.*, DOE Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

[6] *See, e.g.*, *id.*

[7] *See, e.g.*, *id.* at 5.

[8] N. Am. Elec. Reliability Corp., *2024 Long-Term Reliability Assessment*, at 13 (Dec. 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.

[9] *Id.* at 44.

[10] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, FERC Dkt. No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *See also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g*, 182 FERC ¶ 61,096 (2023).

[11] *MISO*, Transmittal Letter, FERC Dkt. No. ER22-495-000, at 3.

MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[12]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-12 and 202-26-19 continue, both in the near and long term. The production of electricity from Schahfer continues to be critical to maintain reliability in MISO. MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Schahfer operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand, and transfer capability limits.[13] From January 21–February 1, 2026, Schahfer operated at over 285 MW every day.[14]

In December 2023, MISO released an "Attributes Roadmap," in which it presented an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.[15] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027 there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected risk of loss of load in the winter and spring seasons, which, although not as high as in the summer or fall, will nevertheless increase over time.[16]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, *MISO's Response to the Reliability Imperative.*[17] In a section of that report entitled, *Risks in Non-Summer Seasons*, MISO again stressed that it has resource reliability concerns outside of the summer season.

Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile,

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[12] *Id.* at 3–4.

[13] *See* MISO (@MISO_energy), X (Jan. 24, 2026), https://x.com/MISO_energy/status/201 5072060876140805?s=20.

[14] DOE, *FACT SHEET: Energy Dep't Prevented Blackouts & Saved Am. Lives During Winter Storms* (Feb. 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

[15] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023 %20Attributes%20Roadmap631174.pdf.

[16] *Id.* at 11.

[17] MISO, *MISO's Response to the Reliability Imperative* (updated Feb. 2024), htt ps://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

creating risks in non-summer months that rarely posed challenges in the past.[18] These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season.

In January 2026, NERC released its 2025 Long-Term Reliability Assessment, NERC assessed that the MISO region is at high risk of energy shortfalls over the next five years, stating that it faces significant reliability challenges as "projected resource additions do not keep pace with escalating demand forecasts and announced generator retirements."[19] This determination is based on the combination of accelerating demand growth from new data centers and the retirement of existing thermal generators.[20] The 2025 Long-Term Reliability Assessment notes that "MISO's accredited thermal capacity has decreased by 8.8 GW, driven primarily by reductions in accredited capacity of existing facilities and retirements."[21] The report observes that winter peak periods are a particular concern, with projections showing "shortfalls in planned resources for winter peak periods."[22] However, NERC also concluded that "risks could expand into spring and fall generator maintenance periods when the available dispatchable generation is not enough to counter wind and solar variability when demand is high."[23]

According to NERC's 2026 Summer Reliability Assessment, load growth in the MISO region, led by data centers, "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."[24] It further notes that "[a]bove-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 [Energy Emergency Alerts]."[25] Since the region benefits from transmission connections with neighbors to meet extreme conditions, MISO's reliance on electricity imports will increase when extreme conditions arise.[26]

The evidence indicates that there is also a potential longer-term resource adequacy emergency in MISO. When MISO reported the results of its PRA for the 2025–26 Planning Year, it noted that "new capacity additions were insufficient to offset

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[18] *Id.* at 12.

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[23] *Id.*

[24] NERC, *2026 Summer Reliability Assessment*, at 16 (May 2026), https://www.nerc.com/globalassets/our-work/assessments/nerc_sra_2026.pdf.

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the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[27]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their annual survey (OMS-MISO Survey), which reported the degree to which expected capacity resources satisfy planning reserve margin requirements.[28] The OMS-MISO Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the OMS-MISO Survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin. The OMS-MISO Survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[29] It also projected similar results for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[30]

The primary reasons for these projected deficits also are shown on the OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[31] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.[32]

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with nearly another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, which includes Schahfer's capacity.[33]

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[27] MISO, *Planning Res. Auction: Results for Planning Year 2025–26*, at 13 (Apr. 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[28] OMS and MISO, *OMS-MISO Survey Results* (updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[29] *Id.* at 7.

[30] *Id.* at 9.

[31] *Id.* at 7, 9.

[32] *Id.*

[33] *See* U.S. Energy Info. Admin. , *Indiana Analysis* (Nov. 19, 2025), https://www.eia.gov/states/in/analysis.

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[34] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years after the process begins and are provided an additional three-year grace period to commence commercial operations.[35] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[36] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-12 and 202-26-19 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[37] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[38] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[39]

[34] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[35] *See id.* P 84.

[36] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025) ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

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

[38] *Id*.

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

In addition, President Trump issued a White House Memo for the Secretary of Energy that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[40] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[41]

Further, the Department of Energy detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," which was issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[42]

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025, hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[43]

Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected

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[40] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) (*Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Coal Supply Chains and Baseload Power Generation Capacity*), https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[41] *Id.*

[42] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-11/DOE%20Final%20EO%20Report%20%28REVISED%20OCT%2027%29.pdf.

[43] *Keeping the Lights On: Examining the State of Reg' Grid Reliability; Hearing Before the House Comm. on Energy & Com., Subcomm. on Energy*, 119th Cong. 5 (2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Indep. Sys. Operator), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

demand for energy-hungry data centers to support artificial intelligence."[44] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[45]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[46] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the 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. This 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.

I have 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), Schahfer Units 17 and 18 shall be made available for operation through September 19, 2026.

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[44] *Id.* at 6.

[45] *Id.* at 7.

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

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

A. From June 22, 2026, MISO and NIPSCO shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of Schahfer Units 17 and 18.

B. To minimize adverse environmental impacts, this Order limits operation of Schahfer Units 17 and 18 to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 have operated in compliance with the allowances contained in this Order.

C. All operations of Schahfer Units 17 and 18 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency conditions or to use other geographic or temporal flexibilities available to generators.

D. By July 7, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

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

F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from June 22, 2026, through September 19, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 18th Day of June 2026.

Chris Wright
Secretary of Energy

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

<u>Indiana Utility Regulatory Commissioners</u>
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

	)	
Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit SSS: Department, Order No. 202-26-30 (June 18, 2026)

Department of Energy
Washington, DC 20585

Midcontinent Independent System Operator, Inc. Order No. 202-26-30
Center Point Energy
Regarding F.B. Culley Generating Station

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA),[1] and section 301(b) of the Department of Energy (DOE or the Department) Organization Act,[2] and for the reasons set forth below, I hereby determine that an emergency exists in portions of the Midwest region of the United States (U.S.) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes. Issuance of this Order will meet the emergency and serve the public interest.

BACKGROUND

The F.B. Culley Generating Station ("Culley") is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW.[3] Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 was slated to cease operations in December 2025.[4]

Order No. 202-25-13, issued pursuant to FPA section 202(c), required that Culley Unit 2 remain in operation for 90 days, through March 23, 2026. Subsequently, Order No. 202-26-20, issued pursuant to FPA section 202(c), required the Culley Unit to remain in operation for 90 days, until June 21, 2026. These orders were based on my determination that emergency conditions existed in the region served by the Midcontinent Independent System Operator, Inc. (MISO).

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Info. Admin., *Form EIA-860, Schedule 3: Generator Data* (2024), https://www.eia.gov/electricity/data/eia860/.
[4] It likely would be difficult for the coal-fired units to resume operations once retired. Specifically, practical issues, such as employment, contracts, and permits, may greatly increase the timeline for resumption of operations during the period they are needed. Moreover, if CenterPoint Energy were to begin disassembling the units or other related facilities, the associated challenges would be greatly exacerbated. The costs and time of decommissioning a coal plant are extensive, and restarting such decommissioned plants would presumably cost the same as decommissioning in dollars and time, if not more. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist. *See* Jennifer Lessick, et al., *Bus. Models for Coal Plant Decommissioning*, at 9-12 (Aug. 2021), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-31348.pdf.

Specifically, I determined that MISO faced tight reserve margins due to well--documented year-round resource adequacy concerns, particularly during periods of high demand or low generation resource output.[5] I determined that the continued operation of Culley Unit 2 would provide additional generation capacity during these periods, which would help prevent the loss of power to homes and businesses that would otherwise pose a risk to public health and safety.[6] I determined that the continued operation of Culley Unit 2 was necessary to alleviate immediate and anticipated threats to reliability.[7]

My determination was based on several facts. First, in its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area, which covers portions of Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, North Dakota, South Dakota, Texas, and Wisconsin, is at an elevated risk, "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[8] Additionally, the LTRA notes that "[t]he departure of MISO's coal fleet has continued with a reduction in capacity of around 6 GW in the past year, and a projected reduction of a further 12 GW over the next five years."[9]

Second, MISO's year-round resource adequacy concerns are well-documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[10] MISO justified this revision by explaining that "Reliability risks associated with [r]esource [a]dequacy have shifted from 'Summer only' to a year-round concern."[11] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates

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[5] *See, e.g.*, *Midcontinent Indep. Sys. Operator, Inc*, Order No. 202-25-12, at 1–4 (Dec. 23, 2025).

[6] *See, e.g.*, *id.*

[7] *See, e.g.*, *id.* at 5.

[8] N. Am. Elec Reliability Corp., *2024 Long-Term Reliability Assessment*, at 13 (Dec. 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/nerc_ltra_2025.pdf.

[9] *Id.* at 44.

[10] *Midcontinent Indep. Sys. Operator, Inc.*, Transmittal Letter, FERC Dkt. No. ER22-495-000 (filed Nov. 30, 2021). FERC accepted MISO's proposed tariff revisions on August 31, 2022. *See also Midcontinent Indep. Sys. Operator, Inc.*, 180 FERC ¶ 61,141 (2022), *order on reh'g & compliance*, 182 FERC ¶ 61,096 (2023).

[11] *MISO*, Transmittal Letter, FERC Dkt. No. ER22-495-000, at 3.

emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[12]

CONTINUING EMERGENCY CONDITIONS

The emergency conditions that necessitated the issuance of Order Nos. 202-25-13 and 202-26-20 continue, both in the near and long term. The production of electricity from Culley continues to be critical to maintain reliability in MISO. MISO's resource adequacy concerns were most recently demonstrated during Winter Storm Fern, when Culley operated under a cold weather alert and declared conservative operations from January 23–February 1, 2026. On January 24, MISO declared an Energy Emergency Alert (EEA) 1, as well as an EEA 2 "MaxGen" event for MISO's North and Central Regions due to generation outages, high demand, and transfer capability limits.[13] From January 21–February 1, 2026, Culley operated at roughly 30 MW almost every day.[14]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape.[15] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/2024 Planning Year the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected risk of loss of load in the winter and spring seasons; which although not as high as in the summer or fall, will nevertheless increase over time.[16]

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[14] DOE, *FACT SHEET: Energy Dep't Prevented Blackouts & Saved Am. Lives During Winter Storms*, (Feb. 2026), https://www.energy.gov/articles/fact-sheet-energy-department-prevented-blackouts-saved-american-lives-during-winter-storms.

[15] MISO, *Attributes Roadmap*, *supra* note 14, at 3.

[16] *Id.* at 11.

[17] MISO, *MISO's Response to the Reliability Imperative* (Updated Feb. 2024), https://cdn.misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.

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The primary reasons for these projected deficits also are shown on the OMS-MISO Survey. Large amounts of existing generation capacity are projected to be retired each year, while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[31] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements and does not keep up with the growth in demand.[32]

According to the U.S. Energy Information Administration, coal-fired electricity generation in Indiana has declined from 85% of total generation in 2014 to 42% in 2024. Since 2014, approximately 5,000 MW of coal-fired capacity in Indiana have retired, with nearly another 3,900 MW of coal-fired capacity scheduled for retirement by the end of 2028, which includes Culley's capacity.[33]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to

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[27] MISO, *Planning Res. Auction: Results for Planning Year 2025–26*, at 13 (Apr. 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

[28] OMS and MISO, *OMS-MISO Survey Results* (updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[29] *Id.* at 7.

[30] *Id.* at 9.

[31] *Id.* at 7, 9.

[32] *Id.*

[33] *See U.S.* Energy Info. Admin., Indiana Analysis (Nov. 19, 2025), https://www.eia.gov/states/in/analysis.

establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[34] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years after the process begins and are provided an additional three-year grace period to commence commercial operations.[35] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[36] Consequently, the new ERAS process is unlikely to result in the addition of any new generation capacity in the next few years.

Order Nos. 202-25-13 and 202-26-20 were preceded by executive orders on January 20, 2025, and April 8, 2025, in which President Donald J. Trump underscored the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump declared a national energy emergency in Executive Order No. 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[37] The Executive Order adds, "hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[38] In the subsequent Executive Order No. 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[39]

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[34] *Midcontinent Indep. Sys. Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[35] *See id.* P 84.

[36] *See generally* S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025) ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/energy/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

[37] Exec. 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.

[38] *Id.*

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

In addition, President Trump issued a White House Memo for the Secretary of Energy that emphasized the findings of Executive Order No. 14156, stating that "ensuring reliable coal supply chains and baseload power generation capacity is essential to the United States national defense . . . . Without sufficient coal-fired baseload power, the United States will lack the stable electricity required to support defense installations, industrial expansion, and the high-energy demands of emerging technologies, such as artificial intelligence."[40] The President "further determine[d] that action to expand coal supply chain capacity and baseload generation availability is necessary to avert an industrial resource or critical technology item shortfall that would severely impair national defense capability."[41]

Further, the Department of Energy detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," which was issued pursuant to the President's directive in Executive Order No. 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[42]

Grid operators—including MISO itself—have also acknowledged the Nation's current energy crisis. For instance, during a March 25, 2025 hearing before the House Committee on Energy and Commerce, Jennifer Curran, Senior Vice President, Planning and Operations, MISO, testified that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, inadequate transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[43]

Ms. Curran also described "much stronger growth [in demand for electricity] from continued electrification efforts, a resurgence in manufacturing, and an unexpected

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[40] Memorandum from President Donald J. Trump to the Secretary of Energy (Apr. 20, 2026) ("*Presidential Determination Pursuant to Section 303 of the Defense Production Act of 1950, as Amended, on Coal Supply Chains and Baseload Power Generation Capacity*", https://www.whitehouse.gov/presidential-actions/2026/04/presidential-determination-pursuant-to-section-303-of-the-defense-production-act-of-1950-as-amended-on-coal-supply-chains-and-baseload-power-generation-capacity/.

[41] *Id.*

[42] DOE, *Res. Adequacy Rep.: Evaluating the Reliability & Sec. of the U.S. Elec. Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.

[43] *Keeping the Lights On: Examining the State of Reg'l Grid Reliability Before the House Comm. on Energy & Commerce*, Subcomm. on Energy, 119th Cong., at 5 (Mar. 25, 2025) (statement of Ms. Jennifer Curran, Senior Vice President for Planning and Operations, Midcontinent Indep. Sys. Operator), https://www.congress.gov/119/meeting/house/118040/witnesses/HHRG-119-IF03-Wstate-CurranJ-20250325.pdf.

demand for energy-hungry data centers to support artificial intelligence."[44] She added, "[a] growing reliability risk is that the rapid retirement of existing coal and gas power plants threatens to outpace the ability of new resources with the necessary operational characteristics to replace them."[45]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in [his] judgment will best meet the emergency and serve the public interest."[46] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity, or a shortage of electric energy or facilities for generation or transmission of electric energy.

As described above, the 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. This 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.

I have 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), Culley Unit 2 shall be made available for operation through September 19, 2026.

[44] *Id.* at 6.

[45] *Id.* at 7.

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

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

A. From June 22, 2026, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

B. To minimize adverse environmental impacts, this Order limits operation of Culley Unit 2 to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.

C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency conditions or to use other geographic or temporal flexibilities available to generators.

D. By July 7, 2026, MISO is directed to provide the Department (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, as requested by the Department of Energy from time to time.

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

F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.

H. This Order shall be effective from June 22, 2026, through September 19, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Washington, D.C. on this 18th Day of June, 2026.

Chris Wright
Secretary of Energy

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

<u>Indiana Utility Regulatory Commissioners</u>
Chairman Andy Zay
Commissioner Bob Deig
Commissioner Anthony Swinger
Commissioner David Veleta
Commissioner David Ziegner

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit TTT: Department, Order No. 202-26-26 (June 4, 2026)

Department of Energy
Washington, DC 20585

Orlando Utilities Commission
Regarding the Stanton Energy Center

Order No. 202-26-26

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

<u>BACKGROUND</u>

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

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[1] 16 U.S.C. § 824a(c).

[2] 42 U.S.C. § 7151(b).

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

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

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

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

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

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

EMERGENCY CONDITIONS

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

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

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

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

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

[9] *Id.* at 6.

[10] *Id.* at 9.

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

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

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

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

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

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

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[14] *Id.*

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

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

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

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

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

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

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

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

[23] *Id.*

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

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

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

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

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

[26] *Id.* at 4.

[27] *Id* at 10.

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

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

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

ORDER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Chris Wright

Chris Wright
Secretary of Energy

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

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

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit UUU: WECC, Summer 2026 Assessment Overview

Summer Reliability Assessment Western Overview 2026

The Summer Reliability Assessment (SRA) covers the upcoming summer season, providing an evaluation of reliability for projected risk periods while identifying potential reliability issues of interest and regional topics of concern. Among the findings:

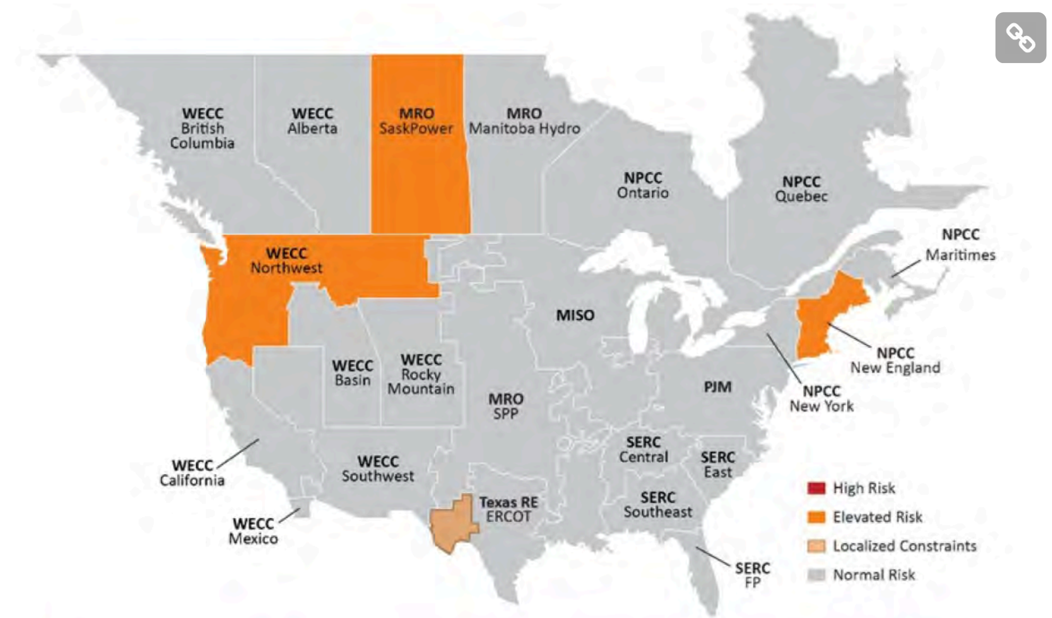
- Continent-wide, the 2026 summer risk profile is characterized by rising demand, significant resource additions in many areas, the prospect of challenging hydrological conditions, and unpredictability associated with large loads.
- All areas have adequate anticipated resources for normal summer peak load conditions, according to the assessment; however, three areas face elevated risk of supply shortfalls during periods of more extreme summer conditions, including the Western Interconnection's Northwest subregion.
- An influx of resources, primarily solar and battery but also natural gas-fired generation, has outpaced demand and boosted reserves, easing resource adequacy concerns across the continent.
- Large loads pose operational challenges for the summer. Recent events in which large loads unexpectedly disconnected from the grid in the Eastern Interconnection and ERCOT highlight the need for operational readiness this summer and illustrate why NERC is closely examining the potential risks posed by large loads.
- The overlap of early summer heat and spring maintenance outages can lead to reliability risks.

NERC Summer Reliability Assessment: Western Overview

Each year, WECC partners with the North American Electric Reliability Corporation (NERC) and the rest of the Electric Reliability Organization (ERO) Enterprise to develop the NERC SRA. This assessment evaluates system resource adequacy and reliability across North America for the upcoming summer season. Below are highlights from the assessment specific to the Western Interconnection.

Key Takeaways

- Common reliability concerns across the Western Interconnection for summer 2026 are threats from wildfire, resource adequacy in periods of extreme heat, and drought, which exacerbates the wildfire threat and can lead to diminished hydro output. These concerns vary in severity in each of the eight WECC subregions.
- Wide-area heat events or wildfires that affect resource and transmission availability across the Western Interconnection are a concern. The ability to import energy may be limited during these events.
- Supply chain constraints and economic uncertainty may affect planned resources across the interconnection.
- Along with challenging hydro conditions, the Northwest’s elevated designation centers on a nearly 5% increase in demand projected for this summer from the 2025 SRA, a nearly 2% decrease in existing resources, and a significant drop in planned resources.



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

Subregion Reliability Highlights

British Columbia: Peak demand is projected to increase 2.4% over last summer’s forecasts, while anticipated resources increase by almost 16%. In WECC's analysis, no loss of load emerged in a range of conditions.

Alberta: Peak demand is projected to increase 2.1% over last year’s forecasts, while anticipated reserve margins exceed the prescribed margin level. In WECC's analysis, no loss of load emerged in a range of conditions.

Northwest: Peak demand is projected to grow 4.6% over last summer’s forecasts, while anticipated resources show a 1.5% increase in energy availability, leading to tighter margins. Supply chain constraints and economic uncertainty may affect planned resource additions. The elevated risk of shortfalls in the assessment occurs in August and September.

California: Extreme heat and wildfires may affect generation and transmission resources and remain a reliability concern. Variability of inverter-based resources is a concern, particularly in the evening when solar generation wanes and wind generation can be curtailed due to Santa Ana Winds.

Mexico: The subregion added 1 GW of gas-fired generation since last summer, significantly improving the outlook from the 2025 SRA. Operating reserves are a concern during periods of extreme heat and elevated demand, however. Anticipated reserves are projected to be 16% higher, but some generating units have reached advanced operational age, resulting in an increase in the forced outage rate. This raises the risk of capacity shortfalls, potentially compromising system reliability during peak summer demand.

Basin: Peak demand is projected to increase by 4%, due in part to a significant decrease in demand response availability, while anticipated resource capacity is expected to increase by 16% from last summer's forecasts.

Rocky Mountain: Peak demand is projected to decline by 3%, while anticipated resource capacity is expected to increase by 15%. Climate change and ecological factors are raising the wildfire risk in the subregion, although the entities have engaged in substantial mitigation efforts.

Southwest: Peak demand is projected to increase by 10% over last summer's forecasts, while anticipated resource capacity is expected to increase by 33% since last summer's forecasts. The subregion faces grid reliability concerns posed by large loads if new generation resources are delayed as new load comes online.


MEXICO


BASIN


BASIN

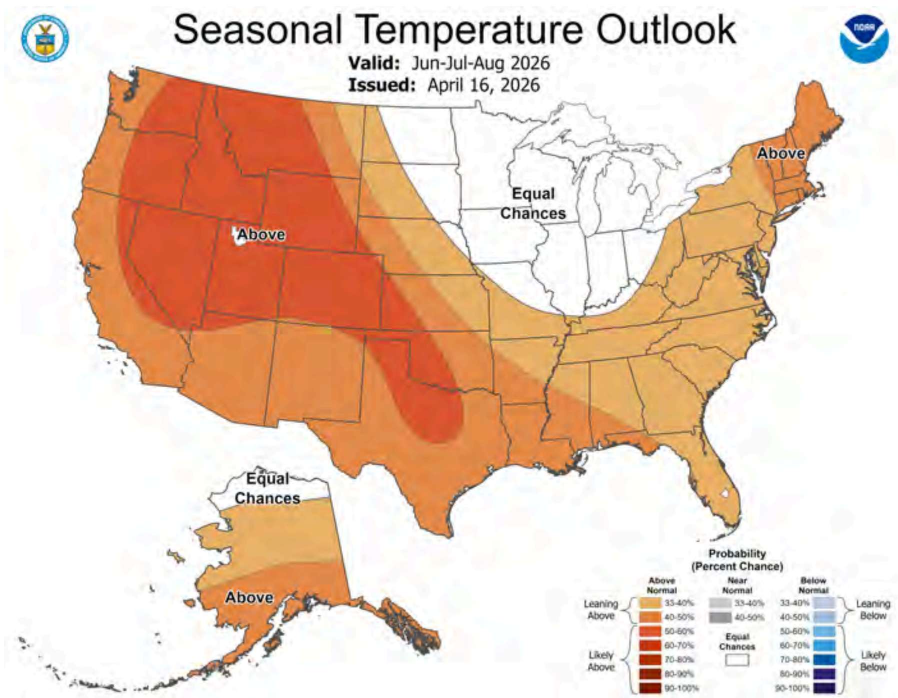

ROCKY
MOUNTAIN

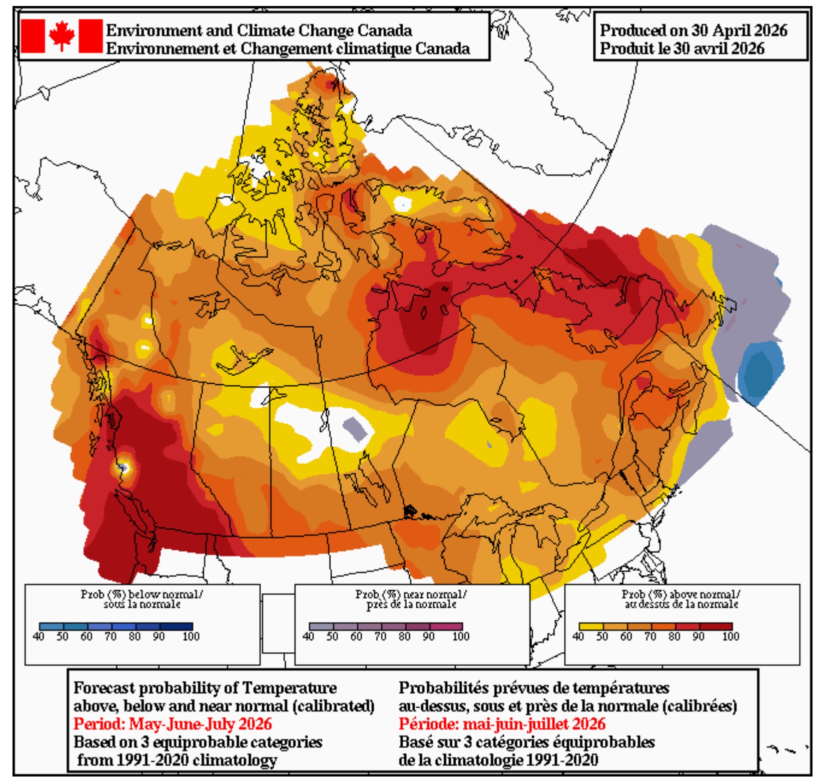

ROCKY
MOUNTAIN


SOUTHWEST

Summer Conditions and Drought Affecting the Bulk Power System

Forecasts indicate above-normal temperatures for much of the West this summer as an El Nino weather pattern is expected. Drier-than-normal conditions are expected in the Northwest, where the snowpack is below average. In Canada, higher-than-normal temperatures are expected in the northeast. Snowpack in Canada is generally in average condition, with a pocket of below-average snowpack in southwest British Columbia. To learn more about the expected summer weather and operating conditions, view the *Reliability in the West Discussion Series: Assessing Summer Conditions and Readiness*.





Extreme Heat

The summer peak declined in the Western Interconnection in 2025, to 163 GW from 168 GW in 2024, as most of the West saw a moderation in heat compared to 2024. And, while the interconnection experienced relatively few emergency events, there were heat events that stressed the system.

- A heat wave in western Canada from late August through early September broke records in British Columbia and exacerbated drought conditions. Parts of western Canada saw generation outages that triggered energy emergency alerts (EEA).
- In Mexico, generation losses in late August triggered EEAs.
- In the Rocky Mountain subregion, Utah and Nevada recorded their warmest years on record.

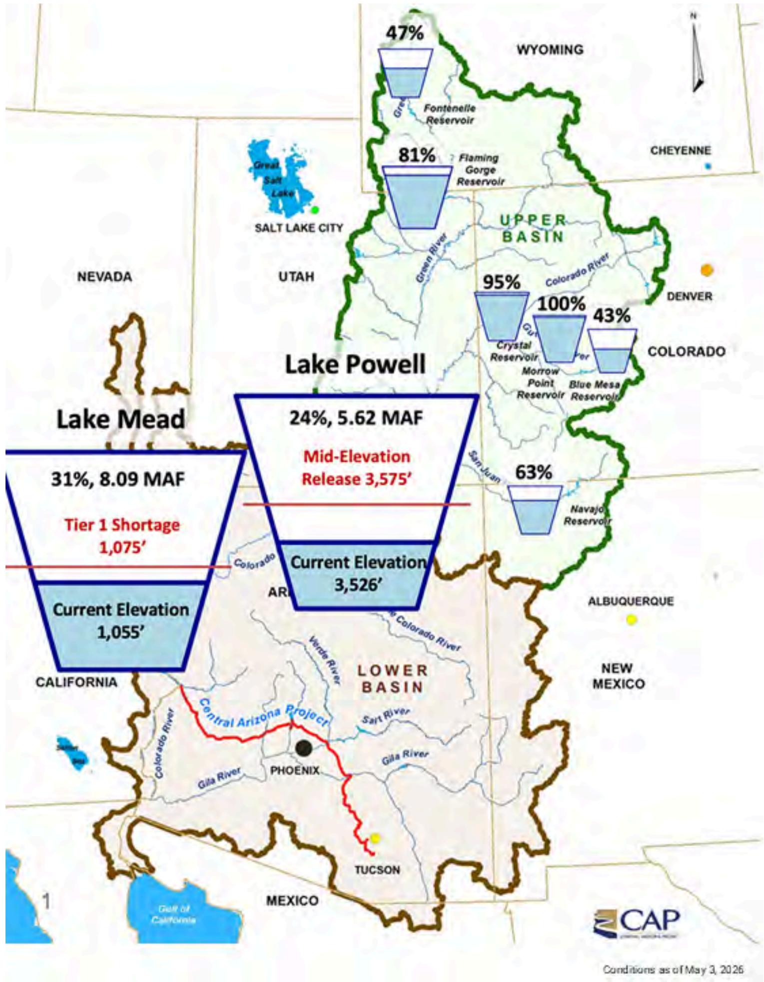
Challenging Hydro Conditions

Drought conditions are either in place or are likely to develop this summer throughout much of the interconnection. This could affect hydropower generation (hydro has the second-most nameplate capacity installed in the Western Interconnection).

In the Northwest subregion, where hydro makes up more than half of the resource mix, the snow water equivalent was at 52% of normal as of April 1. While the water year is forecast to be about average in the Columbia River Basin, snowpack melted earlier in the year. This has implications for the expected resources available in the Northwest.

The Southwest subregion is less reliant on hydro, but one significant hydro facility on the Colorado River System, the 1 GW Glen Canyon Dam at Lake Powell, had been projected to be unable to generate power due to low water levels as soon as August 2026. The Bureau of Reclamation has taken steps to prevent this, announcing plans in late April to release enough water from the Flaming Gorge Reservoir to increase Lake Powell's elevation to sufficient levels for power generation.

Downriver, Hoover Dam is operating in shortage conditions, but the most recent projections indicate Lake Mead will maintain levels needed to generate power at the 2 GW facility throughout the 24-month period studied.



WECC

The Independent Voice of Bulk Power System Reliability in the Western Interconnection

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

	)	
Federal Power Act Section 202(c)	)	Order No. 202-26-31
Emergency Order: Craig Unit 1	)	
	)	

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit VVV: WECC, 2025 Western Assessment Supplemental Information

2025 Western Assessment Supplemental Information

Introduction

WECC's annual Western Assessment of Resource Adequacy provides a high-level examination of resource-adequacy-related risks to the reliability of the Western Interconnection over the next 10 years. Through an energy-based probabilistic approach, WECC examines the risks across the entire interconnection and eight subregions. This work is intended to help stakeholders target specific areas and topics for deeper evaluation and mitigation. The 10-year assessment period for this year's Western Assessment is 2026 through 2035.

This supplemental material provides a more in-depth look at the eight subregions that make up the Western Interconnection, with information on resource portfolio, demand projections, planned resource additions and retirements, and how the subregion fared in WECC's analysis. All times listed are Pacific Time.

Scenarios

WECC performed six scenarios in the 2025 Western Assessment, using data provided by WECC members as of the end of 2024. This information included planned resource additions and retirements over the coming decade, as well as demand forecasts for the 10-year assessment period.

The “All Additions” scenario evaluated resource adequacy assuming all planned resource additions and retirements come to fruition, while three scenarios reduced the planned resource additions. Resource additions in these scenarios were based on capacity decreases of 5%, 15%, and 33%, respectively. These scenarios are called the “95% Additions,” “85% Additions,” and the “67% Additions” scenarios. The reduction in resource additions was applied evenly to each resource type and subregion. Demand forecasts in these scenarios were unaltered for the assessment period and reflect annual and peak demand projections as of year-end 2024.

The remaining two scenarios focused on demand in the years 2030 and 2035. The “High Load Scenario" incorporates large load customer demand that was not included in original demand forecasts due to uncertainty in customer materialization. The additional demand from these customers is modeled as being present 24/7, year-round. Resource additions were not altered in the High Load scenario.

Incremental Large Load Demand Added to Peak Demand Forecast (MW)		
Region	2030	2035
Alberta	1,520	1,995
California	-	100
Northwest	3,137	3,513
Rocky Mountain	597	723
Southwest	3,085	3,798
Total	**8,340**	**10,130**

Incremental Net Energy Added to Load Forecast (GWH)		
Region	2030	2035
Alberta	13,315	17,476
California	-	876
Northwest	27,484	30,774
Rocky Mountain	5,231	6,336
Southwest	27,028	33,273
Total	**73,058**	**88,736**

Large load demand added to the peak and annual demand forecasts in the High Load Scenario.

The “Low Load Scenario" applies percentage reductions to peak and annual demand forecasts in 2030 and 2035. The reductions are seasonal for the peak hour forecasts and applied evenly to the annual demand forecasts. The shoulder season reductions for the peak hour are an average of the summer and winter percentage reductions. The percentages chosen represent an approximation of the typical high-side forecasting error for peak and annual demand. They are shown below. Resource additions were not altered in the Low Load Scenario:

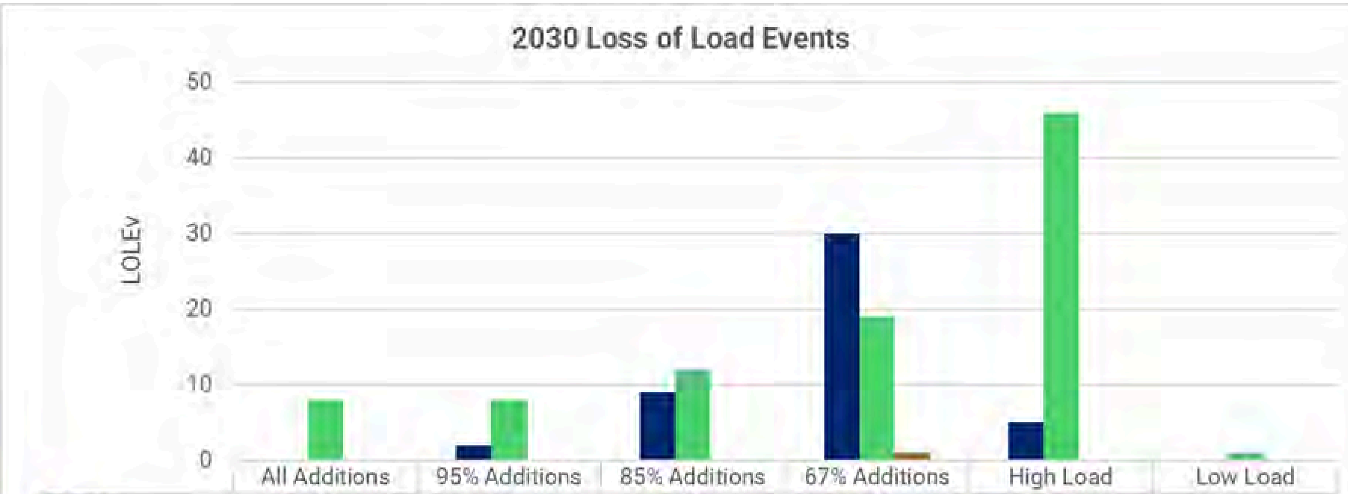
Summer Peak		Winter Peak		Annual Demand	
2030	2035	2030	2035	2030	2035
-2.5%	-5.0%	-5.0%	-10%	-5.0%	-10%

Reductions to peak and annual demand forecasts in the Low Load Scenario

Results

Resource adequacy metrics, such as loss of load events (LOLEv), loss of load hours (LOLH), expected unserved energy (EUE), and duration of loss of load events, were derived for each scenario by subregion and are provided below for years 2030 and 2035.

Loss of Load Events



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	0	2	9	30	5	0
Northwest	8	8	12	19	46	1
Rocky Mountain	0	0	0	1	0	0

LOLEvs by subregion and scenario for 2030

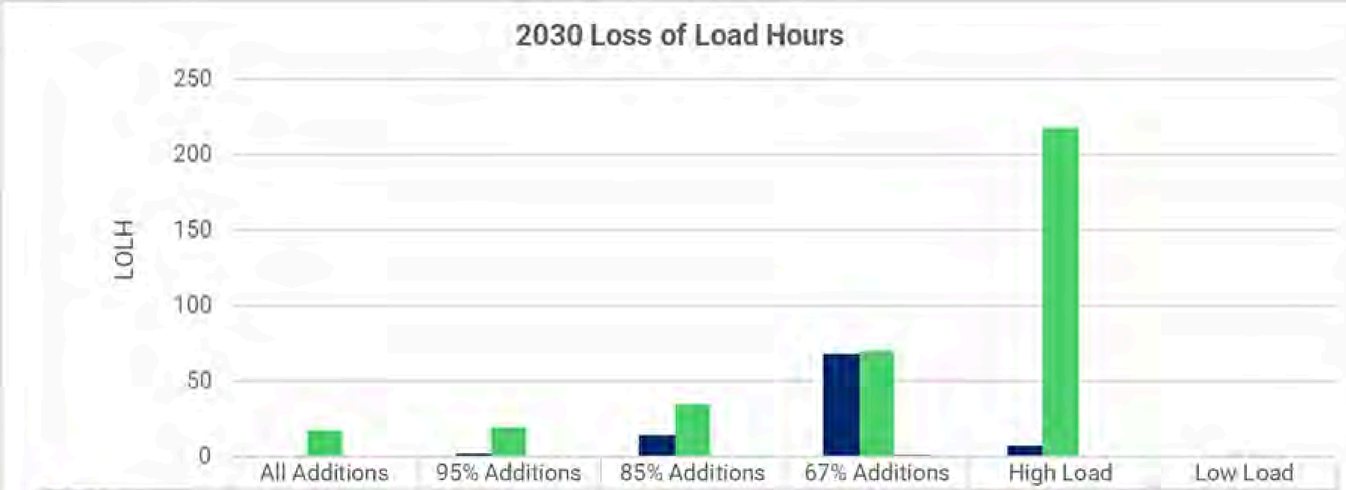
An LOLEv is a period during which system load cannot be served. The Northwest contains the greatest LOLEvs across all scenarios. Both Basin and the Northwest encounter LOLEvs as early as 2029 in the All Additions Scenario, however only the Northwest shows LOLEvs in 2030. When 3 GW of speculative large load demand is added to the Northwest subregion in the High Load Scenario, the Northwest's LOLEvs increase dramatically. It should also be noted that when demand is reduced in the Low Load Scenario, there is a singular LOLEv for the Northwest in 2030. This is noteworthy as the Low Load Scenario incorporates all planned resource additions. The Rocky Mountain subregion has one LOLEv in 2030 in the 67% Additions Scenario.

	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	3	6	18	53	13	0
California	0	0	0	2	0	0
Mexico	0	0	0	19	0	0
Northwest	34	39	48	94	149	3
Rocky Mountain	0	0	1	18	0	0

LOLEvs by subregion and scenario for 2035

Examining the 2035 LOLEvs, California and Mexico show loss of load in the 67% Additions Scenario. California has one LOLEv in 2032 and 2033, and two LOLEvs in 2035. Mexico has one LOLEv in 2034 and 19 LOLEvs in 2035. The Rocky Mountain subregion shows 18 LOLEvs in 2035 in the 67% Additions Scenario and shows an LOLEv in 2034 and 2035 in the 85% Additions Scenario. The Northwest shows LOLEvs across all scenarios in 2035, with the greatest amount shown in the High Load Scenario. The High Load Scenario features over 3.5 GW of additional consumer demand for the Northwest subregion in 2035, driving this increase. The Northwest is also the only subregion showing LOLEvs in 2035 for the Low Load Scenario. Basin shows LOLEvs in all scenarios except the Low Load Scenario.

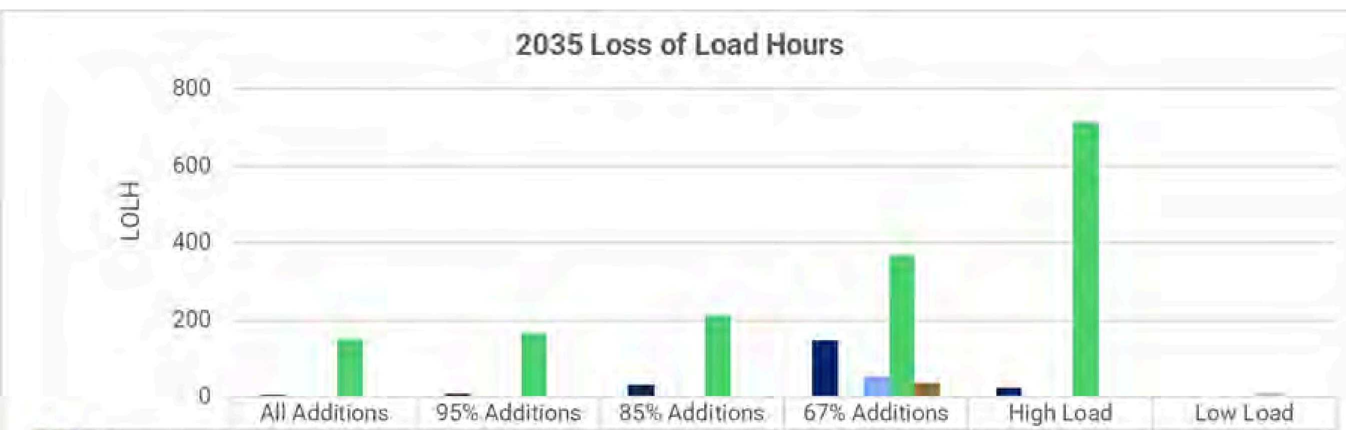
Loss of Load Hours



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	0	2	14	68	7	0
Northwest	17	19	35	70	218	1
Rocky Mountain	0	0	0	1	0	0

LOLHs by subregion and scenario for 2030

LOLHs are the number of hours a subregion's demand is projected to exceed generating capability. LOLHs for each scenario in 2030 are provided above. Results viewed through the lens of LOLHs are generally similar to those of LOLEvs, in that the Northwest and Basin subregions show most of the LOLHs. It is noteworthy in the 2030 67% Additions Scenario that Basin displayed more LOLEvs; however, the Northwest subregion shows greater LOLHs. This indicates the Northwest is generally experiencing longer LOLEvs. In the 2030 67% Additions Scenario, the average length of time per LOLEv in the Northwest is close to four hours, whereas, for Basin, LOLEvs average about two hours. The Northwest shows over 200 LOLHs in the High Load Scenario with 46 LOLEvs, increasing the average length of LOLEv to almost five hours. Rocky Mountain has one LOLH in 2030 in the 67% Additions Scenario.

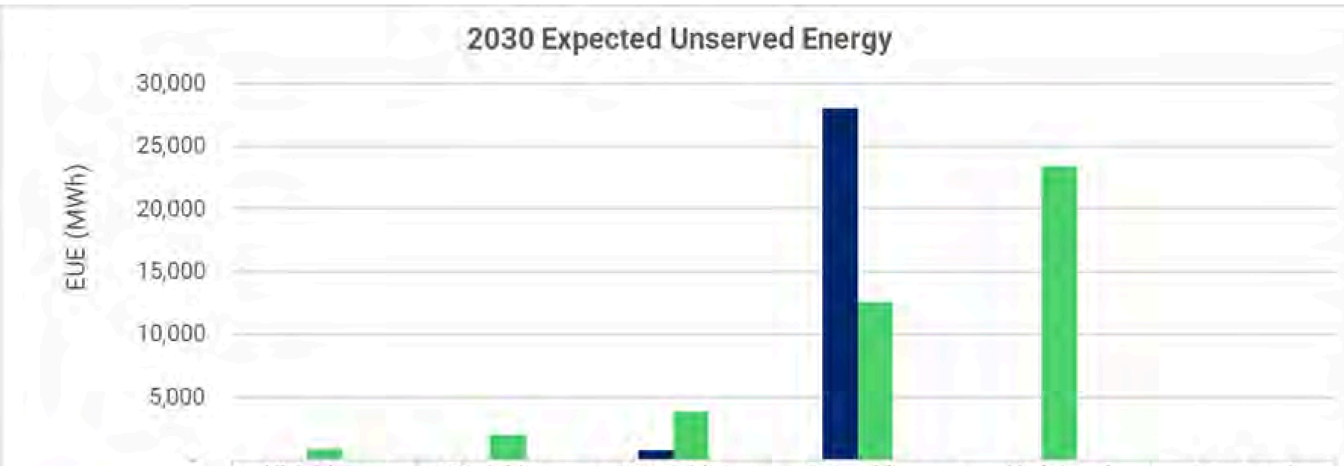


	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	4	7	31	147	24	0
California	0	0	0	2	0	0
Mexico	0	0	0	51	0	0
Northwest	149	165	213	369	714	7
Rocky Mountain	0	0	2	36	0	0

LOLHs by subregion and scenario for 2035

Comparing 2035 to 2030, LOLHs increase across the board in all scenarios. Basin and the Northwest show LOLHs in the All Additions Scenario, whereas Rocky Mountain has LOLHs in the 85% Additions Scenario. The Northwest shows over 700 LOLHs in the High Load Scenario, and similar to the 2030 High Load Scenario, averages approximately five hours per LOLEv. The Northwest also shows seven LOLHs in the Low Load Scenario. Basin shows 147 LOLHs in the 67% Additions Scenario spread over 53 LOLEvs, averaging about three LOLHs per LOLEv. California shows two LOLHs in the 2035 67% Additions Scenario, whereas Mexico shows 51 LOLHs. The 51 LOLHs for Mexico were spread over 19 LOLEvs, resulting in an average duration of about three hours per LOLEv.

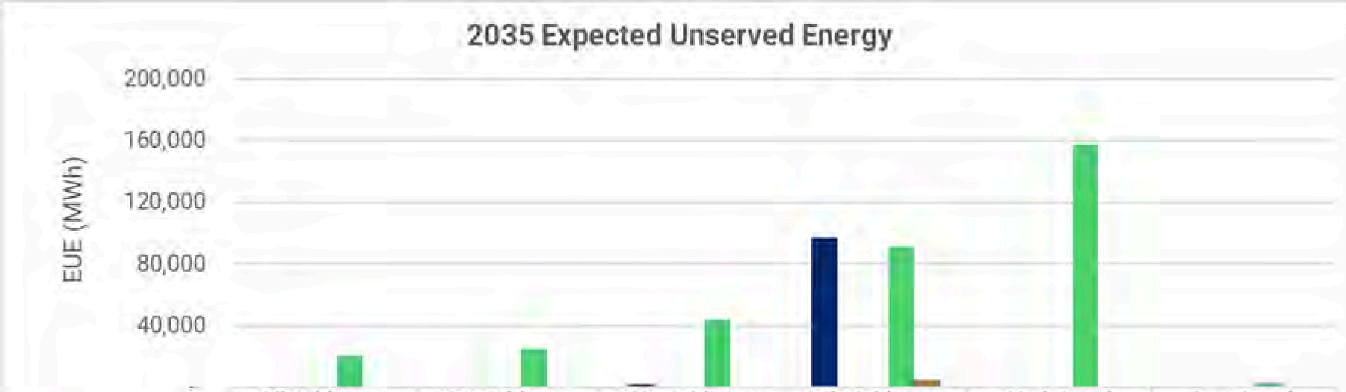
Expected Unserved Energy



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	-	3	814	28,071	29	-
Northwest	929	2,047	3,883	12,622	23,412	46
Rocky Mountain	-	-	-	5	-	-

EUE by subregion and scenario for 2030

EUE is the anticipated demand that will not be served due to demand exceeding available energy. It is intended to provide a measure of energy shortfall. In the 67% Additions Scenario, Basin and the Northwest have nearly identical LOLHs; however, Basin's EUE was 28.1 GWh versus the Northwest's 12.6 GWh. Basin's hourly average EUE in the 2030 67% Additions Scenario is slightly over 410 MWh, whereas the Northwest's hourly average EUE in this scenario is closer to 180 MWh. As such, despite the Northwest having more frequent and longer LOLEvs, the magnitude of energy shortfall in those events is typically shallower than the LOLEvs in Basin. This trend reverses in the High Load Scenario in which Basin shows 29 MWh of EUE over seven LOLHs, whereas the Northwest shows 23.4 GWh of EUE over 218 LOLHs.



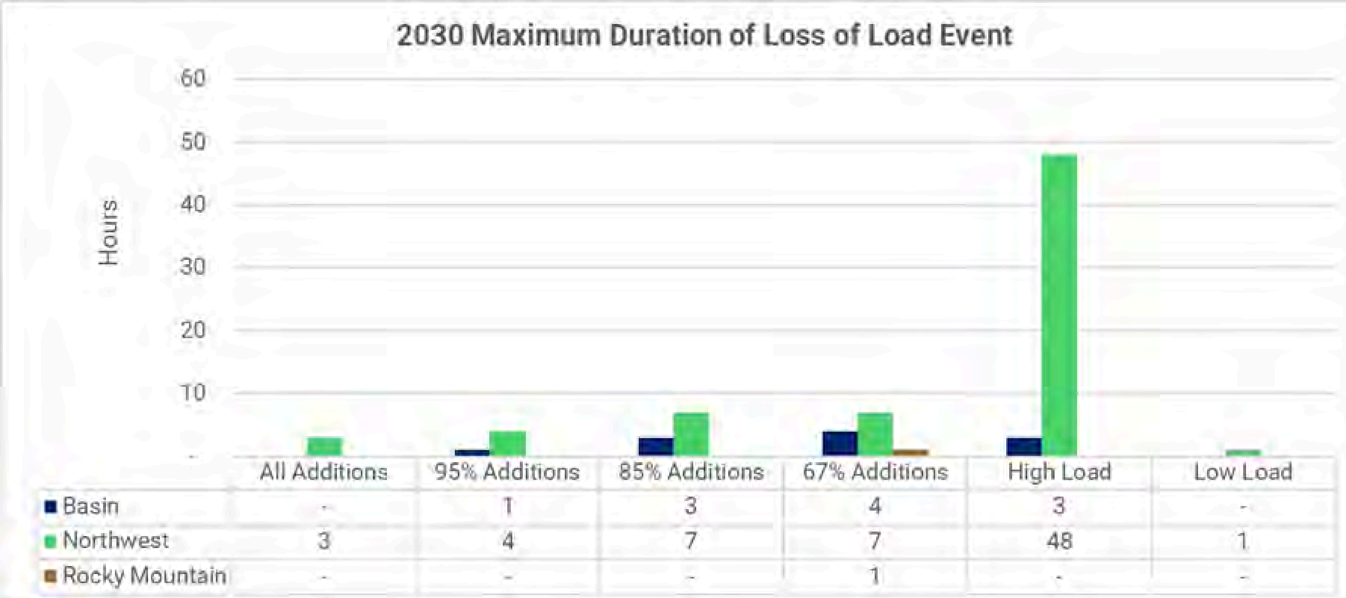
	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	19	50	1,821	97,357	178	-
California	-	-	-	471	-	-
Mexico	-	-	-	234	-	-
Northwest	19,995	24,801	43,443	91,462	157,260	2,871
Rocky Mountain	-	-	29	4,297	-	-

EUE by subregion and scenario for 2035

The 2035 EUE results indicate that the trends identified in 2030 are exacerbated by continued load growth. Basin shows 97.3 GWh of EUE in the 67% Additions Scenario over 147 LOLHs, which is an average of 660 MWh of EUE per LOLH. The Northwest shows 91.4 GWh of EUE over 369 LOLHs, averaging 248 MWh of EUE per LOLH. This again emphasizes that loss of load is anticipated to be a more frequent occurrence in the Northwest but by a smaller margin than experienced in the Basin subregion. Also in the 67% Additions Scenario, the Rocky Mountain subregion shows 4.3 GWh of EUE over 36 LOLHs, which is an average of 120 MWh per LOLH.

In the High Load Scenario, the Northwest's EUE skyrockets to 157 GWh over 714 LOLHs. The LOLEvs for the Northwest subregion in the High Load Scenario effectively become longer, however result in smaller average EUE per LOLH (220 MWh) than experienced in the 67% Additions Scenario.

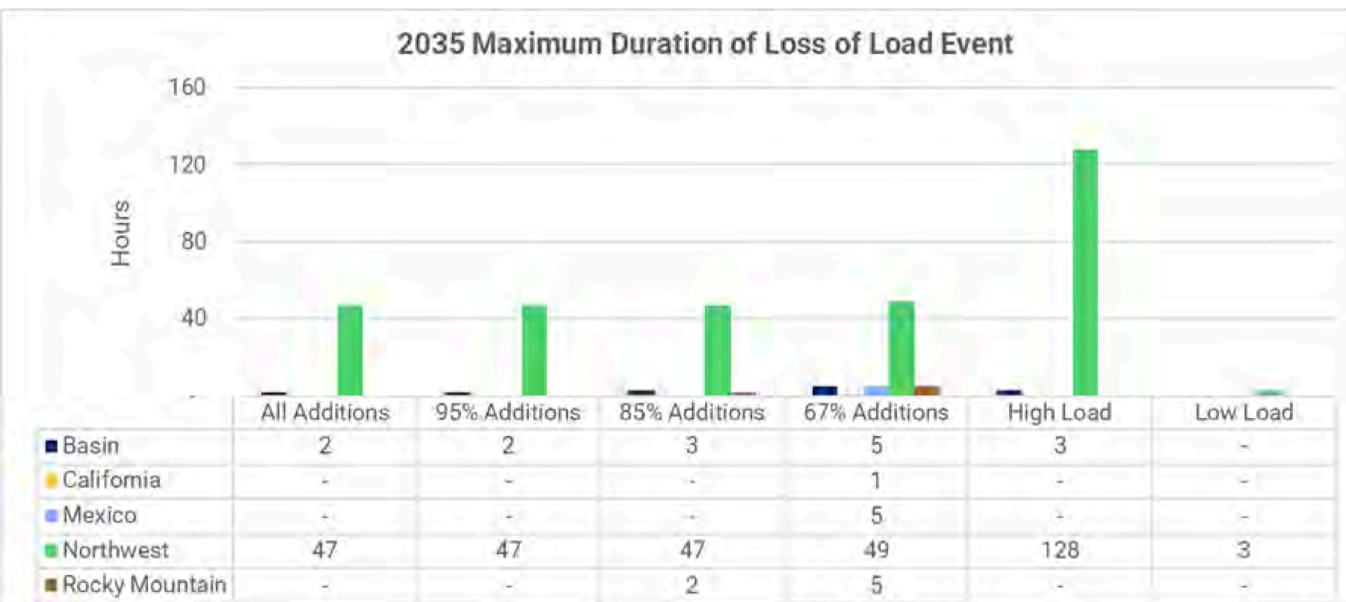
Duration



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	-	1	3	4	3	-
Northwest	3	4	7	7	48	1
Rocky Mountain	-	-	-	1	-	-

Maximum duration of LOLEvs by subregion and scenario for 2030

Average duration of LOLEvs is between one and five hours depending on the scenario and subregion. However, when the maximum duration of LOLEvs is examined, the Northwest stands out. In the 2030 resource addition scenarios, Northwest LOLEvs have a maximum duration of three to seven hours. However, in the High Load Scenario, the Northwest has an LOLEv that lasts 48 consecutive hours in January. Given the cold weather during January and the significant electrification of heating in the Northwest, this is a noteworthy risk.



	All Additions	95% Additions	85% Additions	67% Additions	High Load	Low Load
Basin	2	2	3	5	3	-
California	-	-	-	1	-	-
Mexico	-	-	-	5	-	-
Northwest	47	47	47	49	128	3
Rocky Mountain	-	-	2	5	-	-

Maximum duration of LOLEvs by subregion and scenario for 2035

In 2035, the Northwest again stands out as the subregion with longest-lasting LOLEvs. The resource addition scenarios all show at least one LOLEv that lasts between 47 and 49 hours. The High Load Scenario for the

Northwest shows an LOLEv lasting 128 consecutive hours — equivalent to over five days of outage — in January. This is a significant concern given electricity is a primary fuel for residential heating in the Northwest.

Subregional Data

This section gives a subregional view of present and future resource portfolios, resource additions and retirements, demand forecasts, and loss of load metrics. Loss of load metrics are presented as heat maps that show seasonality, timing, frequency, and magnitude. The loss of load heat maps have been constructed for the years 2030 and 2035 for the All Additions, 67% Additions, and High Load scenarios.

Subregion: Alberta

The Alberta subregion spans the province, which has a population of approximately 5 million. Although its demand peaks in winter, an hour in summer 2024 was within 1.3% of its winter peak and four of the top seven hours were in the summer. There are an estimated 16,369 miles of transmission lines in this subregion.

Current resource mix

Natural gas dominates the resource mix in the Alberta subregion, with 61% of the installed capacity. Wind generation makes up 25% of the resource mix, while solar and hydro make up 8% and 4%, respectively.

2035 resource mix

If all generating resources included in current resource plans are built, in 2035 natural gas's share of the resource mix will decrease to 45%, while solar's share will increase to 23%. Battery storage is expected to grow from 1% of the resource mix to 3% in 2035.

Planned additions

The subregion is expected to add close to 10 GW of new generation over the coming decade, primarily solar (5 GW) and wind (3 GW).

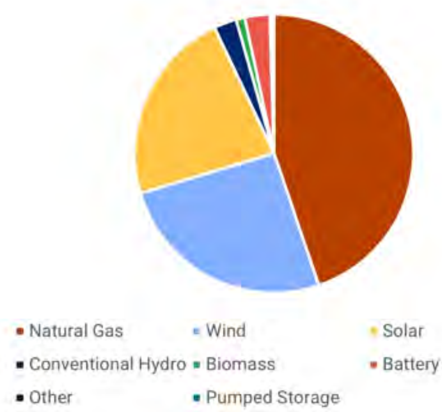
Planned retirements

No retirements are planned in the Alberta subregion through 2035 according to current resource plans.

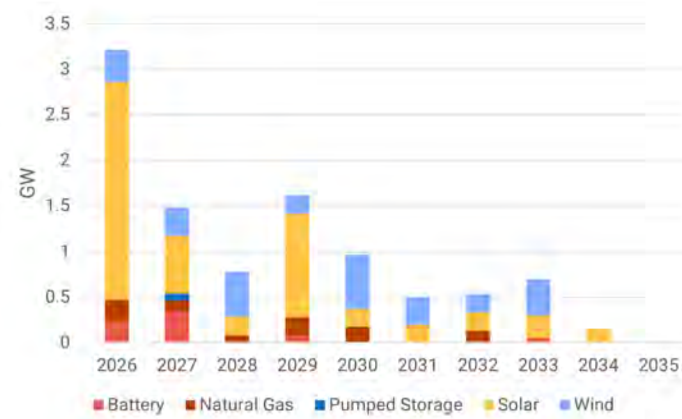
Annual and peak demand

Demand in the subregion is forecast to grow by 9% over the coming decade, while peak demand is projected to increase 8%. A major driver of demand growth in this subregion is transportation electrification.

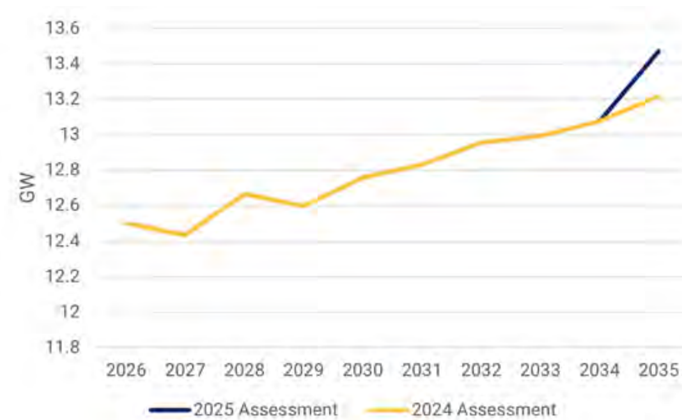
Loss of Load



Resource mix in 2035, if all planned additions are built



Planned resource additions, 2026-2035



Projected peak demand, 2026-2035

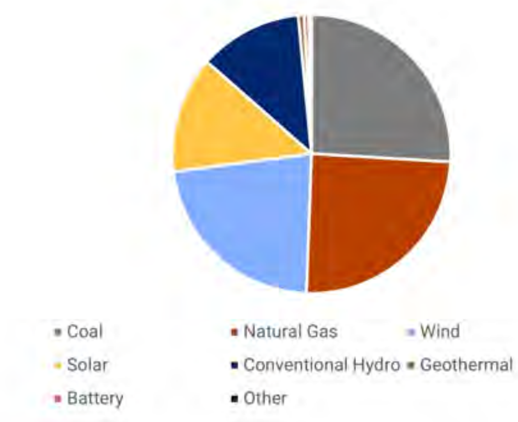
Alberta saw no loss of load in any of the scenarios.

Subregion: Basin

Basin is a summer-peaking subregion that includes Utah, southern Idaho, and part of western Wyoming. The population of this area is approximately 5.4 million. There are an estimated 15,910 miles of transmission lines in this subregion.

Resource mix

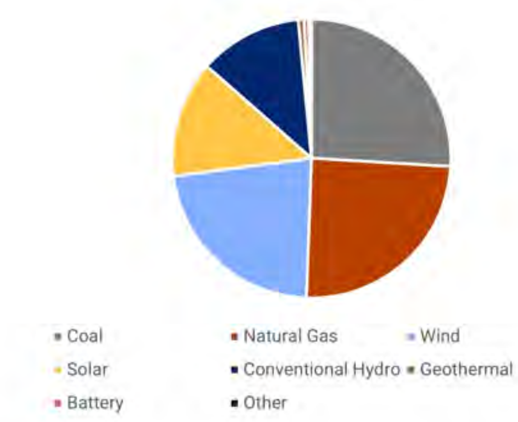
Basin's resource portfolio as of year-end 2024 is primarily coal and natural gas. The two make up 51% of nameplate capacity in the subregion. Wind and solar make a combined total of 36% of the resource mix, with the remaining portfolio primarily composed of hydro resources.



Resource mix, year-end 2024

2035 resource mix

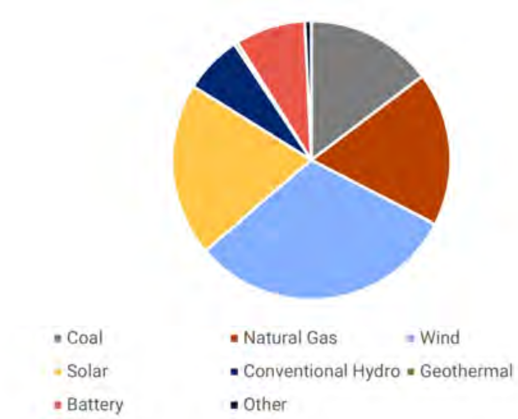
Over the next decade, wind and solar additions are anticipated to shift the resource mix to 51% variable energy resources (VER) and 33% thermal resources. BESSs are anticipated to make up 8% of the resource mix in the subregion by year-end 2035.



Resource mix, year-end 2024

Planned additions

Basin has over 15 GW of resource additions planned from 2026 through 2035. Slightly over 40%, or 6 GW, of the planned additions are wind resources, and over 25%, or 4 GW, are solar resources. BESS makes up 18%, or 3 GW, of the resource additions in the subregion, with half of the BESS capacity planned to be added in 2026.



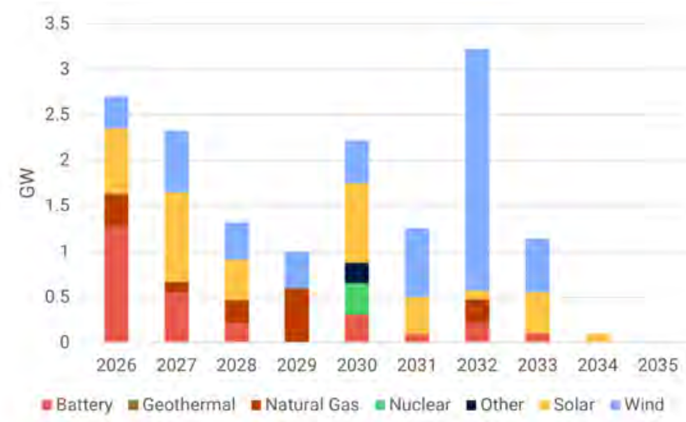
Resource mix in 2035 if all planned resources are built

Planned retirements

Approximately 2.2 GW is planned for retirement through 2035, almost half of which are coal (980 MW). 700 MW of wind resources are planned for retirement over the decade, along with 360 MW of natural gas generation.

Annual and peak demand

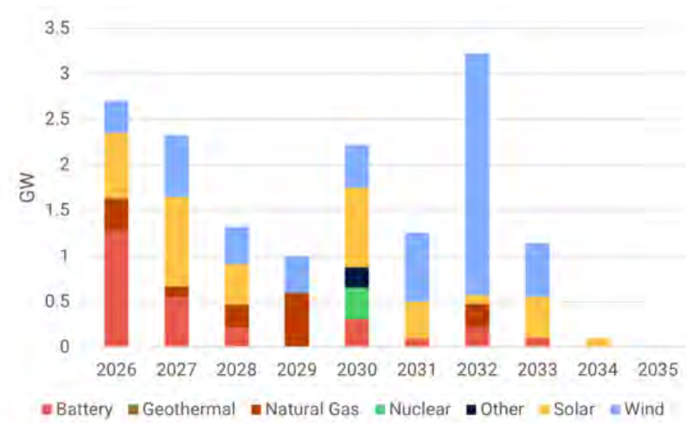
Demand in the subregion is forecast to grow by almost 26% over the coming decade, while peak demand is projected to increase 18%. Interconnection-wide annual energy load is projected to increase by 25%, and peak energy by 20%. Main contributors to demand growth in the Basin subregion are data centers and semiconductor manufacturing.



Planned resource additions, 2026-2035

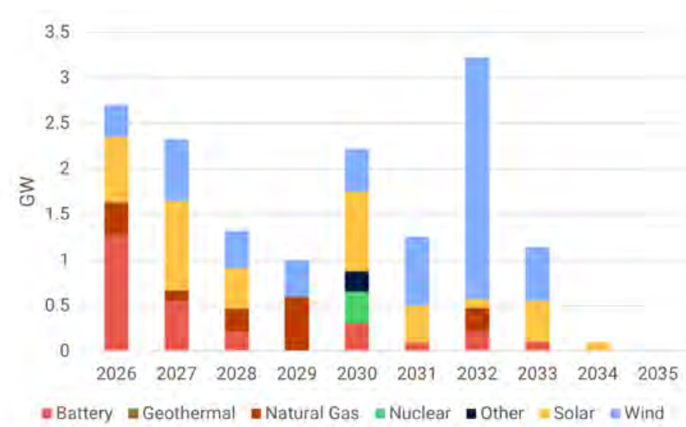
Loss of Load

The heat maps below highlight the loss of load in several scenarios.

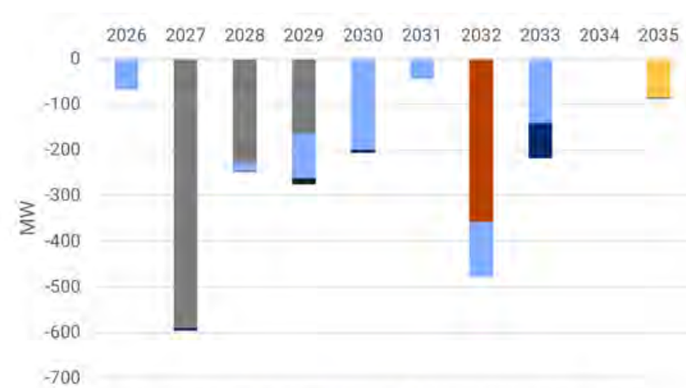


Planned resource additions, 2026-2035

The heat maps for 2030 and 2035 67% Additions Scenario provide the clearest picture of the risk hours for the subregion. Basin is summer-peaking with peak load generally occuring between 3 p.m. and 4 p.m. However, during the summer, heat can linger after the peak hour, resulting in elevated demand lasting through the evening. Basin's planned resource additions are primarily wind and solar. The summer is not generally as windy as winter or shoulder seasons, and solar begins to dissipate in the evening. The elevated loads, coupled with a reduction in solar output during the evening hours, and general variability of wind, results in Basin showing the greatest risk to resource adequacy between 5 p.m. and 10 p.m. during July and August. Summer evenings also correspond with elevated demand in the Rocky Mountain and California subregions, lessening import availability from these subregions to Basin and further contributing to the loss of load.



Planned resource additions, 2026-2035



Basin: All Additions 2035 LOLH	Hour Beginning																							
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	[illegible]	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Natural Gas Coal Wind Solar Conventional Hydro Other

LOLH by month and hour for Basin in the 2035 All Additions Scenario

Basin: All Additions 2035 EUE (MWh)	Hour Beginning																						
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	9	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

EUE by month and hour for Basin in the 2035 All Additions Scenario

Basin: 67% Additions 2030 LOLH	Hour Beginning																						
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	2	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	3	11	10	1	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	6	8	4	2	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4	7	5	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

LOLHs by month and hour for Basin in the 2030 67% Additions Scenario

Basin: 67% Additions 2030 EUE (MWh)	Hour Beginning																						
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	821	109	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	220	7,930	[illegible]	1	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	4,821	7,366	2,746	48	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8	852	292	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

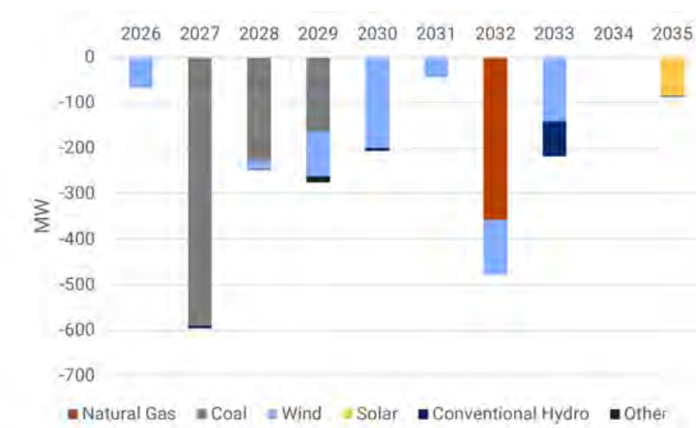
EUE by month and hour for Basin in the 2030 67% Additions Scenario.

Basin: 67% Additions 2035 LOLH	Hour Beginning																						
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	6	5	1	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	11	18	16	7	-	-
8	-	-	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	3	14	18	8	5	1	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7	10	10	3	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

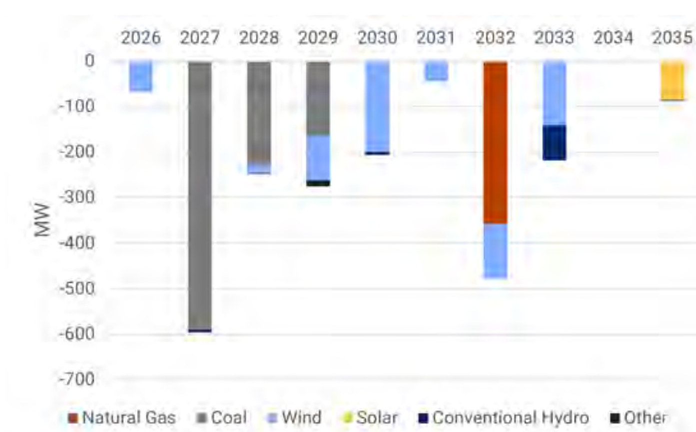
LOLHs by month and hour for Basin in the 2035 67% Additions Scenario

Basin: 67% Additions 2035 EUE (MWh)	Hour Beginning																						
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	290	4,709	1,541	3	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	340	24,790	13,825	188	-	-
8	-	-	-	-	-	-	-	15	-	-	-	-	-	-	-	-	-	18	10,626	19,408	8,615	1,797	2	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	30	5,621	5,089	127	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Planned retirements, 2026-2035



Planned retirements, 2026-2035



Planned retirements, 2026-2035

EUE by month and hour for Basin in the 2035 67% Additions Scenario

Basin: High Load 2030 LOLH	Hour Beginning																						
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	2	1	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

LOLHs by month and hour for Basin in the 2030 High Load Scenario

Basin: High Load 2030 EUE (MWh)	Hour Beginning																						
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	15	3	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

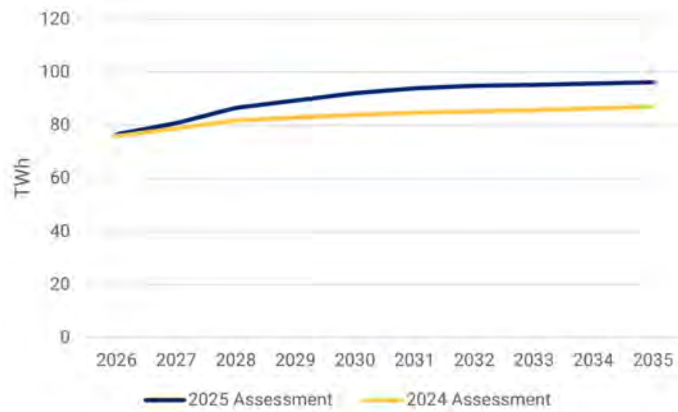
EUE by month and hour for Basin in the 2030 High Load Scenario

Basin: High Load 2035 LOLH	Hour Beginning																						
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3	8	5	1	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

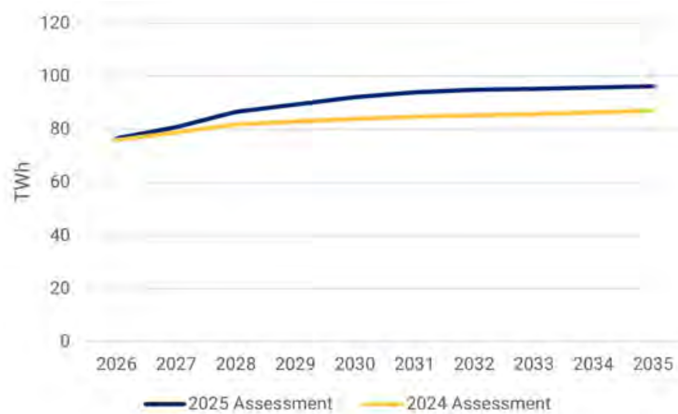
LOLHs by month and hour for Basin in the 2035 High Load Scenario

Basin: High Load 2035 EUE (MWh)	Hour Beginning																						
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	30	13	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	82	22	1	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

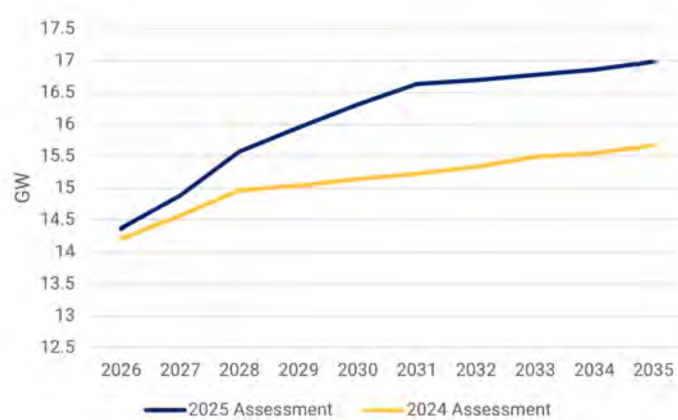
EUE by month and hour for Basin in the 2035 High Load Scenario



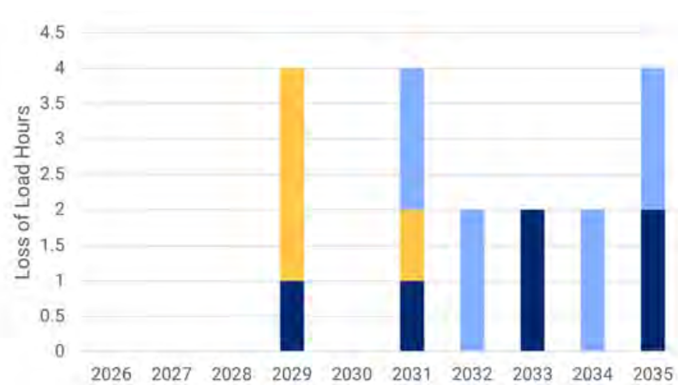
Projected annual demand, 2026-2035



Projected annual demand, 2026-2035



Projected peak demand, 2026-2035



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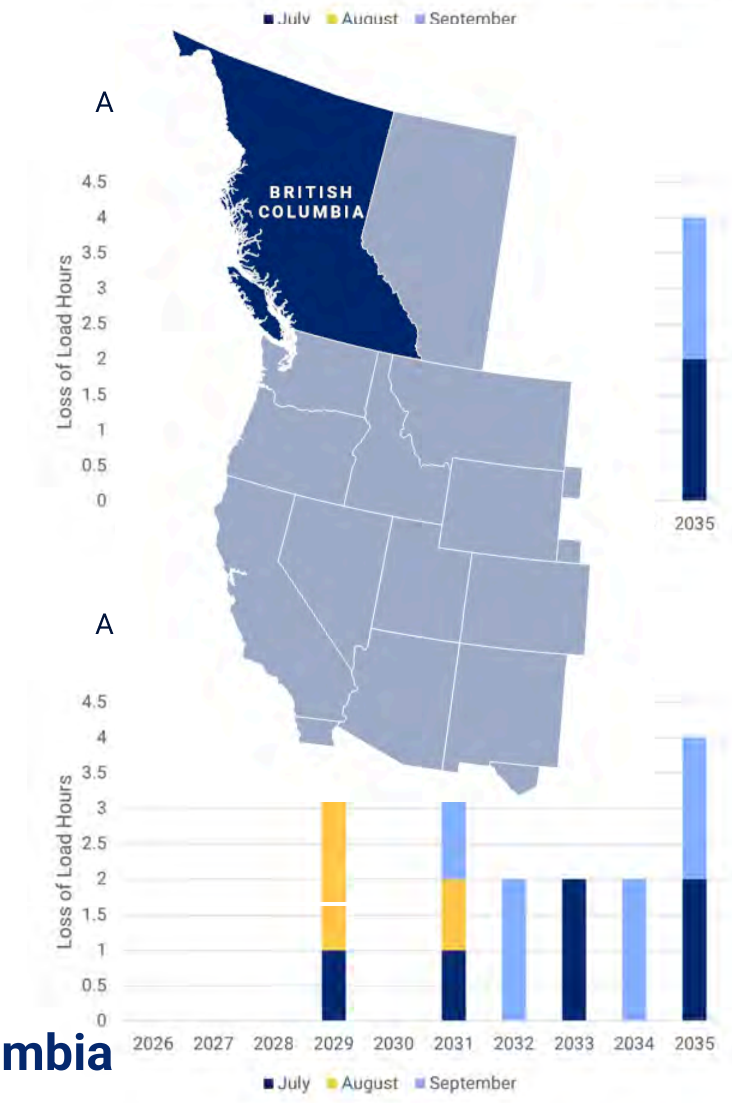
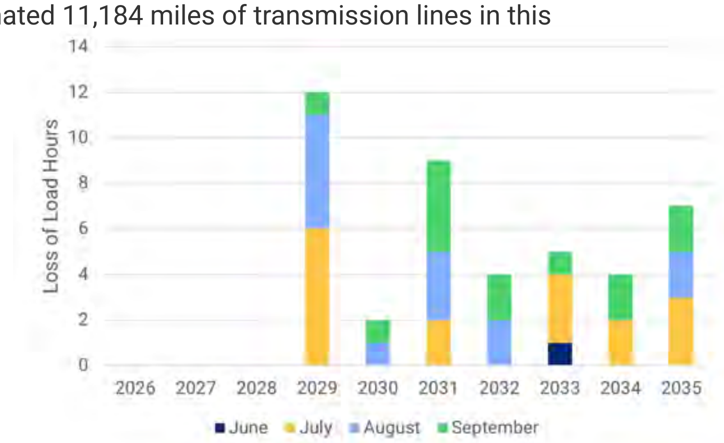


Subregion: British Columbia

British Columbia is a winter-peaking area that spans the province, which has a population of approximately 5.7 million. There are an estimated 11,184 miles of transmission lines in this subregion.

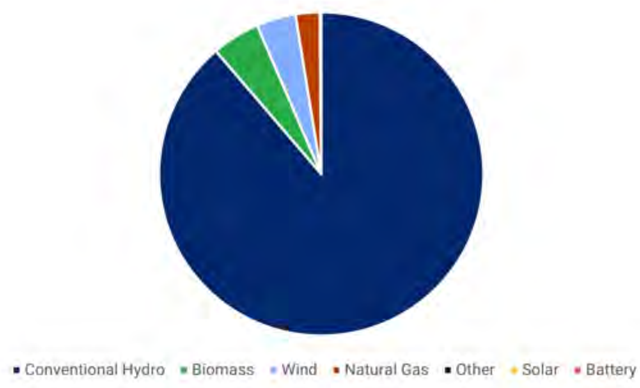
All additions scenario



95% scenario

Current resource mix

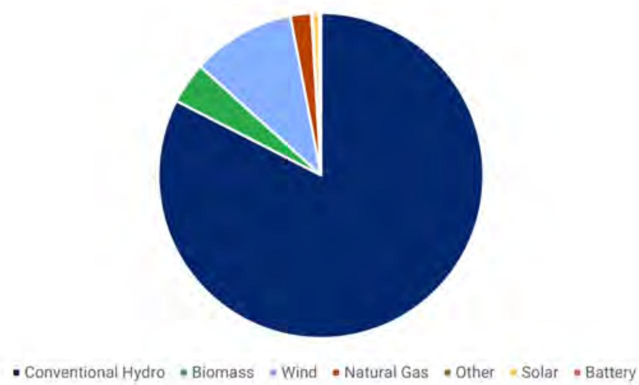
Hydro dominates the resource mix in the British Columbia subregion with 89% of the installed capacity. Biomass makes up 5%, wind 4%, and natural gas 2% of the resource portfolio as of year-end 2024.



Resource mix, year-end 2024

2035 resource mix

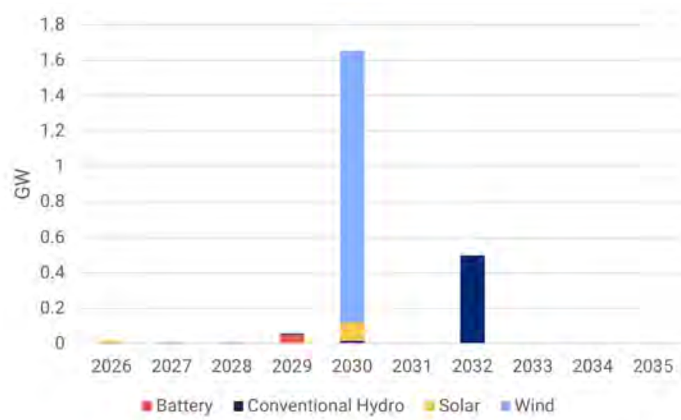
If all generating resources included in current resource plans are built, in 2035, hydro's share of the resource mix would decrease to 83%, primarily due to a large influx of wind capacity, which would then made up 10% of the resource portfolio.



Resource mix in 2035, if all planned resources are built

Planned additions

2.2 GW of new generation is planned in the subregion over the coming decade, including 1.5 GW of wind in 2030. There is also .5 GW of additional hydro capacity planned in 2032.



Planned resource additions, 2026-2035

Planned retirements

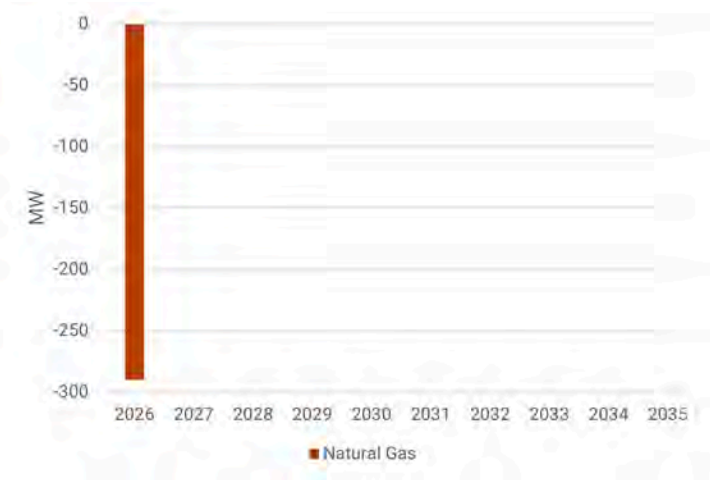
Approximately 290 MW of natural gas generation is slated for retirement over the next decade.

Annual and peak demand

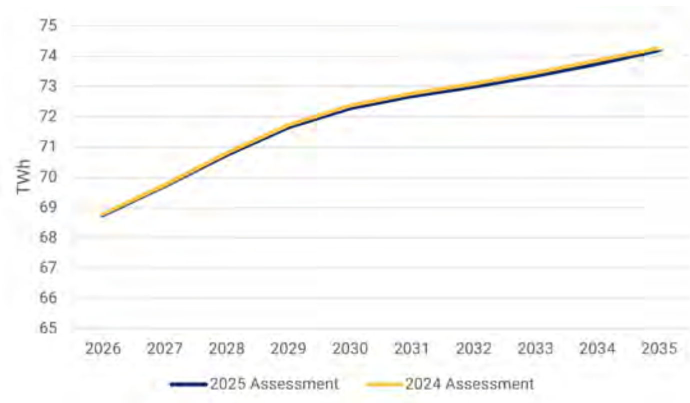
Demand in the subregion is forecast to grow by 8% over the coming decade, while peak demand is projected to increase 3.4%. Population growth, transportation and industrial electrification, and natural gas processing all contribute to demand growth in this subregion.

Loss of Load

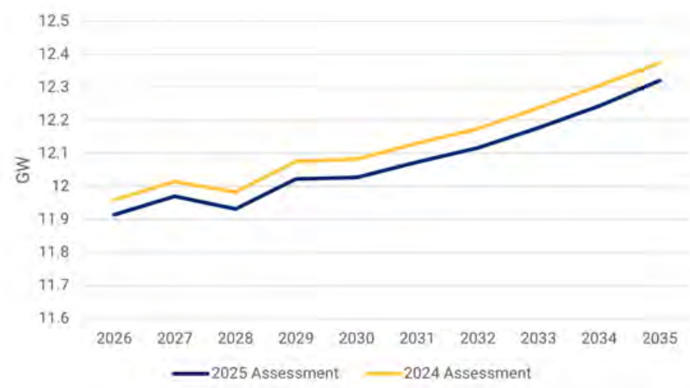
British Columbia saw no loss of load in any of the scenarios.



Planned retirements, 2026-2035



Annual demand forecast, 2026-2035



Peak demand forecast, 2026-2035

Subregion: California

California is a summer-peaking area that includes most of the state, which has a population of over 42.5 million people. There are an estimated 32,700 miles of transmission lines in this subregion.

Current resource mix

Natural gas makes up 37% of the resource mix in the California subregion on a nameplate capacity basis, followed by solar, which makes up 24%. Hydro and BESS make up 12% and 11%, respectively. Wind is 8% of the resource mix.

2035 resource mix

If all generating resources included in current resource plans are built, in 2035, natural gas's share of the resource mix will decrease to 25%, while battery storage and wind will each increase to 17% and solar to 26%.

Planned additions

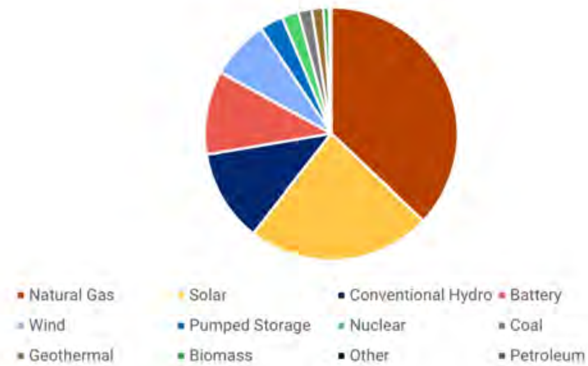
The subregion is expected to add 49 GW of new generation over the coming decade. That includes 19 GW of wind, 15 GW of solar, and 11 GW of BESS. Approximately 2 GW of natural gas and geothermal generation is expected to be added.

Planned retirements

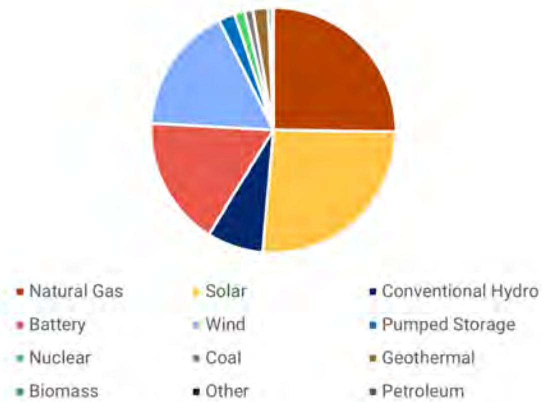
Nearly 6 GW of generation is planned for retirement over the coming decade, nearly all of it natural gas (3.6 GW) and nuclear (2.3 GW).

Annual and peak demand

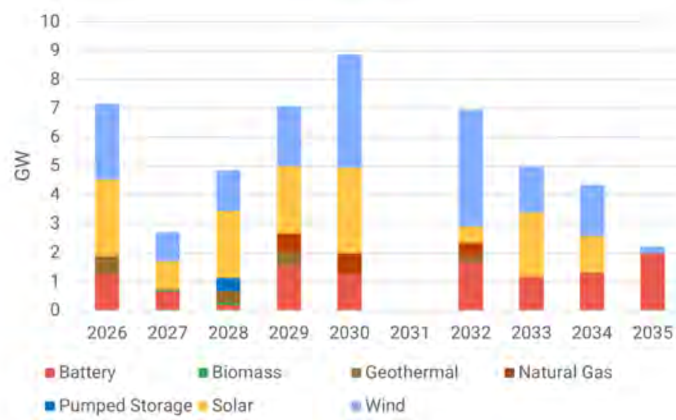
Demand in the subregion is forecast to grow by 26% over the coming decade, while peak demand is projected to increase 21%. Transportation electrification and the anticipation of additional load during extreme heat



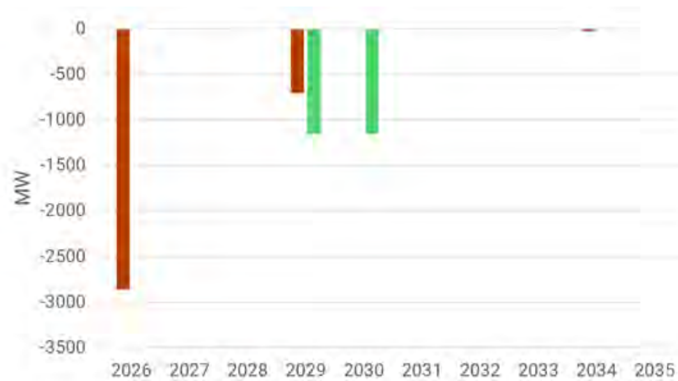
Resource mix, year-end 2024



Resource mix in 2035, if all planned resources are built



Planned resource additions, 2026-2035



events are major factors of demand growth for this subregion.

Loss of Load

The California subregion did not show loss of load in the All Additions or High Load scenarios. California only shows loss of load under the 67% Additions Scenario, and not until 2032, 2033, and 2035. The loss of load heat maps for 2035 for the 67% Additions Scenario are shown below.

California shows two LOLHs in 2035 totaling 471 MWh of EUE in September. This occurs between the hours of 6 and 7 p.m. This time frame is slightly after peak, which generally occurs between 4 and 5 p.m. in this subregion. During the summer, heat can linger after the peak hour, resulting in elevated demand lasting through the evening. California is anticipated to retire 6 GW of natural gas and nuclear capability over the next decade, while adding approximately 34 GW of solar and wind. Solar availability diminishes in the evening, and wind output during this time can vary. The elevated load during summer evenings, coupled with thermal retirements and diminishing solar availability during this period, result in the identified LOLHs shown below.

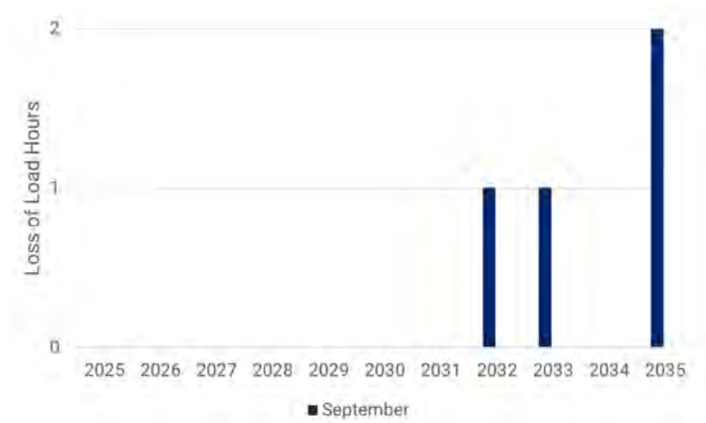
California: 67% Additions 2035 LOLH	Hour Beginning																							
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

LOLHs by month and hour for the California subregion in the 2035 67% Scenario

California: 67% Additions 2035 EUE (MWh)	Hour Beginning																							
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	471	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

■ Natural Gas ■ Nuclear

Planned retirements, 2026-2035



67% Scenario

EUE by month and hour for the California subregion in the 2035 67% Scenario

Subregion: Mexico

Mexico is a summer-peaking area that includes the northern portion of the Mexican state of Baja California, which has a population of 3.8 million people. There are an estimated 1,568 miles of transmission lines in this subregion.

Current resource mix

Natural gas makes up 72% of the resource mix on a capacity basis. This is followed by geothermal at 13%, solar at 8%, and petroleum at 7%.

2035 resource mix

If all generation resources are built according to current resource plans, in 2035, solar's share of the resource mix will increase to 14%, while geothermal and petroleum will decline to 9% and 4%, respectively. Natural gas remains at 72%.

Planned additions

600 MW of solar is planned to be built over the coming decade in the Mexico subregion. This occurs primarily in years 2026 and 2028.

Planned retirements

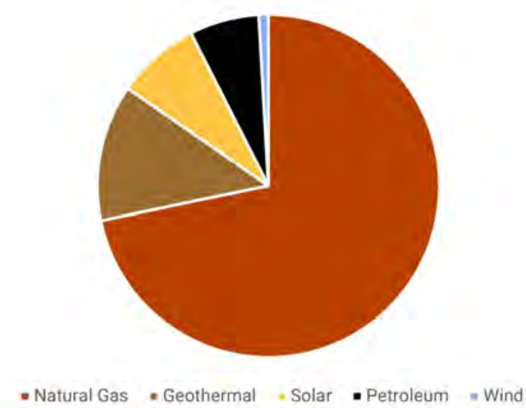
The subregion has no retirements through 2035.

Annual and peak demand

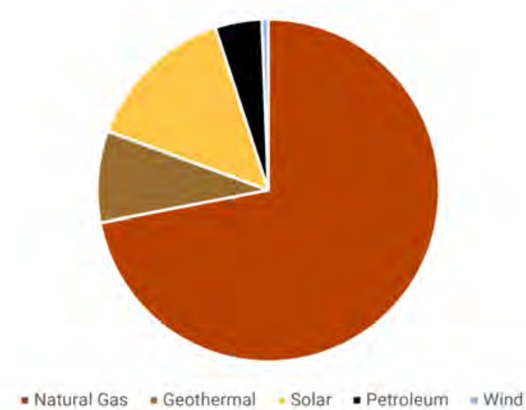
Demand in the subregion is forecast to grow 45% over the coming decade, while peak demand is projected to increase 41%. The anticipation of additional load during extreme heat events is the major factor driving demand growth for this subregion.

Loss of Load

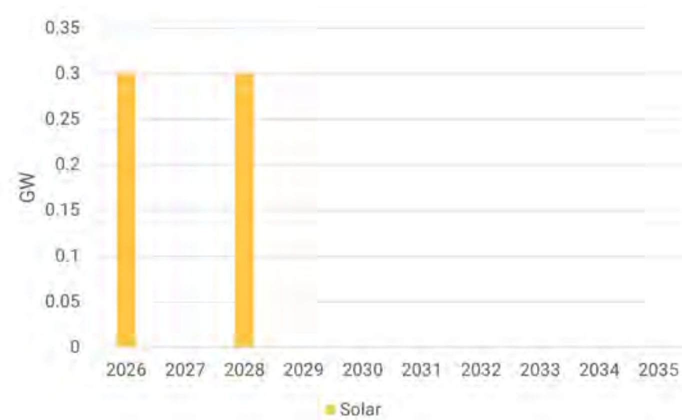
The Mexico subregion only shows loss of load under the 67% Additions Scenario in years 2034 and 2035. The



Resource mix, year-end 2024



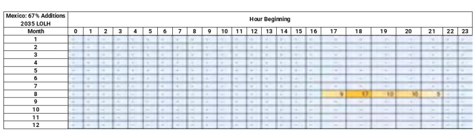
Resource mix in 2035 if all planned resources are built



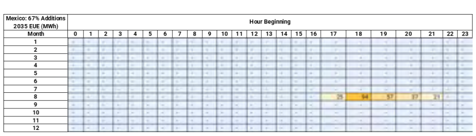
Planned resource additions, 2026-2035

loss of load heat maps for 2035 are provided below for the 67% Additions Scenario.

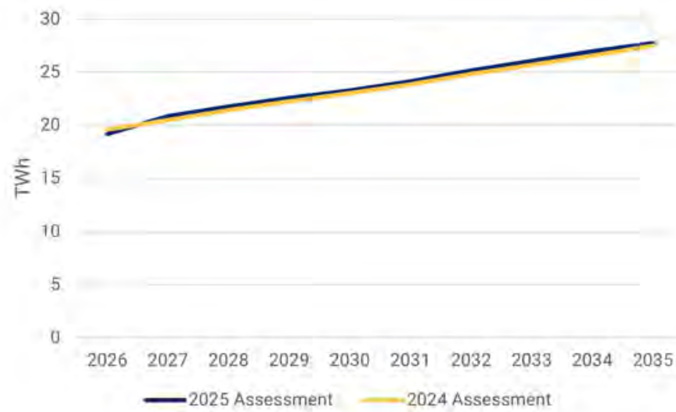
Mexico is a summer-peaking subregion that generally experiences peak load between 4 and 5 p.m. August is typically the hottest month in the subregion, thereby experiencing the greatest demand. Similar to California and Basin, summer heat can last beyond the peak hour, resulting in elevated demand through the evening. Solar is diminished during this period, and solar resources are the only additions planned for this subregion. The significant increase in demand over the next 10 years, coupled with the solar resource additions, which have diminished efficacy as daylight wanes, are the primary reason for the LOLHs during summer evenings after peak. The California subregion does support Mexico if there is surplus energy to do so, but despite the Mexico subregion importing up to the transfer limit from California, loss of load still occurs.



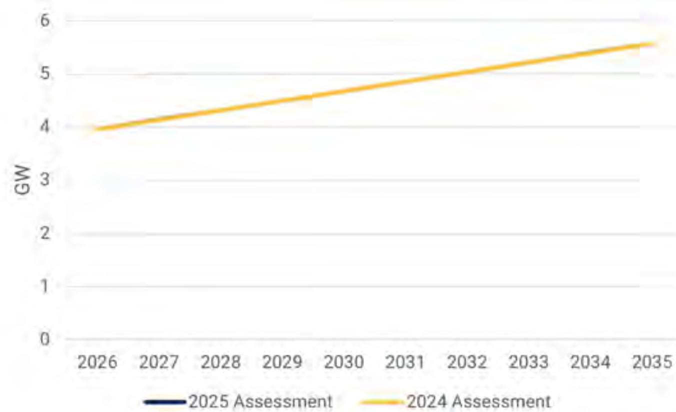
LOLHs by month and hour for the Mexico subregion in the 2035 67% Scenario



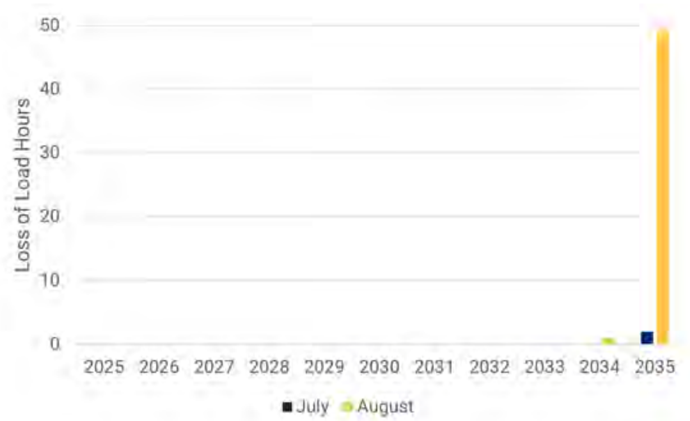
EUE by month and hour for the Mexico subregion in the 2035 67% Scenario.



Annual demand forecast. 2026-2035



Peak demand forecast, 2026-2035



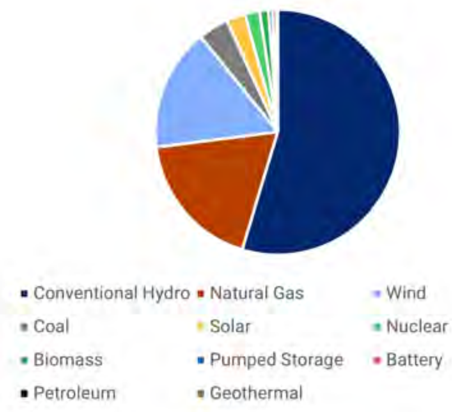
67% scenario

Subregion: Northwest

Northwest is a winter-peaking area that includes Montana, Oregon, Washington, and parts of northern California and Idaho. The population of the subregion is approximately 13.7 million. There are 16 Balancing Authorities in this subregion, which has an estimated 32,751 miles of transmission lines.

Current resource mix

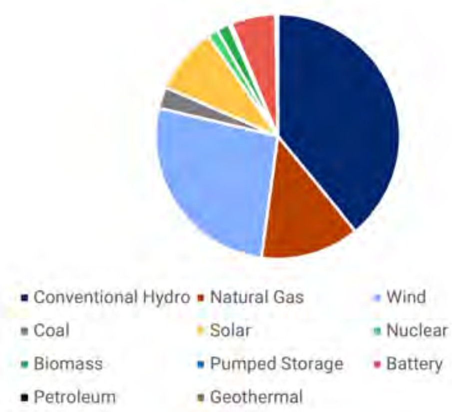
As of year-end 2024, the Northwest's resource portfolio primarily consists of hydro, natural gas, and wind resources. Hydro resources are a significant contributor to the Northwest's energy supply making up 55% of the resource portfolio. Natural gas makes up 18%, and wind accounts for 16%.



Resource mix, year-end 2024

2035 resource mix

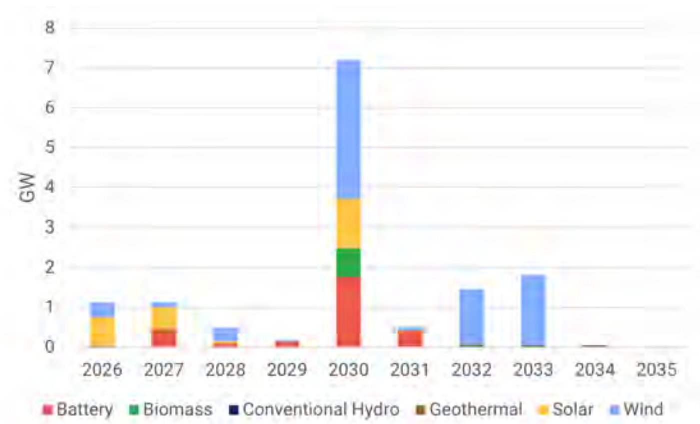
Resource plans indicate a significant influx of wind, solar, and BESS resources by year-end 2035. Wind grows to a 27% portfolio share, BESS increases to 6%, and solar increases to 9%.



Resource mix in 2035 if all planned resources are built

Planned additions

14 GW of new generation is planned in the subregion over the coming decade, including almost 8 GW of wind and 3 GW of battery storage.



Planned resource additions, 2026-2035

Planned retirements

The Northwest has approximately 340 MW of retirements slated to occur between 2026 and 2035. Over one-third of these retirements is biomass facilities. Hydro, wind, and solar retirements make up approximately half the retirements. It is worth noting that part of the renewable retirements may be repowers or non-renewals of purchase power agreements. The remaining retirements are primarily natural gas resources, the majority of which are set to retire in 2035.

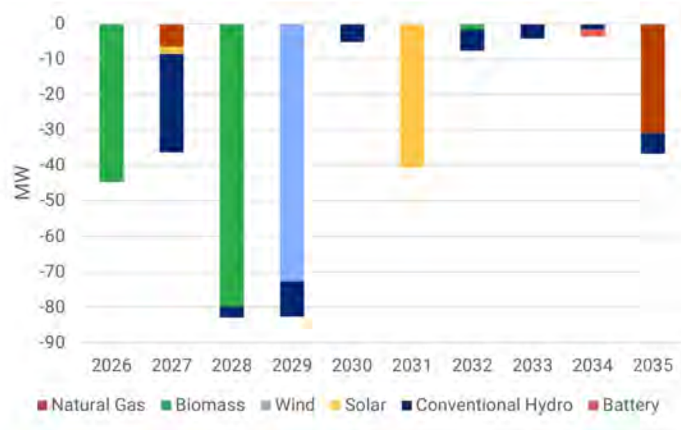
Annual and peak demand

Demand in the subregion is forecast to grow by 24% over the coming decade, while peak demand is projected to increase 21%. Major drivers of demand growth in the Northwest include data centers, residential and transportation electrification, customer growth, and semiconductor manufacturing.

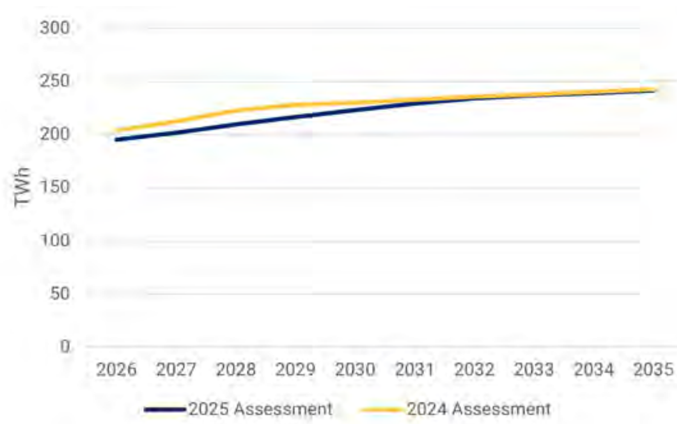
Loss of Load

The Northwest shows loss of load in all scenarios beginning as early as 2028 in the 67% Additions Scenario. Heat maps showing the timing and seasonal loss of load are provided below for the 2030 and 2035 All Additions, 67% Additions, and High Load scenarios.

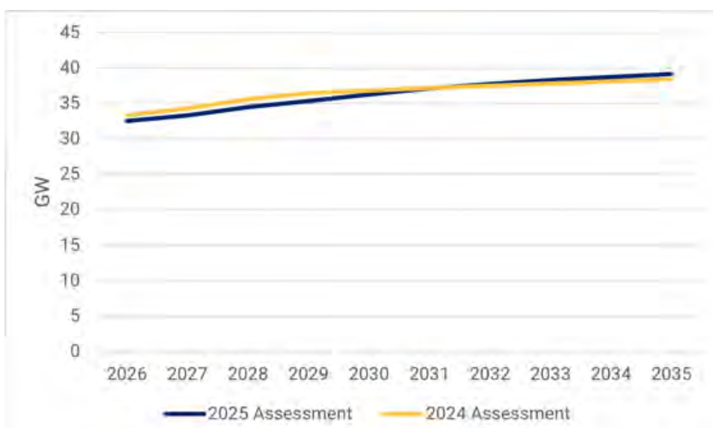
The Northwest is unique in that it experiences loss of load in the summer *and* winter in all scenarios, as well as the shoulder seasons in the High Load Scenario. The Northwest is also unique because, over the last decade, it has experienced system peaks both during the morning ramp (between 7 and 10 a.m.), which are more typical, *and* during the evening between 5 and 6 p.m. Morning ramps in the winter coincide with the greatest frequency of loss of load, whereas in the summer, the evening peak hours are when the greatest energy shortfalls are projected to occur. LOLHs and LOLEvs are greatest in the winter months, primarily in January and December, indicating that these months have a higher propensity for loss of load. Electricity is the predominant source of heat in the Northwest subregion, with the coldest temperatures occurring in the early morning and again dropping in the evening. In the winter, solar primarily contributes between the hours of 9 a.m. and 3 p.m., falling right in between the hours of greatest



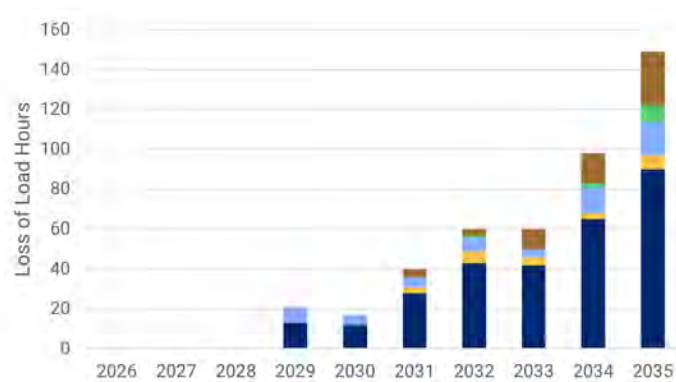
Planned retirements, 2026-2035



Annual demand forecast, 2026-2035



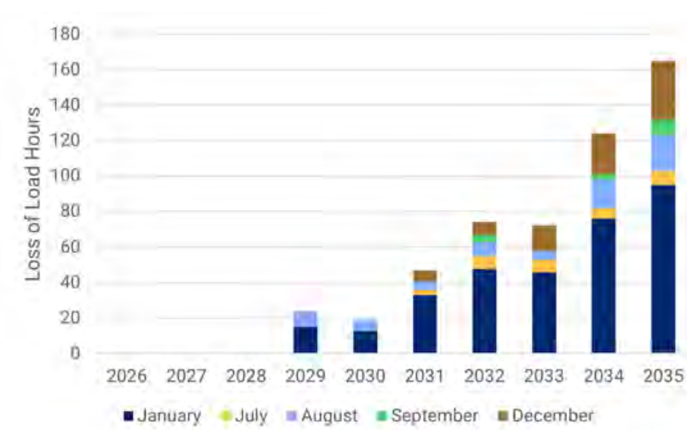
Peak demand forecast, 2026-2035



January July August September December

demand. Solar irradiance is weaker during the winter, which also lessens the contribution from solar resources. Wind makes up over 50% of the projected resource additions for the subregion, however these resources have the highest variability in energy output compared to other VERs. Wind can be prone to icing or overspeed during extreme cold weather events, which may minimize their availability during periods of elevated load. The significant demand associated with heating electrification, coupled with the timing of solar output and high wind variability, are the main drivers of

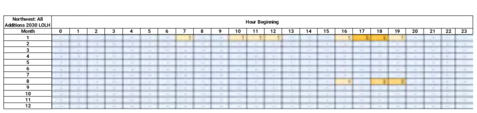
All Additions Scenario



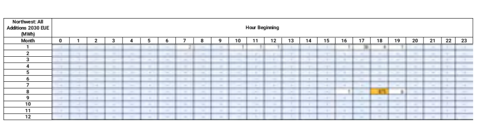
95% Scenario

LOLHs during the winter. In the summer, the primary driver of LOLHs is solar availability diminishing in the evening during periods of elevated demand. Given that BESS resources are modeled as being fully available for discharge, and that the All Additions Scenario shows LOLHs, these results indicate that the Northwest will need additional resources to meet demand over the next decade.

The California, Alberta, and British Columbia subregions support the Northwest during the morning winter ramps and evenings. However, transfer limitations from these subregions are frequently reached when attempting to mitigate loss of load in the Northwest, preventing further support to the subregion. In the summer, the California and Rocky Mountain subregions must meet their own native load obligations in the evenings, and can only provide limited support to the Northwest. The Alberta subregion also assists the Northwest during summer evenings but runs into transfer limitations. Beyond additional resources, additional transfer capability to the Northwest would also help reduce the projected loss of load in the subregion.

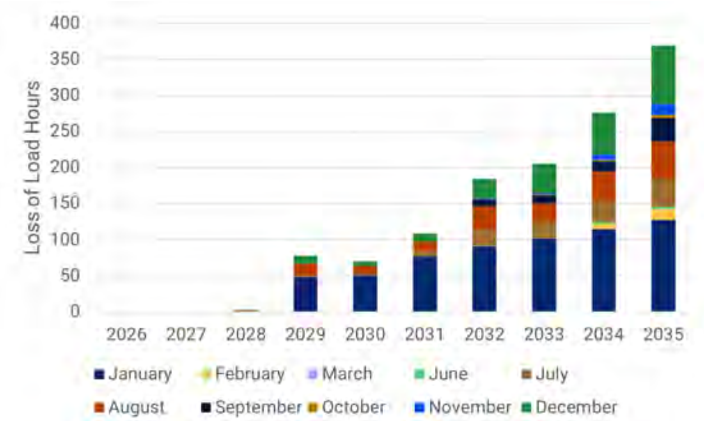


LOLHs by month and hour for the Northwest in the 2030 All Additions Scenario

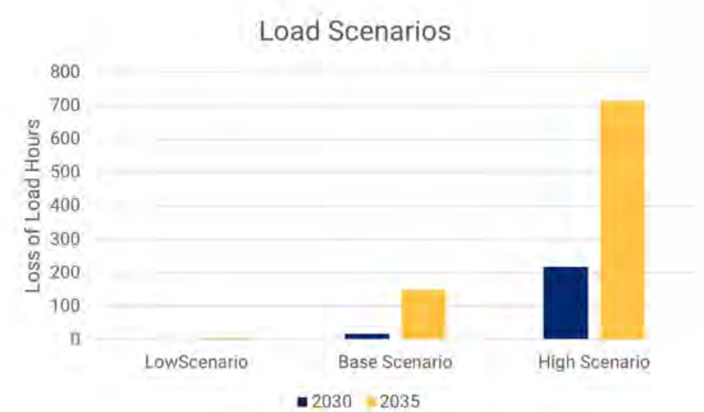


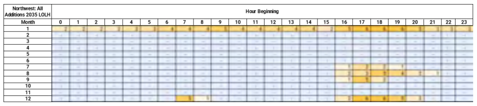
EUE by month and hour for the Northwest in the 2030 All Additions Scenario

85% Scenario

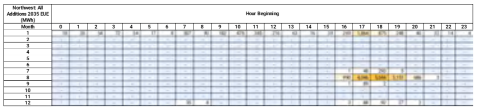


67% scenario

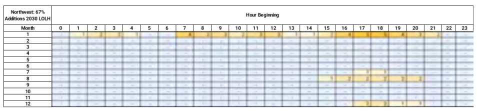




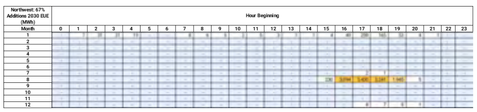
LOLHs by month and hour for the Northwest in the 2035 All Additions Scenario



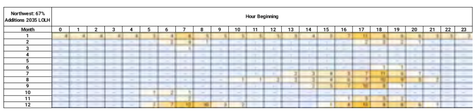
EUE by month and hour for the Northwest in the 2035 All Additions Scenario.



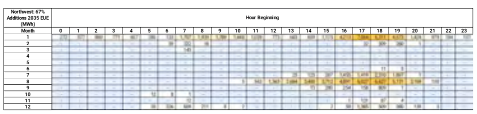
LOLHs by month and hour for the Northwest in the 2030 67% Additions Scenario.



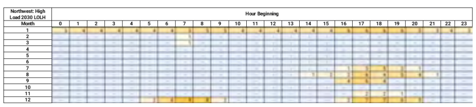
EUE by month and hour for the Northwest in the 2030 67% Additions Scenario



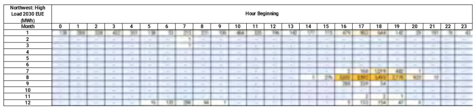
LOLHs by month and hour for the Northwest in the 2035 67% Additions Scenario



EUE by month and hour for the Northwest in the 2035 67% Additions Scenario



LOLHs by month and hour for the Northwest in the 2030 High Load Scenario



EUE by month and hour for the Northwest in the 2030 High Load Scenario

Northwest: High Load 2035 LOLH	Hour Beginning																							
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
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12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

LOLHs by month and hour for the Northwest in the 2035 High Load Scenario

Northwest: High Load 2035 EUE (MWh)	Hour Beginning																							
Month	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
8	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
11	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

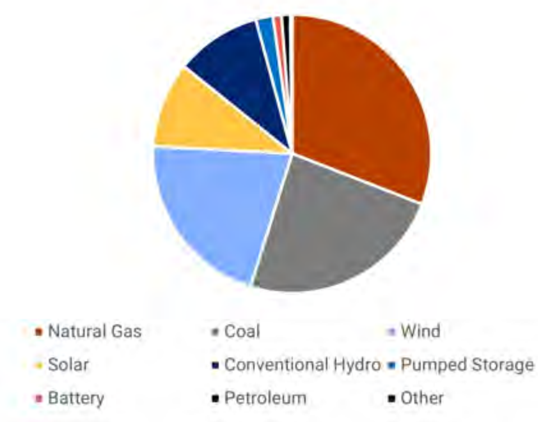
EUE by month and hour for the Northwest in the 2035 High Load Scenario

Subregion: Rocky Mountain

Rocky Mountain is a summer-peaking area that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. There are an estimated 18,800 miles of transmission lines in this subregion.

Current resource mix

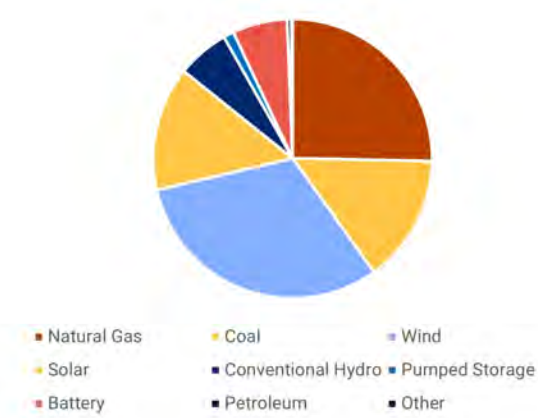
On a capacity basis, the resource portfolio in the Rocky Mountain subregion primarily consists of natural gas, coal, and wind resources. Natural gas and coal together make up 55% of the resource mix, with wind at 21%. Solar and hydro each make up 10%. Battery storage is at 1%.



Resource mix, year-end 2024

2035 resource mix

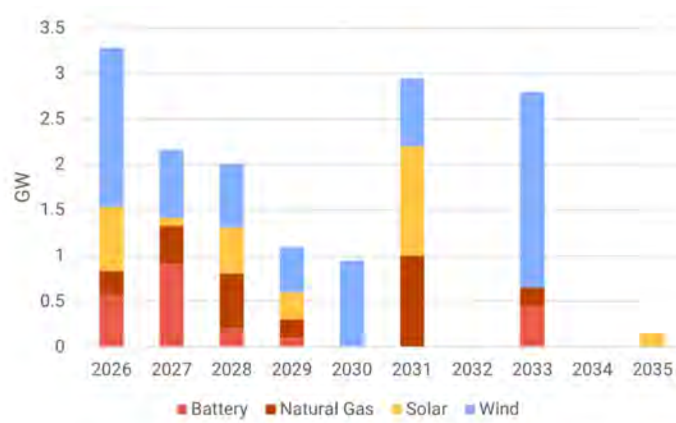
If all generation resources are built according to current resource plans, the capacity of thermal generation in the subregion will decrease to 40%, from 55% today. Wind would increase to 31% of the resource mix, while solar would increase to 14% and BESS to 6%.



Resource mix in 2035, if all planned generation is built

Planned additions

15 GW of new resources is planned in the subregion over the coming decade, including almost 8 GW of wind and 3 GW of both natural gas and solar.



Planned resource additions, 2026-2035

Planned retirements

Over 6 GW of generation is planned for retirement over the coming decade, including 2.8 GW of coal and 1.7 GW of both natural gas and wind.

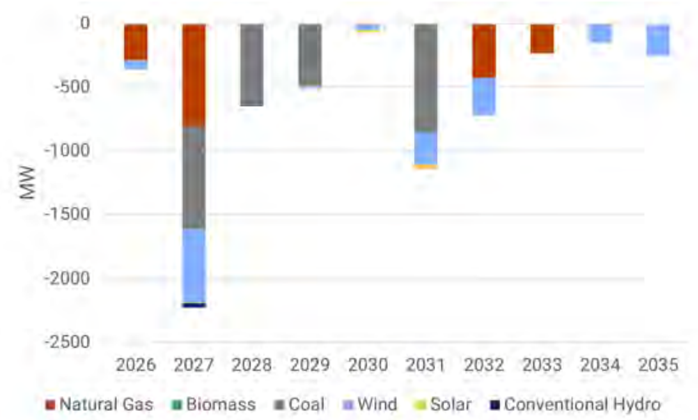
Annual and peak demand

Demand in the subregion is forecast to grow by 27% over the coming decade, while peak demand is projected to increase 23%. Major drivers of demand growth in the Rocky Mountain subregion include data centers, as well as commercial and industrial customer growth.

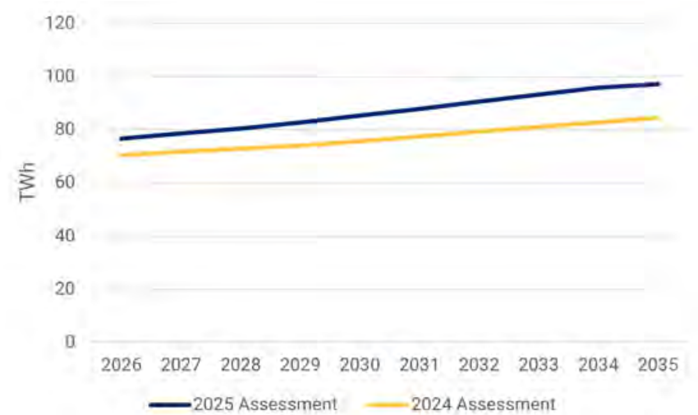
Loss of Load

The Rocky Mountain subregion does not show loss of load in the All Additions or High Load scenarios. This subregion shows loss of load under the 67% Additions Scenario for years 2030 through 2035, as well as one LOLH in 2034 and 2035 of the 85% Additions Scenario. The loss of load heat maps for the 2030 and 2035 67% Additions Scenario are provided below.

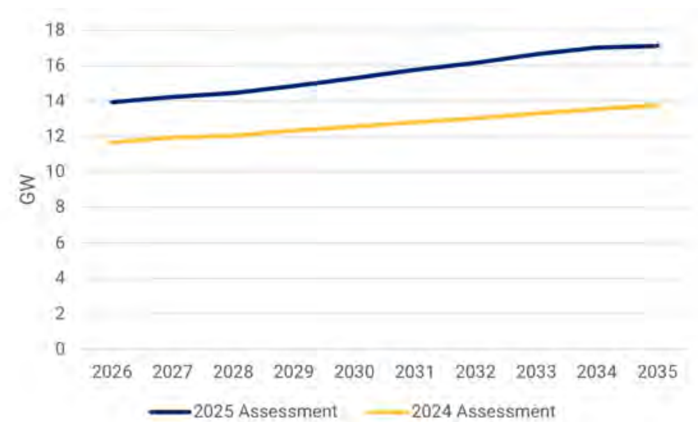
The Rocky Mountain subregion shows one LOLH for 5 MWh of EUE in 2030 and 18 LOLHs for 4,297 MWh of EUE in 2035 in the 67% Additions Scenario. The LOLHs occur between the hours of 4 and 9 p.m., primarily in July and August. This time frame includes the peak hour, which is anticipated to occur in the summer between 4 and 5 p.m. The Rocky Mountain subregion is showing a significant increase in both its annual demand and peak hour forecasts. The 2035 peak hour demand is projected at over 3 GW higher than last year's forecast, and the annual demand totals close to 13 TWh higher than last year's forecast. Similar to other subregions showing LOLHs during and shortly after their summer evening peak, these LOLHs are primarily a product of demand remaining elevated while solar output diminishes. In addition, there are over 6 GW of resource retirements with 4.5 GW of that being thermal resources. The additions in the 67% Additions Scenario total about 10 GW, with close to 7 GW of that being VERs. The reduction in additions, coupled with the increased uncertainty in energy output and unchanged retirements in the 67% Additions Scenario, also contribute to the LOLHs projected for this subregion.



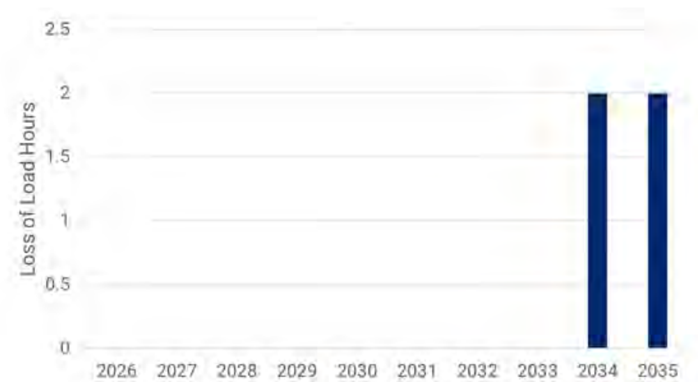
Planned retirements, 2026-2035



Annual energy demand forecast, 2026-2035



Peak demand forecast, 2026-2035



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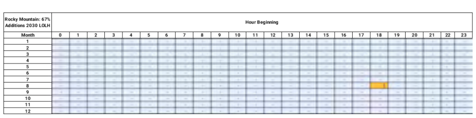
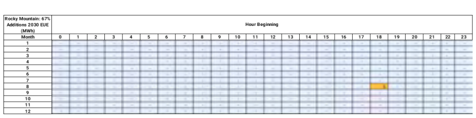
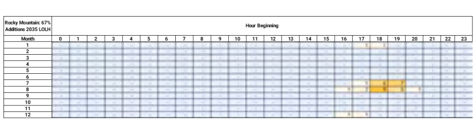


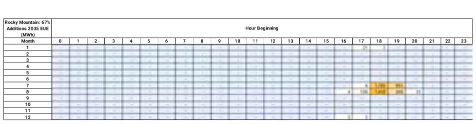
LOLHs by month and hour in the 2030 67% Additions Scenario



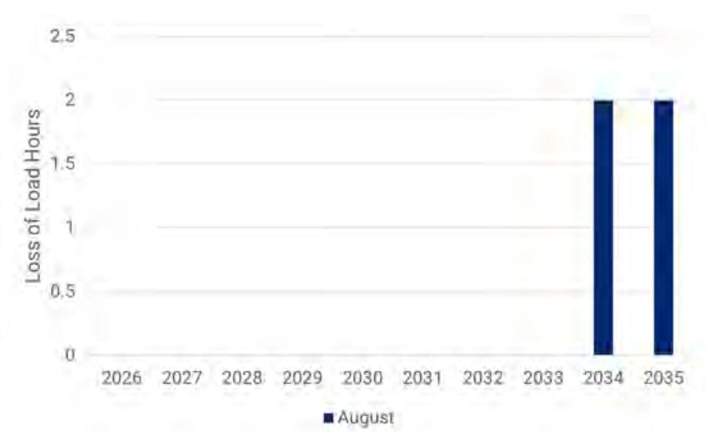
EUE by month and hour for the Rocky Mountain subregion in the 2030 67% Additions Scenario



LOLHs by month and hour for the Rocky Mountain subregion in the 2035 67% Additions Scenario

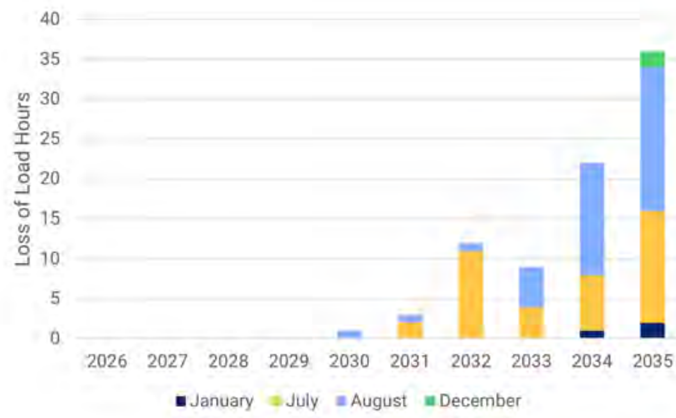


85% Scenario

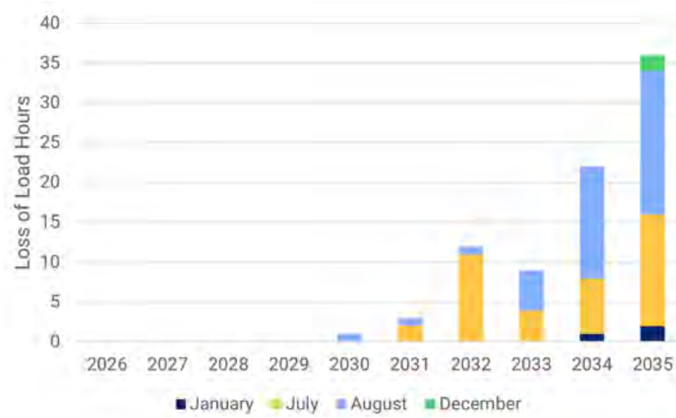


85% Scenario

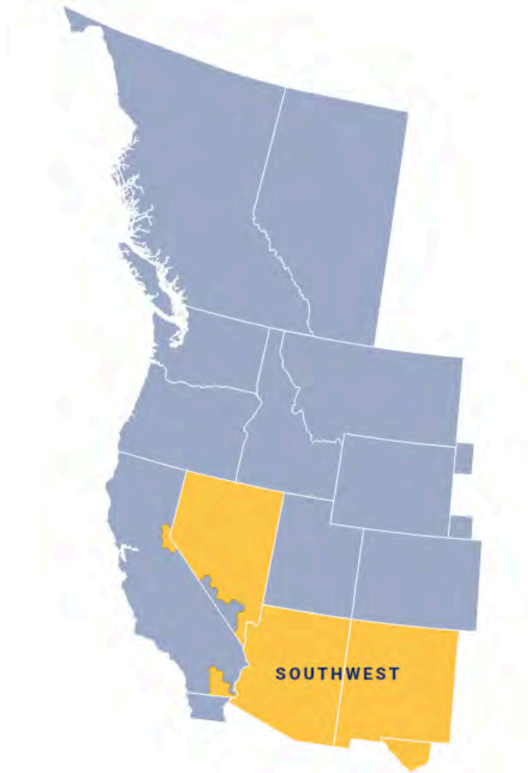
EUE by month and hour for the Rocky Mountain subregion in the 2035 67% Additions Scenario



67% scenario



67% scenario



Subregion: Southwest

Southwest is a summer-peaking area that includes all of Arizona and New Mexico, most of Nevada, and a small part of Texas. The area has a population of approximately 13.6 million. There are an estimated 23,100 miles of transmission lines in this subregion.

Current resource mix

As of year-end 2024, natural gas makes up almost half of the resource mix in the subregion (46%), while solar makes up 16%. Coal, wind, nuclear, and BESS make up between 7% and 9% each of the current resource mix.

2035 resource mix

If all generation resources are built according to current resource plans, in 2035, the resource mix will comprise 22% natural gas, 37% solar, and 18% battery storage. Along with natural gas's significant decline in the share of the resource mix, coal is expected to drop from 9% today to 4% in 2035.

Planned additions

70 GW of new resources are planned in the subregion over the coming decade, more than in any other subregion. Over half of the planned additions are solar (37 GW). 17 GW of BESS is planned, and 10 GW of wind.

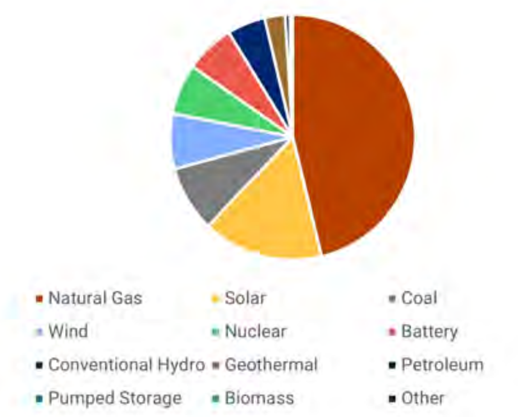
In addition, 40 GW of the planned additions are tier 3 resources, which are more speculative.

Planned retirements

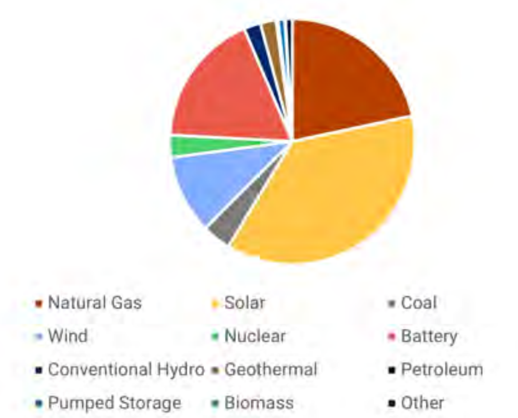
7 GW of generation is planned for retirement over the coming decade, including 3 GW of coal and 2 GW of natural gas.

Annual and peak demand

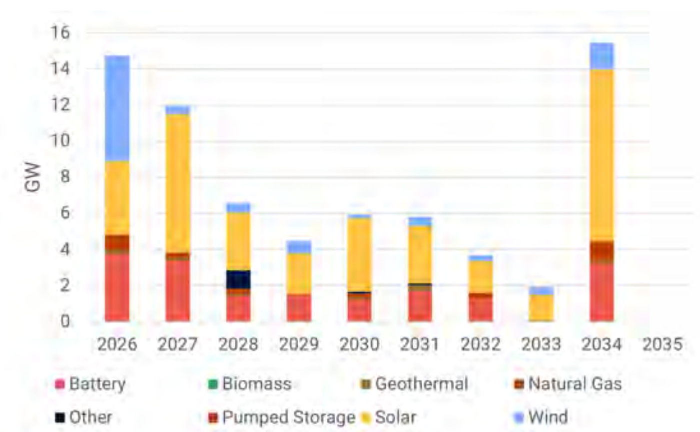
Demand in the subregion is forecast to grow 42% over the coming decade, while peak demand is projected to



Resource mix, year-end 2024



Resource mix in 2035, if all planned resources are built

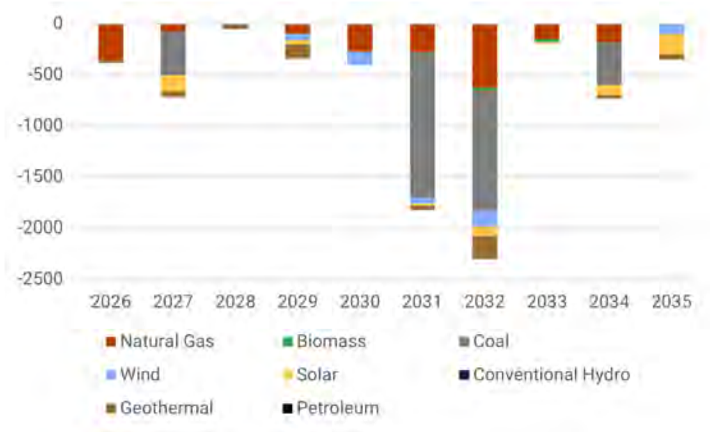


Planned resource additions, 2026-2035

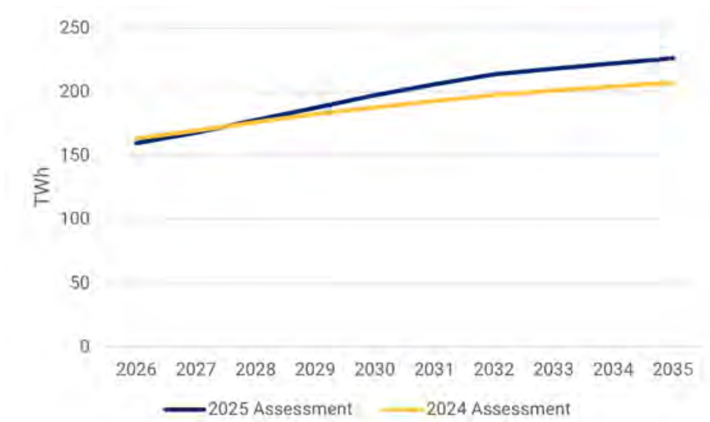
increase 29%. The major drivers of demand growth in the Southwest subregion include data centers, industrial and residential electrification, and residential customer growth.

Loss of Load

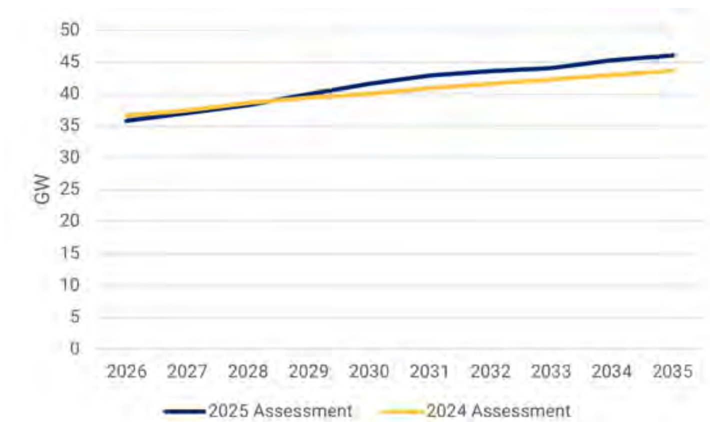
The subregion did not show loss of load in any scenario over the coming decade.



Planned retirements, 2026-2035



Annual demand forecast, 2026-2035



Peak demand forecast, 2026-2035

Transfers

Transfers by subregion for years 2030 and 2035 for the All Additions, 67% Additions, and the High Load scenarios are provided below. Transfers are separated into imports and exports and shown both by month and by hour of the day.

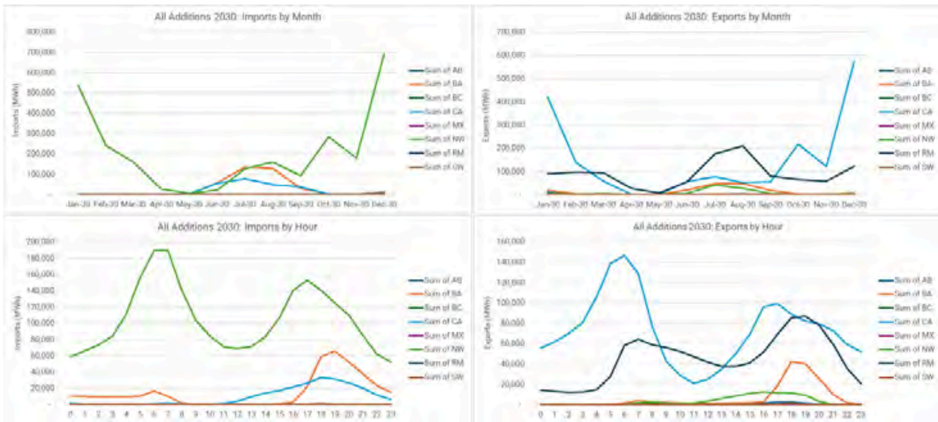
The Northwest shows the greatest amount of imports in all scenarios. This is particularly true in the winter months during the morning and evening ramps. As discussed in the Northwest Loss of Load Section, winter mornings and evenings are the times when this subregion experiences most of its loss of load. MAVRIC's transfer logic only allows for transfers when loss of load is identified for an area in an islanded state. Therefore, the timing and magnitude of imports align with the periods of greatest need for a subregion. Most of the transfers to the Northwest come from the California subregion, specifically during the morning ramp hours of the winter months when the California subregion has surplus energy. There are times where the transfer limits from the California subregion to the Northwest are met, and Alberta, British Columbia, and Rocky Mountain subregions also support the Northwest. However, transfer limits from the Alberta and British Columbia subregions to the Northwest are frequently reached when attempting to mitigate loss of load in the Northwest. This indicates that additional transfer capability to the Northwest from the California, Alberta, or British Columbia subregions would help alleviate winter LOLHs.

Summer evenings in the Northwest appear to be partially supported by the California subregion as well. However, the California subregion's ability to export during the evening becomes limited due to diminished solar and elevated native load. In other words, transfer limits to the Northwest from California during summer evenings are rarely met, as California is satisfying its obligations rather than exporting power. With less support from the California subregion, the Northwest leans more heavily on Alberta and the Rocky Mountain subregion for support. The Alberta subregion appears to hit its transfer limits to the Northwest frequently during summer evenings, indicating that loss of load could partially be alleviated with additional transfer capability from Alberta to the Northwest. The Rocky Mountain subregion can assist during summer evenings to an extent but does not hit its transfer limits to the Northwest. This indicates that, like California, the Rocky Mountain subregion must also meet its native load during summer evenings and can only provide limited support to the Northwest.

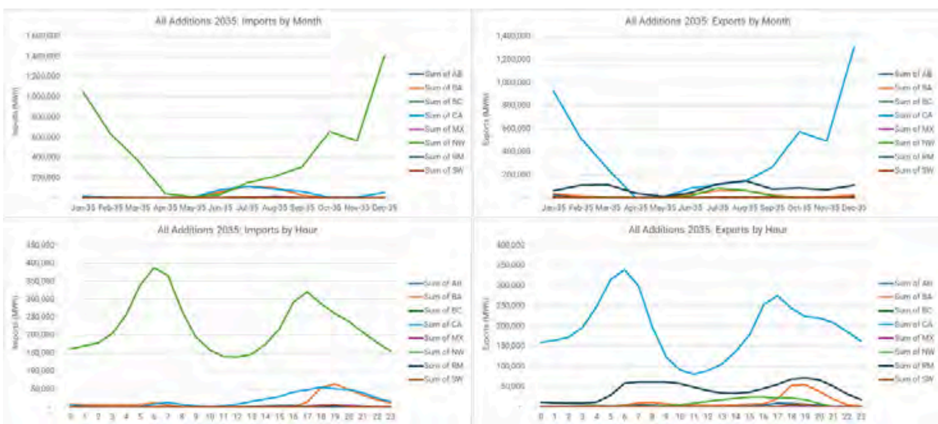
Basin also shows loss of load in all scenarios, primarily during summer evenings in the latter years of the Western Assessment. As such, Basin is primarily shown to import energy from June through August during and after its evening peak. During these hours, external transfers are sourced from the Rocky Mountain, Southwest, and California subregions. The Southwest subregion maxes out its transfer capability to Basin during the summer evening hours, indicating that there may be additional energy in the Southwest that could be provided to Basin if additional transfer capability were available. The Rocky Mountain and California subregions do not meet their transfer limits when assisting Basin on summer evenings, indicating that these subregions are meeting native load obligations with available resources rather than providing surplus energy to Basin. This is exacerbated in the High Load Scenario, in which transfers from the Rocky Mountain and California subregions become even more limited, resulting in an increase in LOLHs within the Basin subregion. This is despite Basin not having additional speculative large load demand in the subregion itself.

The Southwest shows a significant bump in exports during summer evenings in 2035 of the 67% Additions and High Load scenarios. Most of this increase in export activity is to support both the Basin and Rocky Mountain subregions. Mexico displays a notable increase in its imports in the 2035 67% Scenario, which are primarily fulfilled by the California subregion. Many LOLHs in the Mexico subregion occur despite the California subregion exporting up to its transfer limit to the Mexico subregion.

All Additions

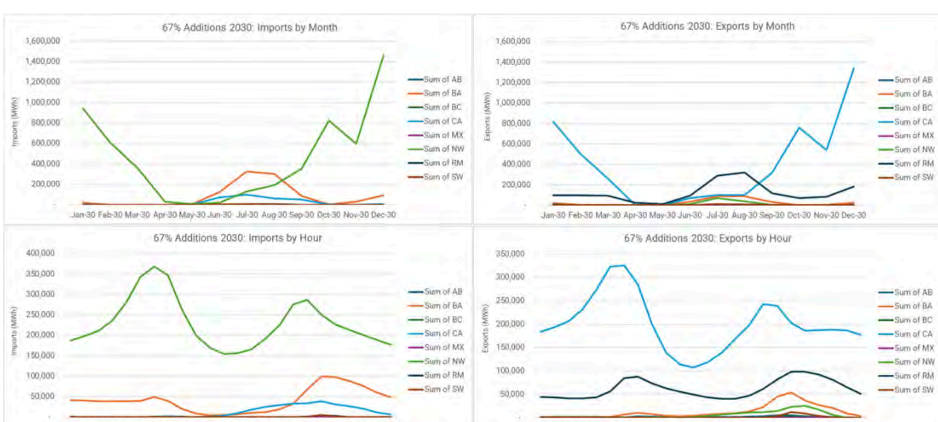


Subregional transfers by month and time of day for the 2030 All Additions Scenario

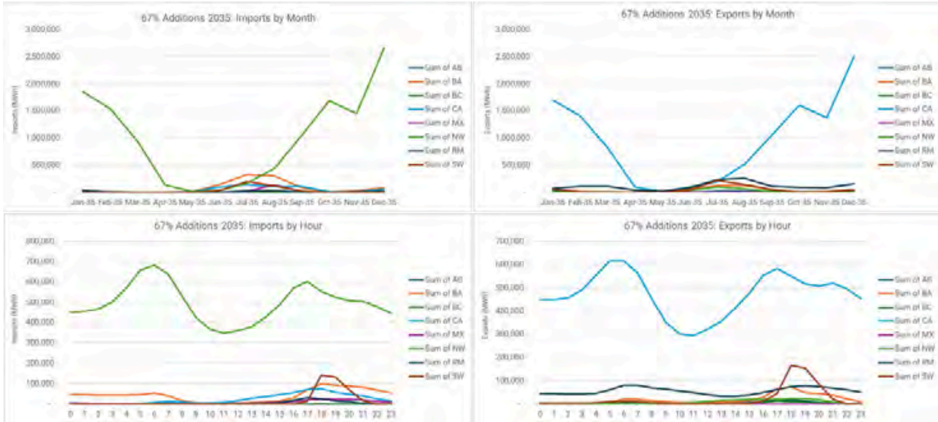


Subregional transfers by month and time of day for the 2035 All Additions Scenario

67% Additions



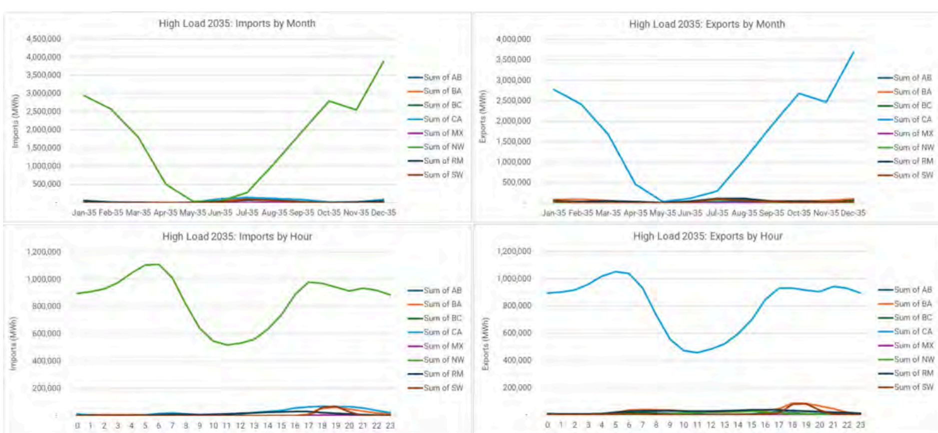
Subregional transfers by month and time of day for the 2030 67% Additions Scenario



Subregional transfers by month and time of day for the 2035 67% Additions Scenario

High Load

Subregional transfers by month and time of day for the 2030 High Load Scenario



Subregional transfers by month and time of day for the 2035 High Load Scenario

Methods & Data

- Read the methodology used in this assessment.
- Read the glossary of terms used in this assessment.
- This year's Western Assessment uses eight new subregional boundaries that better align with operational and planning realities and are consistent with other WECC assessments.
- This assessment uses Loads & Resources data provided by the Balancing Authorities in early 2025.

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Craig Unit 1	))))	Order No. 202-26-31

The State Of Colorado's Request for Rehearing,
Motion To Intervene, And Stay Request

Exhibit ZZZ: CoPUC, Tri-State, Phase II Status Update, filed on June 30, 2026, in Proceeding No. 23A-0585E

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

IN THE MATTER OF THE APPLICATION OF TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC. FOR APPROVAL OF ITS 2023 ELECTRIC RESOURCE PLAN	)	**PROCEEDING NO. 23A-0585E**

TRI-STATE GENERATION AND TRANSMISSION ASSOCIATION, INC.'S PHASE II STATUS UPDATE

Tri-State Generation and Transmission Association, Inc. ("Tri-State"), through its undersigned legal counsel, respectfully submits this status update pertaining to its 2023 Electric Resource Plan ("ERP"). In particular, Tri-State is providing updates on:

1. Acquisition of resources in connection with the Commission's Phase II Decision;
2. The status of the federal funding Tri-State requested from the United States Department of Agriculture ("USDA") under the Empowering Rural America ("New ERA") Program; and
3. 2027 ERP planning.

I. BACKGROUND

On March 17, 2026, Tri-State filed a notice in this proceeding on Phase II developments related to preferred portfolio resource acquisition and federal funding.

II. UPDATE ON NEW RESOURCE ACQUISITION

1. Tri-State continues to make progress toward implementing the Phase II resource acquisitions. No additional contract executions have occurred, but Tri-State is

continuing to pursue the remaining storage bid selected in its preferred portfolio. Tri-State has continued to delay pursuit of back-up bid resources until further certainty regarding New ERA program funding is attained, as discussed below.

III. UPDATE REGARDING FEDERAL FUNDING

2. As described in previous filings, Tri-State pursued federal support for certain ERP-related activities under the USDA New ERA program to assist rural electric cooperatives in financing clean energy investments.

3. Tri-State's New ERA application was selected for an award. Tri-State executed commitment letters with the USDA for the New ERA award in late 2024 and early 2025 and began preliminary planning to utilize the funds.

4. On January 27, 2025, the incoming administration issued a directive halting the implementation of certain programs, including New ERA grants, pending further review. USDA subsequently released the funding on March 25, 2025;[1] however, as of the date of this Status Update, Tri-State has not yet obtained certainty regarding the timing of release of its award funds.

5. Tri-State will file an update on the status of New ERA funding in its ERP Annual Progress Report on December 1, 2026, within this proceeding.

IV. 2027 ERP PLANNING

6. Tri-State intends to begin stakeholder engagement in preparation for the 2027 ERP in Q4 of 2026. Tri-State intends to convene approximately four stakeholder meetings to review topics including, but not limited to, planning reserve margin study

[1] *See* USDA Press Release No. 0061-25 (March 25, 2025), available at https://www.usda.gov/about-usda/news/press-releases/2025/03/25/usda-delivers-rural-energy-commitments-provides-path-applicants-support-us-energy-independence.

and demand response potential study results, scenarios, and generic resources to be modeled in Phase I of the 2027 ERP. Tri-State will also review the requirements of Section 4.12 of the 2023 ERP Settlement Agreement with stakeholders, which addressed the 2027 ERP.

Dated this 30th day of June, 2026.

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