BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-39:
DOE July 7 Press Release

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

Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security

The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.

Energy.gov

July 7, 2025

4 min

The Department of Energy warns that blackouts could increase by 100 times in 2030 if the U.S. continues to shutter reliable power sources and fails to add additional firm capacity.

WASHINGTON— The U.S. Department of Energy (DOE) today released its Report on Evaluating U.S. Grid Reliability and Security. The report fulfills Section 3(b) of President Trump's Executive Order, *Strengthening The Reliability And Security Of The United States Electric Grid*, by

delivering a uniform methodology to identify at-risk regions and guide Federal reliability interventions.

The analysis reveals that existing generation retirements and delays in adding new firm capacity, driven by the radical green agenda of past administrations, will lead to a surge in power outages and a growing mismatch between electricity demand and supply, particularly from artificial intelligence (AI)-driven data center growth, threatening America's energy security.

"This report affirms what we already know: The United States cannot afford to continue down the unstable and dangerous path of energy subtraction previous leaders pursued, forcing the closure of baseload power sources like coal and natural gas," Secretary Wright said. "In the coming years, America's reindustrialization and the AI race will require a significantly larger supply of around-the-clock, reliable, and uninterrupted power. President Trump's administration is committed to advancing a strategy of energy addition, and supporting all forms of energy that are affordable, reliable, and secure. If we are going to keep the lights on, win the AI race, and keep electricity prices from skyrocketing, the United States must unleash American energy."

Highlights of the Report:

- **The status quo is unsustainable.** DOE's analysis shows that, if current retirement schedules and incremental additions remain unchanged, most regions will face unacceptable reliability risks within five years and the Nation's electrical power grid will be unable to meet expected demand for AI, data centers, manufacturing and industrialization while keeping the cost of living low for all Americans. Staying on the present course would undermine U.S. economic growth, national security, and leadership in emerging technologies.

- **Grid growth must match the pace of AI innovation.** Electricity demand from AI-driven data centers and advanced manufacturing is rising at a record pace. The magnitude and speed of projected load growth cannot be met with existing approaches to load addition and grid management. Radical change is needed to unleash the transformative potential of innovation.
- **With projected load growth, retirements increase the risk of power outages by 100 times in 2030.** Allowing 104 GW of firm generation to retire by 2030—without timely replacement—could lead to significant outages when weather conditions do not accommodate wind and solar generation. Modeling shows annual outage hours could increase from single digits today to more than 800 hours per year. Such a surge would leave millions of households and businesses vulnerable. We must renew a focus on firm generation and continue to reverse radical green ideology in order to address this risk.
- **Planned supply falls short, reliability at risk.** The 104 GW of plant retirements are replaced by 209 GW of new generation by 2030; however, only 22 GW comes from firm baseload generation sources. Even assuming no retirements, the model found outage risk in several regions rises more than 30-fold, proving the queue alone cannot close the dependable-capacity deficit.
- **Old tools won't solve new problems.** Traditional peak-hour tests to evaluate resource adequacy do not sufficiently account for growing dependence on neighboring grids. At a minimum, modern methods of evaluating resource adequacy need to incorporate frequency, magnitude, and duration of power outages, move beyond exclusively analyzing peak load time periods, and develop integrated models to enable proper analysis of increasing reliance on neighboring grids.

DOE's report identifies regions most vulnerable to outages under various weather and retirement scenarios and offers capacity targets needed to restore acceptable reliability. The methodology also informs the

potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.

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Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-40:
PIOs' RFR of July Resource Adequacy Report

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

In re	)
Resource Adequacy Report	)
Evaluating the Reliability and Security	)
Of the United States Electric Grid	)
	)

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar

I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar ("Public Interest Organizations") hereby move, to the extent necessary, to intervene and request rehearing of the Department of Energy's ("Department" or "DOE") "Resource Adequacy Report: Evaluating the Reliability and Security of the United States" ("RAR").[1] The Department issued the RAR in response to Executive Order 14,262 *Strengthening the Reliability and Security of the United States Electric Grid,* April 8, 2025 ("Grid EO"),[2] and claims that the RAR is a "uniform methodology to identify at-risk region(s) and guide reliability interventions" as directed by the Grid EO.[3] But the Department simultaneously disclaims the utility of the RAR to guide interventions uniformly, acknowledging on the very first page that the various "entities responsible for the maintenance and operation of the grid" have information "that could further enhance the robustness of reliability decisions" in their parts of the grid.[4]

The flaws in the RAR continue. The Department overstates assumptions about demand growth and likely retirements while understating likely new entry, building into the RAR an inherent bias toward a finding of inadequate resource adequacy. The Department also departs from best practices by using a

[1] July 7, 2025, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf (attached as Ex. 1) (hereinafter, the "RAR").

[2] 90 Fed. Reg. 15521 (Apr. 8, 2025) (hereinafter "Grid EO").

[3] *Id.* at vi.

[4] *Id.* at i.

deterministic approach, which fails to account for necessary uncertainties and demonstrates that the RAR's findings should not be taken as conclusive or form the basis for further extraordinary actions. And on some critical aspects of the RAR analysis, the Department simply fails to explain its own methodology; while the Department describes two thresholds at which the RAR projects outages will occur, it fails to explain when it applies the standard threshold and when it applies the elevated one. These flaws render any reliance on the RAR to "guide reliability interventions" arbitrary and capricious.

While the Department acknowledges that the RAR is unsuitable to guide reliability interventions uniformly and provided no notice or opportunity to comment, the Department nevertheless does not clarify how it will use the RAR, creating confusion as to whether the RAR, in conjunction with the Grid EO, is intended to function as a final rule. Public Interest Organizations believe that the RAR should not be used as the basis for future action by the Department. We submit this request for rehearing in an abundance of caution, to the extent the Department later argues that any of these issues must have been raised in a request for rehearing within 30 days of the publication of the RAR, 16 U.S.C. § 825*l*. We also reserve our right to argue in later proceedings that 16 U.S.C. § 825*l* does not apply.

In sum, the RAR is a poorly crafted solution in search of a problem; there is no "energy emergency" and the regulatory bodies who actually possess authority to ensure resource adequacy are doing their jobs. Consequently, the RAR serves no useful purpose and should simply be withdrawn. By DOE's own admission, the RAR cannot reasonably be relied on to guide DOE interventions, nor, given the false premise and multiple mistaken assumptions, does it provide any value even as a purely informational report. On the contrary, it will only cause confusion for grid operators, energy providers, and members of the public. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

II. STATEMENT OF ISSUES

1. The Department intrudes on Federal Energy Regulatory Commission ("FERC" or "the Commission") and state authority. 16 U.S.C. §§ 824a(c),824o-1; 42 U.S.C. § 7113.
2. The RAR's findings, even if accurate, do not demonstrate any emergency allowing the Department to compel generation under the Federal Power Act. 16 U.S.C. § 824a(c); S. Rep. No. 74-621 (1935); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,985.

3. The RAR is analytically flawed and does not rely upon substantial evidence. 16 U.S.C. 824a(a); 16 U.S.C. § 824o(a)(3).
4. The Department cannot use the RAR as a "uniform methodology" without giving notice and taking public comment. 5 U.S.C. §§ 552, 553; 10 C.F.R. §§ 205.371; 205.373.
5. The Department cannot use the RAR as a "uniform methodology" without following National Environmental Policy Act procedural requirements. 42 U.S.C. § 4332(C).

III. INTERVENTION

Each of the Public Interest Organizations has interests that may be directly and substantially affected by the use of this RAR as a "uniform methodology" to guide "reliability interventions," including the issuance of Emergency Orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c).[5] To the extent that the RAR is determined to be an Order or Rule, each party may intervene in this proceeding.[6] And to the extent the Department treats the RAR as binding and uses it to guide reliability interventions, each of the Public Interest Organizations and their members will suffer concrete injuries that are redressable through rehearing.[7] Each organization is therefore aggrieved if the RAR is a "uniform methodology" for use in guiding interventions, as the Department purports, and each organization may properly apply for rehearing, assuming without conceding that the rehearing procedures apply.[8]

A. Natural Resources Defense Council

Natural Resources Defense Council ("NRDC") is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by fossil fuel fired power plants. NRDC works to achieve clean

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[5] *See* RAR, Ex. 1 at iv.

[6] *See* U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025) (archived version attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed. *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website. *See also* Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 30, 2005) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.") (attached as Ex. 3).

[7] *See, e.g. Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009).

[8] *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all. NRDC has hundreds of thousands of members across the United States. These NRDC members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual impacts of these facilities' operations. In addition, NRDC members are ratepayers in regions who will be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. For that reason, NRDC filed requests for rehearing of DOE's 202(c) orders issued to the J.H. Campbell and Eddystone plants, the latter of which explicitly stated that it would be reexamined following publication of the methodology. NRDC has five U.S. offices that also will be subject to higher electric bills as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

B. The Ecology Center

The Ecology Center is a Michigan-based non-profit organization headquartered in Ann Arbor, Michigan, with additional offices in Detroit, Michigan. Ecology Center is a public interest organization with more than 50 years of experience advocating for clean energy production, healthy communities, environmental justice, and a sustainable future. Ecology Center works at the local, state, and federal level. Its programs address systemic sources of poor health and environmental degradation through unique partnerships with environmental health and environmental advocates. Ecology Center has over 6,000 members and supporters, that live, use electricity, and pay electric bills in Michigan and could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. In addition, Ecology Center members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject Ecology Center members to air and water pollution in the areas where they live, work, and recreate.

C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a non-profit membership organization with hundreds of thousands of members nationwide whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across

the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. Recent 202(c) Orders issued by the DOE have harmed members of EDF by causing increases in pollution, which impact the health of people and nature, and in energy costs. EDF has submitted requests for rehearing regarding the DOE Orders related to the J.H. Campbell and Eddystone power plants and a Petition for Review regarding the DOE Order regarding the J.H. Campbell plant. Further 202(c) Orders issued as a result of the RAR, including extensions of the J.H. Campbell and Eddystone orders and orders directed at other generators, will result in further pollution and cost impacts that will harm EDF members.

D. Environmental Law and Policy Center

Environmental Law and Policy Center ("ELPC") is a not-for-profit environmental organization with members, contributors, and offices throughout the Midwest. Among other things, ELPC advocates before state public service commissions and the Federal Energy Regulatory Commission for clean, reliable energy generation in order to reduce ratepayer costs and improve environmental outcomes. ELPC members in the Midwest live, work, and recreate near power plants that burn coal or other fossil fuels and are directly impacted by their pollutants. In addition, ELPC members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. ELPC and its members could be subject to higher electric bills and impacted by additional pollution as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." ELPC has a longstanding organizational commitment to protect the interests of its members, to reduce pollution caused by fossil fuel-fired power plants, and to promote clean, reliable energy generation.

E. Public Citizen

Public Citizen, Inc. hereby intervenes in these proceedings. Public Citizen, Inc. is an active intervenor and participant before the Federal Energy Regulatory Commission in Federal Power Act proceedings, as well as before the U.S. Department of Energy in both electricity export and natural gas export dockets to ensure just and reasonable rates and that utilities' operations are consistent with the public interest. Established in 1971, Public Citizen, Inc. is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of American household consumers. Public Citizen has members in all 50 states and represents the interests of consumers, not represented by any other party in this proceeding. Financial details about our organization are on our website: www.citizen.org/about/annual-report/.

F. Sierra Club

Sierra Club is a national environmental non-profit whose purpose is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. To those ends, the Sierra Club and its members have worked to limit pollution caused by fossil-fuel-fired power plants through public education and advocacy at the local, state, and federal level. Sierra Club represents over 640,000 members nationwide, many of whom reside and recreate in the regions in which the RAR purports to identify resource shortfalls requiring the continued operation of coal- and gas-fired generation. Sierra Club members in those areas would be harmed by the pollution and the increased utility rates caused by any such continued operation.

G. Vote Solar

Vote Solar is an independent 501(c)(3) non-profit working to re-power the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. In over half of the country, Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally. Vote Solar members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. Vote Solar is not a trade organization, nor does it have corporate members. Vote Solar is committed to promoting clean, renewable energy and transitioning away from coal generation.

IV. BACKGROUND

A. Executive Orders

The genesis of the RAR lies in the President's unsupported day one declaration of a national energy emergency: *Declaring a National Energy Emergency* ("Energy Emergency EO").[9] That declaration's lack of factual underpinning was highlighted in a recent report by DOE's independent statistics and analysis arm, the Energy Information Administration ("EIA"). The EIA report highlights how U.S. energy production and exports are currently at an all-time high.[10] Nonetheless, the Energy Emergency EO was cited as a basis for the

[9] Exec. Order No. 14,156, 90 Fed. Reg. 8433 (January 20, 2025) (hereinafter "Energy Emergency EO") (attached as Ex. 4). *See* also RAR, Ex. 1 at vi (explaining that the Grid EO "builds on" the Energy Emergency EO).

[10] *See* U.S. EIA, *U.S. primary energy production, consumption, and exports increased in 2024* (June 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

President's follow-up grid-specific executive order, the Grid EO, that led to DOE's publication of the RAR.[11]

The Grid EO directed DOE to take three steps to address the President's assertion that there may be lack of grid reliability in the future, including: 1) to streamline the processes to issue orders pursuant to Federal Power Act Section 202(c);[12] 2) to develop a reserve margin assessment methodology and use it to identify at risk regions and critical energy resources within those regions and to publish that methodology within 90-days of the Grid EO;[13] and 3) to establish a protocol for identifying critical generating resources and taking action to prevent retirement or conversion of the fuel source of such resources.[14]

Notably, the Grid EO was issued in conjunction with a series of actions by President Trump and DOE designed explicitly to prop up the coal and gas industries, including: 1) Executive Order 14,261, *Reinvigorating America's Beautiful Clean Coal Industry,*[15] which seeks to restart coal leasing and expand coal mining on federal lands, in addition to making these processes easier by offering loans and streamlining permitting;[16] 2) a Presidential Proclamation entitled *Regulatory Relief for Certain Stationary Sources to Promote American Energy* that exempts coal plants from complying with the U.S. Environmental Protection Agency's updated Mercury and Air Toxics Standards;[17] and 3) Executive Order 14,260, *Protecting American Energy from State Overreach*,[18] which directs the U.S.

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[11] Nor does the Energy Emergency EO supply legal support for the Grid EO. Under the National Emergencies Act, 50 U.S.C. § 1631, a declaration of national emergency does not authorize the exercise of emergency powers "unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act." But as Congress made clear, the statute "is not intended to enlarge or add to Executive power" such as authority under Section 202(c), only to "establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes." S. Rep. No. 94-1168, 3 (1976).

[12] Grid EO Section 3(a).

[13] *Id.* Section 3(b).

[14] *Id.* Section 3(c).

[15] *See* Exec. Order No. 14,261, 90 Fed. Reg. 15,517 (Apr. 8, 2025).

[16] DOE simultaneously announced several initiatives to subsidize the coal industry, including loan guarantees for coal-fired power plant projects. Dep't of Energy, *Energy Department Acts to Unleash American Coal by Strengthening Coal Technology and Securing Critical Supply Chains* (Apr. 8, 2025), https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing.

[17] Proclamation No. 10914, 90 Fed. Reg. 16777 (Apr. 8, 2025).

[18] Exec. Order No. 14,260, 90 Fed. Reg. 15513 (Apr. 8, 2025).

Department of Justice to take action to block states' exercises of their police powers to protect their residents from pollution caused by coal and fossil-fuel sources.[19]

B. RAR

On July 7, 2025, DOE published the RAR on its website. The RAR includes a deterministic analysis of the resource adequacy of the current electric system and three 2030 cases: (1) the Plant Closure case includes 104 GW of coal and gas retirements plus 100% of NERC's Tier 1 additions; (2) the No Plant Closures case includes no retirements but 100% of NERC's Tier 1 additions; and (3) the Required Build case begins with the Plant Closures scenario and projects what additional added perfect capacity would be needed to meet the RAR's determined reliability standards.[20] Each of the three 2030 scenarios assume 50 GW of load growth from data centers and an additional 51 GW of load growth from other sources.[21] The Department finds in the RAR that, under the current system, only ERCOT fails to achieve DOE's selected resource adequacy targets,[22] but that, based on the methodology used to forecast the 2030 scenarios, there will be broader resource adequacy issues in 2030.[23] And, notwithstanding the RAR's upfront acknowledgement that the analysis used "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level,"[24] the Department proceeds to make broad declarations of future need based on its findings in the RAR.[25]

DOE explained that the RAR was being issued pursuant to the Grid EO. The RAR incorporates a full copy of the Grid EO and explains that "[t]his report serves as DOE's response to [the Grid EO's] Section 3(b) … by delivering the required uniform methodology to identify at-risk region(s) and guide reliability

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[19] These actions mimic President Trump's failed efforts to prop up the coal industry during his first term, including DOE's proposed rule, soundly rejected by FERC, that would have provided assured cost recovery (including a return on equity) for coal and nuclear plants (*see* 162 FERC ¶ 61,012), and the President's unfulfilled directive that DOE use Section 202(c) and the Defense Production Act to block closure of uneconomic coal plants while requiring grid operators to bear the costs. *See* Draft Memorandum (May 29, 2018), https://embed.documentcloud.org/documents/4491203-Grid-Memo/.

[20] RAR, Ex. 1 at 4-5.

[21] *Id.* at 2-3, 15-17.

[22] *Id.* at 7.

[23] *Id.* at 6-9.

[24] *Id.* at i.

[25] *Id.* at 1-2. *See also*, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security.

interventions."[26] DOE's statement that it intends to use the methodology "to guide reliability interventions" and that DOE will continue to use the RAR "on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States" suggests that the RAR may be intended to also serve as the protocol called for by Section 3(c) of the Grid EO.[27] But the RAR fails to clarify this, or, if the RAR does not also serve as DOE's response to Section 3(c), whether a protocol has been or will be developed, or whether any protocol will be made public. The RAR does not include any discussion of Section 3(a) of the Grid EO. To the extent that the Department addressed that portion of the Grid EO's directions, it has not made any process changes public. On the contrary, the Department has made its processes under Section 202(c) even less transparent by removing the existing process guidance from the DOE website.[28]

Notwithstanding the statement in the RAR that DOE intends to use the "methodology to identify at-risk region(s) and guide reliability interventions," e.g., Section 202(c) Orders,[29] other portions of the RAR make clear that it can't and shouldn't be used as a basis for interventions, specifically not issuance of 202(c) Orders. First and foremost, the reliability projections in the RAR focus on conditions five years from now and concede that there are not current grid conditions that fit within Section 202(c)'s definition of an "emergency." Second, the Department candidly concedes the RAR's lack of robustness: "DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."[30]

C. Section 202(c) Orders

Section 202(c) of the Federal Power Act allows the Secretary of Energy, in certain emergency situations, to require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary

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[26] RAR, Ex. 1 at vi.

[27] *Id.*

[28] *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website.

[29] *See* Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.").

[30] RAR, Ex. 1 at i.

determines will best meet the emergency and serve the public interest. Section 202(c) has an important purpose: to mitigate electricity shortages caused by war, drought, and other emergencies. In granting DOE the authority that Section 202(c) provides, Congress considered the severe societal consequences of blackouts and determined that avoiding those consequences justified allowing DOE to act without notice and to require operations that override environmental laws. But Congress was also very careful to narrowly limit DOE's use of that authority, as the title of the provision makes clear, to "temporary" "emergency" situations.[31] And while the statute doesn't define "emergency," DOE's regulations include a lengthy definition which reinforces the key element in the statute: 202(c) orders are for situations that are sudden and unexpected, not for longer term grid management.[32]

1. DOE's Past Use of 202(c) Orders

The Department's application of Section 202(c) consistently confirms the urgency of the conditions necessary to invoke the provision and underscores the lack of authority for the planned implementation scheme described in the Grid EO and RAR.[33] The Department's predominant practice has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[34]

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[31] *See, e.g., Richmond Power & Light,* 574 F.2d at 617 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor.").

[32] 10 C.F.R. § 205.371: "'Emergency,' as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. In such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed. Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent. Where an electricity outage or service inadequacy qualifies for a section202(c) order, contractual difficulties alone will not be sufficient to preclude the issuance of an emergency order."

[33] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[34] *See, e.g.,* Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and

The law also requires the Department to narrowly tailor the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, limit the order to "only [the] hours necessary to meet the emergency," be "consistent with any applicable Federal, State, or local environmental law or regulation," and to "minimize[] any adverse environmental impacts.[35] Up until recently, the Department has routinely followed these provisions of the law.[36]

2. DOE's Recent Misuse of Section 202(c)

Prior to issuance of the RAR but consistent with the direction in the Grid EO, DOE issued two Section 202(c) orders blocking the planned closures of two fossil-fuel fired generation resources that were unreliable, uneconomic, and at the end of their useful lives: the J.H. Campbell coal-fired plant in West Olive Michigan,[37] and units 3 and 4 of the Eddystone oil and gas fired plant in Eddystone, Pennsylvania.[38] The Eddystone 202(c) Order stated that "DOE plans to use this methodology [i.e., the RAR] to further evaluate Eddystone Units 3 and 4," thus raising questions about DOE's intentions as to the legal status and efficacy of the RAR.

Public Interest Organizations filed requests for rehearing for both the J.H. Campbell and Eddystone 202(c) Orders.[39] In both cases DOE failed to identify conditions that would qualify as "emergencies" for the purpose of issuance of Section 202(c) Orders. And both Section 202(c) Orders impose significant costs on ratepayers,[40] while increasing emissions of air pollutants and providing no

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December 26) (attached as Ex.5); Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires) (attached as Ex.6); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century) (attached as Ex. 7).

[35] 16 U.S.C.§ 824a(c)(2).

[36] *See, e.g.,* Ex.5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex.6, Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

[37]Dep't of Energy Order No. 202-25-3 (May 23, 2025) (attached as Ex. 8).

[38]Dep't of Energy Order No. 202-25-4 (May 30, 2025) (hereinafter "Eddystone 202(c) Order") (attached as Ex. 9).

[39] Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-3 (June 18, 2025) (hereinafter "Campbell RFR") (attached as Ex.10);Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-4 (June 27, 2025) (hereinafter "Eddystone RFR") (attached as Ex.11).

meaningful corresponding reliability benefit.[41] The Department denied both of Public Interest Organization's requests for rehearing by operation of law.[42]

D. Existing Mechanisms Ensure Resource Adequacy

In the United States, how electricity is bought and sold varies by region. Electric utilities can be either traditionally regulated and operate as vertically integrated monopolies, or they can operate in deregulated, competitive markets where electric energy prices are set by the market. Both vertically integrated utilities and utilities in deregulated markets are subject to federal oversight, and in some of the deregulated states, the state nonetheless exercises oversight over the terms of retail supply offers, especially for retail customers. And all utilities are subject to reliability standards developed by the North American Electric Reliability Corporation ("NERC") and approved by FERC. In sum, FERC, Regional Transmission Organizations ("RTOs"), States, and NERC all play a hand in ensuring resource adequacy.

1. Vertically integrated utilities

Until the 1990s, utilities were generally vertically integrated such that generation, transmission, and distribution resources were all held by the same entity.[43] Vertically integrated utilities must seek state approval for power plant investments.[44] Many state regulators require utilities to demonstrate the necessity of proposed investments through an integrated resource planning process.[45] This process is used for long-term planning and requires the utility to justify its investments and demonstrate how it plans to meet customer electricity demand.[46] Even though vertically integrated utilities generate their own electricity, many

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[40] *See e.g.* U.S. Sec. and Exch. Comm'n, Form 10-Q, Consumers Energy Company Quarterly Report For the Quarterly Period Ended June 30, 2025, at 39, 62, 92 (2025) https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf (describing costs of $29 million to operate Campbell through June 30, 2025); FERC Docket No. ER25-2653-000 (PJM proposed cost allocation to implement DOE Order 202-25-4).

[41] *See* Campbell RFR, Ex. 10 at 11-14; Eddystone RFR, Ex. 11 at 56-60. 87-88.

[42] Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-3A (July 28, 2025) (attached as Ex. 12); Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-4A (Aug. 1, 2025) (attached as Ex. 13).

[43] *See* Kathryne Cleary and Karen Palmer, *US Electricity Markets 101* (March 17, 2022), Resources for the Future, https://www.rff.org/publications/explainers/us-electricity-markets-101/.

[44] *Id.*

[45] *Id.*

[46] *Id.*

trade with other utilities during times of need. These wholesale market transactions are subject to regulation by FERC.[47]

2. Competitive markets

Advances in technology and statutory changes led to the development of energy markets and merchant generation that is not owned by incumbent utilities.[48] In the 1990s, FERC fostered competitive markets through rules that allowed the establishment of independently-operated voluntary RTOs that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources through Order Nos. 888, 890, and 2000.[49] As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Deregulated states use markets to determine which power plants are necessary for electricity generation.[50] Even in deregulated states, the state sites new generation. Market price signals encourage new investment when supply is tight and encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.[51]

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[47] *See* FERC, *Electric Power Markets* (last updated March 27, 2025), https://www.ferc.gov/electric-power-markets.

[48] *See, e.g.,* Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012, PP 7-11 (2018); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,639-31,645 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

[49] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 638-41 (1996), Order No. 890, FERC Stats. & Regs. ¶ 31,241, at 124-352 (1997), Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 99-130 (1999).

[50] State regulators in competitive markets still practice oversight over utilities. For example, some states, such as Michigan, use both the market and integrated resource planning. *See* Michigan Public Service Commission, *Phase III – Integrated Resource Plan* (last visited Aug. 4, 2025), https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid/phase-iii-integrated-resource-plan-mirpp-filing-requirements-demand-response-study-energy-waste-red. Other state legislatures or commissions have enacted subsidies to keep nuclear plants alive, such as in New York, Illinois, Ohio, and New Jersey. *See* U.S. EIA, Five states have implemented programs to assist nuclear power plants (Oct. 7, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41534.

[51] *See, e.g.*, Judy Chang et al., The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, 1, 3-7 (April 2019) https://www.brattle.com/wp-content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-

As explained by FERC, its "support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers."[52] In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by "providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers."[53]

3. FERC and NERC Reliability Regulation

As part of its role in regulating the wholesale electric industry, FERC has implemented Congressional mandates to ensure system reliability, including establishing NERC as the Electric Reliability Organization, which sets industry standards for grid reliability that are approved by FERC;[54] coordination requirements for the natural gas and electricity market scheduling;[55] investigation and improvements required in light of the grid's response to extreme weather events;[56] and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.[57]

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customer-bills/ (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen; John Tsoukalis et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, at 6, 46, 77-78 (Apr. 27, 2019), https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf (discussing cost savings across regional wholesale markets).

[52] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, P 11 (2018).

[53] *Id.* (citation omitted).

[54] PJM, NERC and Reliability Fact Sheet (Jan. 5, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf. *See also* PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf.

[55] PJM, PJM Promotes Gas/Electricity Industry Coordination (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/gas-electric-coordination-fact-sheet.pdf. *See also* Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015).

[56] *See e.g.,* Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024). *See also* FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf; FERC, NERC and Regional Entity Joint Staff, The February 2021 Cold Weather Outages in Texas and the

V. ARGUMENT

A. The Department Is Intruding on FERC and State Authority.

The Department's authority over reliability is strictly circumscribed to respond to imminent emergencies;[58] this authority does not extend to regulating long-term or overarching aspects of the electricity sector. Rather, Congress reserved to the states and FERC the authority to regulate the electric sector generally and to regulate resource adequacy and reliability specifically. Recent actions—starting with the Energy Emergency EO and culminating in the RAR—indicate, however, that DOE is not remaining in its designated lane.[59] The RAR lays bare the Department's agenda to prop up fossil fuel businesses by utilizing emergency authority in a systematic fashion that goes well beyond the scope of DOE's authority under the Federal Power Act and illegally intrudes upon authorities that Congress has explicitly reserved to the states or given to FERC.

The authority to maintain a reliable electric system in the United States has evolved over the years to include parties at the federal, regional, state, and local levels.[60] But the Department of Energy has never been granted primary regulatory authority over either reliability or resource adequacy of the grid. Rather, the Department of Energy Organization Act of 1977 ("Organization Act")[61] and the

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South Central United States (Nov. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[57] *Id.*; *see also* Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

[58] *See* 16 U.S.C. §§ 824a(c),824o-1.

[59] *See* Energy Emergency EO, Ex. 4; Grid EO Sec. 3 (RAR, Ex. 1 at C); RAR Ex. 1; DOE, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security; Eddystone 202(c) Order, Ex. 9; Dep't of Energy Order No. 202-25-3 (May 23, 2025), Ex. 8.

[60] *New York v. FERC*, 535 U.S. 1, 5-8 (2002) ("Prior to 1935, the States possessed broad authority to regulate public utilities"). *See generally* Nat'l Ass'n of Reg. Util. Comm'rs ("NARUC"), *Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms* (Nov. 2023) https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3?_gl=1*oyp366*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzEkdDE3NTM5ODk1NzUkajI1JGwwJGgw; NARUC, *Resource Adequacy Primer for State Regulators* (July 2021), https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[61] 42 U.S.C. § 7111 *et seq.*

Federal Power Act[62] give to the Department only narrow, emergency authority over the electric system—for example through Federal Power Act Sections 202(c) and 215A.[63] The President's declaration of an energy emergency (even if it were legitimate) and other executive orders cannot expand these statutorily defined authorities.[64] And while the Department may of course analyze policy implications and issue reports on various topics—as it has done since its founding—DOE's statements indicate that the RAR is not simply a policy analysis. The Department states—without limitation—that it will use the RAR "to identify at-risk region(s) and guide reliability interventions."[65] Thus, taking DOE at its word, the RAR is beyond the Department's authority.

Further, to the extent that it is an indication of the Department's broader scheme, in the RAR, the Department ignores the limitations on its authority and the comparative breadth of authority explicitly reserved to the states and FERC over the Department. "States are responsible for resource adequacy in siting of electric facilities, establishing retail electric rates, and overseeing the reliability of the distribution system."[66] State public utility commissions review utility proposals for long-term impacts to the system's reliability. "Most states address resource adequacy by requiring large investor-owned utilities to file long-term planning documents like integrated resource plans that include strategies for reliably meeting future demand."[67]

The structure and language of the Organization Act and Federal Power Act reflect Congress's deliberate choices to preserve this traditional state authority over generating facilities and to circumscribe the Department's emergency authority in light of the states' role. Congress noted in the Organization Act that "[n]othing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction."[68] And the first sentence of the Federal Power Act declares that

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[62] Subsequent legislation has also amended and updated these authorities. *See e.g.* Fixing America's Surface Transportation Act (FAST Act), Pub. L. No. 114–94, 129 Stat. 1312 (2015); Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[63] 16 U.S.C. §§ 824a(c), 824o-1.

[64] *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023); *see also* S. Rep. No. 94-1168, 3 (1976), (the National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*.") (emphasis added).

[65] RAR, Ex. 1 at vi.

[66] NARUC, *Resource Adequacy Primer for State Regulators*, at 9 (July 2021) https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[67] Nat'l Renewable Energy Lab'y, *Explained: Fundamentals of Power Grid Reliability and Clean Electricity*, at 4 (Jan. 2024) https://docs.nrel.gov/docs/fy24osti/85880.pdf.

[68] 42 U.S.C. § 7113.

federal regulation extends "only to those matters which are not subject to regulation by the States."[69] Section 201(b)(1) further states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy."[70] The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities,[71] including the authority to order their closure.[72] Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[73] And when Congress added new authority regarding reliability to the Federal Power Act in 2005, it also still explicitly clarified that "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard…."[74]

The RAR also intrudes upon authority that Congress explicitly and repeatedly gave exclusively to FERC, not the Department. In 1935, Congress passed the Federal Power Act, creating the Federal Power Commission to engage in "federal regulation of electricity in areas beyond the reach of state power."[75] However, until the 1970s, the federal government played a very limited role in energy policy and generally left to private industry and state and local governments the task of establishing energy policies and planning.[76] In 1977, Congress passed the Organization Act,[77] creating both the Department and FERC. The Organization Act transferred most of the authority for overseeing the electric system in the

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[69] 16 U.S.C. § 824(a).

[70] *Id.* § 824(b)(1).

[71] *See, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016).

[72] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (2009) (under Section 201(b), states retain the right "to require retirement of existing generators" or to "take any other action in their role as regulators of generation facilities."). *See also Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[73] 16 U.S.C. § 824a(b).

[74] 16 U.S.C. § 824o.

[75] *New York v. FERC*, 535 U.S. 1, 6 (2002).

[76] DOE, *A Brief History of the Department of Energy,* https://www.energy.gov/lm/brief-history-department-energy. *See also* DOE, *Department of Energy 1977-1994, A Summary History* (Nov. 1994), https://www.energy.gov/sites/prod/files/2017/09/f36/DOE%201977-1994%20A%20Summary%20History_0.pdf.

[77] Public Law 95–91 (1977), 42 U.S.C. § 7101 *et seq.*

Federal Power Act to FERC, not the Department;[78] the Department retained primary authority only over "emergency interconnection."[79]

While FERC is housed within the Department, FERC is an independent agency with distinct authority from the Department that the Department may not modify or supersede.[80] Generally the Department "is authorized to establish, alter, consolidate or discontinue such organizational units or components within the Department as [the Secretary] may deem to be necessary or appropriate."[81] But this authority explicitly does not extend to FERC. The Organization Act explains that the Department may not abolish "organizational units or components established by" the Organization Act, nor may it "transfer [] functions vested by this chapter in any organizational unit or component."[82] Because the Organization Act created[83] and transferred specific authority to FERC,[84] the Department has no authority to alter FERC itself nor to seize FERC's statutorily prescribed authority.

Further, "the decision of the Commission involving any function within its jurisdiction . . . shall be final agency action . . . and *shall not be subject to further review by the Secretary* or any officer or employee of the Department."[85] While the Department can propose rules under FERC's jurisdiction, FERC maintains "exclusive jurisdiction . . . to take final action on any proposal made by the Secretary."[86] And when the Department proposes a rule in the exercise of its own functions that FERC determines significantly affects any function within FERC's jurisdiction, FERC can insist on changes that DOE must adopt if DOE wants to issue the rule.[87]

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[78] 42 U.S.C. § 7172 (transferring functions from Federal Power Commission to FERC); 42 U.S.C. § 7151 (the function of the Federal Power Commission is transferred to the Secretary except as provided to FERC). The Department and FERC share authority over certain parts of the Federal Power Act that primarily address recordkeeping and administration. 42 U.S.C. § 7172(a)(2) ("The Commission may exercise any power under the following sections to the extent the Commission determines such power to be necessary to the exercise of any function within the jurisdiction of the Commission: (A) sections 4, 301, 302, 306 through 309, and 312 through 316 of the Federal Power Act.").

[79] *See* 42 U.S.C. § 7172(a)(1)(B).

[80] *See* 42 U.S.C.A. § 7112 (Congressional declaration of purpose in establishing Department); 42 U.S.C. § 7171 (establishment of FERC).

[81] 42 U.S.C. § 7253.

[82] 42 U.S.C. § 7253.

[83] 42 U.S.C. § 7171 (establishment of FERC).

[84] 42 U.S.C. § 7172(a) (transferring functions from Federal Power Commission to FERC).

[85] 42 U.S.C. § 7172(g) (emphasis added).

[86] 42 U.S.C. § 7173. *See* 162 FERC ¶ 61,012.

[87] 42 U.S.C. § 7174.

In 2005, Congress expanded FERC's authority to specifically encompass reliability by updating the Federal Power Act in the 2005 Energy Policy Act.[88] While "FERC had previously addressed electric grid reliability in an indirect manner, such as allowing the cost recovery of public utility expenditures that address discrete reliability matters,"[89] there had been no mandatory reliability standards adopted by any federal regulator. When providing recommendations on reliability in 1998, the Department had concluded "that the U.S. Congress should explicitly assign oversight of bulk-power reliability to the FERC."[90] The new Section 215 followed the Department's suggestion and "tasked FERC [—not the Department—] with a direct role over an entire new field of activity."[91] Section 215 authorizes FERC to certify an electric reliability organization; FERC designated NERC. It is therefore NERC that develops reliability standards that FERC reviews to ensure consistency with federal law.[92] The broad reliability authority Congress granted to FERC contrasts with the very narrow, emergency authority in Section 215A that Congress granted to the Department.[93] The RAR appears to duplicate FERC and NERC's reliability efforts, impermissibly intruding upon authority Congress chose to give FERC —subject to elaborate procedural and substantive limitations—not the Department.

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[88] Pub. L. No. 109-58, 119 Stat. 594 (2005).

[89] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[90] DOE, *Maintaining Reliability in a Competitive U.S. Electricity Industry* at vii-viii, xiv (Sept. 29, 1998), https://certs.lbl.gov/sites/all/files/basic-page/maintainting-reliability-in-competitive-electricity-industry-1998_0.pdf ("The Administration has proposed legislation that would provide the federal oversight necessary to make reliability standards mandatory. The NERC has begun to reinvent itself to respond to the changing needs of the industry. In addition, the FERC has undertaken several reliability initiatives. However, much more is needed. The Congress, for example, urgently needs to clarify the FERC's authority over an electric industry self-regulating reliability organization and expand the FERC's jurisdiction for reliability over the bulk-power system.") ("The Task Force is confident that the electricity industry, overseen by the Federal Energy Regulatory Commission (FERC) and a restructured self-regulating reliability organization (such as the planned North American Electric Reliability Organization [NAERO]), can and will maintain today's high levels of reliability."). *See also* S. Rep. No. 106-324, Electric Reliability 2000 Act (proposals from Congress such as this one gave FERC the authority over reliability).

[91] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[92] FERC, Reliability Explainer (Aug. 16, 2023) https://www.ferc.gov/reliability-explainer#:~:text=Both%20NERC%20and%20FERC%20have,blackouts%20or%20systematic%20compliance%20failures.

[93] The 2015 amendment to Federal Power Act creating Section 215A (16 U.S.C. 824o-1(d)) gives DOE the authority to issue orders to address emergencies related to malicious acts resulting from physical attacks to the grid at limited 15-day increments.

Finally, the Department arbitrarily and capriciously assumes that the existing systems are not working. The states and FERC have—pursuant to their authority—established systems to maintain resource adequacy and reliability including integrated resource planning processes and capacity markets. These existing systems are designed to signal to build more energy generation when energy demand rises.[94] Recently, as the Department notes in the RAR, energy demand has been rising; but the Department fails to acknowledge that the state and FERC systems already are appropriately responding, negating claims of an emergency or the need for the Department to interfere, as discussed *infra* in Section C.[95] For example, PJM's, SPP's, and MISO's new "fast track" processes—adopted to address concerns of resource adequacy—"alone would add roughly twice what the DOE assumed for the entire nation."[96] The RAR is written arbitrarily and capriciously incorporating the implicit assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm.

In sum, Congress has explicitly reserved to the states and FERC primary regulatory authority over resource adequacy and reliability. The Department's only authority to directly regulate reliability of the electric grid is narrow emergency authority such as Federal Power Act Sections 202(c) and 215A. The Department does not have broader authority to interfere with resource adequacy or reliability regulations. To the extent that the RAR is the confirmation of the attempt to usurp that authority from the states and FERC, via a "uniform methodology" in the RAR, it is outside of DOE's statutory authority and contrary to law.

B. The Department's Findings in the RAR, Even if Accurate, Do Not Demonstrate Any Emergency Allowing the Department to Compel Generation Under the Federal Power Act.

Even if the findings in the RAR were accurate (which they are not, as explained in Section C below), they would not empower the Department to exercise any statutory authority, under "section 202 of the Federal Power Act" or otherwise, to override state- or market-driven changes to the electricity generating facilities supplying the grid.[97] As discussed in Section A above, the Federal Power Act gives the Department tightly circumscribed authority over resource adequacy planning, to address "emergency" conditions through "such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy" as

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[94] *See e.g.* DOE, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Energy Markets, at 3.8 (May 2002); GridLab, GridLab Analysis: Department of Energy Resource Adequacy Report, at 4 (July 11, 2025) (hereinafter "GridLab Analysis") (attached as Ex. 14).

[95] GridLab Analysis, Ex. 14 at 2-3.

[96] GridLab Analysis, Ex. 14 at 3.

[97] Grid EO at Sec. 3 (RAR, Ex. 1 at C-3).

"will best meet the emergency and serve the public interest."[98] The statutory text, structure, and history, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c), all establish that its "emergency" authority is confined to sudden, unexpected, imminent, and specific electricity shortfalls. The information in the RAR, at most, expresses the Department's view that bulk-power system reliability will be insufficient in 2030. The Department's conclusions in the RAR—even if assumed to be accurate for the sake of argument—consequently provide no basis for the Department to manipulate the electricity market.

1. The Federal Power Act only permits the Department to intervene when necessary to address an imminent, unexpected, and specific electricity shortfall.

The Federal Power Act's text, context, and structure, as well as caselaw and the Department's longstanding regulations, all establish that it does not permit the Department to "prevent" generating facilities "from leaving the bulk-power system" or "converting" from one fuel-source to another based on the Department's view of long-term reliability needs.[99] The Act provides the Department only authority to intervene in electricity markets when necessary to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response, through the cabined authority provided by Section 202(c) of the Act.

a. The Text of Section 202(c) Narrowly Limits the Department's Authority to Emergencies: Imminent, Unexpected, and Certain Shortfalls in Electricity Supply.

The Act's text empowers the Department to require generation only in an "emergency;"[100] the Act primarily reserves authority over generation to the states, allocating more limited federal regulatory power to different agencies, *see section* A above. The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "*sudden* or *unexpected* appearance or occurrence . . . An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency."[101] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency

[98] 16 U.S.C. 824a(c).

[99] Grid EO at Sec. 3(c)(ii) (RAR, Ex. 1 at C-4).

[100] 16 U.S.C. § 824a(c).

[101] Emphasis added.

is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action."[102]

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency." The authority granted by Section 202(c) is, in the first instance, a war-time power.[103] An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example.[104]

The text's use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where "an emergency *exists*."[105] That near-term focus along with the statute's strictly "temporary" authority[106] precludes use of Section 202(c) to pursue long-term policy goals, such as "fear of overdependence" on foreign oil supplies,[107] or "energy independence."[108]

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course.[109] The resulting statutory "machinery for the

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[102] Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* Rolsma, Ex. 7 at 812 n.147 (noting that dictionaries have given the term "emergency" the "same meaning for many years").

[103] 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress").

[104] 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light,* 574 F.2d at 615 (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

[105] 16 U.S.C. § 824a(c) (emphasis added).

[106] 16 U.S.C. § 824a(c).

[107] *Richmond Power & Light*, 574 F.2d at 617.

[108] RAR, Ex. 1 at 1. *See Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

[109] 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy") & 824a(b)

promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[110]

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for "temporary" central command-and-control only in case of "emergency"—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply,"[111] rather than mere want of more abundant supply in the future.[112] Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns—e.g., potential shortfalls years into the future, or an expected "expansion of artificial intelligence data centers and an increase in domestic manufacturing,"[113]—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure.[114]

b. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability.

That the Department's Section 202 powers may not be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements for the bulk-power system.[115] Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202—did not provide the

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(allowing federal government to order "physical connection … to sell energy or to exchange energy" upon application, and after an opportunity for hearing).

[110] S. Rep. No. 74-621 at 49 (1935).

[111] *Id.*

[112] *cf.* Eddystone 202(c) Order, Ex. 9 at 2 (imposing responsibility on PJM "to ensure maximum reliability on its system").

[113] Grid EO at Sec. 1 (RAR, Ex. 1 at C-4).

[114] *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

[115] 16 U.S.C. § 824o.

federal government with the power to enforce measures designed to ensure broad, long-term reliability.[116]

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and operators of the bulk-power system" but with "fair stakeholder representation."[117] FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[118] Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational.[119] And Section 215 carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[120]

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

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[116] *See* 70 Fed. Reg. 53,118 ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); RAR of the National Energy Policy Development Group (May 2001) at p. 7-6, https://www.nrc.gov/docs/ml0428/ml042800056.pdf (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "one factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (Section 215 "changes our current voluntary rules system" for long-term reliability "to a mandatory rules system."). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[117] 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system").

[118] *Id.* § 824o(d)(2)-(4).

[119] *Id.* § 824o(e).

[120] *Id.* § 824o(i)-(j).

202(c).[121] Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the Department may not, through Section 202(c) "emergency" orders, use long-term reliability concerns to mandate the generation it views as required to address long-term reliability needs.

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

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s authority is confined to imminent and unavoidable resource shortages, rather than a mechanism to address long-term concerns as to the reliability of the bulk-power system. The regulations define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating or transmission facilities—not a means of planning against distant expectations or risks.[122] Emergencies "may result" from a number of events.[123] The use of the verb "result," defined as "arise as a consequence, effect, or conclusion," suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur.[124]

Moreover, the events are characterized by those produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent."[125] Where the culprit is increased demand, it must be "a *sudden* increase in customer demand" producing a "*specific* inadequate power supply situation,"[126] rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . . *will* cause the applicant [for a 202(c) Order] to be unable to meet its

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[121] *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the Federal Power Act "is strong evidence that [a separate section] confers no such authority on [agency].").

[122] 10 C.F.R. § 205.371 (emphasis added).

[123] *Id.* ("may result from the unexpected outage," "may be the result of weather conditions," "can result from a sudden increase in customer demand").

[124] Merriam-Webster's Collegiate Dictionary (11th ed. 2003) 1063.

[125] 10 C.F.R. § 205.371

[126] *Id.* (emphasis added).

normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers."[127]

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can result* in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning.[128] An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate to meet far-distant needs.[129] As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[130]

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

Two courts have addressed the scope of authority under Section 202(c), and both determined that this Section applies only when there is a sudden, unexpected, imminent, and specific emergency.

Richmond Power and Light of City of Richmond, Indiana v. FERC, 574 F.2d 610 (D.C. Cir. 1978), arose out of the 1973 oil embargo. The Federal Power Commission needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer for electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England.[131] The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order.[132] The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition.[133] A dissatisfied utility

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[127] 10 C.F.R. § 205.375 (emphasis added).

[128] 10 C.F.R. § 205.371 (also recognizing that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*" (emphasis added)).

[129] *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply).

[130] 46 Fed. Reg. at 39,985–86.

[131] 574 F.2d at 613.

[132] *Id.*

[133] *Id.*

sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition.[134]

The court easily upheld the Commission's decision not to invoke Section 202(c).[135] Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order.[136] The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, there was no need for a Section 202(c) order, and the court agreed.[137]

Trying another tactic, the utility argued that "dependence on imported oil leaves this country with a *continuing* emergency."[138] The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[139] Interpreting this statutory language, the court upheld the Department's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[140] Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period."[141] To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. The utility argued that the Federal Power Commission used the wrong section and should have used Section 202(c) instead.

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[134] *Id.* at 614.

[135] *Id.*

[136] *Id.*

[137] *Id.* at 615.

[138] *Id.* (emphasis added).

[139] *Id.*

[140] *Id.*

[141] *Id.* at 233-34.

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency."[142] For non-emergency situations, "[o]n the other hand, Section 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[143] The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

e. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy.

The Department's past applications of Section 202(c) corroborate the urgency of the emergency conditions that are the necessary predicate for any Department intervention under that section.[144] The Department's predominant practice outside of wartime has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[145] The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment.[146]

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department

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[142] *Id.* at 234 (citing 16 U.S.C. § 824a(c)).

[143] *Id.*

[144] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[145] *See, e.g.,* Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between Christmas Eve and Boxing Day); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Ex.7 Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of war-time shortages during the twentieth century).

[146] *See, e.g.*, Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

views as necessary to ensure long-term resource sufficiency—and for good reason.[147] Any such use would exceed the Department's statutory authority.

2. In the RAR, DOE purports to identify only long-term, uncertain, and generalized concerns with bulk-power system reliability, which do not enable the Department to compel generation pursuant to Section 202(c).

Given the statutory limitations described above, the RAR provides no basis for the Department to use Section 202(c) to require that particular "generation resources" are "retained as an available generation resource," or to "prevent . . . an identified generation resource . . . from leaving the bulk-power system or converting" its fuel source.[148] Nor does the Department identify any other source of legal authority for DOE to impose such requirements. In the RAR, the Department only purports to identify capacity shortages that might affect bulk-system reliability in 2030.[149] The Department acknowledges that all but one region—ERCOT—currently meet its criteria.[150] Its claim that shortages might arise five years from now, even if it were correct—would present no "emergency" under Section 202(c). Those non-imminent resource needs are, rather, precisely the long-term reliability and resource adequacy matters over which Congress allocated responsibility to FERC and NERC.

Second, the Department identifies only a "risk of power outages" even in 2030[151] based on the Department's projected "AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth."[152] The Department acknowledges, meanwhile that its analysis "is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system."[153] The RAR—even by its own terms—thus does not specify any shortfall that is certain enough to justify invocation of the Department's emergency powers under Section 202(c). Its numbers are, rather, "indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need."[154] Section 202(c) does not authorize the Department to order generation based on such non-certain shortfalls; it provides distinct, and

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[147] *See Richmond Power and Light,* 574 F.2d at 616.

[148] Grid EO at 2.

[149] *E.g.,* RAR, Ex. 1 at 1, 20, 27, 30, 32, 40.

[150] RAR, Ex. 1 at 7.

[151] *Id.* at 1.

[152] *Id.* at 7.

[153] *Id.*

[154] *Id.*

much more limited powers, by which the Department may facilitate "an abundant supply of electric energy throughout the United States."[155]

And third, the Department does not claim to identify any particular location in which a shortfall might occur, or the specific resources that might best serve to address such shortfall. Instead, in the RAR, the Department provides aggregate estimates of potential loss-of-load under "varied grid conditions and operating scenarios based on historical data."[156] But those estimates do not demonstrate that any single generating facility would best meet the resulting shortfall, and could not therefore justify an emergency order directing a facility to remain available.

Consequently—even setting aside methodological flaws—the Department asserts resource risks in the RAR that are neither imminent, certain, nor specific. Those risks do not describe an emergency that would permit the Department to intervene pursuant to Section 202(c). They represent, rather, the Department's view as to measures that might "assur[e] an abundant supply of electric energy throughout the United States."[157] Section 202 does not permit the Department to compel generation on that basis. The Department also describes in the RAR the measures the Department believes "necessary to provide for reliable operation of the bulk-power system."[158] But Section 215 gives FERC, not the Department, the power to provide for reliable operation of the bulk power system, and specifies the procedures by which such measures must be developed and enforced; the Federal Power Act does not permit the Department to end-run those limitations by deeming long-term reliability an emergency. The RAR consequently could not form the basis of any action by the Department to compel generation under Section 202 of the Federal Power Act.

C. The RAR Is Analytically Flawed and Does not Rely Upon Substantial Evidence.

The RAR is severely flawed and does not meet DOE's own information quality standards. There are significant informational and methodological limitations and clear analytical and data errors. Any reliance on the RAR to "guide interventions" or to serve as a basis for any DOE decisionmaking would be arbitrary and capricious and not based on substantial evidence, in violation of the Administrative Procedure Act.

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[155] 16 U.S.C. § 824a(a).

[156] RAR, Ex. 1 at 2. *See, e.g., id.* at 21.

[157] 16 U.S.C. § 824a(a).

[158] 16 U.S.C. § 824o(a)(3).

1. The RAR falls woefully short of informational and methodological best practices.

DOE admits the RAR was hastily thrown together without sufficient information. At the outset, DOE acknowledges the resource adequacy analysis in the RAR "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[159] Indeed, "[h]istorically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued."[160] DOE continues to explain that a key takeaway of the RAR is the need for "strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security."[161] The candor in these comments is revealing; these limitations prove that the RAR does not meet the requirements of the Information Quality Act ("IQA") or DOE's guidelines thereunder.[162] The RAR should be withdrawn so that the Department does not continue to disseminate this poor-quality information, and the RAR should not be relied on in any decisionmaking. In the alternative, the Department should not use the RAR as support for any final action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before releasing a final version that incorporates and responds to public comment.

The IQA directs agencies to "ensur[e] and maximiz[e] the quality, objectivity, and integrity of information (including statistical information) disseminated by Federal Agencies."[163] Office of Management and Budget ("OMB") guidelines issued

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[159] RAR, Ex. 1 at i.

[160] *Id.*

[161] *Id.*

[162] *See* Pub. L. 106-554 Sec. 515, 114 Stat. 2763A-153.

[163] *Id.* OMB's government-wide information quality guidelines direct agencies to issue their own implementing guidelines. Agencies must provide the public a way to administratively seek and obtain correction of information disseminated by the agency that does not comply with OMB or agency guidelines. *See* Office of Management and Budget, Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information, 67 Fed. Reg 8452 (Feb. 22, 2002); Office of Management and Budget, Memorandum for the Heads of Executive Departments and Agencies (Apr. 24, 2019) (hereinafter "OMB Guidelines 2019 Update"), https://www.whitehouse.gov/wp-content/uploads/2019/04/M-19-15.pdf.

Pursuant to the OMB directive, DOE has issued its own agency-specific information quality guidelines. *See* Dep't of Energy, Final Report Implementing Office of Management and Budget Information Dissemination Quality Guidelines (Oct. 1, 2002), no. 6450-01-p, https://www.energy.gov/sites/prod/files/cioprod/documents/finalinfoqualityguidelines03072011.pdf; Dep't of Energy, Final Report Implementing Updates to the Department of Energy's Information

pursuant to the IQA require agencies to ensure that scientific information including "factual inputs, data, models, analyses . . . related to such disciplines as . . . engineering, or physical sciences" undergo certain review procedures to maintain quality standards.[164]

To that end, agencies must "choose a peer review mechanism that is adequate, giving due consideration to the novelty and complexity of the science to be reviewed, the relevance of the information to decisionmaking, the extent of prior peer reviews, and the expected benefits and costs of additional review."[165] Agencies must "strive to ensure that their peer review practices are characterized by both scientific integrity and process integrity," including the "rationale and supportability" of the agency's findings and ensuring "avoidance of real or perceived conflicts of interest" and "a workable process for public comment and involvement."[166] Agencies are encouraged to "have the choice of input data and the specification of the model reviewed by peers before the agency invests time and resources in implementing the model and interpreting the results," in order to "focus attention on data inadequacies in time for corrections . . . before the agency becomes invested in a specific approach."[167] Additionally, peer reviewers must "ensure that scientific uncertainties are clearly identified and characterized," and "ensure that the potential implications of the uncertainties for the technical conclusions drawn are clear."[168] OMB IQA guidelines also require agencies to evaluate "the sensitivity of the agency's conclusions to analytic assumptions."[169] These steps of peer review determine a report's "fitness . . . for policy purposes."[170]

DOE IQA guidelines further note that "in disseminating certain types of information to the public, other information must also be disseminated in order to ensure an accurate, clear, complete, and unbiased presentation."[171] Agencies should provide open access to data and modeling information underlying a report.[172]

Quality Act Guidelines (2019) (hereinafter "DOE IQA Guidelines 2019 Update"), available at https://www.energy.gov/cio/articles/2019-final-updated-version-doe-information-quality-guidelines.

[164] OMB, Final Information Quality Bulletin for Peer Review, 70 Fed. Reg. 2664, 2667 (Jan. 14, 2005); *see also* OMB Guidelines 2019 Update at 4.

[165] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg. at 2668.

[166] *Id.*

[167] *Id.*

[168] *Id.* at 2669.

[169] OMB Guidelines 2019 Update at 4.

[170] *Id.*

[171] DOE IQA Guidelines 2019 Update at 16.

[172] OMB Guidelines 2019 Update at 8; *See also*, e.g., *Chem. Mfrs. Ass'n v. U.S. EPA*, 870 F.2d 177, 200 (5th Cir. 1989) ("fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency."); *United States v. Nova Scotia Food*

Additionally, DOE is "responsible for ensuring that the information [being disseminated in a report] is consistent with the OMB and DOE guidelines and that the information is of adequate quality for dissemination."[173] For reports containing "influential financial, scientific, or statistical information," DOE must "identify for the [Chief Information Officer] a high ranking official" who is responsible for higher level review of the report's conclusions.[174]

OMB's IQA guidelines recognized that the "[f]ederal government's assessment of risk can directly or indirectly influence the response actions of state and local agencies or international bodies."[175] Thus, under the OMB and DOE guidelines, influential information—information routinely embargoed because of "potential effect on markets" or information "on which a regulatory action with a $100 million per year impact is based"—must meet the highest standards of quality and transparency, and should undergo the rigorous review procedures outlined above.[176]

Here, the RAR does not comply with IQA requirements, rendering any further reliance on it to be arbitrary and capricious. For example, the RAR appears to be inconsistent with internal review processes required: it should have undergone peer review because of its "influential" nature, particularly if the RAR is, as it purports to be, a "uniform methodology" to guide reliability interventions, such as Federal Power Act Section 202(c) orders, which have outsize economic impacts. However, there is no evidence that the RAR underwent any peer review, and, given the time constraints, it is unlikely it did. The Department further failed to make available all underlying data and modeling information used to create the RAR. Additionally, as described in detail below, the RAR relies on improper analytic assumptions, including overstated demand and understated supply forecasts. The RAR includes faulty analysis based on these improper assumptions despite DOE's acknowledgment of significant informational limitations regarding regional- and utility-level engineering data. In addition, the RAR contains numerous errors, such as referring to appendices that do not exist or incorrect appendices,[177] stating

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Prods. Corp., 568 F.2d 240, 251-53 (2d Cir. 1977) (holding that regulation was promulgated in arbitrary and capricious manner where agency failed to disclose data on which it relied).

[173] DOE IQA Guidelines 2019 Update at 22.

[174] *Id.* at 22-23.

[175] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg at 2667.

[176] DOE IQA Guidelines 2019 Update at 7.

[177] *See* RAR, Ex. 1, at 12 (referring to nonexistent "Outputs" section of an unnamed appendix); *id.* (referring to Appendix B for further detail regarding retirement assumptions, whereas Appendix B describes Canadian transfer limits).

inaccurate units for generation capacity,[178] and falsely asserting bulk power system load shedding occurred in regions during certain events.[179]

2. In the RAR, the Department overstates assumptions about demand.

In the RAR, the Department assumes 101 GW of load growth by 2030—a 15% increase over 2025 load. This increase is more than double the high case in the U.S. EIA 2025 Annual Energy Outlook, which forecasts 6% growth.[180] This extraordinarily high assumed load growth contributes substantially to the findings of low resource adequacy under the Plant Closures scenario in the RAR. As explained below, in the RAR, the Department omits consideration of many factors that will likely dampen load growth in the coming 5 years, thus undermining the validity and usefulness of its results.

The Department assumes 50 GW of load growth from data centers by 2030, which it characterizes as the midpoint among other available forecasts.[181] However, it does not appear that DOE's forecast accounts for load flexibility at these data centers, which would significantly reduce the overall demand that these centers place upon the grid during the periods of peak system risk. While certain data centers may not be capable of load curtailment due to their purpose, many can be flexible. Even a small amount of data center load flexibility provides significant benefits. A recent study by experts at Duke University found that curtailment at data centers during only 0.25% of the year would enable 76 GW of data center power demand to be added to the system today, without triggering resource adequacy problems or requiring further expansion.[182] The White House recently issued an AI Action Plan endorsing demand flexibility as a means to maintain resource adequacy as data center capacity expands: "the United States should investigate new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[183]

The Electric Power Research Institute has begun an initiative to enhance data center flexibility in light of its benefits for grid reliability, under which

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[178] *Id.* at 9 (text stating that PJM has a shortfall of 2.4 MW).

[179] *See infra* subsection C.6.

[180] *See* GridLab Analysis, Ex. 14 at 2.

[181] RAR, Ex. 1 at 2.

[182] Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems at 20. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University, https://nicholasinstitute.duke.edu/publications/rethinking-load-growth (attached as Ex. 15).

[183] White House, Winning the Race: America's AI Action Plan 15 (July 2025), https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

demonstration projects were set to deploy in the first half of 2025.[184] Early results from other projects to test data center flexibility have been promising.[185] Evaluations of the RAR by GridLab and the NYU Institute for Policy Integrity ("IPI") both have concluded that the Department's failure to account for data center load flexibility renders its findings of elevated reliability risk in 2030 suspect.[186] This is particularly true for DOE's findings concerning the ERCOT region, considering that in June 2025, Texas enacted a law allowing curtailment of these loads during grid emergencies.[187]

Furthermore, it is unclear whether the RAR's data center load forecasts account for potential constraints on the growth of data centers, such as shortages of critical semiconductor chips,[188] and other grid equipment like transformers and switchgears.[189] In addition to the Texas policy mentioned above, states and utilities are proposing new tariff designs for data centers to ensure that data centers don't

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[184] Elec. Power Rsch. Inst., EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027.").

[185] *See* Anuja Ratnayake, Unlocking AI Potential with Data Center Flexibility, ENERGYCENTRAL (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-aipotential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance.").

[186] NYU Institute for Policy Integrity, *Enough Energy*, at 25 (attached as Ex. 16) (hereinafter "IPI Report"); *see also* GridLab Analysis, Ex. 14 at 2 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

[187] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis, UTILITY DIVE (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

[188] *See, e.g.* London Economics International LLC, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* at 39 (July 7, 2025) (attached as Ex. 17), https://www.selc.org/wp-content/uploads/2025/07/LEI-Data-Center-Final-Report-07072025-2.pdf.

[189] How big tech plans to feed AI's voracious appetite for power, The Economist (July 28, 2025), https://www.economist.com/business/2025/07/28/how-big-tech-plans-to-feed-ais-voracious-appetite-for-power.

pose risks to the distribution system or shift costs to other consumers, all of which could slow or redirect the forecasted data center load growth.[190] The Department fails to evaluate any of these dynamics in the RAR.

In addition to the overall rate of data center load growth, the Department also uses a poorly described and supported methodology to allocate data center load to different regions. As the IPI observes, DOE used state-level growth ratios to allocate the projected data center load across regions, "[b]ut it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load)."[191] IPI posits that "some computing demand may be served from other regions if it will be cheaper to integrate the data center elsewhere," and observes that "[g]iven the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets."[192] Figure 8 in the RAR (New Data Center Build) shows that DOE's estimates for the percentage of data center load growth that will be built in various RTOs in some cases differs substantially from the percentages in the various forecasts that DOE used to calculate its overall data center load growth estimate. DOE does not explain why it discards these studies' more geographically specific estimates and instead relies on a single state-level growth ratio derived from a different study.

The Department's approach to estimating non-data center load growth by 2030 is also poorly explained in the RAR and likely flawed. DOE relies upon NERC's 2024 Long-Term Reliability Assessment forecast for overall load growth, but because the Department otherwise seeks to include elevated levels of data center load growth in the RAR, it must back out an estimate of data center load growth from the overall forecast.[193] The estimate that DOE chooses to back out is a "low-growth" case for data center load from a different source (which DOE presents in volumetric consumption terms, rather than peak demand). This approach, without further information to understand DOE's analysis, could have resulted in DOE over-estimating non-data center load growth. This effect is likely exacerbated by recent changes in federal law that will reduce electricity consumption from

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[190] Jason Plautz, *Rulemakers play catch-up as data centers multiply*, E&ENews by Politico (July 18, 2025), https://www.eenews.net/articles/rulemakers-play-catch-up-as-data-centers-multiply/.

[191] IPI Report, Ex. 16 at 26.

[192] *Id.*

[193] RAR, Ex. 1 at 17 ("Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC [Long-Term Reliability Assessment] forecast, for example, the 2024 [Long-Term Reliability Assessment] saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.").

specific sectors, including vehicles and hydrogen electrolysis. The utility forecasts included in the NERC Long-Term Reliability Assessment included projections of vehicle and building electrification that depend in part on tax credits and incentives that were revoked prior to publication of the RAR as part of the One Big Beautiful Bill Act ("OBBBA"). Recent analysis shows that the elimination or reduction of tax credits that supported new sources of electricity load growth will have a meaningful effect by 2030.[194] As a result, DOE's non-data center load growth projections are likely overstated.

3. Assumptions about supply are unsupported.

a. In the RAR, the Department Overstates Likely Retirements.

The Department finds the most dire resource adequacy shortfalls occur in the Plant Closures case, in which it assumes 104 GW of retirements by 2030.[195] This estimate is much higher than the most recent data from the EIA released in June 2025 in its authoritative Form 860, which shows 50 GW fewer retirements than assumed in the RAR.[196] As GridLab experts explained, DOE assumed not only "these 50 GW of likely retirements, but [also] included another 50 GW of *announced* retirements."[197] While it may be appropriate to include announced retirements in certain long-term planning exercises, it is unreasonable to assume such retirements will happen as the basis for extraordinary emergency actions. Without more detail about any formal or binding characteristics of those announcements, or the factors purportedly driving those announcements, it is impossible to verify the validity of this input that doubles the amount of otherwise projected resource retirements. Even EIA's Annual Energy Outlook, which does model projected retirements beyond those already formally noticed, finds 10 GW fewer thermal retirements by 2030 than does DOE.[198] Without further support for the 50 GW assumed retirement

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[194] *See, e.g.,* Princeton NetZero Lab and Evolved Energy Research, A Fork in The Road: Impacts of Federal Policy Repeal on the U.S. Energy Transition, at Tab 12 (last updated July 3, 2025), https://public.tableau.com/app/profile/evolvedenergyresearch/viz/AForkinTheRoad_ImpactsofFederalPolicyRepealontheU_S_EnergyTransition_June/1Title (showing approximately 100 TWh annual energy use reduction in 2030 compared to mid-range estimates of the status quo ante).

[195] RAR, Ex. 1 at 5.

[196] U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0. *See also* GridLab Analysis, Ex. 14 at 2.

[197] GridLab Analysis, Ex. 14 at 2; *see also* IPI Report, Ex. 16 at 24 (explaining that DOE's "number includes both 'confirmed' retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and 'announced' retirements—which are publicly stated but not officially noticed.").

[198] According to the U.S. EIA's 2025 Annual Energy Outlook, coal-fired generating capacity is projected to decline by 93.6 GW between 2025 and 2030 in the Reference case, approximately 10

value, the Plant Closures case is nothing more than speculation about what might happen if certain assumptions were to come true.

Such assumptions are particularly unjustified given that, as GridLab notes, "[m]ost likely many plants will choose not to retire due to the changing regulatory and economic landscape."[199] The IPI makes a similar point in their critique of DOE's retirement assumptions, noting that "the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources."[200] As one snapshot of this trend, high capacity prices in the PJM region led to 1.1 GW of resources withdrawing formal deactivation notices since last summer.[201] IPI also observes that the Trump Administration is seeking to rescind or reexamine many federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire before 2030, "which could cause resources to delay their retirements."[202]

b. In the RAR, the Department Understates Likely New Entry by 2030 and Other Sources of Supply.

Among the most impactful and unsupported assumptions in the RAR is that "only [generation] projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built" by 2030.[203] DOE thus constrains its analysis to include only projects designated as Tier 1 in the NERC 2024 Long Term Resource Assessment, which it then maps to Interregional Transfer Capability Study regions. Because Tier 1 includes only resources that are already under construction, have signed construction service agreements, and similar

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fewer GW of retirements than modeled in the DOE report. No other fossil fuel technology shows a net decrease in generating capacity in the 2025 Annual Energy Outlook analysis. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[199] GridLab Analysis, Ex. 14 at 2.

[200] IPI Report, Ex. 16 at 24.

[201] PJM Inside Lines, PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal (July 22, 2025) https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/ ("Since the 2025/2026 Base Residual Auction results were posted on July 30, 2024, 17 generating units totaling approximately 1,100 MW worth of Capacity Interconnection Rights have withdrawn their retirements").

[202] IPI Report, Ex. 16 at 24-25.

[203] RAR, Ex. 1 at 12.

characteristics,[204] this assumption "results in minimal capacity additions beyond 2026."[205] As experts at GridLab observe, the assumption that "no projects are built post 2026, [] is not realistic for a report forecasting to 2030."[206] This is especially true given rising energy prices due to increased demand, which is attracting more investment to the market and driving new construction of generation resources.

The Department also states in the RAR that of these Tier 1 additions, just 22 GWs of generator additions are "firm" (thermal) resources, which severely underestimates new gas generation compared to other projections. According to GridLab, "a more reasonable assumption for forecasted capacity additions is the EIA 860 released in June 2025, which has 35 GW of gas additions, and another 53 GW of batteries [for a total of] 88 GW of firm additions by 2030."[207] Other federal government projections are even higher: EIA's 2025 Annual Energy Outlook projects 90 GWs of new fossil generators added to the system through 2030.[208] 80 GWs of the EIA-projected natural gas growth are in earlier development stages and likely did not meet the 2024 NERC Long-Term Reliability Assessment Tier 1 criteria to be included in the RAR.

As researchers at the IPI conclude, DOE departed from best practice in declining to include any resources classified by NERC as "Tier 2" resources[209] in the overall resource adequacy analysis for 2030, even those at advanced stages of the interconnection process.[210] A reasonable process could have involved "examin[ing]

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[204] *See* IPI Report, Ex. 16 at n.155 (citing NERC, 2024 Long Term Reliability Assessment, 137 (last updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[205] RAR, Ex. 1 at A-5.

[206] GridLab Analysis, Ex. 14 at 3.

[207] *Id.*

[208] According to the U.S. EIA, the policy-neutral reference case projects a 93.29 GW increase in combined cycle, fossil steam, and combustion turbine capacity between 2025 and 2030. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[209] NERC defines Tier 2 resources as those having one of the following characteristics: "Signed/approved Completion of a feasibility study, Signed/approved Completion of a system impact study, Signed/approved Completion of a facilities study, Requested Interconnection Service Agreement, Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)." NERC, 2024Long Term Reliability Assessment, 137 (Dec. 2024, updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[210] IPI Report, Ex. 16 at 23.

historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region."[211] For example, for the PJM region, the Independent Market Monitor's analysis shows that 15% of generation projects (on an energy basis) successfully enter service.[212] As of late 2024, PJM had over 44 GW of accredited capacity in its interconnection queue.[213] To assume that none of this capacity would enter service by 2030, as DOE's analysis does, is unreasonable.

Such an analysis should also consider factors pointing towards even faster queue times than those seen in the historical data, given factors now expediting interconnection queues such as implementation of FERC Order 2023, streamlining of tools to better utilize existing points of interconnection (e.g., surplus interconnection service), and various interconnection fast tracks that FERC has recently approved.[214] For example, it is unreasonable for DOE to exclude from consideration the over 9 GW of accredited capacity that PJM selected in May 2025 to participate in its Reliability Resource Initiative—the vast majority of these projects (primarily gas and battery energy storage systems) are committed to be online by 2030,[215] but are omitted in DOE's analysis because they do not yet have a signed interconnection agreement. DOE paints an inaccurate picture of new entry by ignoring recently adopted policies designed to address the very same tightening supply and demand conditions that DOE describes.

DOE also underestimates the extent to which interregional transfers of energy could help to prevent or address any shortfalls. Noting that it relies upon the interregional transfer capacities identified by NERC in its Interregional Transfer Capability Study, DOE explains that "[i]mports are assumed to be available up to the minimum total transfer capacity and spare generation in the

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[211] *Id.*

[212] Monitoring Analytics, 2024 State of the Market Report, at 705 (2024) https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q2-som-pjm-sec12.pdf (noting 14.9% completion rate).

[213] PJM, Reliability Resource Initiative MRC Update, at slide 6 (Nov. 7, 2024) https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241107-special/item-04---reliability-resource-initiative---presentation.ashx.

[214] *Id. See also* Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at 4 (May 27, 2025), https://www.ferc.gov/media/manu-asthana-pjm-president-and-ceo (touting recent improvements to PJM's interconnection queue by noting that "[a]n additional approximately 18 GW is being processed to move to the final study phase for completion this year, and an additional 56 GW (including projects from Transition Cycle 2 and Reliability Resource Initiative) will be through the queue by late 2026.").

[215] PJM, Reliability Resource Initiative Results Summary, at slide 9 (May 6, 2025) https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf.

neighboring subregion."[216] Because the Interregional Transfer Capability Study calculated interregional transfer capacities for both summer and winter, and for each direction of flow, it is unclear what DOE means regarding allowing transfers up to the minimum. As the IPI observes: "If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity."[217] This is yet another example of where DOE fails to explain its methodology with sufficient detail to enable an evaluation of whether its approach is reasonable, or is supported by substantial evidence.

4. DOE's use of a deterministic analysis provides an incomplete and inaccurate picture.

For the RAR, DOE employs a deterministic approach in examining resource adequacy; that is one that "evaluate[s] resource adequacy using relatively stable or fixed assumptions about the representation of the power system," rather than a probabilistic approach that "incorporate[s] data and advanced modeling techniques to represent uncertainty that require more computing power."[218] DOE explains it chose a deterministic approach "for transparency and to model detailed historic system conditions."[219] However, deterministic approaches have significant limitations; as NERC explained in the Interregional Transfer Capability Study on which DOE otherwise heavily relies, because that study did not employ a probabilistic approach, it "should not be considered a North American resource adequacy assessment."[220] The problem, as IPI explains, is that "[b]y examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty."[221] Furthermore, as NERC itself has explained, under a deterministic approach, "some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future."[222] As IPI concludes, neither of DOE's professed reasons for using a deterministic approach justifies departing from best practices, as "DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach."[223]

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[216] RAR, Ex. 1 at 12.

[217] IPI Report, Ex. 16 at 26.

[218] RAR, Ex. 1 at 2 n.2.

[219] *Id.*

[220] IPI Report, Ex. 16 at 21 (citing NERC, Interregional Transfer Capability Study, at 4 (2024) (hereinafter "NERC ITCS")).

[221] IPI Report, Ex. 16 at 21.

[222] *Id.* (citing NERC ITCS at 138).

[223] *Id.* at 21.

DOE may have chosen a less sophisticated and rigorous approach given the limited amount of time in which the Grid EO required this analysis to be completed, but regardless of the reason, the limitations inherent in DOE's deterministic methodology mean that its findings should not be taken as conclusive or form the basis for further extraordinary actions.[224]

5. DOE uses an elevated threshold for determining when outages will occur.

In the RAR, the Department projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[225] This approach, and the particular values used as thresholds, come from the NERC Interregional Transfer Capability Study, which uses 3% as the default threshold and 6% only in a sensitivity analysis. NERC explains that the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" in order for a Balancing Authority to continue to hold the minimum reserves needed to protect the system from cascading or widespread outages.[226] In the sensitivity examined by NERC, using the 6% threshold "significantly altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida."[227]

As the IPI analysis notes, DOE provides no further explanation for when and how it uses 6% as a threshold versus 3%.[228] While the Department directs readers to an appendix with further detail, the appendices do not in fact provide any further information regarding this critical assumption.[229] Furthermore, "the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis," and that if "DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate the extent of expected outages."[230] DOE's failure to explain its own methodology concerning such a critical input to its analysis, including through the failure to provide information in an appendix that the RAR states exists, renders the RAR arbitrary and capricious. Insofar as the RAR's results for 2030 scenarios depend upon the 6% threshold, DOE must explain why

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[224] *Id.* ("Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.")

[225] RAR, Ex. 1 at 12.

[226] IPI Report, Ex. 16 at 22 (citing NERC ITCS, at 91 n.90, 85).

[227] IPI Report, Ex. 16 at 22 (citing NERC ITCS at 105 tbl.8.4); *see also id.* ("Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.")

[228] IPI Report, Ex. 16 at 22.

[229] *Id.*

[230] *Id.*

such a threshold is appropriate, given the departure from NERC's practice and the evidence in the NERC report considering the propriety of a far lower threshold.

6. DOE inconsistently applies its own methodology.

Several of the findings in the RAR are inconsistent with the methodology that DOE develops. For instance, DOE states that "[a]nalysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE" (the standards DOE developed for this study).[231] DOE further explains that "[w]hen looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour."[232] Despite these clear findings, DOE goes on to state that "PJM, ERCOT, and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load," and asserts that this "results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load."[233] As an initial matter, the PJM system did not experience any lost load due to resource inadequacy during Winter Storms Uri or Elliott.[234] Second, DOE's focus on whether a region had lost load or a risk of lost load in a particular weather year is inconsistent with DOE's own articulation of its resource adequacy standards, as "average indicators" assessed across all scenarios and years.[235] As the IPI notes, these standards are "not a requirement that must be achieved in each and every scenario."[236]

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[231] RAR, Ex. 1 at 7.

[232] *Id.*

[233] *Id. See also Id.* at 9 ("For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year.").

[234] PJM Inside Lines, PJM Releases Winter Storm Elliott Report (July 17, 2023) https://insidelines.pjm.com/pjm-releases-winter-storm-elliott-report/ ("PJM maintained system reliability and served customers throughout the extreme weather that affected the region Dec. 23–25 [2022], and even was able to support its neighbors during certain periods."); *see also* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (noting that PJM was exporting power to neighboring regions during Winter Storm Uri, and investigating rolling blackouts only in Texas and south central states).

[235] RAR, Ex. 1 at 5.

[236] IPI Report, Ex. 16 at 20.

D. Notice and Comment Procedures Are Required for Any "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the Administrative Procedure Act, federal agencies must provide notice and an opportunity for public comment when issuing rules, with limited exceptions not applicable here.[237] If the RAR is, as the Department claims on page vi, a "uniform methodology" for agency decisionmaking on reliability interventions, then the Department needed to provide notice and seek and respond to public comment on this methodology. The Department cannot slip in "entirely new information critical" to its "determination[s]" without taking and responding to public comment.[238]

In the past, when the Department sought to create uniform triggers for reliability intervention within its authority, it issued notice and sought comment.[239] If the RAR is a "uniform methodology" for reliability interventions, then the Department has effectively amended those prior regulations on reliability interventions without following legally required procedures. For example, the Department has regulations defining "emergency" and setting forth procedures for an applicant to demonstrate an "emergency" in the context of Federal Power Act Section 202(c) orders.[240] If the RAR is now a mandatory factor in determining whether there is an "emergency," the Department has changed its existing regulations without following required notice and comment procedures.

E. NEPA Procedures Must Be Followed for Any RAR on Legislative Proposals or "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the National Environmental Policy Act ("NEPA"), agencies must include a "detailed statement" on the environmental impacts of a proposed action "in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment."[241] If the RAR is a "uniform methodology" for agency decisionmaking on reliability interventions, it qualifies as a major federal action requiring, at a minimum, an Environmental Assessment and most likely, under the circumstances, a full

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[237] 5 U.S.C. §§ 553(b), (c).

[238] *Am. Pub. Gas Assoc. v. DOE*, 72 F.4th 1324, 1338 (D.C. Cir. 2023) (cleaned up).

[239] *See* Grid Security Emergency Orders: Procedures for Issuances, 83 Fed. Reg. 1174 (Jan. 10, 2018) (final rule on Federal Power Act section 215A procedures issued after notice and comment); Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984 (Aug. 6, 1981) (final rules concerning emergency interconnections under Federal Power Act sections 202(c) and 202(d) issued after notice and comment).

[240] 10 C.F.R. §§ 205.371; 205.373.

[241] 42 U.S.C. § 4332(C).

Environmental Impact Statement. However, the RAR does not contain any statement whatsoever, and certainly no "detailed statement," on environmental impacts.

Yet the RAR purports to guide "government decisionmakers" on one of the most significant issues that affect the environment—electricity generation. The electricity sector is responsible for wide-ranging environmental impacts—from smog to greenhouse gas emissions to toxic metals to acid rain.[242] Uniform rules on reliability interventions would significantly affect the environment because some of these reliability interventions allow environmental rules for electricity generators to be waived.[243]

VI. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department withdraw the RAR. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) provides a detailed explanation of the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

Dated: August 8, 2025

Respectfully submitted,

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[242] *See* EPA, Human Health & Environmental Impacts of the Electric Power Sector (Feb. 6, 2025) https://www.epa.gov/power-sector/human-health-environmental-impacts-electric-power-sector.

[243] *See* 16 U.S.C. § 824a(c)(4)(A).

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-40a:
Department's Response to PIOs' RFR of July Resource Adequacy Report

Department of Energy
Washington, DC 20585

September 5, 2025

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RE: August 8, 2025 Submission

To Whom It May Concern:

Thank you for your August 8, 2025 submission on behalf of the Natural Resources Defense Council, the Ecology Center, the Environmental Defense Fund, the Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar (collectively, the Public Interest Organizations). The submission was titled "Motion to Intervene and Request for Rehearing of Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar" (Submission). It was not filed in any active docket.

On July 7, 2025, the U.S. Department of Energy (DOE) issued the Report on Strengthening U.S. Grid Reliability and Security (Resource Adequacy Report or RAR), fulfilling Section 3(b) of Executive Order 14262. The RAR presents a unified, transparent methodology for assessing the reliability of the bulk power system and identifying regions at elevated risk of resource inadequacy under projected load growth and plant retirement scenarios. DOE developed this approach in coordination with NERC and leading industry experts to provide a consistent, data-driven framework for informing federal reliability interventions, particularly as the grid faces surging demand from AI-driven data centers, reindustrialization, and electrification.

In the Submission, the Public Interest Organizations seek rehearing of the RAR under section 313 of the Federal Power Act (FPA).[1] An application for rehearing under section 313 of the FPA[2] may be filed only by a "person, electric utility, State, municipality, or State commission" that is "aggrieved" by "an order issued by [DOE]."[3] If these prerequisites are not met, there is no basis for rehearing. Here, we note that the RAR is simply a report that details the current condition of the United States electrical grid. It contains no directives, nor does it impose legal duties upon any party, including the Public Interest Organizations. As such, it cannot be considered an "order" by which the Public Interest Organizations are "aggrieved" within the meaning of section 313 of the FPA, as would be required to request rehearing. Accordingly, DOE will take no action on the Submission.

---

[1] Submission at 1.
[2] 16 U.S.C. § 825*l*(a).
[3] *Id.*

Sincerely,

Tina Francone
Director of the Grid Deployment Office, Acting

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-41:
Inst. Pol'y Integrity Report



Enough Energy

A Review of DOE's Resource Adequacy Methodology

Jennifer Danis
Christoph Graf, Ph.D.
Matthew Lifson

July 2025

Institute *for*
Policy Integrity
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Jennifer Danis is the Federal Energy Policy Director at the Institute for Policy Integrity at NYU School of Law, where Christoph Graf, Ph.D. is a Senior Economist and Matthew Lifson is an Attorney.

The authors thank Dr. Adria Brooks and Rob Gramlich for their valuable feedback.

This report does not purport to present the views, if any, of NYU School of Law.

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Executive Summary

On April 8, 2025, President Trump issued an Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) requiring the Department of Energy (DOE) to (1) "identify current and anticipated regions with reserve margins below acceptable thresholds" and (2) "establish . . . a protocol to identify which generation resources within a region are critical to system reliability."[1] DOE responded on July 7, 2025 with its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[2]

This report reviews best practices for analyzing whether a region is resource adequate and for identifying whether a particular resource is critical for resource adequacy. It next analyzes the DOE Study as compared to those best practices. Finally, it examines next steps for U.S. resource adequacy policy following the DOE Study, in light of different entities' respective authorities over the issue.

In Part 1, this report outlines a four-step process for evaluating whether a region is resource adequate and then identifying which resources are critical. Each step involves choices between traditional methods and best practices adapted to the evolving risks posed by the energy transition and the new conditions brought about by climate change.

- *Step 1*: *Set a Resource Adequacy Target*: Planners should define resource adequacy targets using a multi-metric approach that captures not just outage frequency but also magnitude and duration, possibly supplemented by metrics focused on tail risks instead of expected values. Targets should be region-specific and reflect a local cost-benefit analysis that weighs the incremental benefits and costs of achieving reduced outages.
- *Step 2: Conduct Resource Adequacy Modeling:* Rather than focusing narrowly on annual peak load, planners should assess whether a region achieves the target from Step 1 by modeling all 8,760 hours of the year in chronological order using probabilistic techniques that account for uncertainty like the Monte Carlo method. Best practices include incorporating weather-linked dependencies; climate-adjusted inputs; and realistic assumptions about retirements and additions, interregional imports, and storage and demand response dynamics. This modeling more accurately reflects the risks posed by variable generation and energy-limited resources.
- *Step 3: Establish Accreditation Values:* Resource accreditations—the specific contribution of a resource or resource type to resource adequacy—should be derived from Step 2's probabilistic modeling of a resource's ability to contribute during hours of highest risk.

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1 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

2 U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (2025), https://perma.cc/A587-S88S.

Effective Load Carrying Capability or related probabilistic methods should be applied to all resource types, including thermal plants, to accurately describe their contributions under a wide range of possible futures and hard-to-predict risk periods. Accreditation methods should be applied equally to thermal and variable resources to allow for technology-neutral comparisons.

- *Step 4: Calculate the Reference Margin Level and the Reserve Margin:* Using the resource adequacy modeling and accreditation values from Steps 2 and 3, planners should calculate a reference margin level—the amount of accredited capacity that corresponds to achieving the resource adequacy target. Comparing a region's actual resource fleet to this benchmark allows planners to determine whether the exit or entry of specific resources would affect achievement of the reference margin level and thus the resource adequacy target, given the resources' accreditations.

Part 2 compares the best practices from Part 1 to DOE's methodology in the DOE Study—in which DOE concluded that all transmission planning regions except ERCOT are currently resource adequate but that all regions except ISO-NE and NYISO will be resource inadequate in 2030. Across multiple dimensions, DOE's approach departs from best practices in ways that call these results into question.

- *Resource Adequacy Targets:* DOE's use of a multi-metric standard—2.4 hours of lost load per year and 0.002% normalized unserved energy—is consistent with best practices, but the choice of values is not. Neither value is appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences. Additionally, DOE inappropriately attempts to label PJM as currently resource inadequate even though the region achieves DOE's own target according to DOE's modeling.

- *Resource Adequacy Modeling:* DOE models all 8,760 hours of the year chronologically but relies on a deterministic rather than probabilistic framework, limiting its ability to assess uncertainty or tail risks. This less accurate approach evaluates adequacy only under a fixed set of historical weather and load years. Further, DOE's truncated description of how its model decides whether an outage has been triggered makes this assumption impossible to fully evaluate, but DOE's limited explanation does suggest that it may have adopted an overly conservative approach that exaggerates resource adequacy risk. Finally, DOE's 2030 results are significantly shaped by unrealistic assumptions about additions, retirements, load, and possibly interregional imports.

- *Accreditation and Reference Margin Levels:* The DOE Study does not attempt to identify resources that are critical for any region's resource adequacy, and thus does not calculate accreditation values or reference margin levels. But DOE does estimate the amount of perfect capacity required to bring certain regions to the 0.002% NUSE target. DOE could build upon this approach in the future to calculate reference margin levels, but any future efforts should attend to all prongs of its multi-metric resource adequacy target. Additionally, DOE's perfect capacity additions inexplicably bring regions far beyond 0.002% NUSE, meaning that DOE overstates how difficult it would be to cure the purported resource adequacy shortfalls.

Part 3 answers what should happen next for U.S. resource adequacy policy now that DOE has published its study.

- Given how DOE's statutory authority under Section 202(c) of the Federal Power Act is limited to emergencies, DOE's own conclusion that most regions are not currently experiencing resource adequacy shortfalls suggests that DOE has limited legal authority to address potential problems in 2030. Moreover, the limitations of the DOE Study call into question the accuracy of DOE's forecasts.
- Instead of DOE, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation could more appropriately—and less intrusively from the perspective of states, grid operators, and markets—support resource adequacy by issuing reliability standards that require best practices for regions' resource adequacy efforts. Rather than establishing a national resource adequacy target, these standards would govern how regions select resource adequacy targets, evaluate if they are achieving them, and measure the contributions of specific resources. This step would be in line with the Federal Energy Regulatory Commission's Order No. 747, which approved analytical guardrails for resource adequacy analysis for a portion of the U.S.

Introduction

How does a regional electric grid operator know when its region has enough electricity to meet demand and whether any specific generation resource, like a particular coal plant, is essential for doing so? President Trump's Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) implicates these questions: The EO directs the Department of Energy (DOE) to assess if each region of the United States has sufficient energy resources to meet current and future demand, and to identify and retain critical resources.[3] On July 7, 2025, DOE responded to the EO by publishing its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[4]

This report addresses the EO and the DOE Study's fundamental concern: resource adequacy. Resource adequacy is one key aspect of a power system's reliability. It refers to a system's "ability . . . to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages."[5] Resource adequacy thus concerns whether a system's supply of energy exceeds demand. Determining whether an area is resource adequate is, however, ultimately a policy question, rather than an engineering one, because it would be prohibitively expensive to build a system that serves 100% of demand under all conditions.[6] Deciding whether a region is resource adequate always explicitly or implicitly balances society's desire for reliable electricity with the cost of providing that reliability.

Starting from first principles, Part 1 examines how to determine whether a region meets its selected resource adequacy target and how a planner can know whether any one particular resource is critical for resource adequacy. Part 2 discusses whether the DOE Study reflects, rejects, or obscure these first principles. Part 3 explores next steps for U.S. resource adequacy policy following the publication of the DOE Study, considering the respective roles of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), DOE, grid operators, and states.

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3 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

4 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2.

5 Burçin Ünel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System 11 (2018), https://perma.cc/UDB5-DEEM (citing a NERC "Frequently Asked Questions" page that is no longer available).

6 Energy Sys. Integration Grp., New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements 38 (2024), https://perma.cc/NXU4-N4UG.

Part 1: Best Practices for Resource Adequacy

The EO requires DOE to evaluate the sufficiency of regions' "reserve margins" and establish a resulting protocol to identify "critical" resources that should be retained.[7] To figure out what kind of buffer will ensure that a region achieves a given level of resource adequacy, and to label specific generators as essential for that resource adequacy, a planner would need to undertake a four-step process. At each step, the planner must pick between antiquated approaches and newer best practices.

First, the planner must make the policy choice of selecting a resource adequacy target for the region that, if achieved, would indicate resource adequacy. Second, it should use resource adequacy modeling to determine whether a region has achieved and will continue to achieve the selected target under foreseeable future conditions. Third, the planner should use its resource adequacy modeling with accurate data curation to derive how each generation and storage resource contributes to meeting the target (their "accreditation" values). Fourth, it should use the resource adequacy modeling plus resources' accreditation values to derive an acceptable reserve margin for the region (the "reference margin level"). At this fourth step, the planner can use the accreditation values to check whether the exit of a particular resource would cause a region to dip below the reference margin level.

These best practices have largely emerged to address the resource adequacy challenges caused by the energy transition and extreme weather events caused by climate change. Whereas traditional methods have focused on whether demand would exceed supply during peak load hours, system risk has shifted to *net* peak hours, i.e., when load minus variable generation is highest.[8] Measuring whether supply will meet demand has itself become more complicated. Increasingly, it has become important to perform modeling resource adequacy chronologically—each hour reflecting the conditions that came before it—to account for the dynamics of battery storage resources and demand response.[9] And policymakers now are also confronting the outdated idea that thermal resources are "perfect" capacity, given their weather-related vulnerabilities.[10]

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7 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

8 Juan Pablo Carvallo et al., Lawrence Berkeley Nat'l Lab'y, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions 13 (2023), https://perma.cc/5VLY-B7HF.

9 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report 9 (2024), https://perma.cc/KE8D-W6VX.

10 Nat'l Ass'n of Regul. Util. Comm'rs, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms 32–34 (Nov. 2023), https://perma.cc/K88X-2JCR.

Step 1: Pick a Resource Adequacy Target

Before any analysis can determine if a system is resource adequate, policymakers must set a clear resource adequacy *target*.[11] This first step involves two distinct choices: (1) selecting one or more metrics to represent the variables by which resource adequacy will be judged, and (2) setting the numerical values for those chosen metrics to achieve the resource adequacy target.

Consider what it would take to set a target, not for resource adequacy, but for human health. First, you would pick the metrics that you think would best define whether a person is healthy, e.g., blood pressure, resting heart rate, or cholesterol levels. Using only one metric would not give you enough information. And paying attention to only each metric's average levels without also examining whether the metric ever reaches dangerous levels could obscure risk of a catastrophic health event. Second, you would pick a value for each metric, like a blood pressure of less than less than 120/80 mmHg. To pick that value, you would consider the best available evidence on what level is optimal.

Similarly, when it comes to resource adequacy, the best practice is to move beyond the standard approach of attending primarily to the *frequency* of outages and to also consider their *magnitude* and *duration*. Additionally, regions should consider metrics focused on the extremes of the probability distribution, rather than expected value metrics that could label a system as resource adequate when a low probability (but plausible) event would be catastrophic.

When selecting numerical values for the chosen resource adequacy metrics, the best practice is to consider the best available evidence on the tradeoff between the benefits and costs of additional resource adequacy. The optimal level of resource adequacy may be different in each region, depending on the local costs of the investments that would be needed to reduce shortfall events and the local consequences of a shortfall.[12] A resource adequacy target should ideally represent the level of resource adequacy that the system planner has identified as socially optimal because it balances costs and benefits.

Metrics

Historically, U.S. policymakers have framed their resource adequacy targets in terms of loss of load expectation (LOLE),[13] and this metric remains widespread.[14] LOLE typically refers to the number of days per year in which an outage occurs and is largely a measure of frequency.[15]

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11 *See* Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 2 tbl.1.

12 *Id.* at 39, 41.

13 Elec. Power Rsch. Inst., Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice 31 (2024), https://perma.cc/W4VF-VQPD.

14 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8 tbl.2.

15 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future 3, 8 (Apr. 2022), https://perma.cc/7G9V-CNWB. Technically, the number of days per year in which an outage occurs is "loss of load days" (LOLD), which is a special case of the broader concept of LOLE, which can be used with different event-periods. *Id.* at 7–8. In North America, however, LOLE typically means LOLD. *Id.* at 7; *accord* Gord Stephen et al., *Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric* at 2, https://perma.cc/A9DJ-C3B5.

Frequency is an important characteristic to track because consumers prefer fewer outages.[16] LOLE coarsely accounts for duration, too, in that an outage that stretches multiple days will count as an additional event for each additional day.

LOLE does, however, obscure important aspects of resource adequacy. It will not differentiate between (1) a 10-hour event with 1 GWh of load shed that is followed by a second identical event within the same day and (2) a 30-minute event with 5 MWh of load shed. Customers are not indifferent, however, between these two situations.[17] Because damages depend on outages' frequency, magnitude, and duration, LOLE neglects key dimensions of resource adequacy affecting customers' wellbeing.[18] Attending to these characteristics when setting resource adequacy targets is more important than ever, because changes in the resource mix and extreme weather due to climate change mean that loss-of-load events have become less uniform and thus less interchangeable.[19]

The Multi-Metric Approach

The best practice is to supplement the traditional LOLE metric (or a different frequency-focused metric like "loss of load events," which separately counts all events within a year and thus differentiates between events that occur during the same day[20]) with additional metrics that capture other dimensions of resource adequacy.[21] Both the Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) have done exactly this, augmenting their LOLE-based targets to include magnitude and duration metrics.[22] Under a multi-metric approach, a system could be declared resource adequate if it achieves selected value targets for each and every metric,[23] or if it achieves some minimum number or combination of the metrics (e.g., any two of a system's three metrics).[24]

A leading magnitude metric that could be incorporated into a multi-metric approach is expected unserved energy (EUE): the amount of demand that the system will fail to serve during a period, typically a year.[25] A region's EUE can be contextualized by dividing it by the region's total annual load—this is called normalized unserved energy (NEUE).[26] Australia uses an annual unserved

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16 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

17 *Id.* at 3.

18 *Id.* at 10.

19 *Id.* at 11, 15, 22.

20 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

21 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 33–37; Elec. Power Rsch. Inst., Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches 23 (2022), https://perma.cc/ZH4Y-ZD7J; Juan Pablo Carvallo et al., *supra* note 8, at 28–29; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at vii.

22 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

23 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 35.

24 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 31–32.

25 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

26 *Id.* at 18.

energy metric,[27] as does NWPCC.[28] Planning around these magnitude metrics can help a region avoid catastrophic events associated with significant unserved energy.[29]

But, like LOLE, magnitude-focused metrics like EUE and NEUE are incomplete alone; they do not account for how the unserved energy is distributed throughout the year.[30] An alternative or complementary magnitude metric is "peak shortfall," defined as the largest expected outage of the period.[31] Peak shortfall is potentially useful because damages from a single outage increase nonlinearly with its scale.[32] Both ERCOT and NWPCC have versions of a peak shortfall metric (NWPCC's complements its EUE metric).[33]

For duration, a popular metric that could supplement frequency and magnitude metrics is loss of load hours (LOLH), which measures the number of hours per year in which an outage occurs.[34] LOLH fundamentally resembles LOLE, but is more granular because it analyzes each hour, rather than each day. As such, LOLH does a better job at expressing the aggregate duration of all shortfalls in a region.[35]

Many countries use LOLH as their sole resource adequacy metric,[36] but, in aggregating hours, it neglects the duration of individual events—even though damages increase nonlinearly with an outage's duration.[37] Supplemental metrics such as average shortfall duration[38] and the maximum shortfall length (used in Texas and NWPCC)[39] can capture this aspect of duration.

Accounting for Tail Risks

Beyond questions of frequency, magnitude, and duration, a separate question when using any chosen metric is whether to look at the mean of the distribution, extremes, or both. Traditionally, regions have framed their LOLE, EUE, and LOLH goals in terms of their *mean* values.[40] But the energy transition and climate change have increased the risk of extremely damaging tail risks,[41]

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27 *Id.* at 9.

28 Nw. Power & Conservation Council, *supra* note 22.

29 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 19 tbl.4.

30 *Id.*

31 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide 18 (2024), https://perma.cc/CB7Q-MXZM (using the equivalent phrase "MW Short").

32 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 3.

33 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

34 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

35 *Id.* at 8.

36 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8.

37 *Id.* at 3.

38 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

39 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

40 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment 4 (2023), https://perma.cc/M3A5-2WAL; Juan Pablo Carvallo et al., *supra* note 8, at 12.

41 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 22.

making it increasingly appropriate to factor these risks into regions' metrics.[42] When it comes to resource adequacy, customers care not just about how the how severe and common outages will be on average, but also about how bad the worst outages they will experience could be.

One option for assessing these potentially severe consequences is the "value at risk" method. This method defines the selected metric (whether it is focused on frequency, magnitude, or duration), not in terms of its expected value, but in terms of how bad some relatively unlikely but still plausible scenario would be.[43] For example, one of NWPCC's metrics is the maximum shortfall length, framed in terms of what the maximum shortfall length will be at the 97.5th percentile of the distribution, i.e., how long the shortfall would be if there were only a 2.5% chance that the shortfall could be longer.[44] Planners can also frame a metric both in terms of expected value *and* value at risk for the same system: Belgium previously had an LOLE metric that simultaneously required an expected value of less than 3 LOLH and required the 95th percentile of the distribution to be less than 20 LOLH.[45]

An alternative to the value at risk method is the "conditional value at risk" method, in which the metric is framed not in terms of the value at some percentile of the distribution, but in terms of the average value of the distribution beyond the percentile.[46] Policymakers' preference between these two options will depend on their risk tolerance, as the value at risk method will equally weight all tail events while the conditional value at risk method effectively places more weight on extreme events even within the tail.[47]

Values

After picking resource adequacy metrics—whether singular or multi-valued, and based on expected values, tail risks, or a combination of the two—the second step for setting a resource adequacy target is picking the numerical value for the metric(s). In the U.S., the most common value for the LOLE metric is 0.1, i.e., outages should occur no more than 0.1 days per year.[48] Selecting a value inherently involves balancing customers' desire for resource adequacy with the cost of achieving it.[49]

Notwithstanding that tradeoff, U.S. resource adequacy planners have largely set these values without any economic analysis. The origin of the widespread 0.1 LOLE target is somewhat enigmatic, especially relative to its contemporary significance, but it appears to describe the

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42 *See* Juan Pablo Carvallo et al., *supra* note 8, at 29; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 8; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

43 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

44 Nw. Power & Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2029 12 (2024), https://perma.cc/GZY2-PKY7.

45 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 17.

46 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

47 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 27 fig.8.

48 *Id.* at 8.

49 *Id.* at 38.

level of resource adequacy that happened to exist in the 1940s.[50]

The values used in NERC's reports on regions' long-term resource adequacy similarly seem arbitrary. NERC uses a LOLH metric, labeling regions with greater than 2.4 LOLH as high risk, 0.1-2.4 as elevated risk, and less than 0.1 as normal risk. NERC does not explain the basis for these categories, but they appear to stem this from a common (but widely criticized) hourly conversion of the 0.1 LOLE standard.[51] And NERC's values for the NEUE metric—above 0.002% is high risk, less than 0.002% but above zero is elevated risk, negligible or zero is normal risk—is adapted from Australia's 0.002% NEUE target without considering the different national contexts.[52] Context matters because the U.S. and Australia may vary in terms of how damaging outages would be (e.g., how bad it would be to lose electric heating and cooling in light of the region's temperatures) and how expensive it would be to avert them (e.g., the country-specific cost of building a natural gas peaker plant).

A better practice would be to use economic principles to select a socially efficient resource adequacy target, i.e., to select the value at which the incremental costs of additional resource adequacy equal the incremental benefits of achieving it.[53] Where policymakers do estimate the *costs* of improving resource adequacy, they often turn to the concept of "cost of new entry" (CONE).[54] CONE, expressed in $/MWh, represents the marginal investment and fixed costs of adding additional capacity to the system to achieve a more stringent resource adequacy standard.[55] Historically, planners assumed the marginal resource was a combustion turbine, but today it is more accurate to assume a portfolio of diverse resources.[56] Considering CONE by itself, however, does not accurately capture the social marginal cost of achieving higher levels of resource adequacy, because adding capacity can have follow-on effects like reducing the cost of energy.[57] Accordingly, it is better to estimate total net CONE, which nets out potential system benefits such as reduced energy costs for loads and lower operating costs.[58]

To estimate the *benefits* of additional resource adequacy, planners typically rely on the value of lost load (VOLL).[59] The VOLL represents the societal cost of failing to serve a unit of energy

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50 Kevin Carden et al., Nat'l Regul. Rsch. Inst., The Economics of Resource Adequacy: Why Reserve Margins Are Not Just About Keeping the Lights On 2 (2011), https://perma.cc/LS2F-2EZR; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

51 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment 11–12 (2024), https://perma.cc/GJB2-VCZQ; Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

52 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

53 Kevin Carden et al., *supra* note 50, at 1; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 38–42; Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

54 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 13, 41–42.

55 *Id.* at 42.

56 *Id.*

57 Christoph Graf et al., *Cost-Effective Capacity Markets* 29, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4864513 (posted June 21, 2024); Kevin Carden et al., *supra* note 50, at 8–9.

58 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 42.

59 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

demanded by consumers and is denominated in $/MWh.[60] Estimates vary significantly across customer classes,[61] but modelers can capture this through averaging.[62] More challenging is capturing how the VOLL varies with an outage's particular characteristics. For relatively short outages, the first hour tends to the most expensive,[63] indicating that many frequent outages could be more socially disruptive than a consolidated one of equal length. Long-duration outages result in damages that increase nonlinearly (food spoilage, jeopardized medical care, and loss of access to safe drinking water).[64] Similarly, the VOLL can increase nonlinearly with magnitude: When the grid operator can no longer manage the situation through rotating outages, the resulting uncontrolled outage is much more damaging.[65] Accordingly, undertaking a cost-benefit analysis that allows VOLL to vary with duration and magnitude would produce a more accurate, cost-benefit-justified resource adequacy target.

Many jurisdictions use some version a cost-benefit analysis when setting their resource adequacy targets. In the European Union, countries solve for their specific LOLH targets by dividing a local CONE value by the local VOLL, which, in 2023, resulted in a range from 1 LOLH (Sweden) to 15 LOLH (Czechia).[66] The United Kingdom uses this same approach.[67] Australia periodically reviews its 0.002% NEUE target to ensure that the implied "value of customer reliability," which is akin the VOLL, is close to its estimated value.[68] Somewhat analogous to these examples, the administratively set, downward-sloping demand curves for capacity markets in U.S. regions like PJM embody the tradeoff between the benefits and costs of additional resource adequacy, because the curves dictate how much regions are willing to pay for each increment of additional capacity given the capacity's incremental benefits.[69] Technically, though, this cost-benefit thinking happens not when *setting* the resource adequacy target, but in deciding whether to under-, over-, or exactly *achieve* an already-determined target.

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60 Jennifer Danis et al., Inst. for Pol'y Integrity, Transmission Planning for the Energy Transition: Rethinking Modeling Approaches 6 (2023), https://perma.cc/5A6L-DJHL.

61 Michael J. Sullivan et al., Ernest Orlando Lawrence Berkeley Nat'l Lab'y, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States xii, tbl.ES-1 (2015), https://perma.cc/CT53-8WEA.

62 *See* Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

63 Michael J. Sullivan et al., *supra* note 61, at xii, tbl.ES-1.

64 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 23 fig.5.

65 *See, e.g.*, Joshua W. Busby et al., *Cascading Risks: Understanding the 2021 Winter Blackout in Texas*, 77 Energy Rsch. & Soc. Sci. (2021); Sergio Castellanos et al., *A Synthesis and Review of Exacerbated Inequities from the February 2021 Winter Storm (Uri) in Texas and the Risks Moving Forward*, 5 Progress in Energy (2023); Hassan Haes Alhelou et al., *A Survey on Power System Blackout and Cascading Events: Research Motivations and Challenges*, 12 Energies 1, 16–17 (2019).

66 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 39 fig.12, 40.

67 *Id.* at 40.

68 Reliability Panel AEMC, Final Report: Reliability Standard and Settings Review 2018 i, 14 (2018), https://perma.cc/TAN8-TPXZ.

69 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 76 (2006) ("In addition, we agree with PJM that a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. Under a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value. Incremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level. This value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market.").

Step 2: Conduct Resource Adequacy Modeling

Once the policymaker sets a resource adequacy target, a resource adequacy model can predict whether a region is achieving it (and will continue to do so). Traditionally, modeling was limited to examining whether demand would exceed supply during one or a few peak load hours. But the energy transition, combined with extreme weather from climate change, requires planners to rethink prevailing resource adequacy modeling techniques. For most systems, it is now important to model all 8,760 hours of the year, in chronological order, to accurately capture the risk of load shed.

Along with improving models' temporal resolution, it has become important to make more sophisticated assumptions about modeling inputs. In particular, it has become critical to capture how supply and demand have become more dependent on the weather, which, in turn, has become more extreme. In general, a best practice is to use the Monte Carlo method, and run many (on the order of hundreds or thousands) simulations of grid operations, allowing the model to randomly pull from a distribution of possible values for every input.[70] Additionally, best practices exist for curating the data for each input and their interdependencies, such as representing the relationship between the weather and thermal outages.[71]

Temporal Scope

Historically, resource adequacy modeling focused on the likelihood that supply would exceed demand during one (or a few) top demand hours, ignoring the risk of inadequate supply during the rest of the year.[72] This simplification was more plausible when the grid was dominated by dispatchable resources with relatively predicable outputs.[73]

Now, with the increased penetration of wind and solar, periods of resource adequacy risk have shifted from peak demand to "net peak" demand, defined as load minus energy from non-dispatchable resources.[74] In this new reality, the system is most likely to lack sufficient supply when there is high demand unserved by wind or solar. And, just as weather dictates the performance of these variable resources, it also affects outages at thermal generators (e.g., interruptions of natural gas supply) and load (not just by influencing customers' demand, but also by altering

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70 See Inputs, below, for a more detailed description of the Monte Carlo method.

71 For example, cold winter snaps have historically yielded correlated outages of thermal generators. Nick Wintermantel & Nick Simmons, Astrapé Consulting 8 (2022), https://perma.cc/6D7Y-QCZ2. Similarly, extreme hot weather can require both thermal and nuclear units to cease operations, if the unit can no longer use intake water bodies for cooling. *E.g., High French River Temperatures to Hit Nuclear Production Next Week*, Reuters (June 20, 2025), https://www.reuters.com/business/energy/high-french-river-temperatures-hit-nuclear-production-next-week-2025-06-20.

72 Juan Pablo Carvallo et al., *supra* note 8, at 9; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2.

73 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2; Juan Pablo Carvallo et al., *supra* note 8, at 1, 27.

74 Jill Moraski et al., Clean Air Task Force, Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways 21 (2025), https://perma.cc/3A39-FQLW.

behind-the-meter generation that typically provides "negative" load).[75] Given this confluence of variables, the best practice is now to examine all 8,760 hours of the year when evaluating the likelihood and expected characteristics of shortfalls.[76]

The increased prevalence of energy-limited resources like battery storage and demand response have similarly complicated more traditional resource adequacy modeling assumptions. Battery storage's ability to avoid a resource adequacy shortfall will depend on its state of charge.[77] For example, a battery could have sufficient energy to prevent a shortfall in the morning and then, if it has no opportunity to recharge, be empty for a second event that same afternoon. Similarly, demand response participants have only a limited willingness to curtail or shift their demand; activating the program degrades its later effectiveness.[78] Accordingly, the best practice for resource adequacy modeling is to not just to consider all 8,760 hours, but to do so sequentially, capturing how storage and demand response used in one hour can affect their subsequent availability.[79]

Inputs

To keep pace with the many uncertainties of contemporary resource adequacy analysis, planners have shifted to probabilistic modeling approaches like the Monte Carlo method.[80] Under this best practice, rather than assessing resource adequacy using specific expected values for each input, the user provides the model with a probability distribution for different inputs, and the model randomly samples from those distributions across hundreds or thousands of simulated scenarios.[81] The model will draw the load for each hour, along with potentially correlated variable generation, thermal resource availability, and transmission outages.[82]

While the Monte Carlo method can yield more accurate resource adequacy estimates than simpler methods, its accuracy depends on the user-provided probability distributions, as well as accurate specification of key interdependencies.[83] For weather data, the current best practice is to use as many years as are available, with hourly resolution and geographic granularity.[84] And, especially when forecasting longer-term resource adequacy, it has become important to account

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75 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

76 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

77 Energy Sys. Integration Grp., Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation 11 (2023), https://perma.cc/4ETD-JQK2.

78 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 55–56.

79 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 9; Juan Pablo Carvallo et al., *supra* note 8, at 9; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 44.

80 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 9.

81 *Id.* at 10.

82 Juan Pablo Carvallo et al., *supra* note 8, at 13.

83 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 12.

84 Juan Pablo Carvallo et al., *supra* note 8, at 30.

for climate change projections,[85] including the increasing severity of extreme events.[86]

For load, the best practice is to capture its relationship to the weather, and to add a probabilistically determined amount of distributed generation as negative load.[87] Similarly, for generation, the best practice is to derive the relationship between weather and its output, while also accounting for how technological improvements will improve production profiles,[88] along with the possibility of other types of common mode failures.[89]

Other important considerations include realistic assumptions about electricity imports from neighboring regions (e.g., probabilistically modeling neighbors' operations during tight periods),[90] intraregional transmission constraints,[91] the impact of probabilistic intraregional transmission failures,[92] and for when the model decides that an outage has been triggered.[93]

Additionally, for forecasting longer-term resource adequacy, modelers need to make assumptions about which resources retire and come online. These assumptions will have a large bearing on model outputs. For retirements, modelers should include announced retirements while also forecasting unannounced retirements by accounting for likely retirements due to federal and state policy, age-based retirements, and retirements driven by economics.[94] For near-term new generation and storage, modelers should consider projects that have cleared or will soon clear the interconnection queue, along with expected build times.[95] To anticipate later-term resource additions, modelers should consider resource costs and trajectories, regulatory incentives and barriers, and other relevant drivers. As with other inputs, modelers can implement retirements and additions through a distribution of probabilities, rather than strict assumptions about what will occur.[96]

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85 *Id.*

86 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 22.

87 Juan Pablo Carvallo et al., *supra* note 8, at 31.

88 *Id.* at 32.

89 Elec. Power Rsch. Inst., Modeling New and Existing Technologies and System Components in Resource Adequacy 17–18 (2023), https://perma.cc/3CWR-G5LM; Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 37–38; *How MISO Utilizes PLEXOS for Enhanced Resource Adequacy*, Energy Exemplar (Oct. 9, 2024), https://perma.cc/VQY8-WAVX.

90 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 31; Adria E. Brooks et al., Grid Strategies LLC, Resource Adequacy Value of Interregional Transmission 31 (2025), https://perma.cc/77FQ-L94V; Sam Hostetter & Derek Stenclik, Analysis of Resource Adequacy Across the Eastern Interconnection 7, 16 (2025), https://perma.cc/LCU4-LBZF.

91 Elec. Power Rsch. Inst., Resource Adequacy Scenario Selection Guide 6, (2024), https://perma.cc/FZ5A-5G2M.

92 Juan Pablo Carvallo et al., *supra* note 8, at 13–14; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 12.

93 Kevin Carden et al., *supra* note 50, at 7.

94 Inst. for Pol'y Integrity, Comments on Policy-Driven Retirements in the Context of Order No. 1920 at 4–6 (Oct. 18, 2024), https://perma.cc/GB4R-X55D.

95 *E.g.,* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

96 *See* Inst. for Pol'y Integrity, Comments, *supra* note 94, at 7–8.

Step 3: Accreditation

After resource adequacy modeling, the next step is to derive how much credit each resource deserves for its contribution towards the system's resource adequacy—a process called "accreditation." A resource's accreditation, typically expressed as a fraction of its nameplate capacity, captures the resource's estimated availability during the periods when resource adequacy is most strained.[97]

If a planner is interested in determining only whether a system is achieving its resource adequacy target, this step is unnecessary because Step 2 will accomplish that.[98] Nor is this step strictly necessary to determine how the retirement of any particular resource would affect reaching the resource adequacy target; a planner can accomplish that by re-running Step 2 without the resource included.

But, as explained further in Step 4, accreditation is important to calculate a region's *reference reserve margin*, i.e., the resource adequacy cushion that, when obtained, suggests that the system will achieve its resource adequacy target. Accreditation is also valuable because, once a planner calculates the reference margin level, having these accreditation values can allow a policymaker to quickly estimate how the retirement or addition of particular resources would affect maintaining that margin, without needing to re-run the resource adequacy modeling. This kind of analysis could satisfy the EO's call for a protocol to "identify which generation resources within a region are critical to system reliability."[99]

Historically, planners accredited thermal resources at their full nameplate capacity—reflecting an assumption that they could always generate at maximum capacity during the moments of greatest resource adequacy risk—or accredited them based on their nameplate capacity discounted by their average forced outage rate.[100] Variable resources have often been accredited based on their historical performance during peak load hours.[101]

With the energy transition and climate change, however, the best practice is to derive a resource's accreditation from the resource adequacy modeling described in Step 2 using a probabilistic

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97 An Pham et al., Nat'l Renewable Energy Lab'y, Average and Marginal Capacity Credit Values of Renewable Energy and Battery Storage in the United States Power System 5 (2024) (using the equivalent phrase "capacity credit"). These times have become increasingly decoupled with peak load events. Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 4.

98 Juan Pablo Carvallo et al., *supra* note 8, at 36 ("Capacity accreditation is not inherent to resource adequacy assessments . . . ."); Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at vii ("While resource adequacy analysis assesses whether there are enough resources to serve load across the system, capacity accreditation measures the contribution of individual resources toward meeting that goal, both in terms of capacity and energy.").

99 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15522 (Apr. 14, 2025).

100 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 9, 37; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 5.

101 Juan Pablo Carvallo et al., *supra* note 8, at 36.

method.[102] Probabilistic methods like Effective Load Carrying Capability (ELCC) analyze how slight changes in the modeled resource inputs would affect resource adequacy outcomes.[103] They typically work by adding more of the studied resource to the model, beyond what exists in the base case, and then adding load until the model's base case resource adequacy outcome is restored.[104]

The benefit of probabilistic approaches like ELCC is that, when the modeling inputs from Step 2 are well-curated, the resulting accreditations will more accurately reflect a resource's contribution to resource adequacy during the true risk periods.[105] Additionally, these methods consider a wide range of possible futures, including the possibility of tail events, rather than assuming the future will resemble the past.[106]

The best practice is to apply these ELCC-style methodologies to both variable and thermal resources, storage, and transmission.[107] It is important to treat all resource types equally because capacity accreditation provides a technology-agnostic way of comparing resources' resource adequacy contributions.[108] That purpose is compromised when the resource adequacy value of variable resources is reduced to account for myriad factors affecting their output, without parallel reductions capturing thermal resources' weather dependency and common mode outages.[109] With increased saturation of natural gas resources—which are susceptible to fuel disruptions and extreme weather—it is more important than ever to accurately account for thermal generations' winter risks, especially the risk that a significant amount of thermal capacity will become unavailable at once.[110] Probabilistic methods are ideal for understanding the effect of these risks, including tail risks, in light of the complicated interdependencies of all the factors that dictate the timing of resource adequacy shortfalls.[111]

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102 *Id.* at 36–37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning 24–27 (2011), https://perma.cc/294F-25KU.

103 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 13.

104 *Id.*

105 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 12–14; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 15; Christoph Graf et al., *supra* note 57, at 30. As explained in Step 2 above, these risk periods are becoming harder to predict due to weather's increased influence on supply and demand, and because of increased energy-limited resources in the generation mix.

106 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 14.

107 Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 28; Adria E. Brooks et al., *supra* note 90, at 31.

108 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 32, 37.

109 *Id.* at 37–38.

110 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 24; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 40–41; Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 30; Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 27.

111 *See* Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 11 ("Increasingly, periods of risk are driven by correlation among many components that are often weather-related, including high load, low renewable resource availability, drought, and correlated outages and fuel supply disruptions from the fossil fuel generators."); N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 91 ("If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar

Step 4: Calculating the Reference Margin Level and the Reserve Margin

Using Step 2's resource adequacy modeling and Step 3's accreditations, a planner can assess whether a region's fleet would achieve its appropriate reference margin level.[112] The reference margin level typically expresses the amount of accredited capacity that a region would need to achieve its resource adequacy target. The planner will conduct resource adequacy modeling, adding or subtracting additional capacity or load until the system reaches the resource adequacy target. The reference margin level is the sum of the accredited capacity needed to achieve the target.

Once the planner derives the reference margin level (how much total accredited capacity the system requires), it is also possible to answer whether any particular resource is critical to achieving the margin. To check this, the planner would subtract the accredited capacity of the resource in question from the total accredited capacity of the region, and check whether the difference exceeds the reference margin level.

Reference Margin Levels

Historically, reference margin levels were—and, in some places, continue to be—resource adequacy targets in themselves (e.g., a target of accredited capacity that is 15% above peak load).[113] But setting a target framed entirely around the summed accredited capacity, even when informed by years of operating experience at different margin levels, yields a target that does not explicitly aim to achieve any particular outcome.[114] As explained in Step 1, targets are more typically expressed in terms of outcomes: the frequency, duration, and/or magnitude of shortfalls.

Yet the idea of a reference margin level has persisted, as planners often convert their outcome-focused targets into the equivalent reference margin levels.[115] For example, a region might have a 0.1 LOLE target and then determine that the 0.1 LOLE target is achieved when the region's installed capacity has an accreditation of at least 15% above peak load.[116] The same type of translation is possible for targets set using other metrics, like EUE or LOLH.[117]

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resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.").

112 This is also commonly referred to as a planning reserve margin, connoting that it includes resources that are in reserve and only be dispatched in highly constrained scenarios.

113 Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 24; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8–9.

114 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 5–6; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 29–30.

115 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 7; Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 1.

116 Juan Pablo Carvallo et al., *supra* note 8, at 28.

117 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 15; Juan Pablo Carvallo et al., *supra* note 8, at 29.

Given how resource adequacy risk has evolved, however, the best practice is to derive the reference margin level using the probabilistic resource adequacy modeling from Step 2 (itself conducted in accordance with best practices).[118] Doing this helps to ensure that the margin is calculated to comprehensively reflect year-round risks. Indeed, when resource adequacy risk shifts beyond peak load hours, the amount of accredited capacity necessary to achieve the resource adequacy target can become *lower* than peak load—because resources' accreditations will be based on their outputs during moments of greatest risk, which may be lower than their outputs at peak load.[119] Accordingly, calculating a reference margin level that matches accredited capacity to peak load would overestimate the necessary margin.

While there are multiple plausible ways to use probabilistic resource adequacy modeling to convert the resource adequacy target to a reference margin level, the general approach depends on whether the modeling reveals that the system is exactly achieving the target, underachieving it, or overachieving it. For the rare case in which the system happens to be exactly achieving the resource adequacy target, then the sum of the total accredited capacity installed on the system equals the reference margin level. It can be expressed as MW of accredited capacity, or in reference to some other amount, like a percentage of peak load.[120]

It is more likely, however, that the system is either above or below the resource adequacy target. In these instances, it is common to add or subtract accredited capacity in the model until the system achieves the target.[121] Then, the reference margin level will be the amount of accredited capacity on the modeled system when the target is achieved, again expressed as a quantity of MWs or as a percentage of peak load.

Effect of Particular Resources

Once the reference margin level and accreditation values have been calculated, it becomes possible to test how the exit (or entry) of a particular resource would affect the region's resource adequacy.

An example is useful in understanding how. Imagine that the reference margin level for a region is 25 GW, and its resource mix has 26 GW of accredited capacity. As is, the region would be exceeding its reference margin level by 1 GW. If any resource with an accreditation greater than 1 GW were to exit the grid, that would cause the actual reserve margin to dip below the reference margin level. Because the reference margin level was calculated following Steps 1–3,

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118 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 6, 11; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 11.

119 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 18.

120 *Id.*; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 6.

121 Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also, e.g.*, MISO, Planning Year 2025–2026 Loss of Load Expectation Study Report 34–35, https://perma.cc/4VV5-4FHU; Western Power Pool, Western Resource Adequacy Program, 102 Forward Showing Reliability Metrics 14 (2024), https://perma.cc/7A6Q-A96E; NYISO, 2024 Reliability Needs Assessment 44 (2024), https://perma.cc/LD5E-RMV9; IESO, Annual Planning Outlook: Resource Adequacy and Energy Assessments Methodology 19 (2024), https://perma.cc/26N7-QC5J.

this dip would indicate that the region can no longer be expected to achieve the resource adequacy target (e.g., 0.1 LOLE) underlying the 25 GW reference margin level. In contrast, any resource with an accredited capacity of 1 GW or less could retire without causing the system to violate its resource adequacy target.

Importantly, this technique for evaluating individual resources' impact works only for relatively small changes to the system, such as the exit or entry of one or a few plants. When larger changes happen in the region's resource composition, the new mix will itself affect resources' accreditation values, because these values inherently depend on the entire fleet composition.[122] To calculate the resource adequacy effect of major changes to the fleet (e.g., the retirement of half of the coal capacity in a region), it would be necessary to re-run the modeling from Step 2 with different inputs.

Having reviewed resource adequacy terms, methodologies, and best practices, Part 2 next uses this understanding to discuss DOE's recent resource adequacy modeling endeavor.

[122] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 30.

Part 2: DOE's *Resource Adequacy Report*

On July 7, 2025, DOE published its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study), responding to the EO's request for a "uniform methodology to identify at-risk region(s) and guide reliability interventions."[123] The report does not fulfill the EO's separate request for a "a protocol to identify which generation resources within a region are critical to system reliability."[124]

The DOE Study generally examines the resource adequacy of two time periods: today and 2030. According to the study, today, only ERCOT currently fails to achieve DOE's selected resource adequacy targets.[125] Under DOE's assumptions about load growth (including load growth from data centers), resource additions, and retirements, its modeling shows that all transmission planning regions will be resource inadequate in 2030 except ISO-NE and NYISO.[126] When reporting that a region is or would be resource inadequate, DOE sometimes calculates the amount of perfect capacity that could restore the region to resource adequacy.[127]

The DOE Study borrows heavily from NERC's recent Interregional Transfer Capability Study, which analyzed interregional transmission capacity and evaluated how additional interregional capacity could improve resource adequacy.[128] In contrast to NERC's Interregional Transfer Capability Study, the DOE Study does not consider how shortfalls could be mitigated through additional interregional transmission, which can be an alternative to new generation.[129]

Building on Part 1's discussion of how a resource adequacy model's metrics, values, and input assumptions drive its results, this Part evaluates DOE's resource adequacy methodology, including its input choices for load growth, resource additions, and retirements. At each step, it discusses the assumptions embedded in DOE's modeling choices, and reviews why those assumptions provide a weak basis for commanding specific, aging resources to continue serving load at consumers' expense and outside of existing market structures.

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123 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at vi.

124 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

125 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7.

126 *Id.* at 8.

127 *Id.* at 5. The exact meaning of these perfect capacity quantities is unclear due to contradictions within the DOE Study. At times, DOE explains that these are the perfect capacity quantities that restore the system to 0.002% while assuming projected retirements. *Id.* At other points, though, DOE states that these quantities assume no retirements. *Id.* at 9.

128 *Id.* at 2; N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study vi, ix (2024), https://perma.cc/U7M3-L56J.

129 *See generally* Adria E. Brooks et al., *supra* note 90.

Resource Adequacy Targets

The DOE Study uses a multi-metric resource adequacy target of 2.4 LOLH and 0.002% normalized unserved energy (NUSE), which is the deterministic equivalent to NEUE.[130] DOE's decision to use a multi-metric target aligns with best practices, and its decision to use LOLH and NEUE together is reasonable. But DOE's value selections for these metrics are problematic.

For LOLH, DOE indicated that it picked 2.4 because that value "translates into one day of lost load in ten years," i.e., the traditional 0.1 LOLE standard.[131] This decision does not align with best practices for two reasons. First, it seeks to unquestioningly replicate the already arbitrary 0.1 LOLE standard (which merely captures the level of resource adequacy that happened to exist in the 1940s).[132] DOE's choice thus does not reflect any meaningful cost-benefit analysis.

Second, DOE's conversion of 0.1 LOLE to 2.4 LOLH is inaccurate.[133] A region with 0.1 LOLE will experience only one day with an outage—of any length—across ten years, which will be 24 hours in only the most extreme case. A region with 2.4 LOLH will have 24 hours of outages across the decade, across any combination of hours. DOE's selection of 2.4 LOLH metric would therefore, in the vast majority of cases, permit a greater duration and frequency of outages.[134] Although this 2.4 LOLH target might indicate that, all else being equal, DOE's methodology is too permissive, DOE's inputs and assumptions likely dominate its analysis and lead DOE to overestimate potential shortfalls.

Turning to NUSE, DOE reports that it selected 0.002% because NERC uses that same value in its long-term resource adequacy assessments.[135] But, as discussed in Part 2, NERC adopted that value from Australia without any consideration of how the costs and benefits of resource adequacy differ in the U.S. context.[136] In contrast, DOE previously used 0.001% in the National Transmission Planning Study.[137]

Moreover, contrary to best practices, for both LOLH and NUSE, DOE imposes the same resource adequacy target across the entire continental United States, without considering regional differences. As noted in Part 1, when it comes to averting outages, regions face different costs and benefits with regard to resource adequacy and thus different socially optimal levels of resource adequacy.

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130 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4, 14 ("This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.").

131 *Id.* at 4.

132 Kevin Carden et al., *supra* note 50, at 2; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

133 Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

134 Gord Stephen et al., *supra* note 15, at 3, https://perma.cc/A9DJ-C3B5.

135 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4 n.10.

136 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

137 U.S. Dep't of Energy, National Transmission Planning Study: Chapter 2: Long-Term U.S. Transmission Planning Scenarios 4, 82 (2024), https://perma.cc/R8RA-23E2.

Finally, at times, the DOE Study appears to struggle with the very meaning of a resource adequacy standard: It questions both PJM's and SPP's resource adequacy, even though each satisfies the metrics DOE's itself picked for its analysis. For PJM in particular, DOE notes that the region currently satisfies both prongs of the resource adequacy metric, but not for the particular weather year that includes Winter Storm Elliot.[138] Seemingly for this reason, DOE concludes that PJM needs 2.4 GW of additional perfect capacity to be resource adequate now.[139] But DOE's resource adequacy targets are, in DOE's own words, "average indicators" to be achieved across all modeled scenarios, not a requirement that must be achieved in each and every scenario.[140] PJM is resource adequate today according to DOE's targets.

Of course, as discussed in Part 1, it may be reasonable for a system planner to set a resource adequacy target that depends, in part, on each region's performance during tail risks. But DOE has not done so here.

Resource Adequacy Modeling

DOE's resource adequacy modeling is inconsistent with best practices. DOE's high-level decisions about the study's overall modeling approach and data input decisions both diverge from the best practices described in Part 1.

Deterministic Model

While the DOE Study appropriately examines all 8,760 hours of the year in chronological order,[141] DOE departs from best practices by using deterministic modeling rather than a probabilistic approach (like the Monte Carlo method), perhaps because of the EO's relatively short timeline.[142] Rather than randomly sampling probability distributions for each input to construct hundreds or thousands of plausible scenarios, DOE "evaluates whether a power system has sufficient resources . . . under a pre-defined set of conditions which correspond to the past few years of real-world events."[143] DOE uses twelve years of data (2007–2013 and 2019–2023) for weather, load, and generation.[144]

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138 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7, 9, 27.

139 *Id.* at 9.

140 *Id.* at 7.

141 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10, 12–13.

142 *Id.* at 2. The EO provided an extremely accelerated deadline of 90-days for DOE to produce results. *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025). The DOE Study itself provides additional evidence for this conclusion, with its acknowledgement that "[p]robabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty" but "require more computing power." U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.

143 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10.

144 *Id.* at 11. While DOE uses historical data for the years 2019–2023, it uses "synthetic" data for 2007–2013. *Id.* "The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historic approach used historical measured data for load, as well as wind and solar resource output, from recent years and scaled it appropriately to represent future conditions." N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 74.

By examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty. Indeed, in the Interregional Transfer Capability Study, from which DOE borrowed, NERC itself explains the limitations of this same deterministic approach and same data: Some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future.[145] Addressing the deterministic vs. probabilistic distinction, NERC cautions that, because a "[p]robabilistic resource adequacy analysis was not conducted[,] . . . . the [Interregional Transfer Capability Study] should not be considered a North American resource adequacy assessment."[146]

DOE grounds its use of a deterministic model in "transparency" and an interest in "model[ing] detailed historic system conditions."[147] Neither is a reason to step away from best practices: DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach. Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.

Outage Threshold

Another modeling choice is the threshold for determining when a shortfall event has occurred. DOE projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[148] This choice means that DOE identifies shortfall events in the hours when, after exhausting imports and demand response, a region's excess energy falls below 6% or 3% of hourly load—but it is not clear when DOE uses 6% versus 3%. DOE states that more details are available in a section of the study's appendix entitled "Outputs," but, as of publication of this report, no such section appears to be available.[149]

NERC uses a 3% threshold in its Interregional Transfer Capability Study, using 6% only in a sensitivity analysis.[150] According to NERC, the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" and reflects how "a Balancing Authority will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages."[151] It is impossible to tell from the DOE Study when DOE used 6% versus 3%, but the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis.

If DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate

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145 *Id.* at 138.
146 *Id.* at 4.
147 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.
148 *Id.* at 12.
149 *Id.*
150 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 84.
151 *Id.* at 91 n.90, 85.

the extent of expected outages. In NERC's Interregional Transfer Capability Study, this change alone *significantly* altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida.[152] Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.[153]

Inputs

DOE's prediction that most regions will experience resource inadequacy by 2030 depends heavily on its assumptions about resource additions, retirements, load growth, and interregional imports. In each instance, DOE makes choices that raise significant questions about the validity of its modeling results.

Additions

DOE assumes that the only resource additions by 2030 will be those NERC currently categorizes as "Tier 1."[154] To be a Tier 1 resource, the resource must have achieved at least one milestone from a NERC list that signifies the unit is "very mature in the development pipeline."[155] This assumption is very conservative: The study itself admits that "[t]his results in minimal capacity additions beyond 2026."[156] In other words, DOE's finding of widespread resource inadequacy in 2030 rests on the assumption that very little will be built from 2027–2030. For example, NERC identifies 17,047 MW of Tier 1 resources slated to come online in PJM throughout 2025 and 2026, but only 1,108 MW from 2027–2030.[157]

The drop-off in Tier 1 resources after 2026 is not due to a shortage of projects in development, but rather because NERC currently classifies much of the capacity that will come online between 2027 and 2030 as "Tier 2."[158] Tier 2 resources occupy a wide range of positions in the interconnection queue, from the earliest stages (e.g., those having completed a feasibility study) to the very end

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152 *Id.* at 105 tbl.8.4

153 *Id.*

154 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4.

155 *Id.* at A-5. More specifically, the resource must have finished construction, be under construction, have a signed/approved interconnection service agreement, have a signed/approved power purchase agreement, have a signed/approved construction service agreement, have a signed/approved wholesale market participant agreement, or (if it is in the footprint of a vertically integrated utility) be included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement. N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

156 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at A-5. *See also* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report*, GridLab (July 11, 2025), https://perma.cc/B3GC-T7GA ("The report assumes just 22 GW of new 'firm' capacity (narrowly defined as gas) is added which is based on NERC LTRA 'Tier 1' – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030**.") (bolded text in original).

157 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 89.

158 *See id.* at 137.

of the process (e.g., those that have requested an interconnection service agreement).[159]

In recent years, the median project has taken approximately 55 months (4.58 years) to go from entering the queue to commercial operation.[160] Extrapolating from this historical trend reveals that a large number of Tier 2 resources will likely be operating by 2030. DOE should have anticipated some of them in the 2030 resource mix, and it departed from best practices by excluding all Tier 2 resources.[161] To do this forecasting accurately, DOE should have examined historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region.[162]

And applying historical statistics for time spent in a region's interconnection queue would itself be a conservative methodology for DOE to use, as FERC Order 2023 and related regional interconnection queue updates are set to speed up waiting times.[163] For example, the DOE Study found a 10.5 GW resource adequacy deficit for PJM in 2030 but failed to consider the almost 12 GW of nameplate capacity—mostly gas—that PJM is fast-tracking through its Reliability Resource Initiative.[164] PJM expects that 90% of this capacity will be online by 2030.[165] PJM is simultaneously pursuing other resource adequacy interventions, including a FERC-approved change to surplus interconnection service (to allow new generators to come online faster by taking advantage of underutilized transmission capacity),[166] and a FERC-pending proposal to expedite the process to transfer capacity interconnection rights from retiring generators to new resources.[167]

Finally, recently "retired" resources represent another potential source of fast additions.[168]

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159 *Id.*

160 Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 41 (2024), https://perma.cc/5DE4-XNK6.

161 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 23 fig.2.

162 *See generally* Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (2024), https://perma.cc/5DE4-XNK6.

163 *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

164 Donnie Bielak, PJM, Reliability Resource Initiative: Additional Summaries 2 (2025), https://perma.cc/Y2AB-3CEM; Donnie Bielak, PJM, Reliability Resource Initiative: Results Summary 6 (2025), https://perma.cc/MYQ8-Y53G. *See also* Ric O'Connell, *supra* note 156 ("The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.").

165 *PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth*, PJM Inside Lines (May 2, 2025), https://perma.cc/8EW2-G2XZ.

166 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,083 (2025).

167 Proposed Revisions to PJM's Open Access Transmission Tariff, PJM, Docket No. ER25-____-000 (Jan. 31, 2025), https://perma.cc/J9T3-MCGL.

168 *E.g.*, Francisco "A.J." Camacho & Daviel Schulman, *Mothballed Nuclear Plant on Brink of Revival*, EnergyWire (July 15, 2025), https://subscriber.politicopro.com/article/eenews/2025/07/15/mothablled-nuclear-plant-on-brink-of-revival-00445239.

Retirements

DOE's assumption that 104 GW of nameplate capacity will retire by 2030 likely overestimates retirements.[169] This number includes both "confirmed" retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and "announced" retirements—which are publicly stated but not officially noticed.[170] These data come from NERC's Long-Term Reliability Assessment 2024 model.[171] In turn, NERC receives reports of confirmed retirements directly from each region, while announced retirements come from multiple sources, including Energy Information Agency Form 860 data, trade press, and utility integrated resource plans.[172]

These data likely overestimate retirements.[173] First, the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources.[174] Second, federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire were projected to result in significant retirements before 2030.[175] But the Trump Administration has begun to rescind or reexamine these rules, which could cause resources to delay their retirements.[176]

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169 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

170 *Id.* at 12.

171 *Id.*

172 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 28 n.19.

173 Ric O'Connell, *supra* note 156 ("The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.") (bolded text in original).

174 Aurora Energy Research, Impact of Reform to Clean Energy Tax Credits on Investment, Jobs and Consumer Bills 10 (2025), https://perma.cc/VHR5-UEGP; ("Most demand is made up through more production from existing plants (35%), meaning these plants are running for longer hours and/or at higher output levels. Some projects that retired in the base case scenario see longer lifetimes in Tax Credit Removal scenario because of more favorable economics due to clean energy decline (making up 17% of lost generation), and the rest is made up for by new build thermal plants (29%)."); Energy Innovation Pol'y & Tech. LLC, Federal Clean Energy Tax Credits Make Energy More Affordable—A Meta-Analysis (2025) https://perma.cc/QH2E-7PLL ("The research is clear—repealing technology-neutral energy tax credits would raise annual energy bills up to $140–$220 per year nationally, and over $500 per year in some states."). *See also* Ethan Howland, *PJM Capacity Prices Hit Record Highs, Sending Build Signal to Generators*, Utility Dive (July 31, 2024), https://perma.cc/UC6U-QHYT ("Prices in the PJM Interconnection's latest capacity auction hit record highs, which should provide incentives for power plant companies to build new generating resources and keep existing ones operating, according to the grid operator."); Ethan Howland, *MISO Summer Capacity Prices Jump to $666.50/MW-day as Power Supplies Shrink*, Utility Dive (Apr. 29, 2025), https://perma.cc/A6S5-4A4U ("Capacity prices for the upcoming summer season jumped to $666.50/MW-day from $30/MW-day last year across the Midcontinent Independent System Operator's footprint—driven in part by declining surplus capacity, according to the results of its latest planning resource auction released Monday.").

175 PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks 8 (2023), https://perma.cc/7J3A-FL8U.

176 *EPA Launches Biggest Deregulatory Action in U.S. History*, EPA (Mar. 12, 2025), https://perma.cc/55MN-2SUB.

Load

The DOE Study assumes 50 GW of growth in data center load and 51 GW of additional non-data center load.[177] DOE does not account for the possibility that this data center load could be flexible, even as one study suggests that 76 GW of additional data center load could be accommodated today if it could be curtailed only 0.25% of the time, and relevant corporations have confirmed flexibility potential.[178]

In June 2025, Texas enacted a law that allows ERCOT to curtail certain new loads over 75 MW during emergencies.[179] DOE assumes an additional 8 GW of data center load in ERCOT by 2030 and finds a reliability shortfall of 10.5 GW (which is likely an overestimate for the reasons discussed elsewhere in this Part, including how this 10.5 GW brings ERCOT to 0.0008% NUSE instead of 0.002% NUSE).[180] Accordingly, Texas's new law could go a long way towards avoiding the DOE-identified resource adequacy problem. Other regions like PJM are considering strategies to soften the resource adequacy impact of data centers, including ways to better encourage their participation in demand response programs.[181] DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT.

Additionally, how DOE chose to distribute the projected 50 GW of data center load across regions is questionable. The DOE Study explains it used state-level growth ratios to perform this allocation.[182] But it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load). In fact, some computing demand

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177 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2–3.

178 Tyler H. Norris et al., Nicholas Inst. for Energy, Env't & Sustainability, Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 2 (2025), https://perma.cc/6693-3HZU; *EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability,* Elec. Power Rsch. Inst. (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027."); Anuja Ratnayake, *Unlocking AI Potential with Data Center Flexibility*, EnergyCentral (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-ai-potential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance."). *See also* Ric O'Connell, *supra* note 156 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

179 S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, *Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis*, Utility Dive (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

180 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 40.

181 Tim Horger, PJM, Large Load Additions Workshop 28 (2025), https://perma.cc/4HSN-CW4W.

182 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 17.

may be served from other regions if it will be cheaper to integrate the data center elsewhere. Given the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets.[183]

Interregional Imports

The DOE Study states that it has adopted the interregional transfer capacities from NERC's Interregional Transfer Capability Study but also notes that transfers are "available up to the *minimum* total transfer capacity."[184] NERC's values describe the available transmission capacity between regions, including sub-regions of larger transmission-constrained regions like PJM, SPP, and MISO.[185] NERC provides a summer value and a winter value for each interregional interface and for each direction of flow.[186]

It is unclear what DOE means when it says that transfers are allowed up to their "minimum." If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity.

Accreditation & Reference Margin Levels

While DOE issued its study in response to the EO's request for a "methodology to identify current and anticipated regions with reserve margins below acceptable thresholds,"[187] it does so through resource adequacy modeling, rather than by calculating accreditation values and using them to derive reference margin levels. As explained in Part 2, properly performed resource adequacy modeling is sufficient to determine whether a region is resource adequate.

In contrast, accreditations and reference margin levels are useful in combination to quickly evaluate how the loss or addition of a particular resource would affect whether a region achieves its resource adequacy target without re-running regional resource adequacy modeling. They are thus more applicable to EO Section 3(c)'s separate command to establish a "protocol to identify which generation resources within a region are critical to system reliability.[188] Thus far, DOE has not released a study implementing this provision. DOE may eventually supplement the DOE Study with additional accreditation and reference margin level analyses.

Nonetheless, while the DOE Study does not calculate accreditation values or reference margin levels, it does undertake the related exercise of evaluating how much additional perfect capacity would bring certain regions to resource adequacy.[189] (DOE calculated these perfect capacity

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183 *See id.* at 9, 17.

184 *Id.* at 18, 12, A-1 (emphasis added).

185 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 7, 9–10.

186 *Id.* at 17–24.

187 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

188 *Id.* at 15522.

189 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

additions for only four of the seven regions that failed to achieve 0.002% NUSE in 2030: PJM, SPP, SERC, and ERCOT—not MISO, CAISO, or West Non-CAISO.[190]) More specifically, DOE asked how much perfect capacity it would take for regions to achieve the 0.002% NUSE resource adequacy standard in 2030.[191]

If, in the future, DOE were to also calculate the accredited capacity of a region's fleet and then add the solved-for perfect capacity, it could calculate the region's reference margin level. Similarly, although DOE did not perform any perfect capacity analysis for regions that achieve 0.002% NUSE, DOE could subtract perfect capacity from the accredited capacity of the regional fleets to solve for reference margin levels. Once DOE calculates a region's reference margin, it could look at the accredited capacity of any resource to evaluate how its exit or entry would affect achievement of the reference margin level.

In calculating any reference margin levels, DOE should attend to all prongs of its multi-metric resource adequacy target. Here, DOE Study's perfect capacity exercise focuses exclusively on 0.002% NUSE. But if a region achieves 0.002% NUSE and not 2.4 LOLH, it would be resource inadequate according to the terms of this DOE Study. Separate reference margin levels may apply to each prong, and a region would be resource adequate only when the highest reference margin level is achieved.

Additionally, going forward, DOE should better prioritize accuracy in any new studies with respect to calculating a region's need for perfect capacity additions/subtractions. Critically, while DOE asserted that it added the amount of perfect capacity needed to bring each region to 0.002% NUSE, the 10.5 GW that it added to PJM actually brought it to 0.0003% NUSE; the 500 MW added to SERC brought it to 0.0002% NUSE; the 1.5 GW added to SPP brought it to 0.0002% NUSE; and the 10.5 GW added to ERCOT brought it to 0.0008% NUSE.[192] All of these values indicate significantly greater resource adequacy that 0.002% NUSE, sometimes by an order of magnitude.

While DOE explains that its perfect capacity additions were done "by hand with a limited number of iterations (15)" such that the capacity additions "should not be considered the minimum possible capacity to accomplish these targets," that approach does not appear to explain why DOE brought these regions far beyond the 0.002% NUSE target.[193] Rather, this explanation suggests that, for each of the regions, DOE could have achieved these high levels of resource adequacy using less perfect capacity than it added. Accordingly, to achieve 0.002% NUSE, DOE likely could have added much less perfect capacity than it did. Identifying resources that meet these overestimated capacity levels could result in overpaying to achieve a different resource adequacy target than selected.

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190 *Id.* at 20–42.
191 Id. at 5.
192 *Id.* at 27, 30, 32, 40.
193 *Id.* at 19.

Part 3: Next Steps

Having reviewed best practices for resource adequacy modeling and the DOE Study, this final section discusses next steps for U.S. resource adequacy policy considering the diverse actors in this space and their respective authorities.

The Federal Power Act (FPA) gives FERC, and FERC's designated "Electric Reliability Organization" (ERO), NERC, jurisdiction over and responsibility for ensuring "[e]lectric reliability" for the "bulk power system," i.e., the high-voltage transmission network and the energy that flows through it.[194] More specifically, the FPA requires NERC to "establish and enforce reliability standards," which take effect after FERC approves them.[195] Importantly, FERC can also order NERC to submit reliability standards on particular topics and can independently enforce reliability standards.[196] NERC's six regional entities (comprising the continental U.S. plus Canada) also have authority to propose reliability standards to NERC.[197]

Achieving reliability arguably requires that bulk power system be resource adequate because, as FERC explains, "[i]f resources cannot meet load, or are insufficient to provide a reserve margin above expected load, then instability, uncontrolled separation or cascading failures can result from the unanticipated loss of a system element."[198] But, although reliable grid operations depend in part on resource adequacy, the FPA does not put FERC and NERC in the driver's seat for this aspect of reliability. FERC lacks authority to *directly achieve* resource adequacy because it cannot order construction of electric generation facilities.[199] Rather, states retain their traditional authority "over facilities used for the generation of electric energy,"[200] which some exercise by requiring utilities to submit integrated resource plans describing their plans to meet future demand.[201] Other states fully or partially delegate this authority to the Regional Transmission Organizations (RTOs) that operate their regional grids, e.g., by relying on the RTOs to achieve resource adequacy through capacity markets.[202]

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194 16 U.S.C. § 824o(a).

195 16 U.S.C. § 824o(a)(2), (d). FERC does not have authority to create reliability standards directly. *See id.* at § 824o(d).

196 16 U.S.C. § 824o(d)(5), (e)(3).

197 16 U.S.C. § 824o(e)(4); *ERO Enterprise; Regional Entities,* N. Am. Elec. Reliability Corp., https://perma.cc/EQ9E-BXJW.

198 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 25 (2011). Reliable operation also encompasses a second aspect of reliability not implicated by the EO—operational reliability—which refers to "ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts." Burçin Ünel & Avi Zevin, *supra* note 5, at 11.

199 16 U.S.C. § 824o(a)(3). The FPA also prohibits FERC from directing utilities to build transmission, and states retain primary siting authority for transmission. *See id.*; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P258 (2024).

200 16 U.S.C. § 824(b)(1).

201 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy United (Aug. 11, 2015), https://perma.cc/5MDN-26QY.

202 Dena Adler & Jennifer Danis, Inst. for Pol'y Integrity, Reducing Pollution Without Sacrificing Reliability 14–16

But FERC and NERC can still play an important role for resource adequacy: FERC and NERC, through reliability standards, can ensure grid operators are proactively conducting appropriate resource adequacy assessments and analyses. In Order No. 747, FERC approved a regional reliability standard for conducting resource adequacy assessments.[203] This enforceable reliability standard requires, at a minimum, that entities within the applicable footprint conduct an annual analysis of what reserve margin would be necessary to ensure no more than 0.1 LOLE, using specific inputs like the median load forecast and accounting for important factors like fuel availability.[204] This reliability standard does not require regions to actually achieve 0.1 LOLE, only to conduct the mandated analysis.[205] A future reliability standard could require regions to instead adopt best practices comparable to those described in Part 1.

Turning to DOE, the DOE Reorganization Act put emergency grid reliability powers in DOE's hands for addressing certain emergency situations. Section 202(c) of the FPA empowers DOE, upon the finding of an emergency, to require, among any things, "such generation . . . as in its judgment will best meet the emergency and serve the public interest."[206] Section 202(c) and its implementing regulations, along with the common understanding of the word "emergency," indicate that this authority is limited to unexpected events.[207] Additionally, DOE's implementing regulations indicate that a shortage caused by a resource's poor economics would not qualify as an emergency, unless the shortage is "imminent."[208] When promulgating these regulations, DOE noted that:

> 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.[209]

(2024), https://perma.cc/G6J3-9ZL4. These capacity markets are FERC-jurisdictional, and operate according to rules contained in tariffs filed with FERC, specifying particulars like demand curve type, resource accreditation, and formulas for calculating reserve margins. *See, e.g.*, *PJM Interconnection, L.L.C.*, 191 FERC ¶ 61,066, at P 8 (2025).

203 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 1 (2011).

204 Standard BAL-502-RF-03, N. Am. Elec. Reliability Corp., https://perma.cc/9MB5-5H67.

205 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 33 (2011) ("The only obligations under BAL-502-RFC-02 are analysis and documentation requirements. This regional Reliability Standard does not specify how the results of the analysis required in this standard are to be used. For example, BAL-502-RFC-02 does not require state commissions to use the resource assessment analysis resulting from BAL-502-RFC-02 for economic decisions regarding resource adequacy requirements.").

206 16 U.S.C. § 824a(c)(1).

207 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; Burçin Ünel & Avi Zevin, *supra* note 5, at 37–38.

208 10 C.F.R. § 205.371 ("Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent.").

209 Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985 (Aug. 6, 1981) (codified at 10 C.F.R. pt. 205).

In a departure from prior practice,[210] DOE has now used this authority to prevent thermal plants from retiring.[211] These orders have already drawn challenges from multiple parties, including from a politically diverse coalition of utility regulators.[212] Parties argue, among other points, that the plants' retirements were not unexpected; that the regions would be resource adequate even without the plants; and that DOE's newly asserted authority over resource adequacy triggers the major questions doctrine.[213]

Having nationally set best practices and principles for determining resource adequacy in the face of rapidly escalating demand and the clean energy transition could be useful if they are well vetted and use appropriate legal constructs. The FPA in conjunction with the DOE Reorganization Act suggest that the appropriate course of action for the federal government to support resource adequacy would be for NERC and FERC to set national resource adequacy *planning* standards (not a national resource adequacy target) to help regions guard against potential resource adequacy risks that might materialize in the future, instead of allowing DOE to stretch its 202(c) emergency authorities.

The DOE study itself cautions, "the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "one of the key takeaways from this study process is the underscored 'call to action' for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our

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210 Cong. Rsch. Serv., Federal Power Act: The Department of Energy's Emergency Authority 4 (updated 2025), https://perma.cc/AU8L-VR55.

211 *DOE's Use of Federal Power Act Emergency Authority*, U.S. Dep't of Energy, https://perma.cc/DPB9-6B74.

212 Ethan Howland, *Groups Appeal DOE "Emergency" Order Keeping Michigan Plan Online*, Utility Dive (updated June 20, 2025), https://perma.cc/P9YZ-FNLK; Ethan Howland, *Eight Utility Regulators Challenge DOE Order Keeping Michigan Coal Plant* Open, Utility Dive (June 26, 2025), https://perma.cc/55FE-2RYR; Motion to Intervene and Request for Rehearing of the Joint Consumer Advocates, Dep't of Energy Order No. 202-25-4 (June 27, 2025), https://perma.cc/PD74-6CNC.

213 Request for Rehearing by Michigan Attorney General Dana Nessel, Dep't of Energy Order No. 202-25-3, at 27–31, 35–36 (June 18, 2025); Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al., Dep't of Energy Order No. 202-25-3, at 29–36 (June 18, 2025), https://perma.cc/4MYN-MHZC; Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Dep't of Energy Order No. 202-25-3, at 2–6 (June 23, 2025), https://perma.cc/D3PG-56H2. *See also* Brief of the Institute for Policy Integrity at 4–13, V.O.S. Selections, Inc. v. Trump, No. 25-00066-GSK-TMR-JAR (Ct. Int'l Trade May 8, 2025), https://perma.cc/5Z4T-8CHG (describing the major questions doctrine).

214 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at i.

215 *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security*, U.S. Dep't of Energy (July 7, 2025), https://perma.cc/942V-L7VB.

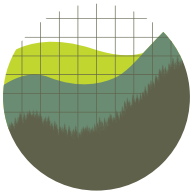
216 *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

collective economic and national security." And it presents a pathway to fulfill DOE's discussion of what will happen next: "The report will inform joint planning processes and help integrate modern metrics into national reliability assessment methodology."[217] FERC directing NERC to develop national resource adequacy planning metrics, protocols, and input parameters would fit neatly within this call to action.

[217] *Reliability*, U.S. Dep't of Energy, https://perma.cc/RSW3-FNN2.

Conclusion

Given ever-increasing demand for electricity—proliferation of data centers for artificial intelligence; electrification of heating, cooling, and transportation; and pushes to onshore manufacturing—maintaining resource adequacy is essential. But there is no single answer to the question of when a system is resource adequate, or even what constitutes resource adequacy. Still, as this report explains, there are better and worse ways to pick resource adequacy targets, to evaluate whether the system has achieved and will maintain them, and to understand the resource adequacy impacts of a particular resource entering or exiting the system. The DOE Study uses some of these best practices but not other important ones, undermining the accuracy of its predictions. The DOE Study will hopefully focus additional attention on resource adequacy and speed up federal and state endeavors already underway to bolster resource adequacy. It does not, however, provide a rational basis for DOE to take action now to thwart ongoing plans for uneconomic, aging resources to retire. DOE's next best step would be to request that FERC open a proceeding eliciting proposals for nationwide, enforceable reliability standards mandating not a national resource adequacy target, but best practices for grid planners to conduct resource adequacy assessments. Additionally, states and grid operators should continue working together to expedite resource permitting, better forecast what hyperscaler demand will materialize, engage in holistic transmission planning, and speed interconnection queues—all of which will support future resource adequacy.



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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-42:
GridLab Report

1

GridLab Analysis: Department of Energy Resource Adequacy Report



Ric OConnell

Rethinking Reliability

July 11, 2025

Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a methodology for "analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."

The Executive Order also directs the DOE to prevent generation sources exceeding 50 MW from retiring or converting fuel sources if it would reduce generating capacity in at-risk regions, based on the new methodology. The DOE has so far issued two emergency orders under section 202(c) of the Federal Power Act. These orders directed plant owners and grid operators to delay by 90 days the retirement of the Campbell coal plant in Michigan owned by Consumers Energy and the Eddystone gas and oil plant in Pennsylvania, owned by Constellation. The EO and its methodology report did not include a mechanism for public input.

Bottomline of the DOE report:

The report warns of a 100X increased risk of outages if the forecasted retirements by 2030 take place. The report blames the lack of "firm" generation replacement in the planned supply.

Bottomline of GridLab analysis:

The report's conclusions are problematic since the **report undercounts the resources that are likely to be added to the grid,** and **overstates** the retirements expected. Utilities and markets *already* have plans to meet increased load growth, yet the **DOE report assumes they are doing nothing after 2026**

the **DOE report assumes they are doing nothing after 2026.**

DOE Report Analysis – Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.
    - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
    - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose

not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.

- Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC LTRA "Tier 1" – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**

- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

DOE Report Assumptions vs. U.S. Energy Information Administration

Energy Information Administration Data:

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

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London Calling: How UK Grid Innovation ...


Conclusion:

If the DOE report had used more consistent assumptions, it would have likely come to very different conclusions. Utilities and RTOs have planning processes and market mechanisms in place to build new resources in response to higher load growth and the retirement of older, uneconomic plants. The DOE's solution to keep older units online past retirement dates is a crude and expensive approach. The DOE should defer to state planning processes and regional markets to meet the challenge.

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Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-43:
Duke University Rethinking Load Growth Study

Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY



Rethinking Load Growth

Assessing the Potential for Integration of Large Flexible Loads in US Power Systems

Tyler H. Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell

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Acknowledgments

The authors would like to thank Jessalyn Chuang and Wendy Wen for their research assistance.

Citation

Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. *Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems*. NI R 25-01. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University.
https://nicholasinstitute.duke.edu/publications/rethinking-load-growth

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INTRODUCTION

A New Era of Electricity Demand

Rapid US load growth—driven by unprecedented electricity demand from data centers, industrial manufacturing, and electrification of transportation and heating—is colliding with barriers to timely resource expansion. Protracted interconnection queues, supply chain constraints, and extended permitting processes, among other obstacles, are limiting the development of new power generation and transmission infrastructure. Against this backdrop, there is increasing urgency to identify strategies that accommodate rising demand without compromising reliability, affordability, or progress on decarbonization.

Aggregated US winter peak load is forecasted to grow by 21.5% over the next decade, rising from approximately 694 GW in 2024 to 843 GW by 2034, according to the *2024 Long-Term Reliability Assessment* of the North American Electric Reliability Corporation. This represents a 10-year compound annual growth rate (CAGR) of 2.0%, higher than any period since the 1980s (NERC 2024). Meanwhile, the Federal Energy Regulatory Commission's (FERC) latest five-year outlook forecasts 128 GW in peak load growth as early as 2029—a CAGR of 3.0% (FERC 2024b).

The primary catalyst for these updated forecasts is the surge in electricity demand from large commercial customers. While significant uncertainty remains, particularly following the release of DeepSeek, data centers are expected to account for the single largest growth segment, adding as much as 65 GW through 2029 and up to 44% of US electricity load growth through 2028 (Wilson et al. 2024; Rouch et al. 2024). Artificial intelligence (AI) workloads are projected to represent 50% to 70% of data center demand by 2030—up from less than 3% at the start of this decade—with generative AI driving 40% to 60% of this growth (Srivathsan et al. 2024; Lee et al. 2025).

Analysts have drawn parallels to the 1950s through the 1970s, when the United States achieved comparable electric power sector growth rates (Wilson et al. 2024). Yet these comparisons arguably understate the nature of today's challenge in the face of stricter permitting obstacles, higher population density, less land availability, skilled labor shortages, persistent supply chain bottlenecks, and demand for decarbonization and greater power reliability. While historical growth rates offer a useful benchmark, the sheer volume of required new generation, transmission, and distribution capacity forecasted for the United States within a condensed timeframe appears unprecedented.

The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably, and sustainably integrate large loads. The time-sensitivity for solutions is amplified by the market pressure for many of these loads to interconnect as quickly as possible. In recent months, the US Secretary of Energy Advisory Board (SEAB) and the Electrical Power Research Institute (EPRI) have highlighted a key solution: load flexibility (SEAB 2024, Walton 2024a). The promise is that the unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources (DERs).

Flexibility, in this context, refers to the ability of end-use customers to temporarily reduce their electricity consumption from the grid during periods of system stress by using on-site generators, shifting workload to other facilities, or reducing operations.[1] When system planners can reliably anticipate the availability of this load flexibility, the immediate pressure to expand generation capacity and transmission infrastructure can potentially be alleviated, mitigating or deferring costly expenditures. By facilitating near-term load growth without prematurely committing to large-scale capacity expansion, this approach offers a hedge against mounting uncertainty in the US data center market in light of the release of DeepSeek and related developments (Kearney and Hampton 2025).

Summary of Analysis and Findings

To support evaluation of potential solutions, this study presents an analysis of the existing US electrical power system's ability to accommodate new flexible loads. The analysis, which encompasses 22 of the largest balancing authorities serving 95% of the country's peak load, provides a first-order estimate of the potential for accommodating such loads with minimal capacity expansion or impact on demand-supply balance.[2]

Specifically, we estimate the gigawatts of new load that could be added in each balancing authority (BA) before total load exceeds what system planners are prepared to serve, provided the new load can be temporarily curtailed as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.

Key results include (see Figure 1):

- 76 GW of new load—equivalent to 10% of the nation's current aggregate peak demand—could be integrated with an average annual load curtailment rate of 0.25% (i.e., if new loads can be curtailed for 0.25% of their maximum uptime)
- 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5%, and 126 GW at a rate of 1.0%
- The number of hours during which curtailment of new loads would be necessary per year, on average, is comparable to those of existing US demand response programs
- The average duration of load curtailment (i.e., the length of time the new load is curtailed during curtailment events) would be relatively short, at 1.7 hours when average annual load curtailment is limited to 0.25%, 2.1 hours at a 0.5% limit, and 2.5 hours at a 1.0% limit
- Nearly 90% of hours during which load curtailment is required retain at least half of the new load (i.e., less than 50% curtailment of the new load is required)
- The five balancing authorities with the largest potential load integration at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW[3]

1 Note that while *curtailment* and *flexibility* are used interchangeably in this paper, *flexibility* can refer to a broader range of capabilities and services, such as the provision of down-reserves and other ancillary services.

2 For further discussion on the nuances regarding generation versus transmission capacity, see the section on limitations.

3 A complete list of abbreviations and their definitions can be found at the end of the report.

Overall, these results suggest the US power system's existing headroom, resulting from intentional planning decisions to maintain sizable reserves during infrequent peak demand events, is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year. In addition, they underscore the potential for leveraging flexible load as a complement to supply-side investments, enabling growth while mitigating the need for large expenditures on new capacity.

We further demonstrate that a system's potential to serve new electricity demand without capacity expansion is determined primarily by the system's load factor (i.e., a measure of the level of use of system capacity) and grows in proportion to the flexibility of such load (i.e., what percentage of its maximal potential annual consumption can be curtailed). For this reason, in this paper we assess the technical potential for a system to serve new load under different curtailment limit scenarios (i.e., varying curtailment tolerance levels for new loads).

The analysis does not consider the technical constraints of power plants that impose intertemporal constraints on their operations (e.g., minimum downtime, minimum uptime, startup time, ramping capability, etc.) and does not account for transmission constraints. However, it ensures that the estimate of load accommodation capacity is such that total demand does not exceed the peak demand already anticipated for each season by system planners, and it discounts existing installed reserve margins capable of accommodating load that exceeds historical peaks. It also assumes that new load is constant throughout all hours.

This analysis should not be interpreted to suggest the United States can fully meet its near- and medium-term electricity demands without building new peaking capacity or expanding the grid. Rather, it highlights that flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion, and enable greater focus on the highest-value investments in the electric power system.

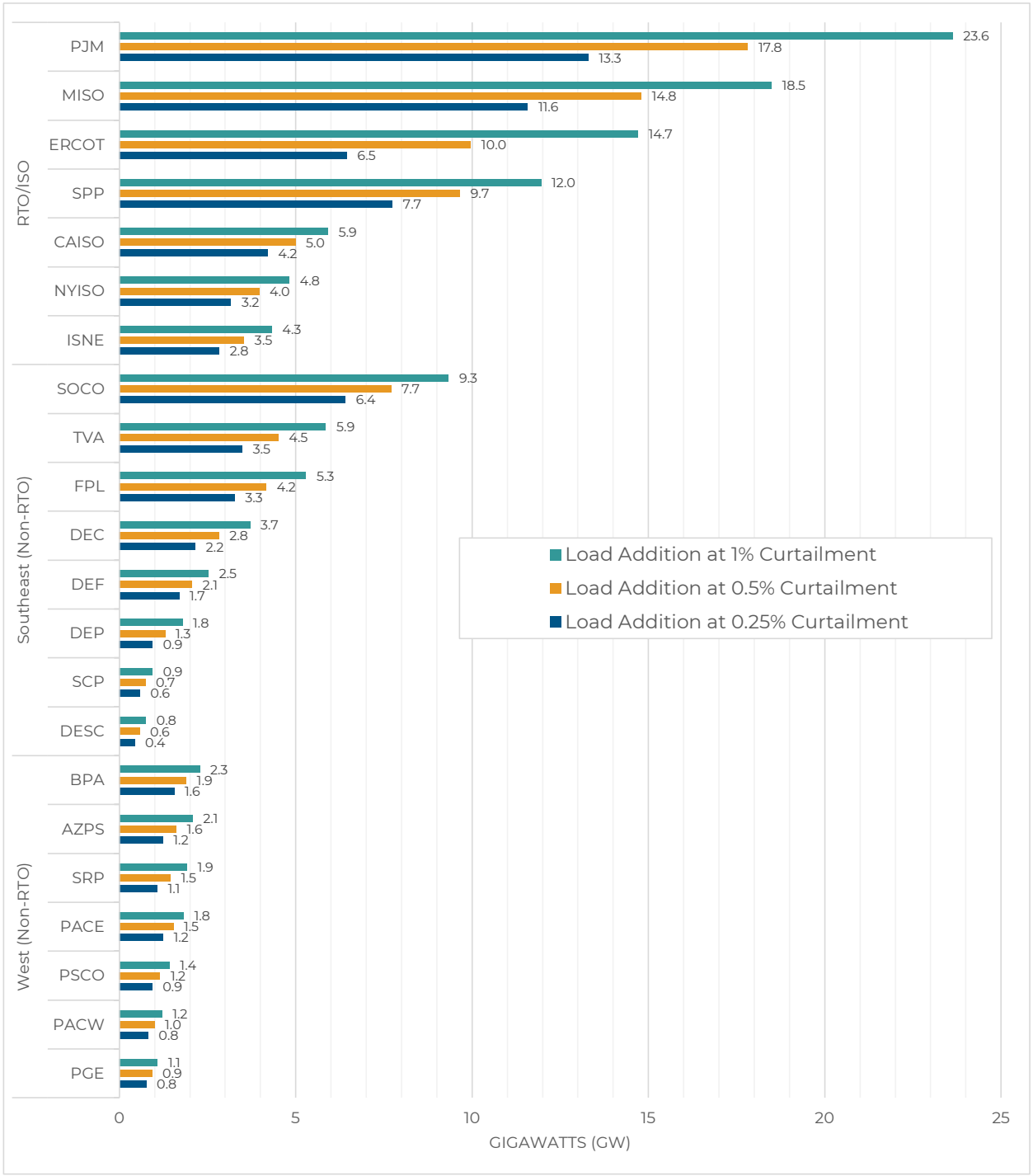
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the role of demand response, particularly for AI-specialized data centers. We then detail the methods and results for estimating curtailment-enabled headroom, highlighting key trends and variations in system headroom and its correlation with load factors across regions. The paper concludes with a brief overview of key findings, limitations, and near-term implications.

BACKGROUND

Load Flexibility Can Accelerate Grid Interconnection

The growing demand for grid access by new large loads has significantly increased interconnection wait times, with some utilities reporting delays up to 7 to 10 years (Li et al. 2024; Saul 2024; WECC 2024). These wait times are exacerbated by increasingly severe transmission equipment supply chain constraints. In June 2024, the President's National Infrastructure Advisory Council highlighted that transformer order lead times had ballooned to two to five years—up from less than one year in 2020—while costs surged by 80% (NIAC 2024). Circuit breakers have seen similar delays: last year, the Western Area Power Administration

Figure 1. System Headroom Enabled by Load Curtailment of New Load by Balancing Authority, GW



Note: *System headroom* refers to the amount of GW by which a BA's load can be augmented every hour in the absence of capacity expansion so that, provided a certain volume of curtailment of the new load, the total demand does not exceed the supply provisioned by system planners to withstand the expected highest peak. The headroom calculation assumes the new load is constant and hence increases the total load by the same GW hour-by-hour.

reported lead times of up to four and a half years for lower voltage classes and five and a half years for higher voltage classes, alongside a 140% price hike over two years (Rohrer 2024). Wood Mackenzie reported in May 2024 that lead times for high-voltage circuit breakers reached 151 weeks in late 2023, marking a 130% year-over-year increase (Boucher 2024).

Large load interconnection delays have recently led to growing interest among data centers in colocating with existing generation facilities. At a FERC technical conference on the subject in late 2024 (FERC 2024c), several participants highlighted the potential benefits of colocation for expedited interconnection,[4] a view echoed in recent grey literature (Schatzki et al. 2024). Colocation, however, represents only a portion of load interconnections and is not viewed as a long-term, system-wide solution.

Load flexibility similarly offers a practical solution to accelerating the interconnection of large demand loads (SIP 2024, Jabeck 2023). The most time-intensive and costly infrastructure upgrades required for new interconnections are often associated with expanding the transmission system to deliver electricity during the most stressed grid conditions (Gorman et al. 2024). If a new load is assumed to require firm interconnection service and operate at 100% of its maximum electricity draw at all times, including during system-wide peaks, it is far more likely to trigger the need for significant upgrades, such as new transformers, transmission line reconductoring, circuit breakers, or other substation equipment.

To the extent a new load can temporarily reduce (i.e., curtail) its electricity consumption from the grid during these peak stress periods, however, it may be able to connect while deferring—or even avoiding—the need for certain upgrades (ERCOT 2023b). A recent study on Virginia's data center electricity load growth noted, "Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion" (K. Patel et al. 2024). The extent and frequency of required curtailment would depend on the specific nature of the upgrades; in some cases, curtailment may only be necessary if a contingency event occurs, such as an unplanned transmission line or generator outage. For loads that pay for firm interconnection service, any period requiring occasional curtailment would be temporary, ending once necessary network upgrades are completed.[5] Such "partially firm," flexible service was also highlighted by participants in FERC's 2024 technical conference on colocation.[6]

Traditionally, such arrangements have been known as *interruptible* electric service. More recently, some utilities have pursued *flexible* load interconnection options. In March 2022, for example, ERCOT implemented an interim interconnection process for large loads seeking to connect in two years or less, proposing to allow loads seeking to qualify as controllable load resources (CLRs) "to be studied as flexible and potentially interconnect more MWs" (ERCOT 2023b). More recently, ERCOT stated that "the optimal solution for grid reliability is for

4 For example, the Clean Energy Buyers Association (2024) noted, "Flexibility of co-located demand is a key asset that can enable rapid, reliable interconnection."

5 Such an arrangement is analogous to provisional interconnection service available to large generators, as defined in Section 5.9.2 of FERC's Pro Forma *Large Generator Interconnection Agreement* (LGIA).

6 MISO's market monitor representative stated, "instead of being a network firm customer, could [large flexible loads] be a non-firm, or partial non-firm [customer], and that could come with certain configuration requirements that make them truly non-firm, or partially non-firm. But, all those things are the things that could enable some loads to get on the system quicker" (FERC 2024c).

more loads to participate in economic dispatch as CLRs" (Springer 2024). Similarly, Pacific Gas and Electric (PG&E) recently introduced a Flex Connect program to allow certain loads faster access to the grid (Allsup 2024).

These options resemble interconnection services available to large generators that forgo capacity compensation, and potentially higher curtailment risk, in exchange for expedited lower-cost grid access (Norris 2023). FERC codified this approach with Energy Resource Interconnection Service (ERIS) in Order 2003 and revisited the concept during a 2024 technical workshop to explore potential improvements (Norris 2024). Some market participants have since proposed modifying ERIS to facilitate the colocation of new generators with large loads (Intersect Power 2024).

Ratepayers Benefit from Higher System Utilization

The US electric power system is characterized by a relatively low utilization rate, often referred to as the *load factor*. The load factor is the ratio of average demand to peak demand over a given period and provides a measure of the utilization of system capacity (Cerna et al. 2023). A system with a high load factor operates closer to its peak system load for more hours throughout the year, while a system with a low load factor generally experiences demand spikes that are higher than its typical demand levels (Cerna et al. 2022). This discrepancy means that, for much of the year, a significant portion of a system's available generation and transmission infrastructure is underutilized (Cochran et al. 2015).

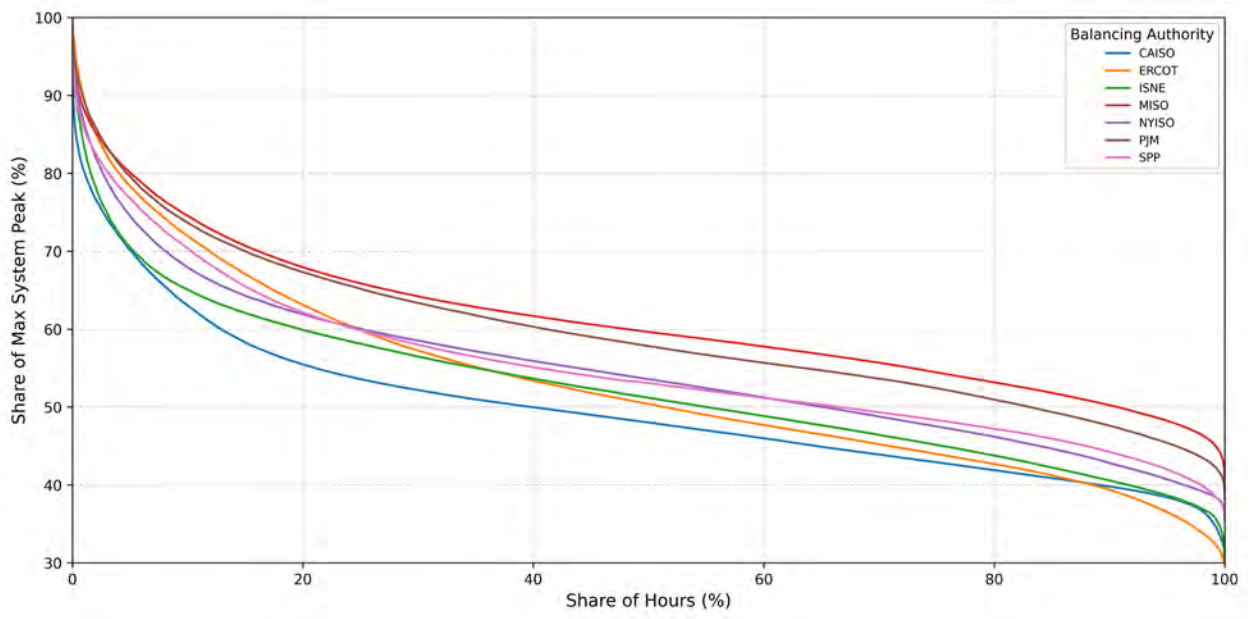
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts add another layer of complexity: some balancing authorities may show higher load factors in summer, yet experience significantly lower utilization in winter, and vice versa.

The *load duration curve* (LDC) illustrates system utilization by ranking demand from highest to lowest over a given period. It provides a visual representation of how often certain demand levels occur, highlighting the frequency and magnitude of peak demand relative to average load. A steep LDC suggests high demand variability, with peaks significantly exceeding typical loads, while a flatter LDC indicates more consistent usage. Figure 2 presents LDCs for each US RTO/ISO based on hourly load between 2016 and 2024, standardized as a percentage of each system's maximum peak demand to allow cross-market comparisons.

A system utilization rate below 100% is expected for most large-scale infrastructure designed to withstand occasional surges in demand. Nevertheless, when the gap between average demand and peak demand is consistently large, it implies that substantial portions of the electric power system—generation assets, transmission infrastructure, and distribution networks—remain idle for much of the year (Riu et al. 2024). These assets are expensive to build and maintain, and ratepayers ultimately bear the cost.

Once the infrastructure is in place, however, there is a strong economic incentive to increase usage and spread these fixed costs over more kilowatt-hours of delivered electricity. An important consideration is therefore the potential for additional load to be added without significant new investment, provided the additional load does not raise the system's overall

Figure 2. Load Duration Curve for US RTO/ISOs, 2016–2024



This figure is adapted from the analysis section of this paper, which contains additional detail on the data and method.

peak demand and thereby trigger system expansion.[7] When new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid's headroom.[8] By strategically timing or curtailing demand, these flexible loads can minimize their impact on peak periods. In doing so, they help existing customers by improving the overall utilization rate—thereby lowering the per-unit cost of electricity—and reduce the likelihood that expensive new peaking plants or network expansions may be needed.

In contrast, inflexible new loads that increase the system's absolute peak demand can drive substantial additional needs for generation and transmission capacity. Even a modest rise in peak demand may trigger capital investments in peaking plants, fuel supply infrastructure, and reliability enhancements. These cost implications have contributed to increasingly contentious disputes in which regulators or ratepayer advocates seek to create mechanisms to pass the costs of serving large loads directly to those loads and otherwise ensure data centers do not shift costs via longer contract commitments, billing minimums, and upfront investment (Howland 2024a; Riu et al. 2024). Some examples include:

- The **Georgia Public Service Commission (GPSC)**, citing "staggering" large load growth and the need to protect ratepayers from the costs of serving those customers, recently implemented changes to customer contract provisions if peak draw exceeds 100 MW, mandating a GPSC review and allowing the utility to seek longer contracts and minimum billing for cost recovery (GPSC 2025). This follows GPSC's approval

7 See the discussion on limitations and further analysis in the following section for additional nuance.

8 Demand charges are often based on coincident consumption (e.g., ERCOT's Four Coincident Peak charge uses the load's coincident consumption at the system's expected seasonal peak to determine an averaged demand charge that may account for >30% of a user's annual bill).

of 1.4 GW of gas capacity proposed by Georgia Power in response to load growth "approximately 17 times greater than previously forecasted" through 2030/2031, a forecast it revised upward in late 2024 (GPC 2023, 2024).

- **Ohio**, where American Electric Power issued a moratorium on data center service requests, followed by a settlement agreement with the Public Service Commission staff and consumer advocates that calls for longer contract terms, load ramping schedules, a minimum demand charge, and collateral for service from data centers exceeding 25 MW (Ohio Power Company 2024).
- **Indiana**, where 4.4 GW of interconnection requests from a "handful" of data centers represents a 157% increase in peak load for Indiana Michigan Power over the next six years. Stakeholders there have proposed "firewalling" the associated cost of service from the rest of the rate base, wherein the utility would procure a separate energy, capacity, and ancillary resource portfolio for large loads and recover that portfolio's costs from only the qualifying large loads (Inskeep 2024).
- **Illinois**, where Commonwealth Edison reported that large loads have paid 8.2% of their interconnection costs while the remaining 91.8% is socialized across general customers (ComEd 2024).

These examples underscore the significance of exploring how flexible loads can mitigate peak increases, optimize the utilization of existing infrastructure, and reduce the urgency for costly and time-consuming capacity expansions.

Demand Response and Data Centers

Demand response refers to changes in electricity usage by end-use customers to provide grid services in response to economic signals, reliability events, or other conditions. Originally developed to reduce peak loads (also called *peak shaving*), demand response programs have evolved to encompass a variety of grid services, including balancing services, ancillary services, targeted deferral of grid upgrades, and even variable renewable integration (Hurley et al. 2013; Ruggles et al. 2021). Demand response is often referred to as a form of *demand-side management* or *demand flexibility* (Nethercutt 2023).

Demand response is the largest and most established form of virtual power plant (Downing et al. 2023), with 33 GW of registered capacity in wholesale RTO/ISO programs and 31 GW in retail programs as of 2023 (FERC 2024a).[9] As a share of peak demand, participation in RTO/ISO programs ranges from a high of 10.1% in MISO to a low of 1.4% in SPP. A majority of enrolled capacity in demand response programs are industrial or commercial customers, representing nearly 70% of registered capacity in retail (EIA 2024).

Following a decade of expansion, growth in demand response program participation stalled in the mid-2010s partially because of depressed capacity prices, forecasted over-capacity, and increasingly restrictive wholesale market participation rules (Hledik et al. 2019). However, the resurgence of load growth and increasing capacity prices, coupled with ongoing advancements in DERs and grid information and communication technologies (ICT) appears likely to reverse this trend.

9 RTO/ISO and retail data may overlap.

Studies of national demand response potential have identified a range of potential scenarios (Becker et al. 2024), ranging as high as 200 GW by 2030 in a 2019 study, comprising 20% of the then-forecasted system peak and yielding $15 billion in annual benefits primarily via avoided generation and transmission and distribution (T&D) capacity (Hledik et al. 2019). Notably, this research was conducted before recent load growth forecasts.

The Participation Gap: Data Centers and Demand Response

For nearly two decades, computational loads—and data centers in particular—have been identified as a promising area for demand response. Early studies explored these capabilities, such as a two-phase Lawrence Berkeley National Laboratory study drawing on six years of research, which concluded in 2010 that "data centers, on the basis of their operational characteristics and energy use, have significant potential for demand response" (Ghatikar et al. 2010) and in 2012 that "[certain] data centers can participate in demand response programs with no impact to operations or service-level agreements" (Ghatikar et al. 2012). The 2012 study provided one of the earliest demonstrations of computational load responsiveness, finding that 10% load shed can typically occur within 6 to 15 minutes.

Despite this promise, data centers have historically exhibited low participation rates in demand response programs as a result of operational priorities and economic incentives (Basmadjian 2019; Clausen et al. 2019; Wierman et al. 2014). Data centers are designed to provide reliable, uninterrupted service and generally operate under service-level agreements (SLAs) that mandate specific performance benchmarks, including uptime, latency, and overall quality of service. Deviation from these standards can result in financial penalties and reputational harm, creating a high-stakes environment where operators are averse to operational changes that introduce uncertainty or risk (Basmadjian et al. 2018).

Compounding this challenge is the increasing prevalence of large-scale colocated data centers, which represent a significant share of the data center market (Shehabi et al. 2024). These facilities house multiple tenants, each with varying operational requirements. Coordinating demand response participation in such environments introduces layers of administrative and logistical complexity, as operators must mediate cost- and reward-sharing agreements among tenants. Further, while data centers possess significant technical capabilities, tapping these capabilities for demand response requires sophisticated planning and expertise, which some operators may not have needed to date (Silva et al. 2024).

Economic considerations have further compounded this reluctance. Implementing a demand response program requires investments in advanced energy management systems, staff training, and integration with utility platforms for which costs can be material, particularly for smaller or midsized facilities. At the same time, financial incentives provided by most demand response programs have historically been modest and insufficient to offset the expenses and opportunity costs associated with curtailed operations. For operators focused on maintaining high utilization rates and controlling costs, the economic proposition of demand response participation may be unattractive.

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The

complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

Table 1. Key Data Center Terms

Term	Definition
AI workload	A broad category encompassing computational tasks related to machine learning, natural language processing, generative AI, deep learning, and other AI-driven applications.
AI-specialized data center	Typically developed by hyperscalers, this type of facility is optimized for AI workloads and relies heavily on high-performance graphics processing units (GPUs) and advanced central processing units (CPUs) to handle intensive computing demands.
Computational load	A category of electrical demand primarily driven by computing and data processing activities, ranging from general-purpose computing to specialized AI model training, cryptographic processing, and high-performance computing (HPC).
Conventional data center	A facility that could range from a small enterprise-run server room to a large-scale cloud data center that handles diverse non-AI workloads, including file sharing, transaction processing, and application hosting. These facilities are predominantly powered by CPUs.
Conventional workload	A diverse array of computing tasks typically handled by CPUs, including file sharing, transaction processing, application hosting, and similar operations.
Cryptomine	A dedicated server farm optimized for high-throughput operations on blockchain networks, typically focused on validating and generating cryptocurrency.
Hyperscalers/hyperscale data centers	Large, well-capitalized cloud service providers that build hyperscale data centers to achieve scalability and high performance at multihundred megawatt scale or larger (Howland 2024b, Miller 2024).
Inferencing	The ongoing application of an AI model, where users prompt the model to provide responses or outputs. According to EPRI, inferencing represents 60% of an AI model's annual energy consumption (Aljbour and Wilson 2024).
Model training	The process of developing and training AI models by processing vast amounts of data. Model training accounts for 30–40% of annual AI power consumption and can take weeks or months to complete (Aljbour and Wilson 2024).

Rethinking Data Centers with AI-Driven Flexibility

Limited documentation of commercial data center participation in demand response has reinforced a perception that these facilities' demands are inherently inflexible loads. A variety of recent developments in computational load profiles, operational capabilities, and broader market conditions, however, suggest that a new phase of opportunity and necessity is emerging.

In a July 2024 memo on data center electricity demand, the SEAB recommended the Department of Energy prioritize initiatives to characterize and advance data center load flexibility, including the development of a "flexibility taxonomy and framework that explores the financial incentives and policy changes needed to drive flexible operation" (SEAB 2024). Building on these recommendations, EPRI announced a multi-year Data Center Flexible Load Initiative (DCFlex) in October 2024 with an objective "to spark change through hands-on and experiential demonstrations that showcase the full potential of data center operational flexibility and facility asset utilization," in partnership with multiple tech companies, electric utilities, and independent system operators (Walton 2024a).[10]

The central hypothesis is that the evolving computational load profiles of AI-specialized data centers facilitate operational capabilities that are more amendable to load flexibility. Unlike the many real-time processing demands typical of conventional data center workloads, such as cloud services and enterprise applications, the training of neural networks that power large language models and other machine learning algorithms is deferrable. This flexibility in timing, often referred to as *temporal flexibility*, allows for the strategic scheduling of training as well as other delay-tolerant tasks, both AI and non-AI alike. These delay-tolerant tasks are also referred to as *batch processing* and are typically not user-prompted (AWS 2025).

This temporal flexibility complements the developing interest in *spatial flexibility*, the ability to dynamically distribute workloads across one or multiple data centers in different geographic locations, optimizing resource utilization and operational efficiency. As stated by EPRI in a May 2024 report, "optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption … some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods" (EPRI 2024). For instance, having already developed a temporal workload shifting system, Google is seeking to implement spatial flexibility as well (Radovanović 2020).

In addition to temporal and spatial flexibility, other temporary load reduction methods may also enable data center flexibility. One approach is dynamic voltage and frequency scaling, which reduces server power consumption by lowering voltage or frequency at the expense of processing speed (Moons et al. 2017; Basmadjian 2019; Basmadjian and de Meer 2018). Another is server optimization, which consolidates workloads onto fewer servers while idling or shutting down underutilized ones, thereby reducing energy waste (Basmajian 2019; Chaurasia et al. 2021). These load reduction methods are driven by advances in virtual workload management, made possible by the "virtualization" of hardware (Pantazoglou et al. 2016).

10 Pointing to EPRI's new DCFlex Initiative, Michael Liebreich noted in a recent essay, "For instance, when they see how much it costs to work 24/7 at full power, perhaps data-center owners will see a benefit to providing some demand response capacity… " (Liebreich 2024).

Finally, temperature flexibility leverages the fact that cooling systems account for 30% to 40% of data center energy consumption (EPRI 2024). For instance, operators can increase cooling during midday when solar energy is abundant and reduce cooling during peak evening demand.[11] While these methods may be perceived as uneconomic due to potential impacts on performance, hardware lifespan, or SLAs, they are not intended for continuous use. Instead, they are best suited for deployment during critical hours when grid demand reduction is most valuable.

Beyond peak shaving, data centers also hold potential to participate in ancillary services, particularly those requiring rapid response, such as frequency regulation. Studies have described how data centers can dynamically adjust workloads to provide real-time support to the grid, effectively acting as "virtual spinning reserves" that help stabilize grid frequency and integrate intermittent renewable resources (McClurg et al. 2016; Al Kez et al. 2021; Wang et al. 2019). This capability extends beyond traditional demand response by providing near-instantaneous balancing resources (Zhang et al. 2022).

Three overarching market trends create further opportunities for load flexibility now than in the past. The first is constrained supply-side market conditions that raise costs and lead times for the interconnecting large inflexible loads, when speed to market is paramount for AI developers. The second is advancements in on-site generation and storage technologies that have lowered costs and expanded the availability of cleaner and more commercially viable behind-the-meter solutions, increasing their appeal to data center operators (Baumann et al. 2020). The third is the growing concentration of computational load in colocated or hyper-scale data centers—accounting for roughly 80% of the market in 2023—which is lending scale and specialization to more sophisticated data center operators. These operators, seek-ing speed to market, may be more likely to adopt flexibility in return for faster interconnec-tion (Shehabi et al. 2024; Basmadjian et al. 2018). The overarching trends underpinning this thesis are summarized in Table 2.

An important consideration for future data center load profiles is the balance between AI-specialized data centers focused on model development and those oriented toward inferencing. If fewer AI models are developed, a larger proportion of computing resources will shift toward inferencing tasks, which is delay-intolerant and variable (Riu et al. 2024). According to EPRI, training an AI model accounts for 30% of its annual footprint, compared to 60% for inferencing the same model (EPRI 2024).

In the absence of regulatory guidance, most advancements in data center flexibility to date are being driven by voluntary private-sector initiatives. Some hyperscalers and data center developers are taking steps to mitigate grid constraints by prioritizing near-term solutions for load flexibility. For example, one such company, Verrus, has established its business model around the premise that flexible data center operations offer an effective solution for growth needs (SIP 2024). Table 3 highlights additional initiatives related to facilitating or demonstrating data center flexibility.

11 Cooling demand for servers is inherently dependent on server workloads. Therefore, reducing workloads saves on cooling needs as well.

Table 2. Trends Enabling Data Center Load Flexibility

Category	Legacy	Future
Computational load profile	• Conventional servers with CPU-dominated workloads (Shehabi et al. 2024) • Real-time, delay-intolerant, and unscheduled processing (e.g., cloud services, enterprise apps) • Low latency critical	• AI-specialized servers with GPU or tensor processing unit (TPU)-favored workloads (Shehabi et al. 2024) • Greater portion of delay-tolerant and scheduled machine learning workloads (model training, non-interactive services) • Higher share of model training affords greater demand predictability • Highly parallelized workloads (Shehabi et al. 2024)
Operational capabilities	• Minimal temporal load shifting • Minimal spatial load migration • High proximity to end users for latency-sensitive tasks • Reliance on Tier 2 diesel generators for backup • Limited utilization of on-site power resulting from pollution concerns and regulatory restrictions (Cary 2023)	• More robust and intelligent temporal workload shifting (Radovanović et al. 2022) • Advanced spatial load migration and multi–data center training (D. Patel et al. 2024) • Flexibility in location for model training • Backup power diversified (storage, renewables, natural gas, cleaner diesel) • Cleaner on-site power enables greater utilization
Market conditions	• Minimal electric load growth • High availability of T&D network headroom • Standard interconnection timelines and queue volumes • Low supply chain bottlenecks for T&D equipment • Low capacity prices and forecasted overcapacity • High cost of clean on-site power options • Small-scale “server room” model	• High electric load growth • Low availability of T&D network headroom • Long interconnection timelines and overloaded queues • High supply chain bottlenecks for T&D equipment • High capacity prices and forecasted undercapacity (Walton 2024b) • Lower cost of clean on-site power options (Baranko et al. 2024) • Data center operations concentrating in large-scale facilities and operators

Table 3. Implementations of Computational Load Flexibility

Category	Examples
Operational flexibility	• Google deployed a "carbon-aware" temporal workload–shifting algorithm and is now seeking to develop geographic distribution capabilities (Radovanović 2020). • Google data centers have participated in demand response by reducing non-urgent compute tasks during grid stress events in Oregon, Nebraska, the US Southeast, Europe, and Taiwan (Mehra and Hasegawa 2023). • Enel X has supported demand response participation by data centers in North America, Ireland, Australia, South Korea, and Japan, including use of on-site batteries and generators to enable islanding within minutes (Enel X 2024). • Startup companies like Emerald AI are developing software to enable large-scale demand response from data centers through recent advances in computational resource management to precisely deliver grid services while preserving acceptable quality of service for compute users
On-site power	• Enchanted Rock, an energy solutions provider that supported Microsoft in building a renewable natural gas plant for a data center in San Jose, CA, created a behind-the-meter solution called Bridge-to-Grid, which seeks to provide intermediate power until primary service can be switched to the utility. At that point, the on-site power transitions to flexible backup power (Enchanted Rock 2024, 2025).
Market design and utility programs	• ERCOT established the Large Flexible Load Task Force and began to require the registration of large, interruptible loads seeking to interconnect with ERCOT for better visibility into their energy demand over the next five years (Hodge 2024). • ERCOT's demand response program shows promise for data center flexibility, with 750+ MW of data mining load registered as CLRs, which are dispatched by ERCOT within preset conditions (ERCOT 2023a). • PG&E debuted Flex Connect, a pilot that provides quicker interconnection service to large loads in return for flexibility at the margin when the system is constrained (Allsup 2024, St. John 2024).
Cryptomining	• A company generated more revenue from its demand response participation in ERCOT than from Bitcoin mining in one month, at times accommodating a 95% load reduction during peak demands (Riot Platforms 2023).

ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

In this section we describe the method for estimating the gigawatts of new load that could be added to existing US power system load before the total exceeds what system planers are prepared to serve, provided that load curtailment is applied as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.[12] We first investigated the aggregate and seasonal load factor for each of the 22 investigated balancing authorities, which measures a system's average utilization rate. Second, we computed the curtailment-enabled headroom for different assumptions of ac-

12 SEAB proposed a similar term, *available flex capacity*, in its July 2024 report *Recommendations on Powering Artificial Intelligence and Data Center Infrastructure*.

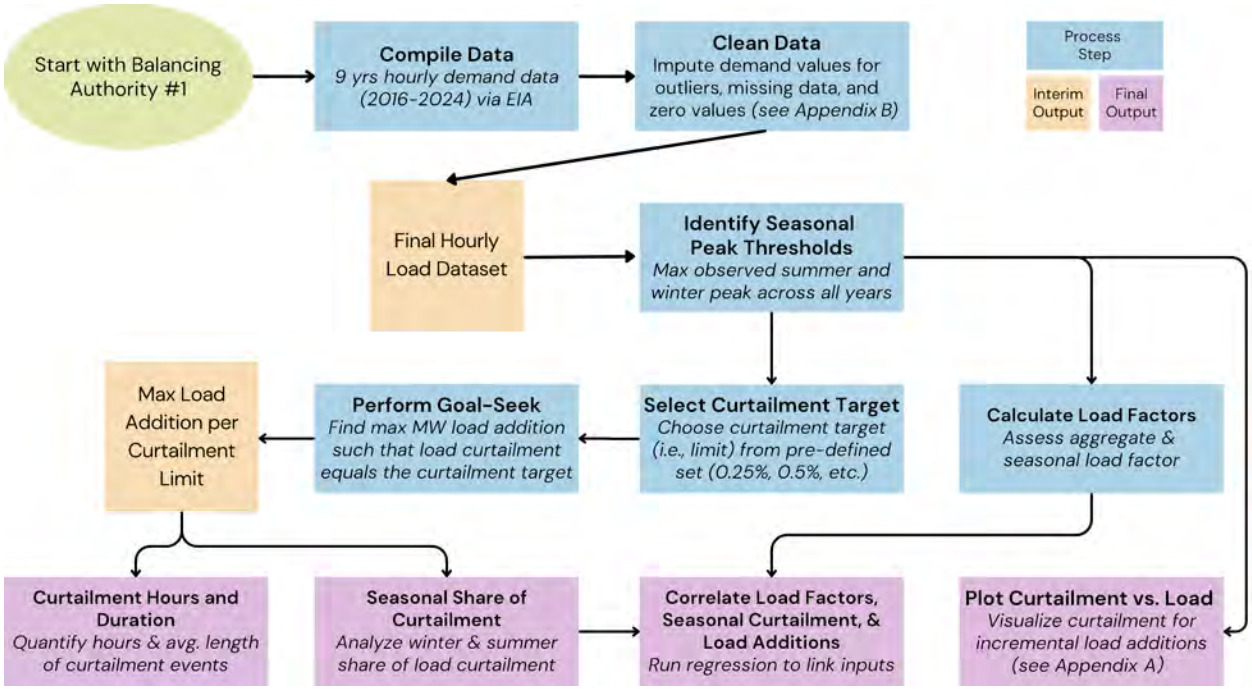
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed historical peak thresholds. Third, we quantified the magnitude, duration, and seasonal concentration of the load curtailment for each balancing authority. Finally, we examined the correlation between load factor, seasonal curtailment, and max potential load additions. This process is summarized in Figure 3.

Data and Method

Data

We considered nine years of hourly load data aggregated for each of the 22 balancing authorities, encompassing seven RTO/ISOs,[13] eight non-RTO Southeastern BAs,[14] and seven non-RTO Western BAs.[15] Together, these balancing authorities represent 744 of the approximate 777 GW of summer peak load (95%) across the continental United States. The dataset, sourced from the EIA Hourly Load Monitor (EIA-930), contains one demand value per hour

Figure 3. Steps for Calculating Headroom and Related Metrics



13 CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

14 DEC; DEP; DEF; DESC; FPL; Santee Cooper, SCP; Southern Company (SOCO); and TVA. Note the different BA codes used by EIA: DUK for DEC, CPLE for DEP, SCEG for DESC, FPC for DEF, and SC for SCP. Also note that Southern Company includes Georgia Power, Alabama Power, and Mississippi Power. A complete list of abbreviations and their definitions can be found at the end of the paper.

15 AZPS, BPA, PACE, PACW, PGE, PSCO, and SRP. Note that EIA uses the code BPAT for BPA. A complete list of abbreviations and their definitions can be found at the end of the paper.

and spans January 1, 2016, through December 31, 2024.[16] Data from 2015 were excluded because of incomplete reporting.[17] The dataset was cleaned to identify and impute values for samples with missing or outlier demand values (see details in Appendix B).

Determining Load Additions for Curtailment Limits

An analysis was conducted to determine the maximum load addition for each balancing authority that can be integrated while staying within predefined curtailment limits applied to the new load. The load curtailment limits (0.25%, 0.5%, 1.0%, and 5.0%) were selected within the range of maximum curtailment caps for existing interruptible demand response programs.[18] The analysis focused on finding the load addition volume in megawatts that results in an average annual load curtailment rate per balancing authority that matches the specified limit. To achieve this, a goal-seek technique was used to solve for the load addition that satisfies this condition,[19] for which the mathematical expression is presented in Appendix C. The calculation assumed the new load is constant and hence increases the total system load by the same gigawatt volume hour-by-hour. To complement this analysis and visualize the relationship between load addition volume and curtailment, curtailment rates were also calculated across small incremental load additions (i.e., 0.25% of the BA's peak load).

Load Curtailment Definition and Calculation

Load curtailment is defined as the megawatt-hour reduction of load required to prevent the augmented system demand (existing load + new load) from exceeding the maximum seasonal system peak threshold (e.g., see Figure 4). Curtailment was calculated hourly as the difference between the augmented demand and the seasonal peak threshold. These hourly curtailments in megawatt-hours were aggregated for all hours in a year to determine the total annual curtailment. The curtailment rate for each load increment was defined as the total annual curtailed megawatt-hours divided by the new load's maximum potential annual consumption, assuming continuous operation at full capacity.

Peak Thresholds and Seasonal Differentiation

Balancing authorities develop resource expansion plans to support different peak loads in winter and summer. To account for variation, we defined seasonal peak thresholds for each balancing authority. Specifically, we identified the maximum summer peak and the maximum winter peak observed from 2016 to 2024 for each balancing authority.[20] These thresholds serve as the upper limits for system demand during their respective seasons, and all

16 Additional detail on EIA's hourly load data collection is available at https://www.eia.gov/electricity/gridmonitor/about.

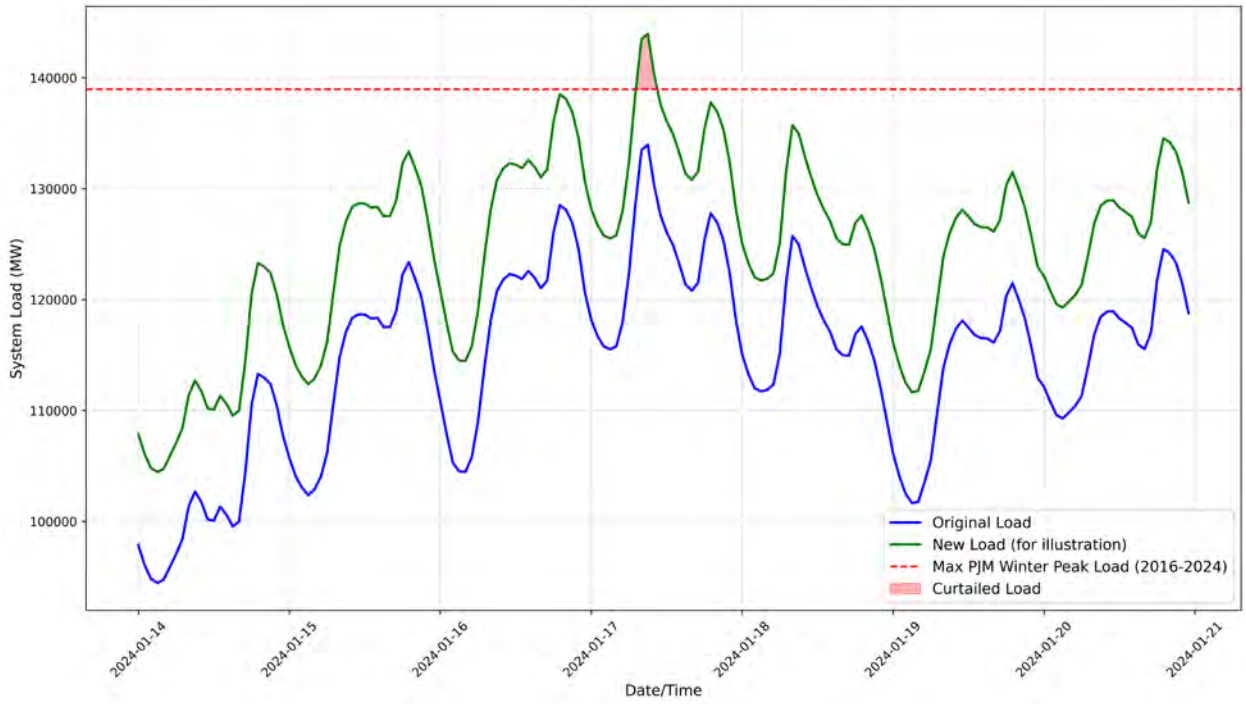
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

18 For example, PG&E's and Southern California Edison's Base Interruptible Programs limit annual interruption for registered customers to a maximum of 180 hours (2.0% of all annual hours) or 10 events per month.

19 The goal-seek approach was implemented using Python's scipy.optimize.root_scalar function from the SciPy library. This tool is designed for solving one-dimensional root-finding problems, where the goal is to determine the input value that satisfies a specified equation within a defined range.

20 To identify the max seasonal peak load, summer was defined as June–August, while winter encompassed December–February. In a few cases, the BA's seasonal peak occurred within one month of these periods (AZPS winter, FPL winter, CAISO summer, CAISO winter), which were used as their max seasonal peak. To account for potential (albeit less likely) curtailment in shoulder months, the applicable summer peak was applied to April–May and September–October and the winter peak to November and March.

Figure 4. Illustrative Load Flexibility in PJM



megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

Year-by-Year Curtailment Analysis

Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments, resulting in a list of annual curtailment rates corresponding to each load increment. To synthesize results across years, we calculated the average curtailment rate for each load addition increment by averaging annual curtailment rates over the nine years. This averaging process smooths out year-specific anomalies and provides an estimate of the typical system response to additional load. This analysis was also used to calculate the average number of hours of curtailment for each curtailment limit and the seasonal allocation of curtailed generation.[21] We also assessed the magnitude of load curtailment required during these hours as a share of the new load's maximum potential draw to calculate the number of hours when 90%, 75%, and 50% or more of the load would still be available.

21 Consistent with the curtailment analysis, summer was defined as June–August and winter as December–February. For BAs located on the Pacific coast (BPA, CAISO, PGE, PACE, PACW), November was counted as winter given the region's unique seasonal load profile.

Figure 5. Load Factor by Balancing Authority and Season, 2016–2024

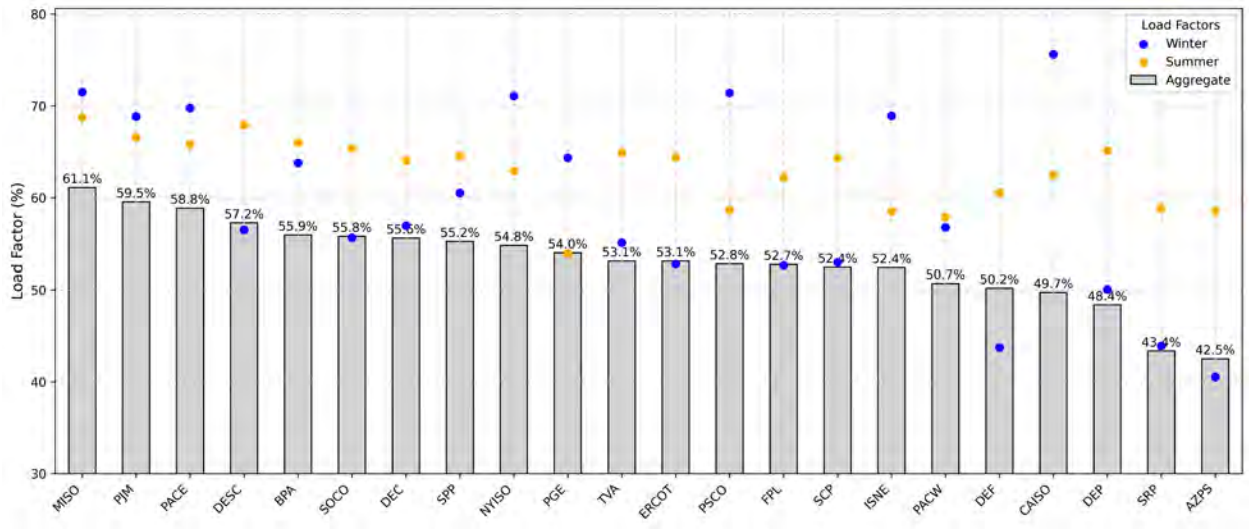
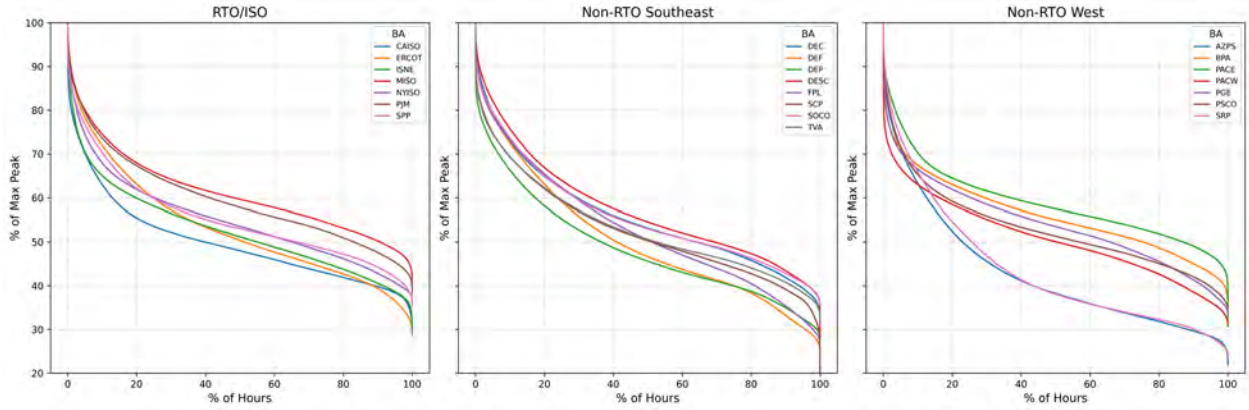


Figure 6. Load Duration Curves by Balancing Authority, 2016–2024



Results

Load Factor

In examining data for 22 balancing authorities, we found that aggregate load factors ranged between 43% to 61% (Figures 5 and 6), with an average and median value of 53%. The BAs with the lowest aggregate load factors were those in the desert southwest, Arizona Public Service Company (AZPS) and Salt River Project Agricultural Improvement and Power District (SRP). In terms of seasonal load factor, defined here as the average seasonal load as a share of seasonal maximum load (i.e., not as a share of the maximum all-time system load), winter load factors were notably lower than summer. The average and median winter load factor was 59% and 57% respectively, compared to 63% and 64% for summer. A majority of the balancing authorities had higher summer load factors (14) than winter (8).

Headroom Volume

Results show that the headroom across the 22 analyzed balancing authorities is between 76 to 215 GW, depending on the applicable load curtailment limit. This means that 76 to 215 GW of load could be added to the US power system and yet the total cumulative load would remain below the historical peak load, except for a limited number of hours per year

Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW

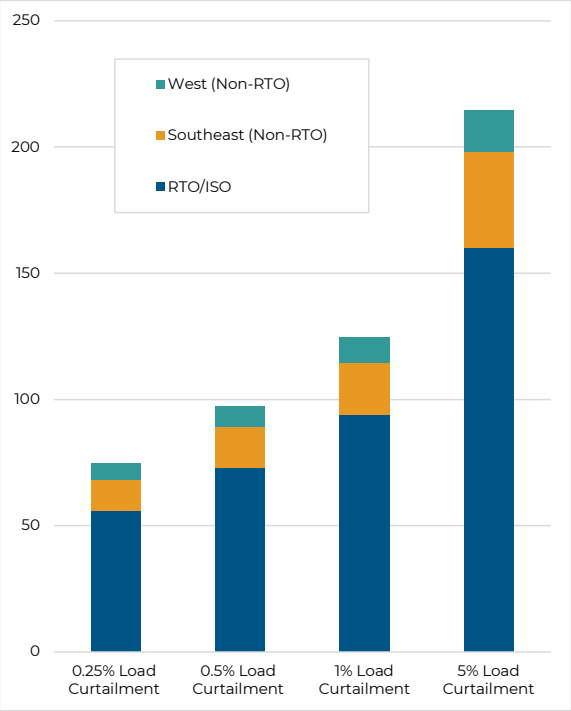


Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW

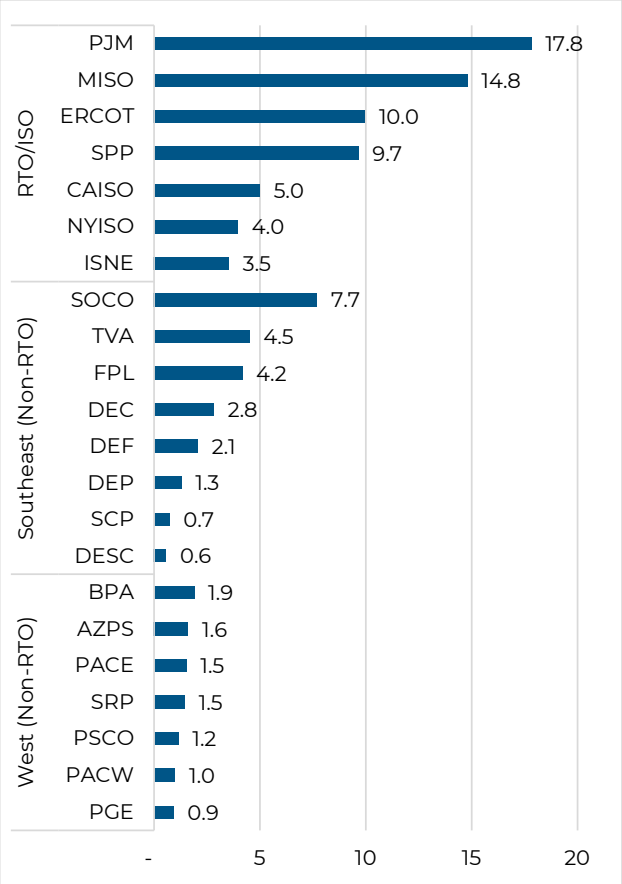
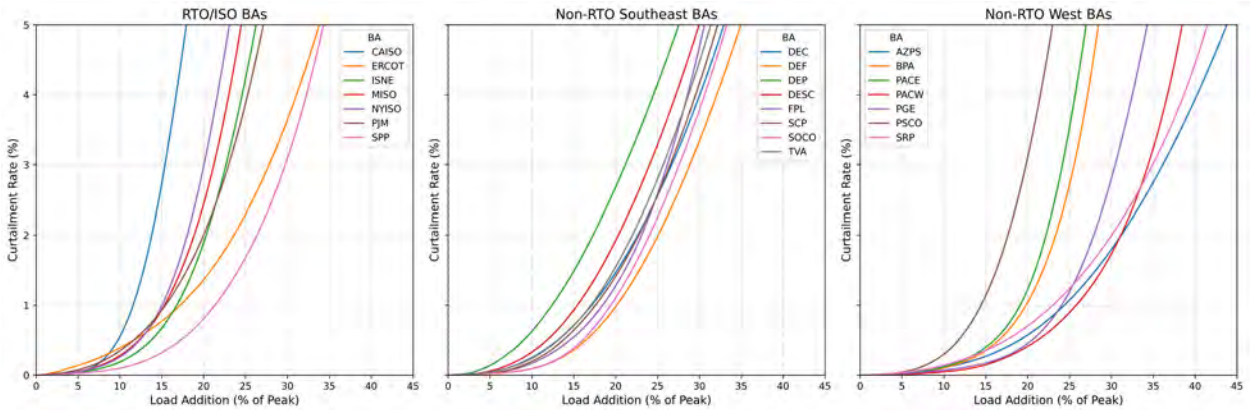


Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



when the new load would be unserved. Specifically, 76 GW of headroom is available at an expected load curtailment rate of 0.25% (i.e., if 0.25% of the maximum potential annual energy consumption of the new load is curtailed during the highest load hours, or 1,643 out of 657,000 GWh). This headroom increases to 98 GW at 0.5% curtailment, 126 GW at 1.0% curtailment, and 215 GW at 5.0% curtailment (Figure 7). Headroom varies by balancing authority (Figure 8), including as a share of system peak (Figure 9). The five balancing authorities with the highest potential volume at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW. Detailed plots for each balancing authority, including results for each year, can be found in Appendix A.

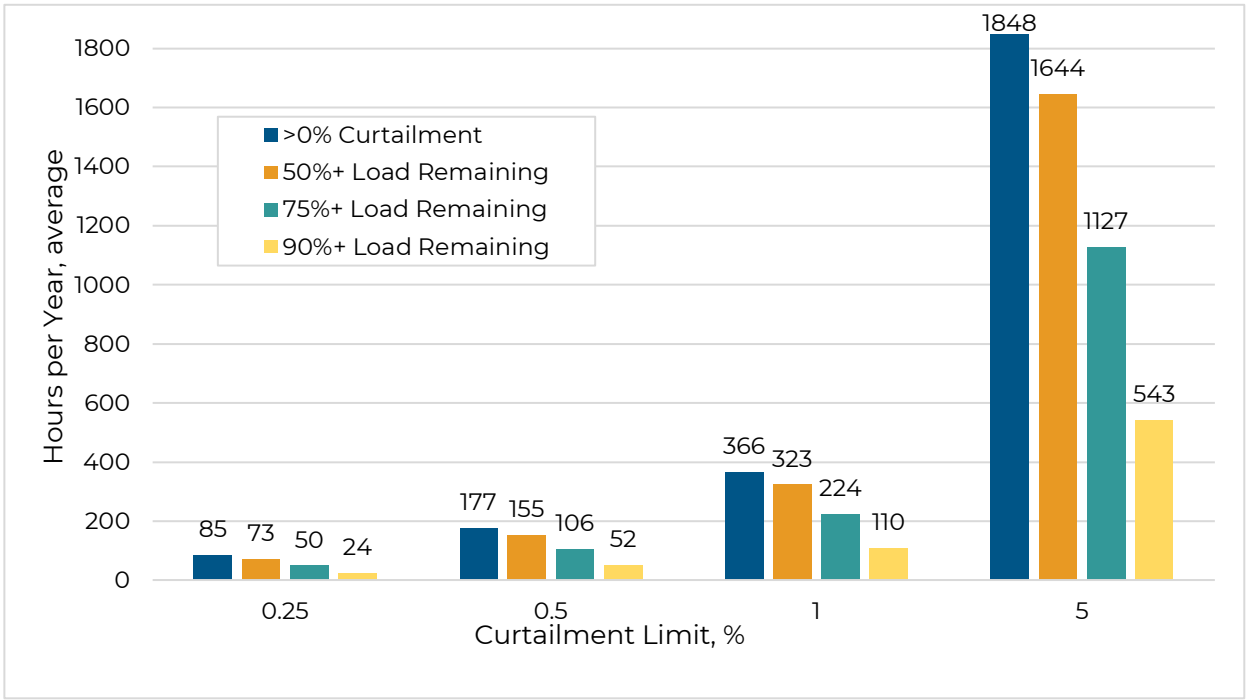
Curtailment Hours

A large majority of curtailment hours retain most of the new load. Most hours during which load reduction is required entail a curtailment rate below 50% of the new load. Across all 22 BAs, the average required load curtailment times are 85 hours under the 0.25% curtailment rate (~1% of the hours in a year), 177 hours under the 0.5% curtailment rate, 366 hours under the 1.0% curtailment rate, and 1,848 hours under the 5.0% curtailment rate (i.e., ~21% of the hours). On average, 88% of these hours retain at least 50% of the new load (i.e., less than 50% curtailment of the load is required), 60% of the hours retain at least 75% of the load, and 29% retain at least 90% of the load (see Figure 10).

Curtailment Duration

The analysis calculated the average hourly duration of curtailment events (i.e., the length of time the new load is curtailed during curtailment events). All hours in which any curtailment occurred were included, regardless of magnitude. The results for each balancing authority and curtailment limit are presented in Figure 11. The average duration across BAs was 1.7 hours for the 0.25% limit, 2.1 hours for the 0.5% limit, 2.5 hours for the 1.0% limit, and 4.5 hours for the 5.0% limit.

Figure 10. Hours of Curtailment by Load Curtailment Limit



Seasonal Concentration of Curtailment

The analysis reveals significant variation in the seasonal concentration of curtailment hours across balancing authorities. The winter-summer split ranged from 92% to 1% for CAISO (California Independent System Operator), where curtailment is heavily winter-concentrated, to 0.2% to 92% for AZPS,[22] which exhibited a heavily summer-concentrated curtailment profile (Figure 12a).[23]

Figure 11. Average Curtailment Duration by Balancing Authority and Curtailment Limit, Hours

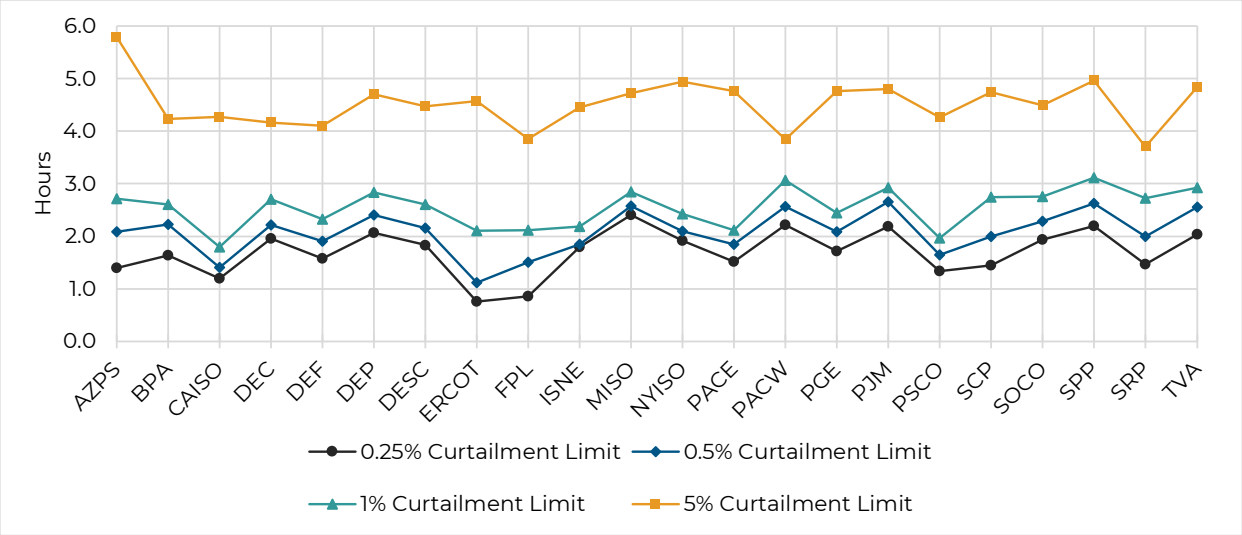
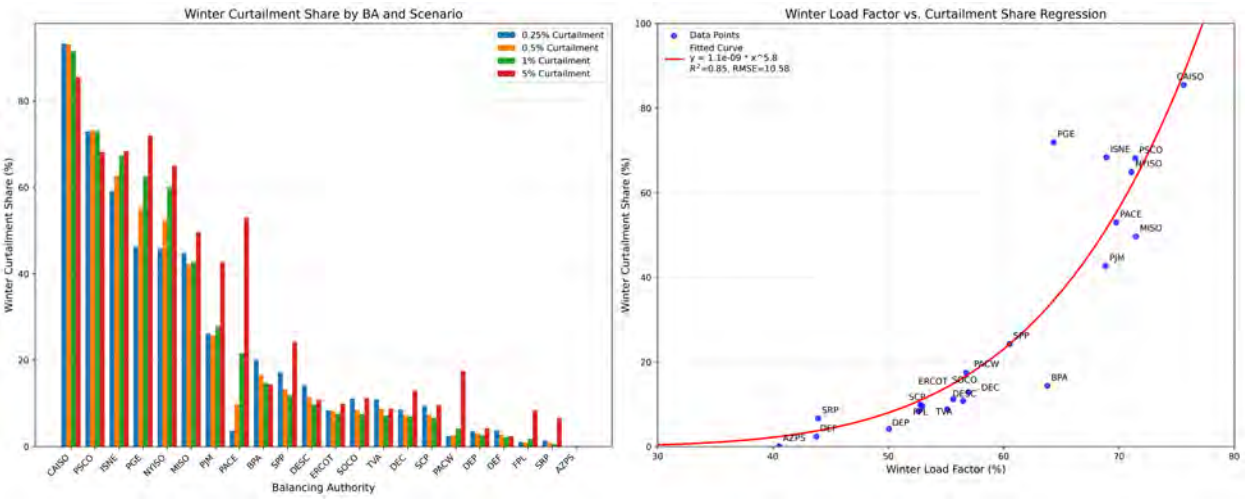


Figure 12. Seasonal Curtailment Analysis



(a) (b)

22 Note the remainder of the curtailment occurred in these BAs in shoulder months (i.e., not summer, not winter).

23 These values correspond to the seasonal curtailment concentration for the 1% curtailment limit.

A key observation is the strong correlation between the winter load factor (system utilization during winter months) and the seasonal allocation of curtailment hours (Figure 12b). BAs with lower winter load factors—indicating reduced system utilization during winter—tend to have greater capacity to accommodate additional load in winter while experiencing a dispro-portionately higher share of curtailment during summer months. This trend is particularly pronounced in balancing authorities located in the Sun Belt region, resulting in a lower win-ter concentration of curtailment hours.

While most BAs exhibited relatively stable seasonal curtailment shares across increasing load addition thresholds, some demonstrated notable shifts in seasonal allocation as load additions increased (e.g., PACW, FPL, NYISO, ISO-NE, PACE, PGE). These shifts highlight the dynamic interplay between system demand patterns and the incremental addition of new load.

Figure 12a illustrates this variability, showcasing the relationship between winter load factor and winter curtailment share across curtailment scenarios.[24]

Discussion

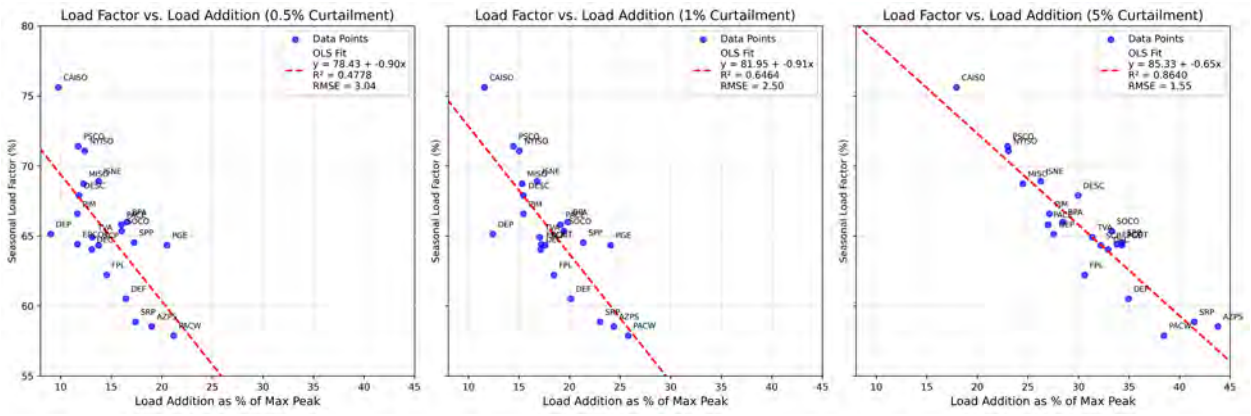
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across balancing authorities, driven by differences in seasonal and aggregate load patterns. This variation suggests that seasonal load factors may be strongly linked to how much additional load a balancing authority can integrate without requiring high curtailment rates.

To explore this relationship, we analyzed system load factors in relation to the additional load that each balancing authority could accommodate while limiting the load curtailment rate to 0.5%, 1.0%, and 5.0% (i.e., the load curtailment limit). To allow for meaningful comparison across BAs, the additional load was standardized as a percentage of the BA's historical peak load. To account for whether a balancing authority's curtailment was concentrated in the summer or winter, the seasonal load factor was selected corresponding to the season with the highest share of curtailment.

The analysis revealed that BAs with higher seasonal load factors tended to have less headroom for the load curtailment limits examined (Figure 13). In simpler terms, systems with higher utilization during their busiest season had less power generation capacity planned to be available that could serve new load without hitting curtailment limits. For example, CAISO, with a seasonal load factor of 76%, could accommodate less additional load compared to PacifiCorp West (PACW) and AZPS, which exhibited lower seasonal load factors and supported larger load additions as a share of peak system load. This relationship grew in statistical significance as the load curtailment limit increased, yielding an R^2 value of 0.48 and an RMSE of 3.04 at the 0.5% curtailment limit, and an R^2 value of 0.86 and an RMSE of 1.55 at the 5% curtailment limit (i.e., 86% of the variation in load addition capacity across balancing authorities can be explained by differences in load factor at a curtailment limit of 5.0%).

24 Note in Figure 12b that a high-degree polynomial function captures the nonlinear growth in the area under the load curve as curtailed load exceeds a fixed peak threshold. This fit generally aligns with expectations, demonstrating that higher-degree terms are necessary to capture the relationship between load factor and curtailed load.

Figure 13. Load Factor Versus Max Load Addition as Share of Peak Load



These findings emphasize the importance of load factor as a predictor of curtailment-enabled headroom. BAs with more uneven peak seasonal demand—characterized by relatively low system utilization in winter or summer—tend to have greater capacity to integrate new loads with limited curtailment. Conversely, systems with more consistent demand across the winter and summer face tighter limits, as their capacity to absorb additional load is already constrained by elevated baseline usage.

Limitations

This analysis provides a first-order assessment of power generation capacity available for serving new curtailable loads, and hence is an exploration of the market potential for large-scale demand response. The primary focus of the analysis is to ensure that total demand, subject to curtailment limits for new load, stays below the system peak for which system planners have prepared. Other considerations important for planning—such as ensuring adequate transmission capacity, ramping capability, and ramp-feasible reserves, among others—are beyond the scope of this study and therefore the results cannot be taken as an accurate estimate of the load that can be added to the system. Additionally, the analysis assumes the new loads do not change current demand patterns but rather shift the existing demand curves upward, and a more precise assessment of the potential for integration of new loads would require detailed characterization of the temporal patterns of the load. There is significant variation in how system operators forecast and plan for system peaks, accounting for potential demand response, and as a result there will be differences in the methods used to estimate potential to accommodate new load. Despite these limitations, the results presented here signal a vast potential that, even if overstated, warrants further research.

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably,

this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

Future Analysis

Enhancing this analysis to more accurately assess the capacity to integrate large curtailable load would require addressing the following considerations:

Network Constraints

This analysis does not account for network constraints, which would require a power flow simulation to evaluate the ability of the transmission system to accommodate additional load under various conditions. As such, the results should not be interpreted as an indication that the identified load volumes could be interconnected and served without any expansions in network capacity. While the existing systems are planned to reliably serve their peak loads, this planning is based on the current load topology and the spatial distribution of generation and demand across the transmission network. A large new load could avoid exceeding aggregate peak system demand by employing flexibility, yet still cause localized grid overloads as a result of insufficient transmission capacity in specific areas. Such overloads could necessitate network upgrades, including the expansion of transmission lines, substations, or other grid infrastructure. Alternatively, in the absence of network upgrades, localized congestion could be addressed through the addition of nearby generation capacity, potentially limiting the flexibility and economic benefits of the new load. These factors underscore the importance of incorporating network-level analyses to fully understand the operational implications of large flexible load additions.

Intertemporal Constraints

This analysis does not account for intertemporal constraints related to load and generator operations. For load operations, response times affect system operations and management of operational reserves. Faster response times from flexible loads could alleviate system stress more effectively during peak demand periods, potentially reducing the reliance on reserve capacity. Conversely, slower response times may require additional reserves to bridge the gap between the onset of system imbalances and the load's eventual response. Moreover, the rapid ramp-down of large flexible loads could lead to localized stability or voltage issues, particularly in regions with weaker grid infrastructure. These effects may necessitate more localized network analyses to evaluate stability risks and operational impacts. On the generation side, intertemporal constraints such as ramping limits, minimum up and down times, and startup times can affect the system's ability to integrate fast-response demand. For instance, ramping constraints may restrict how quickly generators can adjust output to align with the curtailment of flexible loads, while minimum uptime and downtime requirements can limit generator flexibility.

Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly

applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

CONCLUSION

This study highlights extensive potential for leveraging large load flexibility to address the challenges posed by rapid load growth in the US power system. By estimating the curtailment-enabled headroom across balancing authorities, the analysis demonstrates that existing system capacity—intentionally designed to accommodate the extreme swings of peak demand—could accommodate significant new load additions with relatively modest curtailment, as measured by the average number, magnitude, and duration of curtailment hours.

The findings further emphasize the relationship between load factors and headroom availability. Balancing authorities with lower seasonal load factors exhibit greater capacity to integrate flexible loads, highlighting the importance of regional load patterns in determining system-level opportunities. These results suggest that load flexibility can play a significant role in improving system utilization, mitigating the need for costly infrastructure expansion and complementing supply-side investments to support load growth and decarbonization objectives.

This analysis provides a first-order assessment of market potential, with estimates that can be refined through further evaluation. In particular, network constraints, intertemporal operational dynamics, and shifts in loss-of-load expectation periods represent opportunities for future analyses that can offer a deeper understanding of the practical and operational implications of integrating large flexible loads.

In conclusion, the integration of flexible loads offers a promising, near-term strategy for addressing structural transformations in the US electric power system. By utilizing existing system headroom, regulators and market participants can expedite the accommodation of new loads, optimize resource utilization, and support the broader goals of reliability, affordability, and sustainability.

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ABBREVIATIONS

AI	Artificial intelligence
AZPS	Arizona Public Service Company
BA	balancing authority
BPA	Bonneville Power Administration
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CLRs	controllable load resources
CPUs	central processing units
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress East
DERs	distributed energy resources
DESC	Dominion Energy South Carolina
EIA	Energy Information Administration
EPRI	Electrical Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission's
FPL	Florida Power & Light
GPUs	graphics processing units
ICT	information, and communication technology
ISO-NE	ISO New England
LGIA	Large Generator Interconnection Agreement
LOLE	loss of load expectation
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PACE	PacifiCorp East
PACW	PacifiCorp West
PG&E	Pacific Gas and Electric
PGE	Portland General Electric Company
PJM	PJM Interconnection
PSCO	Public Service Company of Colorado
RMSE	Root mean square error
RTO/ISO	Regional transmission organization/independent system operator
SCP	Santee Cooper, South Carolina Public Service Authority
SEAB	Secretary of Energy Advisory Board
SLAs	service-level agreements
SOCO	Southern Company
SPP	Southwest Power Pool
SRP	Salt River Project Agricultural Improvement and Power District
TPU	tensor processing unit
TVA	Tennessee Valley Authority

APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER BALANCING AUTHORITY

Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW

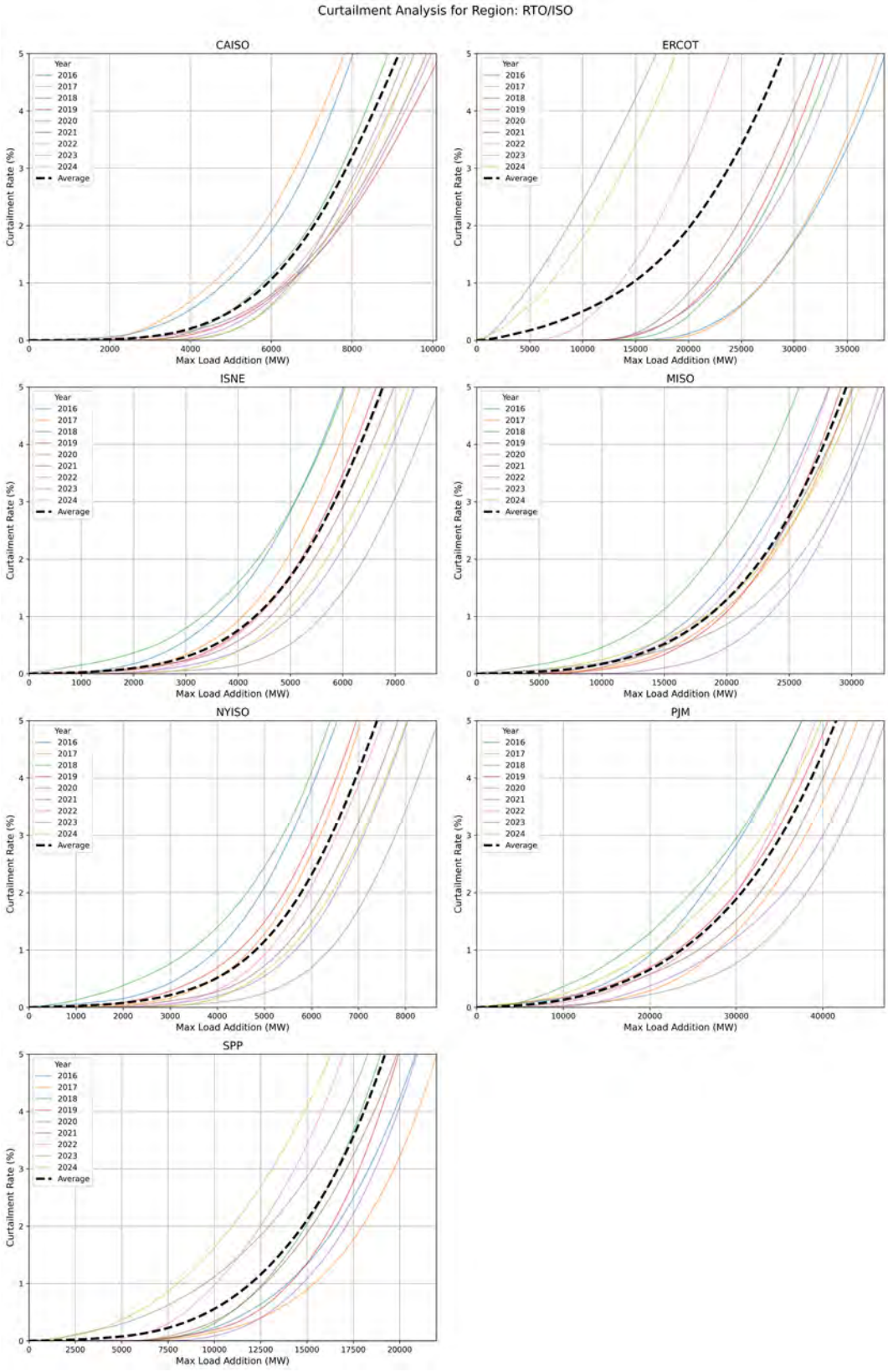


Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW

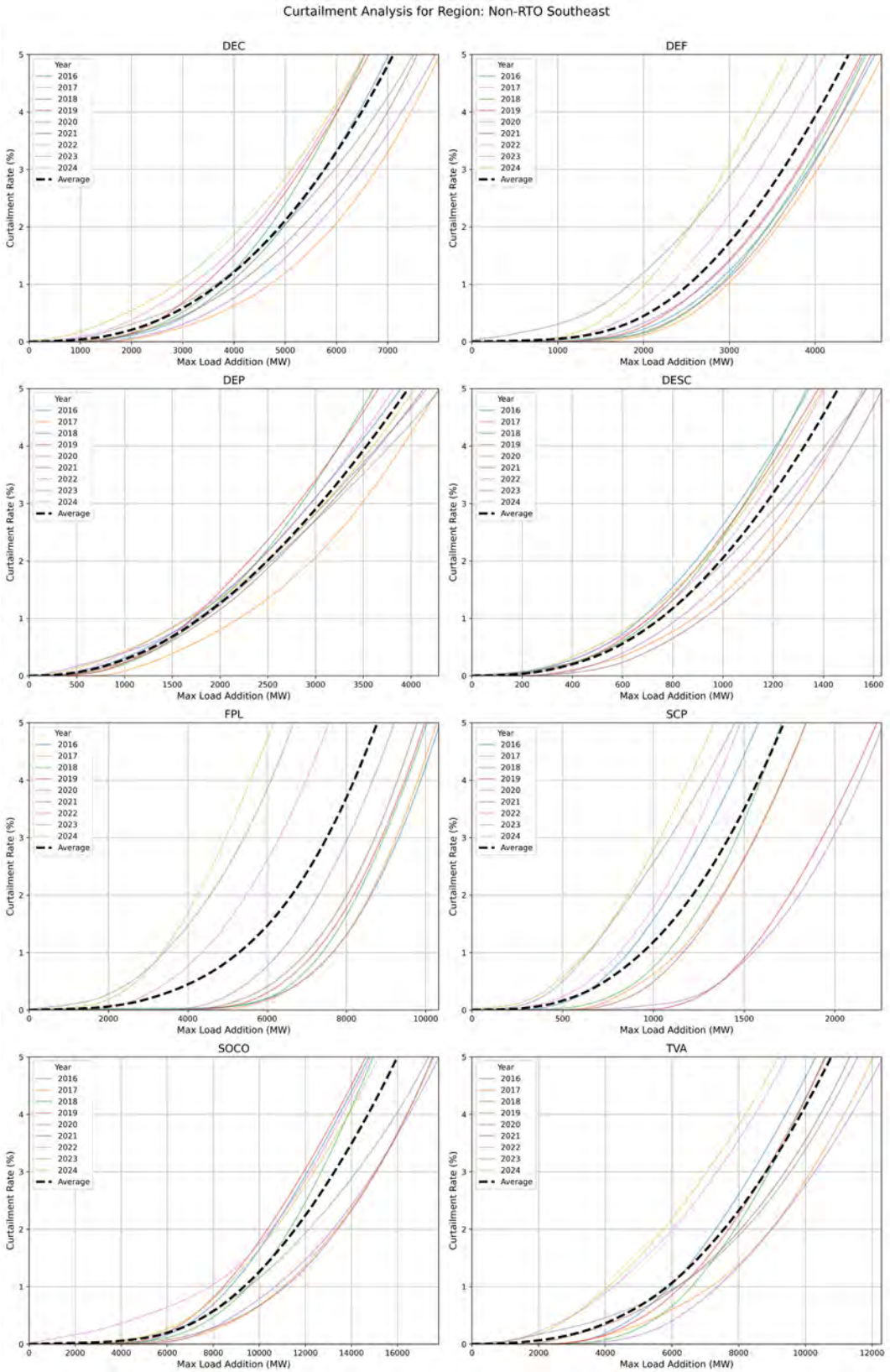
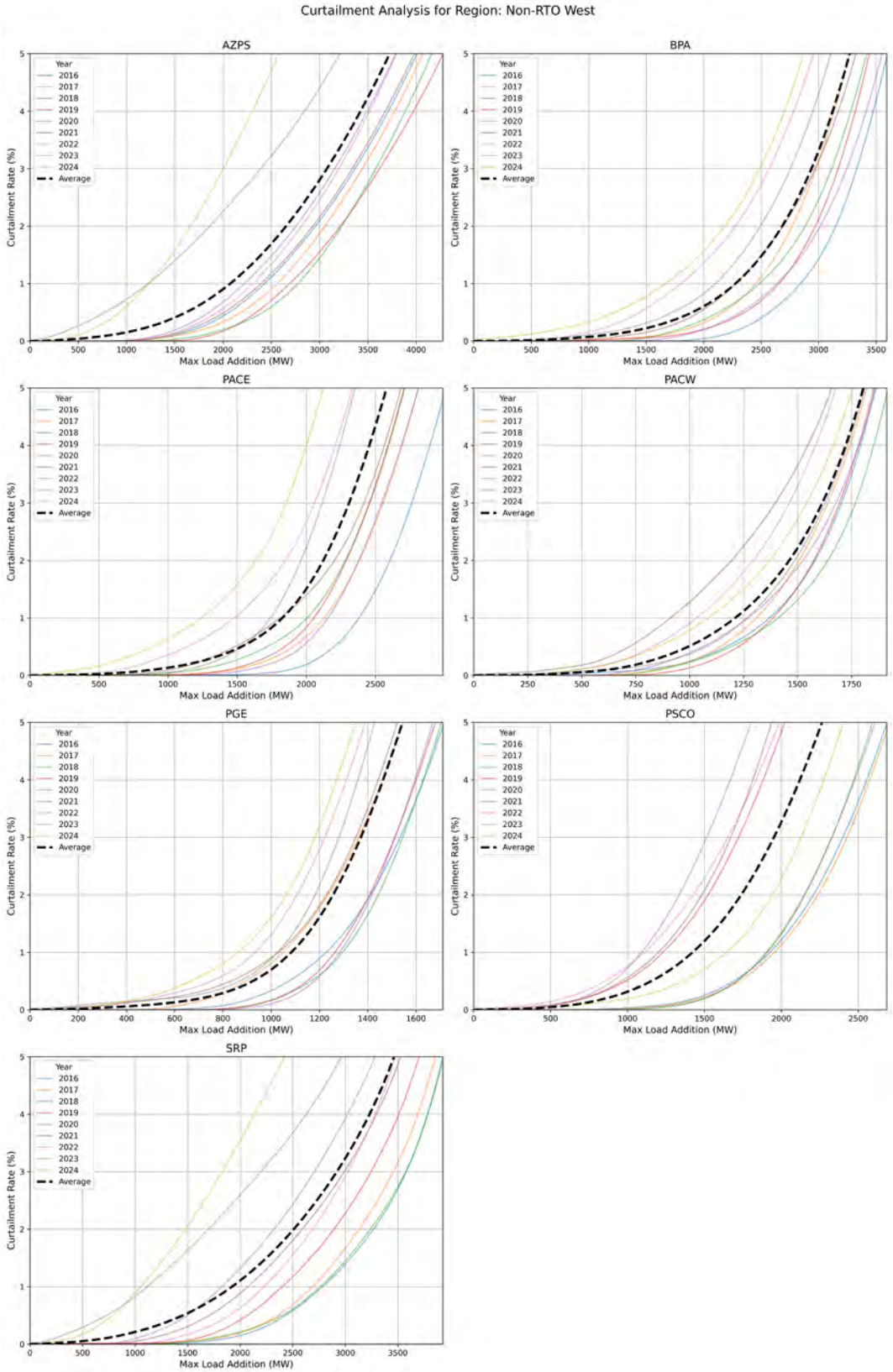


Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



APPENDIX B: DATA CLEANING SUMMARY

The data cleaning process attempted to improve the accuracy of nine years of hourly load data across the 22 balancing authorities, including the following steps:

1. Data normalization
    - **Dates:** Date-time formats were verified to be uniform.
    - **Demand data:** Where the balancing authority had an "Adjusted demand" value for a given hour, this value was used, otherwise its "Demand" value was used. The final selected values were saved as "Demand" and a log was kept.
    - **BA labels:** Labels were mapped to align with widely used acronyms, including:
        - CPLE → DEP
        - DUK → DEC
        - SC → SCP
        - SWPP → SPP
        - SCEG → DESC
        - FPC → DEF
        - CISO → CAISO
        - BPAT → BPA
        - NYIS → NYISO
        - ERCO → ERCOT
2. Identifying and handling outliers
    - **Missing and zero values:** Filled using linear interpolation between adjacent data points to maintain temporal consistency.
    - **Low outliers:** Demand values below a predefined cutoff threshold (such as 0 or extremely low values inconsistent with historical data) were flagged. Imputation for flagged low outliers involved identifying the closest non-outlier value within the same balancing authority and time period and replacing the flagged value.
    - **Spikes:** Sudden demand spikes that deviated significantly from historical patterns were flagged. Corrections were applied based on nearby, consistent data.
    - **Erroneous peaks:** Specific known instances of demand peaks that are outliers (e.g., caused by reporting errors) are explicitly corrected or replaced with average values from adjacent time periods.
3. **Data validation**:
    - Seasonal and annual peak loads, load factors, and other summary statistics were computed and inspected to ensure no unexpected results. Max peaks were compared to forecasted peaks collected by FERC to ensure none were out of range.
    - Logs summarizing corrections, including the number of spikes or outliers addressed for each balancing authority, were saved as additional documentation.

APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{Curtailment_y(L)}{L \cdot 8{,}760}\cdot 100\right) = CurtailLimit$$

where

L	=	load addition in MW (constant load addition for all hours)
N	=	total number of years in the analysis (2016–2024)
$Curtailment_y(L)$	=	curtailed MWh for year y at load addition L
$L \cdot 8{,}760$	=	maximum potential energy consumption of the new load operating continuously at full capacity
$CurtailLimit$	=	predefined curtailment limit (e.g., 0.25%, 0.5%, 1.0%, or 5.0%).

For each hour t in year y, the curtailment is defined as

$$Curtailment_t(L) = \max(0, Demand_t + L - Threshold_t)$$

where

L	=	load addition being evaluated in MW
$Demand_t$	=	system demand at hour t in MW
$Threshold_t$	=	seasonal peak threshold applicable for hour t in MW (i.e., the maximum winter or summer peak across all years)

These hourly curtailments are aggregated to find the total annual curtailment

$$Curtailment_y(L) = \sum_{t \in T_y} Curtailment_t(L)$$

where

T_y	=	all hours in year y.

Replacing $Curtailment_y(L)$ in the original formula, the integrated formula becomes

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{\sum_{t \in T_y}\max(0, Demand_t + L - Threshold_t)}{L \cdot 8{,}760} * 100\right) = CurtailLimit$$

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-44:
RMI Analysis of Coal Plants' Threats to Reliability



Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.

August 12, 2025

By Gabriella Tosado, Ashtin Massie, Joe Daniel

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

The myth

Utilities are struggling to maintain accurate forecasts and identify resources that can meet this growth. There is a high-profile effort to keep coal plants that are set to retire online and run them at unprecedented levels, ostensibly for reasons of reliability. But the truth is, coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

> Coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

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Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives – and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent – meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers,

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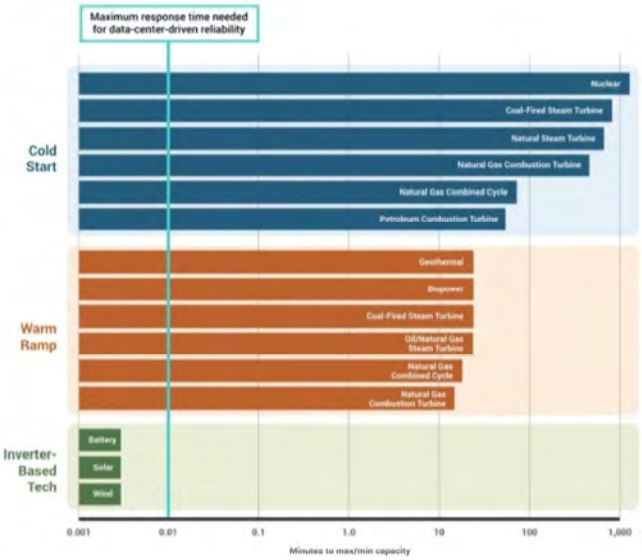
the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not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

Reality #2: The inflexibility of coal plants risks grid stability

Coal boosters often point to the "always-on" nature of coal plants as evidence of their reliability. But that characteristic is a liability, not a strength, when it comes to supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by **independent market monitors** in regions like MISO – which covers 15 US states and a Canadian province – where congestion-related market distortions have cost **over $1 billion a year**. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent ***Incident Review and Guidance on Voltage-Sensitive Large Load Integration*** describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

Minutes needed for a power plant to reach max/min capacity



If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is **4 percent per minute** which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over **12 hours** to reach max capacity. Coal plants simply can't respond fast enough to support the reliability needs of modern data centers. Whether it's the hours-long startup time from a cold state or sluggish ramp rates to turn off, these plants are too slow to provide the real-time flexibility required during sudden load changes or outages.

Reality #3: Clean resources are available now that can better respond to and support data centers for less

The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that **more than 95 percent** of future demand can be met with fast, scalable, and clean solutions:

Shares

Alternative near-term solutions to meet load growth

Technology	Opportunity
Energy Efficiency	Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes.

Virtual Power Plants	60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand.
Advanced Transmission Technologies	Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid.
Clean Repowering	There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection.
Power Couples	New load can be co-located with renewable energy at the site of existing, underutilized generators with approved interconnections—a strategy which we call "Power Couples." There is over 30 GW of opportunity to deploy Power Couples under $100/MWh, and over 50 GW of opportunity under $200/MWh.

Coal plants are a legacy technology, not a solution for the future. Coal plants' operational characteristics make them less suited to meet the scale and speed of these new challenges. The path forward is not about discarding the past, but about building on it with cleaner, more adaptable resources that can reliably serve evolving grid needs.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent **article**, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources **thoughtfully and intentionally**, but propping up coal plants that are not suited for the job is a step in the wrong direction.

RECOMMENDED READING



Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help

June 18, 2025

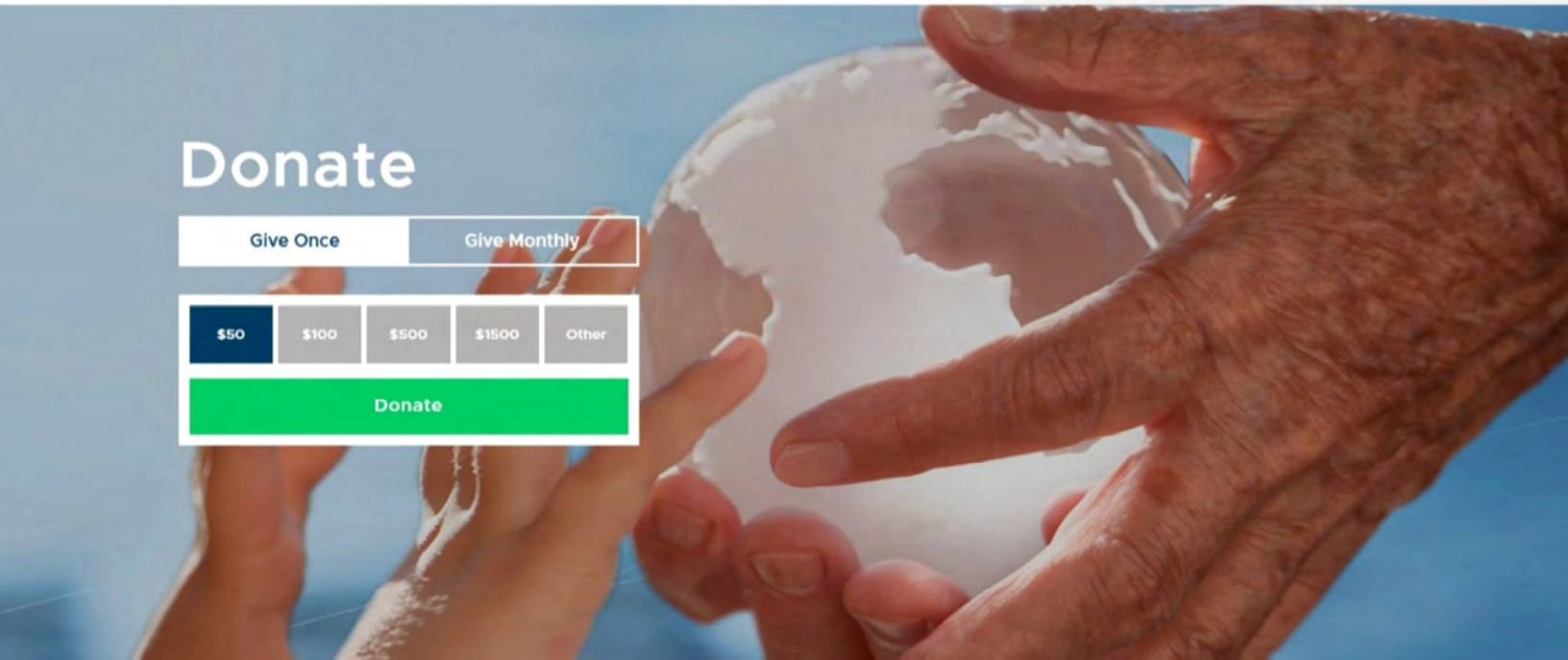
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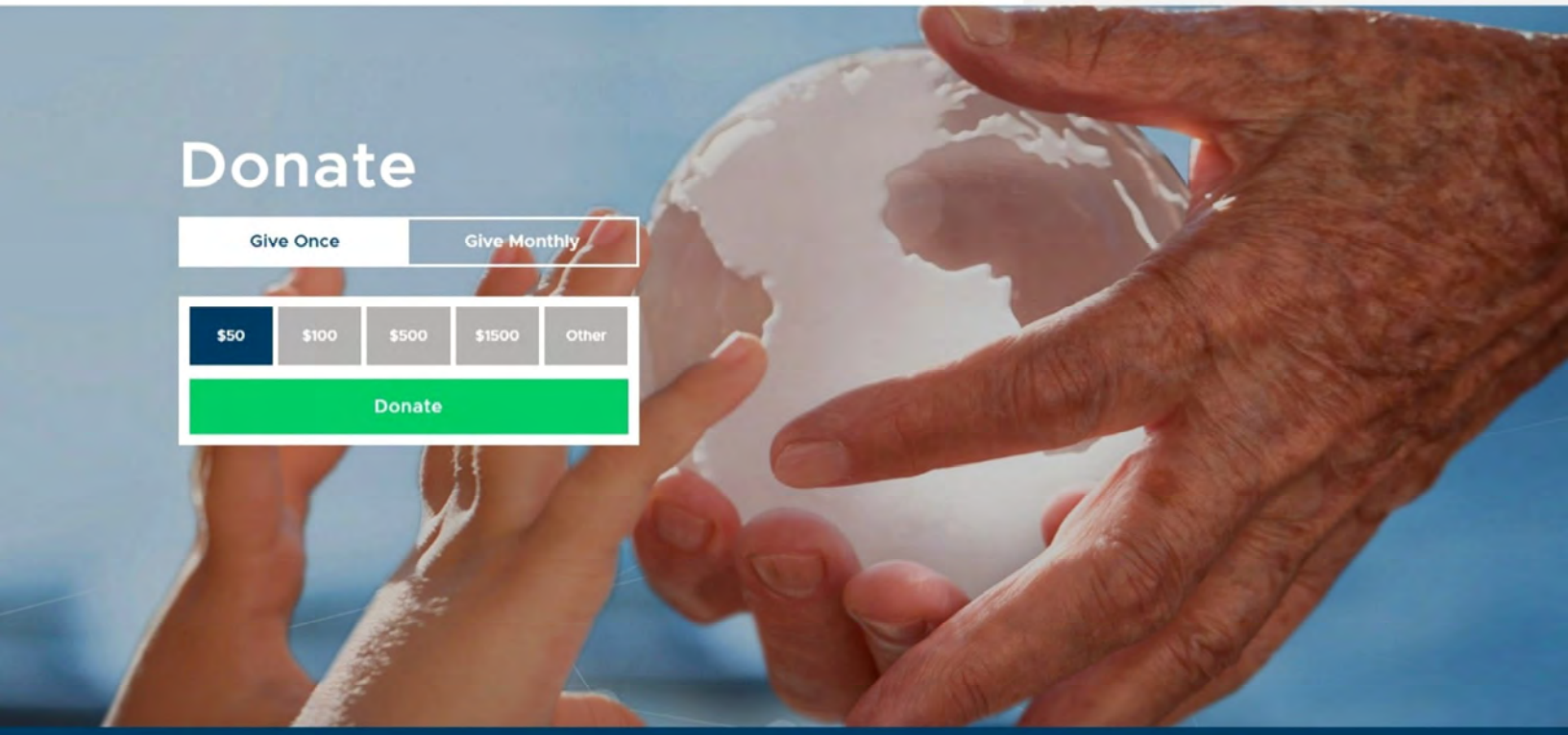
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Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-45:
Energy Innovation Report



ENERGY INNOVATION
POLICY & TECHNOLOGY LLC®

DODGING THE FIRM FIXATION FOR DATA CENTERS AND THE GRID

Eric G. Gimon

Senior Fellow, Energy Innovation

November 2025

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ACKNOWLEDGEMENTS:

I would like to thank my Energy Innovation colleagues for their patient review and feedback on various drafts of this report. I would also like to acknowledge the Energy Systems Integration Group for their conferences, taskforce meetings, and webinars which helped me get started on my research.

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- Interconnection is the key point of leverage to influence when and how data centers join the grid 27
- Using other demand-side resources 28
- Storage and flexibility relieve data center challenges; they can also ease interconnection of new variable renewables 29

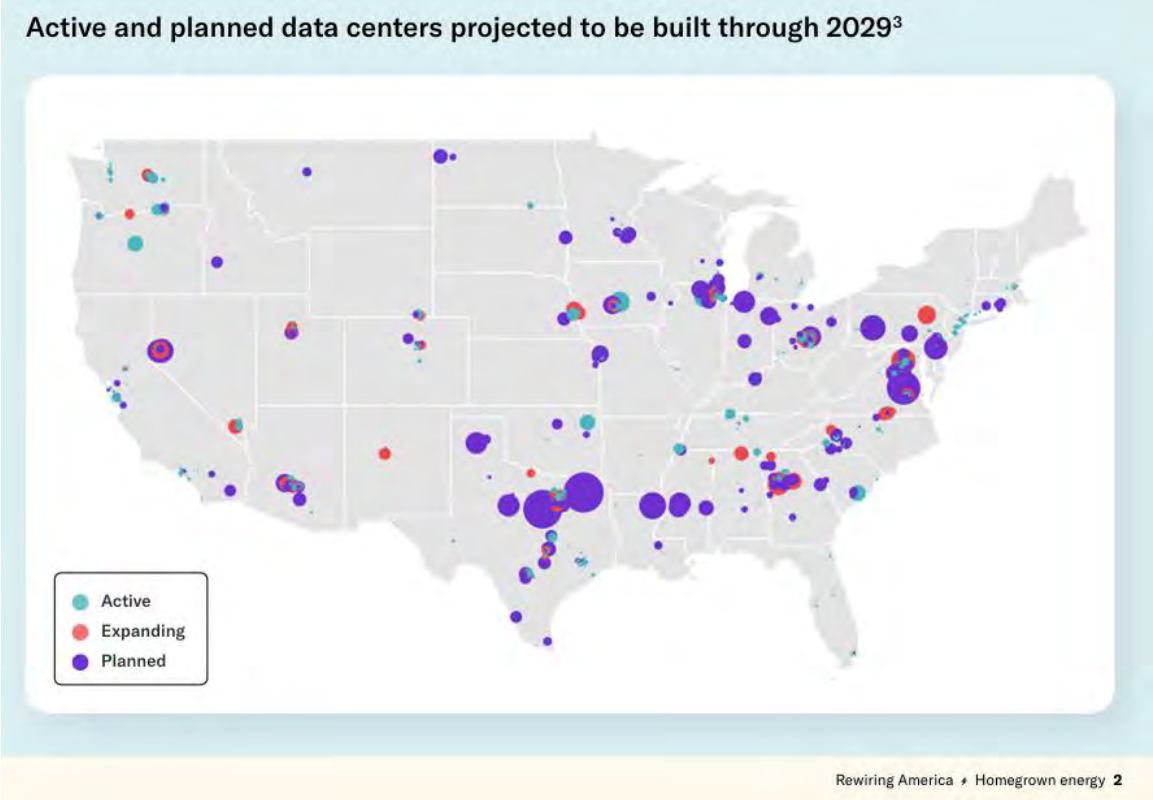
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EXECUTIVE SUMMARY

In multiple states[1,2] (see Figure 1) massive new data center campuses and a coterie of smaller ones have reversed years of flat or declining electricity demand, leaving utilities and policymakers scrambling for solutions.

Figure 1 Existing and Projected data centers from Rewiring America's "Homegrown Energy" report[3].



Faced with this onslaught of new demand, many utilities and developers are depending on old habits by adding new gas plants, refurbishing coal units, or turning to nuclear partnerships along with extensive grid upgrades near new load centers – the "firm fixation."

It reflects a belief that only firm resources and major transmission upgrades can handle data centers' needs. Yet this approach overlooks two essential truths: (1) power plants and data centers are both parts of a larger, interconnected system, and (2) data center loads, especially those driven by artificial intelligence (AI), are far more dynamic than the flat, baseload profiles they are often assumed to be. Firm fixation leads utilities and regulators to default to outdated firm-generation solutions instead of modern, modular approaches that consider the full complexities of today's power grid. At the scale of even the most compact new data centers, connecting to the grid is no small matter.

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Regardless of approach, three features of recent growth are well known to the electricity industry and policy community, and to some extent the wider public. First, new data center load is being amplified by extreme investment interest in AI. Second, incremental load tends to be highly concentrated due to the nature of the growing individual server need for power and the geographic concentration of data centers. Third, the data center industry's appetite for new growth is so large, and other facility capital costs so high that new project owners are willing to pay more for power than average existing electricity consumers.

In a 2024 brief, Energy Innovation proposed instead that a portfolio of solutions – clean energy portfolios, advanced transmission technologies, demand-side flexibility, and efficiency – could work together to obviate the need to rush to meet demand with new fossil generation.[4] Reality so far has deviated significantly from this vision, setting up the power sector for failure: Either new demand will not be met or the negative cost and performance impacts of doing so on other grid users will challenge electricity markets and other long-standing arrangements in a dangerous manner.

The mad scramble to meet data center demand using traditional but crude resource investment methods can create potential missed opportunities to manage load growth that come from a deeper understanding of data centers. Of course, their electricity demand is problematic because it is concentrated, growing fast, and willing to outspend other users. However, it is also far more complex than the flat, 24/7 block it is often assumed to be. This primer identifies six defining features that provide a more nuanced version picture of data centers:

- **Agency and Split Incentives** – Multiple actors (developers, operators, and tenants) and ownership or usage types of data centers create a divided responsibility over grid interaction and access to energy-saving incentives that complicates energy decisions.
- **Clustering** – Facilities tend to concentrate geographically, amplifying local grid stress and transmission costs while creating systemic planning challenges.
- **Consumption Profiles** – Loads are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place.
- **Flexibility** – While some AI-driven workloads can be scheduled for off-peak hours, this flexibility is uneven across facility types and even within users in the same data center campuses. While modest levels of curtailment or load-shifting based demand response during peak hours could ease interconnection bottlenecks and peak demand requirements, these may work best in combination with battery energy storage to overcome split incentives and other complexities.

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- **Backup Requirements** – Current reliance on diesel for backup generation is unsustainable. Batteries and longer-duration storage are cleaner, more scalable options that provide knock-on benefits for the grid if allowed to participate as both backup and demand response.
- **Modularity** – Data centers grow in phases just as demand grows in phases rather than all at once, aligning poorly with "lumpy" firm large one-time investments in dispatchable power plants and infrastructure upgrades, while fitting well with modular renewables and battery deployments.

When examined as a whole, these features undermine the firm fixation logic. One-to-one matching of data centers with dedicated or "captive" firm power plants is particularly unwise for both the power generator and the new data centers, even given their willingness to pay for speed-to-power. Relying on captive plants for all supply such as pairing a nuclear plant with a large data center exposes them to outages, inflexibility, and stranded-asset risks, while hybrid co-location deals still rely heavily on the broader grid.

Most new demand will need to be served fully or in-part through the bulk power system, requiring upgrades in three key areas: **connection infrastructure, grid services (especially peak capacity), and bulk electricity supply.**

Once this is established, it's clear that data centers can tap the grid's advantages as a "system of systems" that pools variable demand and generation resources solutions together and ensures supply and demand match in real-time. As peak demand rises, this crucial service must be met, but not necessarily by firm generation. A deeper understanding of data center demand attributes yields a more complete solution set which includes data center flexibility, onsite storage, portfolios of clean energy, and others.

The challenges data centers pose include lengthy interconnection queues, peak stress, price impacts, and rising emissions – but these are not insurmountable. Three core lessons emerge for policymakers and stakeholders:

- The process of connecting any new **large load is a key leverage point.** It is the moment to ensure consumption tariffs reflect cost causation, encourage flexibility, and align incentives without imposing unworkable burdens later. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the full costs of the infrastructure they trigger, and to nudge data center developers towards solutions such as flexible demand or local storage that relieves local bottlenecks and supports the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

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- **Demand side is a resource hiding in plain sight**. Household electrification and distributed resources can free up tens of gigawatts (GW) at costs comparable to new gas plants and on a faster timetable, offering a more pragmatic and equitable path to integration. Yet at the state and regional level, policy innovation still lags behind. However, several widespread mechanisms exist to channel data center owners and operators' willingness to pay into new solutions that help other existing customers accommodate rapid data center load growth in a fair, fast and equitable way. Because grid connection bottlenecks can be managed by multiple possible combinations of diverse resources, data centers don't need to do all the work of mitigating their grid impacts onsite or through a single counterparty. Once a data center has invested in flexibility and equipment to resolve local connection issues, additional constraints such as upstream transmission and grid services bottlenecks as well as large incremental amounts of annual electricity delivery can be addressed with demand-side solutions from other grid users. A recent report from Rewiring America proposes that many of the resources needed to meet data center load growth could come from sponsoring household upgrades instead of new generation.[5]
- **Storage and flexibility deliver a two-for-one win.** Batteries and managed demand not only ease all manner of data center impacts but can also accelerate renewable integration, providing cleaner, faster, and cheaper capacity than firm fossil solutions. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—a two-for-one advantage. Furthermore, these renewable-plus-battery solutions can capitalize upon existing surplus interconnection to more quickly connect data centers to the grid in co-located arrangements.

This report challenges the electricity and data center industries to move beyond a firm fixation and adopt solutions that leverage the full capabilities of modern power systems.

The next section describes six defining features of data centers: agency, clustering, consumption profile, flexibility, backup needs, and modularity. We then pivot to explaining why traditional firm responses fall short within the broader context of how the modern grid supplies power to consumers, especially large, new consumers. We will look at how new, modular solutions can meet digital demand more effectively. These steps will depend on a more nuanced understanding of data centers, as opposed to how they are often imagined.

Our hope is that this information will empower policymakers to make wiser decisions when faced with AI growth and proposed public investments, avoiding a firm fixation on simplistic approaches and reaching for more realistic answers that embrace the full complexities of the challenge that rapid data center load growth presents today. By moving beyond simplistic assumptions, policymakers can avoid overcommitting to

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outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. We want to leave policymakers with three key takeaways to avoid falling into a firm power matching fallacy and to instead embrace the ability to mix and match resources to meet data center needs.

What began as a major strain on the grid can become the catalyst for building a smarter one, supporting both the digital economy's explosive growth and the clean energy transition.

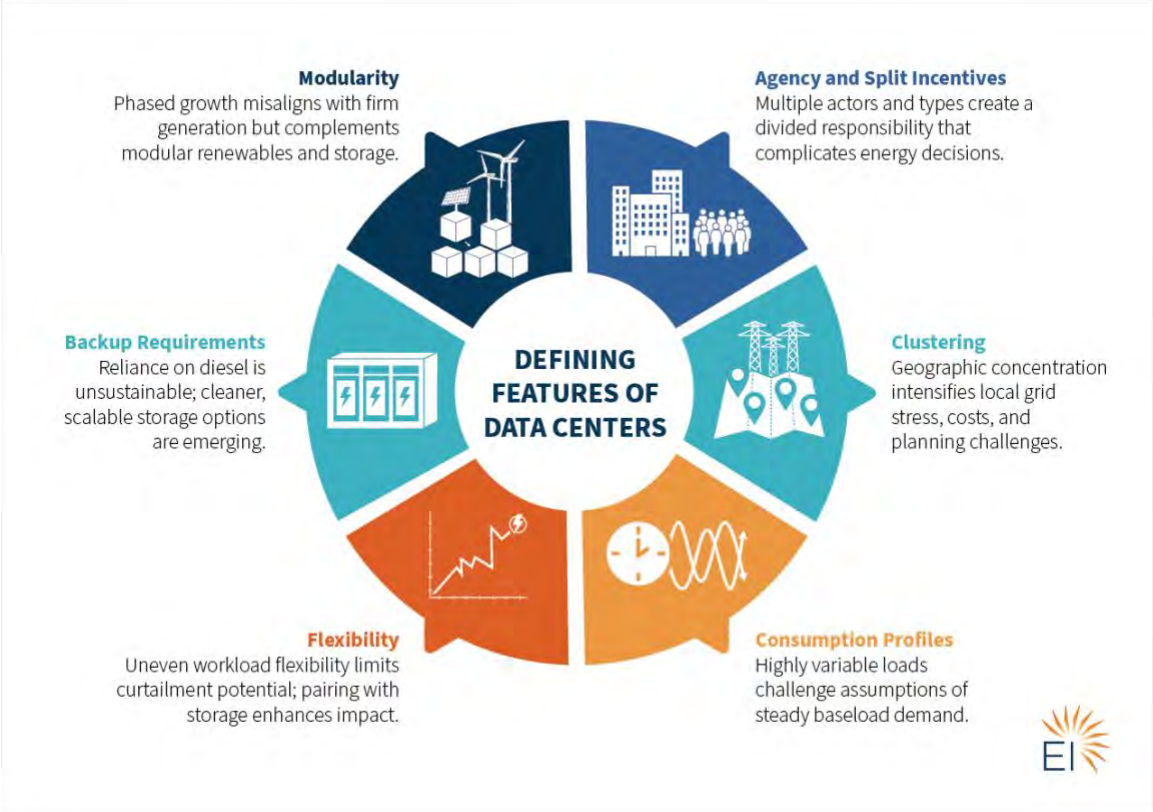
COMMERCIAL AND INDUSTRIAL REALITIES THAT APPLY TO DATA CENTERS

Actual data centers are not the simple "flat 24/7 block of demand" people imagine.

Six different demand features of data centers explain the diversity of data center types (agency, clustering, and profile) and their internal workings (flexibility, backup, and modularity).

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Figure 2 Actual data centers are not the simple "flat 24/7 block of demand" people imagine.



Data Center Feature 1: Agency and the split-incentive problem

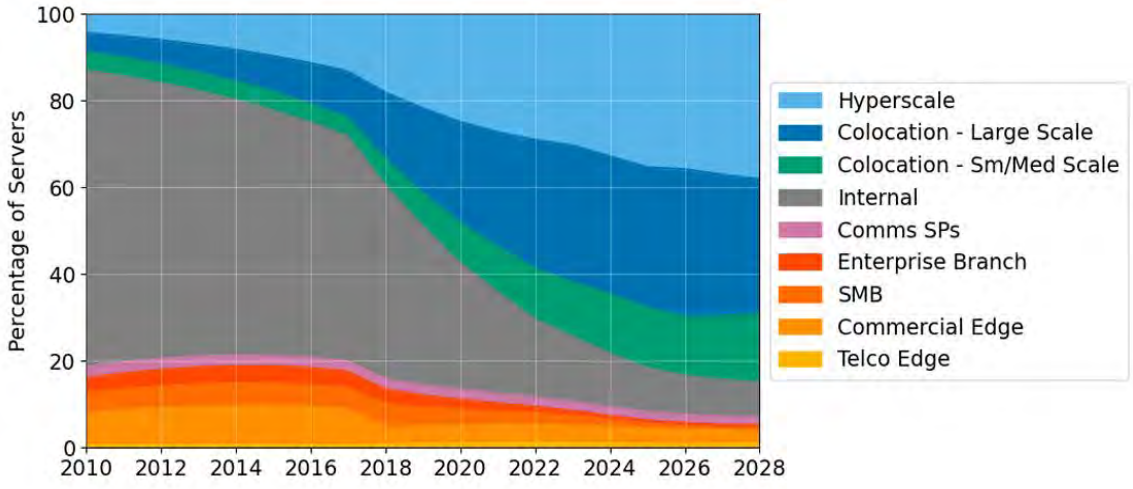
Planning *and* operating *a data center* involves many decision-makers. *Some data centers (often called co-locations or "colos") are facilities where customers can rent space to house their servers and equipment or just run their software on provided equipment. This means the facility is developed and owned by a different company* from those *that rent rack space, buy* computing *capacity, and ultimately consume electricity. Multiple actors force complicated decisions around electricity supply.*

If we want new data centers to adapt their development approach to better integrate with the grid and increase their "speed-to-power," policymakers must understand the planning, construction, and operation of modern data centers. Many different actors are involved, creating a classic split-incentive problem. Loosely speaking, apart from the users or clients, three groups of actors dictate the energy and resource impacts of data centers: developers, facility operators, and service providers. These tend to be separate entities. Overlap sometimes occurs, but usually not enough to prevent split-incentive

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issues. More than half (and an even larger fraction of the current pipeline)[6] of data centers are categorized as co-location facilities—large facilities that rent out space to multiple separate entities.

Figure 3 Distribution of server types by data center type. 2024 United States Data Center Energy Usage Report[7]



We illustrate the split incentives by cataloguing some of the key concerns for each of the three types of decision-makers in the life of a data center. In early stages, data center development is mostly a real estate bet: developers acquire land, water, and electric connection rights and then these rights pass on to the projects they sell. The natural incentive for developers is to keep the range of future owners they could sell to as wide as possible. Hence, they are unlikely to want to enter contracts or agreements (or support legislation) that might prematurely impair any of the land, water, and power consumption rights for their projects. For example, they may not want to agree to be a flexible consumer in return for faster interconnection (load interconnection currently takes three to 11 years) because that might scare off some prospective buyers.

Similarly, owner/operators that lease capacity to data centers customers do not necessarily have much insight into how flexible these customers are or how their customers' usage pattern might change over time. They are conservative about aspects such as whether the tenant-user would be interested in avoiding on-peak usage, participating in time-varying rates, accessing clean energy tariffs, or participating in a demand-response program. Obviously, renters must abide by some rules (via master service agreements or service-level agreements[i]) about behavior that impacts power quality (voltage, frequency, harmonics, transients, etc.) or broader

[i] A master service agreement is an umbrella standardized contractual framework between a utility and the "customer of record" (which could be a data center owner/operator, a tenant/end-customer, or a special purpose entity created to hold the contract) across multiple facilities in the utility's territory. A load serving agreement is more specific to power delivery at a given site.

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electrical concerns (like grounding, interference, and surge protection), but that still leaves a lot of uncertainty for the data center owner/operator. Violations may also pass undetected until a severe problem occurs.

Because data centers are also large electricity consumers, utilities will want to know if contracts are backed by the ultimate users (e.g., hyperscalersii) or an intermediate company that could go bankrupt or disappear. Grid investments involve assets with multi-decadal lifetimes, while the service life of cutting-edge chips can be two to three years. Utilities and their regulators have a strong interest in recovering any incremental costs of investments needed to serve data centers and will look for contractual arrangements to make this happen.

Data Center Feature 2: Clustering, data centers are attracted by similar conditions or to each other

Data center locations tend to be concentrated in a few regions rather than evenly distributed. This clustering amplifies stress on already energy-dense grids. The main drivers are favorable conditions—reliable power, dense fiber, skilled workforce, tax regimes, and land—but anchor investments by hyperscalers or AI campuses could also accelerate the process. Policymakers should avoid treating projects as one-offs and consider the likelihood of a single facility snowballing into a larger cluster.

"Clustering" describes how data centers in the U.S. tend to collect in a handful of regions rather than being evenly distributed. Clustering creates stress for the bulk power system because it takes already energy-dense loads and adds even more load nearby. The easiest explanation for clustering is that it derives from favorable existing conditions: reliable electricity, dense fiber connectivity, neighboring trained workforce, supportive tax regimes, and land availability.

Large anchor projects also draw in more data center development: Once a hyperscaler or AI training facility establishes itself, it signals viability, brings new infrastructure, and lowers costs for additional entrants. Policymakers wanting to provide support for a big project by promises of jobs and tax revenue, risk underestimating the impacts of this attractive force as welcoming one project may quickly lead to a cascade of follow-on facilities, with both outsized benefits and mounting strains.[8]

Recent history reveals a pattern whereby anchor investments amplify favorable local conditions into enduring centers of digital infrastructure. Northern Virginia's "Data Center Alley" grew from early fiber and internet exchange into the world's largest concentration of data centers. Amazon Web Services (AWS) was an early and steady

---

[ii] A hyperscaler is a cloud service provider or operator that builds and manages massive data center networks supporting millions of virtual servers and petabytes of data, operating globally and designed to scale seamlessly across regions. Examples might include Amazon Web Services (AWS), Microsoft Azure, Google Cloud Platform (GCP), Meta (Facebook), Apple, Alibaba Cloud, and Tencent Cloud.

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investor in this cluster.[iii] Today, Data Center Alley reportedly handles roughly ~70 percent of the world's internet traffic, contains over 12 million square feet of commissioned data center space, and sustains hundreds of megawatts of power load.[9]. Reno's Tahoe-Reno Industrial Center became a global hub after Switch and Apple established major campuses, followed by Google and others[10]. Central Ohio offers a newer case: Google and AWS each invested in major builds, quickly attracting colocation providers.[11]. Atlanta and Phoenix look to be on similar paths[12].

In theory, diverse types of data centers should reinforce these patterns. Colocation facilities are drawn to network-dense hubs where they can maximize interconnection to other facilities. For example, enterprise servers might want to easily connect to multiple cloud providers—providers of cornerstone internet services stand to benefit from the reduced latency proximity affords, especially for content delivery like streaming video and games and so on. Hyperscalers could function as anchors, just like a department store in a shopping mall, investing billions into single campuses that create the vendor ecosystems others rely on. However, AI-focused facilities, with their unprecedented power needs, can also reshape the landscape by displacing other data centers competing for the same power network and generation resources.[13]

Electric power infrastructure both attracts and is stressed by clustering. Access to transmission lines and substations is a prerequisite, but as clusters grow, demand can overwhelm grids. Northern Virginia now faces multi-year waits for new hookups[14]. Reno's growth has raised water concerns and left Nevada utilities facing a potential doubling in necessary electrical infrastructure (also spurring them toward large renewable additions)[15]. Ohio illustrates the stakes most vividly: By March 2023, the utility AEP Ohio imposed a moratorium on new data center service agreements in Central Ohio, pending further study citing grid strain. Eventually regulators approved a new tariff[16] requiring data centers to pay for 85 percent of subscribed capacity whether it is used or not, with penalties for cancellation or under-performance and a four-year on-ramp[iv]. Clustering behavior can easily outrun planning and force regulators into reactive steps, introducing delays before more pro-active policies and tariffs can be put in place.

The policy lesson is not to avoid clusters—after all, they bring new jobs, tax revenue, and digital infrastructure—but to keep a skeptical eye on benefits claimed by developers and focus on smart planning. This should consider the multiple interests of stakeholders affected by a data center cluster and work in advance to align land use,

---

[iii] AWS is certainly not the only part of this story but has been called out as a major player. Dan Swinhoe, "The Amazon Factor in Virginia," Data Center Dynamics, November 6, 2024, https://www.datacenterdynamics.com/en/analysis/the-amazon-factor-in-virginia/. Amazon also touts its $51.9 billion investment in Virginia between 2011 and 2021 (capital + operations) in its data center infrastructure in Fairfax, Loudoun, and Prince William counties. Roger Wehner, "Learn About AWS's Long-Term Commitment to Virginia," Amazon, June 7, 2023, https://www.aboutamazon.com/news/aws/aws-commitment-to-virginia.

[iv] Under the decision, new data centers can access up to 50 percent capacity in the first year, 65 percent in the second, 80 percent in the third, and 90 percent in the fourth before getting full access to the grid.

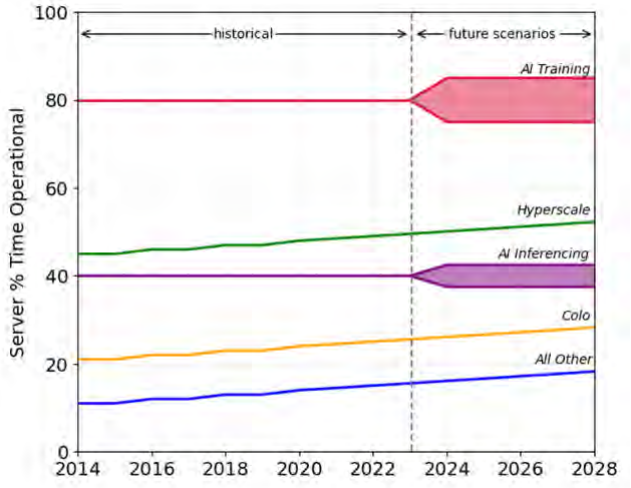
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grid upgrades, generation, flexible loads, and permitting frameworks, ensuring that benefits can be captured without bottlenecks or backlash once clusters grow.

Data Center Feature 3: Consumption profile

Data center electricity usage is not steady or 24/7. Up close, it can be quite choppy and challenging. Batteries could act as a buffer—a keystone solution to managing power quality.

Figure 4 Server utilization by data center type. 2024 United States Data Center Energy Usage Report (LBNL).

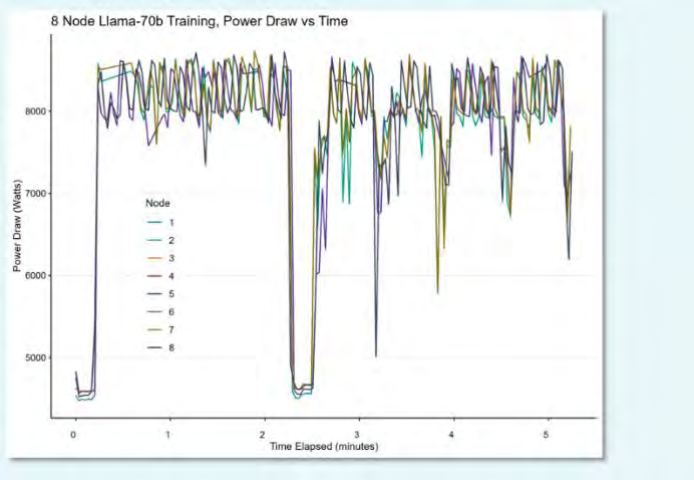


Data centers exhibit considerable variability, especially going between operational and idle states. In Lawrence Berkeley National Laboratory's (LBNL) 2024 United States Data Center Energy Usage Report, the authors explain that in 2014 colos reported 21 percent utilization rates, hyperscalers 45 percent – rising to an estimated 35 percent and 50 percent respectively in 2027. The same report models AI learning centers and AI inferencing at 80 percent and 40 percent utilization rates, respectively. These don't directly translate into electricity consumption load factors because some electricity is used for other purposes like cooling that don't follow a 1:1 relationship with computing load.

Even looking at the whole power consumption profile of a data center, it's important to differentiate between actual load factor (the percentage of possible 24/7 full power use that a data center in fact uses) and availability (the percentage of maximum power a data center expects to have if it wants it, i.e., the *option* to use power). Whether power comes from on-site generation or from the grid, it needs to be prepared to provide power when the data center wants it, and back off when the data center doesn't.

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Figure 5 8 Node trace of power consumption in an AI learning cluster. 2024 United States Data Center Energy Usage Report (LBNL).



Big swings in data center demand will clearly be a challenge, even for the most flexible on-site generation. Given the scale at which many data centers operate, these swings can still create problems for large regional grids[v]. The CEO of Hitachi Energy reportedly commented "there can be swings of 200, 300 MW within a ten-minute period as data centers move from learn vs stop learn mode, and that these types of swings would not be acceptable from other grid customers."

At smaller time scales, large numbers of similar chips in one place switch on and off and can create an aggregate resonance effect[vi]. Existing electrical standards are inadequate for screening out these behaviors, and utilities may not have sufficient sensors to properly trace back issues to a particular data center. In aggregate, the evidence points to data centers deteriorating power quality metrics in their environs.[17]

More research needs to be done that focuses on new large digital loads, including variable generation resources with inverters that center around things like low-voltage ride through or fault clearing. For more information, context, and solutions on some of the challenges with interconnecting these large loads, see GridLab's recent Practical Guidance and Considerations for Large Load Interconnections.

Data centers are not a "perfect baseload" fit to directly couple with large mechanical generators or even the grid, and they will need significant electrical equipment to buffer this connection and prevent extra wear and tear on co-located generation or nearby grid users. Even if some data centers can learn to be flexible, incorporating battery energy storage, especially as the hardware cost decreases, will likely become a key element in managing data center impacts on the grid. When good wind and solar resources are available nearby, batteries can play a dual role in managing both load and generation variability at multiple time scales. Consider the Lancium Clean Campus in under construction in Abilene, Texas: "In addition to the 1.2 GW grid interconnection,

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[v] See the GridLab report *Practical Guidance and Considerations for Large Load Interconnections*, with special attention to July 2024 Northern Virginia Data Center Event called out in Figure 1.2.

[vi] Some of these resonance issues can potentially be solved by on-chip energy management and storage. Rouslan Dimitrov et al., "How New GB300 NVL72 Features Provide Steady Power for AI," Nvidia, July 28, 2025, https://developer.nvidia.com/blog/how-new-gb300-nvl72-features-provide-steady-power-for-ai/?utm.

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Lancium's power plan for the site includes large-scale behind-the-meter battery storage and solar resources, which serve to ensure grid reliability, and economic and carbon optimization."[18]

Data Center Feature 4: Flexibility, or the lack thereof

Flexibility could be key to quickly connecting new data centers, especially those involved with AI learning. Managed demand is possible, but on-site batteries may be a better solution where split incentives or onsite needs make demand control too rigid or complex.

Data centers can be flexible, but different functions involve different levels of flexibility. This is probably hardest to achieve for co-location data centers because the third-party owner which interfaces with the grid and with utilities is not the one deciding what servers inside its facility are doing. Additionally, data centers are tasked with fluctuating sets of applications, creating uncertainty about how reliable or persistent demand management can be as a means of providing flexibility.

Data centers fully owned by large hyperscalers provide a higher degree of control over the whole facility. But the diversity of services being provided, often with low latency (response times) needs, may create constraints on what the hyperscaler can do. Hyperscale data centers provide both regular services—like AWS' cloud computing—and AI workloads such as inference, which involves answering client queries using pre-processed AI models.

For AI learning data centers, which create these large learning models, the goal is to cram as many chips as possible into the same square mile with the fastest internal connectivity so that the collection can operate as one big parallel machine[19]. Much of the possible flexibility here comes from adjusting the timing of computing batches, yet matching these adjustments to power supply flexibility needs is not a given, especially when considering that data center operators will want to prioritize computation over flexibility. This is a consequence of the relatively larger size of the capital investment in computing hardware versus energy generation and distribution for most applications.

Flexibility is a particularly important quality for data centers because they are such a large component of load growth, and just a little flexibility would reduce the need for new peaking resources and speed up interconnection[20]. A 2025 analysis[21] by the Nicholas Institute for Energy, Environment & Sustainability at Duke University finds that just 0.5 percent to 1 percent flexibility opens significant space on the grid: 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5 percent, and 126 GW at a rate of one percent. This level of flexibility is similar to what is provided by demand-response programs that exist today for other loads, but as far as speeding up interconnection, it may be the AI-driven hyperscalers and learning centers, acting more directly under their owners' control and schedules, that can achieve more.

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AI loads are fundamentally more flexible than generic data center loads because they can be processed in batches, easily scheduled, and often internally orchestrated. For example, in a presentation[22] to the Texas grid operator Electric Reliability Council of Texas (ERCOT), the company Emerald AI demonstrated how it could implement flexibility at a data center. The company argued there is enormous potential to control AI data center load, and that "major hyperscalers are amenable to curtailing up to 25 percent for up to 200 hours in return for priority interconnection of 1 GW."

No one knows if any particular data center's operations will remain stable enough to guarantee a given level of flexibility or willingness to curtail over the lifetime of matching local grid upgrades. In some cases, the data center load can be flexible (willing to forgo some batches of work) but not exactly in the way that best serves the local grid. Some amount of local battery energy storage (providing multiple value streams like integrating local on-site variable energy, backup, and power quality services) could also help data centers be more flexible at their grid interface, especially those with less direct control over internal processes.

Data Center Feature 5: Backup needed for disturbances and outages

Most data centers require backup. Demand flexibility and short-duration batteries can either eliminate or lighten the load for traditional backup solutions.

Many data center customers aspire to high availability—as much as 99.999 percent uptime—hence the need for backup power to take over in case of any grid failure. The Uptime Institute, a widely followed source for industry tier certification in data center design, build, and operations,[23] defines four reliability tiers (I through IV) with increasing expectations for performance under challenging conditions, with an eye towards worst-case scenario planning. Many data centers serving enterprise needs require at least a Tier III level of reliability, either because of a direct need, like maintaining accessibility to data under adverse conditions, or as a proxy for operational trustworthiness. For mission-critical operations—major banks, stock exchanges, the military, or hyperscalers serving global customers—a Tier IV level of availability may be required.

Because Tier III and Tier IV facilities require 72 and 96 hours of on-site power capacity, respectively, simple economics dictate that backup is usually in the form of diesel generators with fuel storage on-site. Batteries can also be used to help ride-through disturbances in power supply,[vii] providing faster response times and reducing fuel and maintenance expenses on diesel. However, with today's technology, battery energy storage systems (BESS) that can cover critical needs for three to four days are not

[vii] In current facilities, this ride-through comes via the uninterrupted power system (UPS) usually provided by old-school lead-acid batteries, but modern lithium-ion battery energy systems can provide these services along-side the bulk of backup power needs.

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economically feasible, especially without some form of on-site generation to sustain their state of charge.[viii]

However, diesel does not scale well: As data centers get much larger, massive tank farms for the generators' on-site fuel require complex fire protection, spill containment, and environmental risk mitigation. Furthermore, many air districts (e.g., Virginia, California, or Oregon) place strict caps on generator run time and cumulative emissions in a site or region. Placing more than a hundred diesel generators on one site creates a cumulative permitting challenge and may well face serious local resistance along with the prospect of delays or outright rejection from regulators. Somewhat cleaner gas generators (turbines[ix] or reciprocating engines) are usually connected to a pipeline and require large propane or liquefied natural gas storage facilities to satisfy on-site capacity requirements.

Some large hyperscalers are opting to target better up-time based on statistical estimates rather than explicit proxies for reliability. For example, Microsoft has publicly committed to reducing the use of diesel generators by 2030. To that end, it contracted with Saft, a subsidiary of TotalEnergies, to install four battery energy storage systems, each in groups of four megawatt hours (MWh) and capable of 80 minutes of on-site power, to replace diesel backup.[24] In the U.S., Microsoft's newest Azure region in San Jose, California is also being built diesel-free, but is using natural gas turbines for backup (plus batteries for ride-through). In general, the U.S. grid is quite reliable, with the one-in-ten reliability standard[x] mostly achieved at the transmission service level.[xi] Most outages that do occur are less than one or two hours, so a battery can carry enough of the backup burden to get the facility to a high level of reliability while hardly, if ever, using on-site generation.

As longer-duration storage solutions like Form's 100-hour battery [25] or thermal batteries[26] connected to local renewables and steam turbines in local energy parks[27] emerge, data centers will be able to free themselves from fossil fuel backups while taking advantage of integrated design to combine multiple uses of batteries for flexibility, power quality, and backup.

[viii] To see how this is done in detail, see the NREL Vulcan platform demonstration in collaboration with Verrus. Deepthi Vaidhynathan et al., "Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset" (National Renewable Energy Laboratory, June 2025), https://www.nrel.gov/docs/fy25osti/94844.pdf.

[ix] Although gas turbines face significant supply chain cost and delivery challenges currently. GridLab, *Gas Turbine Cost Report*, https://gridlab.org/gas-turbine-cost-report/.

[x] The one-in-ten reliability standard is a standard that applies for the bulk power system (i.e. transmission level) requiring transmission planners, system operators and reliability planners to aim for nor more than one "event" of involuntary load-shedding in ten years. If one "event" was 24 hours, that is already 99.97 percent up-time.

[xi] Actual recent figures for grid performance are quite good (see table 1.1). North American Electric Reliability Corporation, *2024 State of Reliability*, June 2024, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf.

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Data Center Feature 6: Modularity—data centers are built in phases

Data centers expand in discrete phases, from racks to halls to entire campuses, with uncertain demand and rapidly rising power density. This modular growth pattern matches well with the modularity of renewables-plus-batteries deployment, which can be built in parallel to meet incremental load without the risks of lumpy firm power investments.

For utilities and data center developers, timing capital investments can be challenging. Matching these investments with energy supply for their increasingly electric power sub-components compounds the challenge. Building a new data center means committing to constructing a large building and grid capacity without knowing if consumers will come, how quickly they will deploy, or how their consumption will evolve over time. Tenants in a co-location situation, hyperscalers, and AI data centers may not immediately have all the chips available (or face some other bottleneck) so may want to deploy in phases: slowly building up electrical demand over time until reaching full capacity, if all the anticipated demand materializes. With a chip service life of around two to three years, the balance between increased efficiency and increased computing power may mean newer chips could either increase or decrease electricity demand in each physical asset footprint.[xii]

The digital world's infrastructure is itself modular—built from discrete, substitutable units. Data centers are not just abstract systems of bytes and tokens; they are also collections of tangible components: chips, servers, and, above all, racks. The rack is the main unit of reference: a cabinet holding multiple slender servers or "rack units." Racks are grouped into "pods" of 20–30, and an enterprise client might deploy a couple of pods at a time in either a dedicated or co-location facility. Some tenants lease only a handful of racks in a shared space, while hyperscalers may build entire halls of 200–400 racks, with multiple halls forming a single phase of expansion on a large campus[28].

The modular nature of data centers lets developers manage financial risk by building in phases, with the option to add new capacity quickly but in a planned way. Each phase, however, carries high stakes not only in capital cost but also in power demand. A 2024 Uptime Institute report[29], states finds that four- to six-kilowatt (kW) racks remain common, with a trend towards higher consumption today. Meanwhile, AI applications and high- performance computing are pushing the development of liquid-cooled racks with incredible increases in power density. Vertiv, an Ohio-based company that designs, manufactures, and services critical infrastructure for data centers, reported in its 2024 Investor Event Presentation[30] that extreme rack densities already reach 250 kW

[xii] This is certainly a question in flux. Google has reported that over a recent 12-month period, the energy footprint of the Median Gemini Apps text prompt dropped by 33x! At a given facility this can be achieved by increased throughput or reduced energy use, or both. Amin Vahdat and Jeff Dean, "Measuring the Environmental Impact of AI Inference," Google Cloud, August 21, 2025, https://cloud.google.com/blog/products/infrastructure/measuring-the-environmental-impact-of-ai-inference.

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per rack today and could exceed one MW within five years. That means a space the size of a bedroom closet could consume more power than a thousand average homes. As a result, a single phase of development for a data center might range from on the low end at 250 kW (two-dozen at 10–12 kW per rack) on the low end to 250 MW at the high end (a 1,000 liquid-cooled 250 kW racks) at the high end, with extra overhead for cooling.

The extreme end of data center development is exemplified by data center developer Vantage's recently announced plans [31] to build its $25 billion Frontier campus situated on 1,200 acres in Shackleford County, Texas, with an eventual total consumption of 1.4 GWs—close to average total consumptions of the states of either Rhode Island or Delaware. And this project is not alone: a September 2025 ERCOT staff report[32] to ERCOT's board details 130 GW of non-crypto data center load in the interconnection queue through 2030.[33] In the last few years, Texas has met new additional load with new, mostly clean generation. Of the 428 GWs of generation requests as of August 31, 2025, 204 GWs are for wind and solar and 180 GWs are for energy storage (together 90 percent of all requests).

Data center development may come in all levels of power consumption. However, because developers rarely build, install, and commission data centers in a single phase, projects of all sizes need a power supply that can grow and expand with them. When covering the incremental energy demand from a new data center, a large new single firm resource is an unwieldy indivisible capital investment. A modular approach with renewables plus batteries reduces risk and provides better economics: You're not committing to a single lump-sum investment in a 500 MW gas turbine; you can phase investments, optimize based on real usage, and spread spending—and risk—over time.

With computing loads that grow unevenly, modular investments let operators respond dynamically—deploy more solar, wind, or storage as AI racks come online. As a bonus, you can avoid supply chain bottlenecks because incremental installation bypasses the big lead times and equipment backlogs associated with large generator orders, enabling continuous expansion without project delays. Just as data centers grow in discrete steps, modular renewables and batteries let the grid grow in parallel.

These six features highlight why data center demand is complex, not just a flat, 24/7 block of constant load. We now turn to how supply options can, and cannot, match this demand.

THE BEST WAY TO MEET DATA CENTER DEMAND IS DIVERSE RESOURCE PORTFOLIOS

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When thinking about how to supply new demand from the rapidly growing data center industry, the key point to remember is **one-to-one matching with "firm" resources will not "solve" the load growth needs from data** centers.

In this section, we explain why single, stand-alone generation resource matching for any given industrial load has rarely been the historical course, and how and why that might change. We then describe the three resource buckets that new data center projects need to acquire to use the existing bulk power system. Finally, we discuss how the data center demand features described in the preceding section create further challenges and barriers in acquiring these resources.

Debunking the one-to-one matching myth

If you imagine data centers as large capital assets running power through expensive electronics 24/7, it seems natural to imagine a dedicated "captive" 24/7 power plant built to match this demand, with historical precedent for this one-to-one matching. For example, in the post-war era aluminum producer Alcoa built smelters near cheap grid sources of hydropower in New York and the Pacific Northwest along with captive coal plants in Indiana and Texas to feed the company's aluminum smelters and mills. Today, industrial facilities use on-site combined-heat-and-power (CHP) plants to consume both the electricity and waste heat from fuel-driven power plants to operate industrial facilities with high end-use efficiency, and thus lower energy costs. According to the U.S. Energy Information Administration's (EIA) latest Manufacturing Energy Consumption Survey from 2022, U.S. manufacturers produce around 17 percent of their electricity needs on-site (Table 11.1) and that on-site generation is 97 percent co-generation (Table 11.3).[xiii]

Single plants may not "play nice" with data centers

The demand characteristics of data centers described in the prior section raise immediate concerns regarding matching a captive plant with a data center. For example, while a data center may want 24/7 availability, its actual consumption will ramp up and down significantly with a profile that a large, single on-site generator might struggle to meet. Many fossil generators have a minimum dispatch level they cannot fall below, and "ramp rates" limits dictate how quickly they can adjust up and down. Furthermore, a modular, phased build-out does not lend itself to a single matching resource because in order to provide sufficient power for the full buildout,

[xiii] This survey defines co-generation as "the production of electrical energy and another form of useful energy, such as heat or steam, through the sequential use of energy. Cogeneration includes electricity generated from fossil fuels, such as natural gas, fuel oils, and coal; wood; and other biomass." In practice, the steam/heat is the main other energy output, so co-generation is often used as synonymous with CHP.

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the single resource would have to operate at lower, inefficient, dispatch levels during earlier phases of data center construction and operation.

Beyond a mismatch with the demand characteristics of data centers described in the prior section, there are additional reasons to question using a captive plant as a 1-1 match for a data center.

Captive power plants are not highly reliable alone

Table 4 from the North American Electric Reliability Corporation (NERC) 2024 State of Reliability Overview [34], shows the recent weighted forced outage rate (rate of unexpected failure) was 11.7 percent for coal, 7.7 percent for gas, 6.4 percent for hydro, and 2 percent for nuclear. Another relevant consideration is planned maintenance, like cleaning out coal boilers, maintaining and inspecting gas turbines, or refueling nuclear plants every 18-24 months.[xiv] This means a single supposedly "firm" plant will be unavailable for a double-digit percentage of time—not what data centers are looking for.

If an industry is set on self-supply, one strategy is to over-supply generation. Alcoa's Warrick, Indiana aluminum smelter and mill built three captive 144 MW coal plants alongside a 300 MW coal unit shared 50/50 with the local utility Vectren. With a total capacity of 732 MW but serving a local load of 550 MW,[35] the facility was clearly resilient to losing one unit and still running. But this effectively meant carrying 25 percent more capacity than necessary, without a guarantee of full reliability. Alcoa mitigated this extra cost by selling excess power to the grid and importing power from Unit 4 or the broader grid when necessary. This illustrates the general case that a grid connection remains both a sink for surplus and an important backup option; most on-site power is not fully independent and large loads will still want interconnection to the bulk power system. In fact, payment for grid backup (usually called "standby rates") is a common feature of CHP tariffs.[36].

What happens when the power plant is no longer needed?

An interesting postscript to the Alcoa Warrick plant story is that Alcoa announced it would shut down its aluminum smelter in 2016 (although it had partial restarts post 2018) because of poor market conditions [37] and transferred major rolling mill and finishing operations to Kaiser Aluminum in 2021.[38] It is now left with an unattractive coal generation asset, whose generation capacity now exceeds Alcoa's local demand and

[xiv] This is on average a 32-day process. Aaron Larson, "Planning Is Key to Successful Nuclear Refueling Outages," POWER Magazine, September 1, 2023, https://www.powermag.com/planning-is-key-to-successful-nuclear-refueling-outages/.

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will likely struggle to sell surplus capacity in the broader power market along with most coal assets,[39] which comes with significant environmental remediation liabilities.[xv]

This is always the risk with a captive power plant: One day the load will vanish because of changing economics. Investors will want to know if Plan B exists and that the captive plant is in and of itself an attractive asset with a bright future.

Co-location of prime power generation assets with data centers today

Grid bottlenecks create considerable talk about co-locating "prime power" generation[xvi] with new data centers. This might include leveraging existing nearby assets (for example, the Talen-Susquehanna deal which co-locates a data center next to a nuclear plant[40]), restarting mothballed generators, or building new on-site resources (such as gas plants). But these arrangements are not true one-to-one matches of generation with load, since they still depend heavily on a grid connection for full functionality, sometimes at the expense of other consumers.

For example, in the Talen-Susquehanna deal, the data center is physically adjacent to a pair of nuclear units. It is unlikely the units' output will ramp precisely in step with data center consumption. Therefore, matching local supply with demand creates net output—nuclear output minus on-site data center consumption—variability which must be managed by the grid operator. During the refueling of one nuclear unit, the other must pick up the data center load, thereby reducing exports to the grid. In effect, the grid acts as backup.

Hybrid arrangements using on-site power together with the grid can address bottlenecks. They combine physical and financial hedges. The Talen-Susquehanna deal, for instance, was eventually reshaped into a power purchase agreement after regulatory push-back.[41]. These hybrid deals share many of the properties—and many of the drawbacks—of other on-site generation deals discussed above.

If land is available, the best way to provide on-site prime power is not with a single firm resource but by using an energy park[42] with renewables and batteries, with backup from longer- duration storage and/or gas generators.[43] Then most of the generation is

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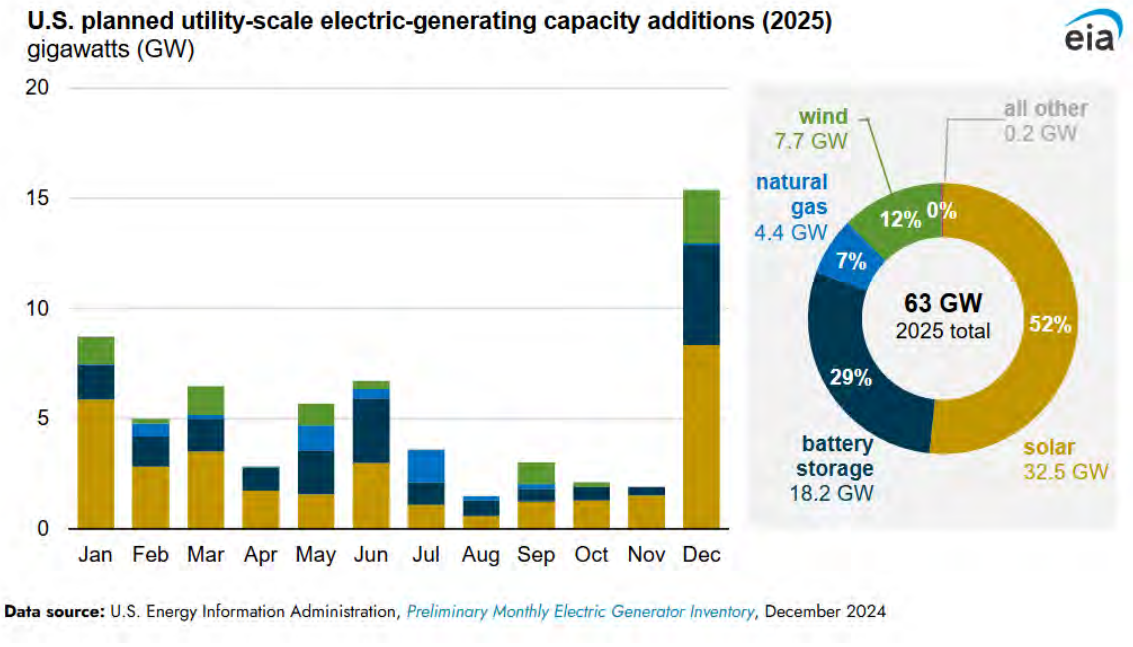
In 2024, Sierra Club and Environmental Integrity Project intervened in a case against Alcoa Warrick for "100+ permit violations" in 2022 and 2023, including releases of mercury, aluminum, chlorine, copper, fluoride, nickel, and zinc into the Ohio River. Environmental Integrity Project, "Groups Intervene in State Action to Stop Aluminum Smelting Plant's Illegal Dumping of Heavy Metals in Ohio River," February 21, 2024, https://environmentalintegrity.org/news/groups-intervene-in-state-action-to-stop-aluminum-smelting-plants-illegal-dumping-of-heavy-metals-in-ohio-river. There are also lingering questions regarding compliance for Warrick's "ash ponds" under the Environmental Protection Agency's Coal Combustion Residuals rules. Hoosier Environmental Council, "Today's EPA Action Means More Coal Ash Cleanup for Indiana" (press release), April 25, 2024, https://www.hecweb.org/wp-content/uploads/2024/04/PRESS-RELEASE-Todays-EPA-Action-Means-More-Coal-Ash-Cleanup-for-Indiana.pdf.

[xvi] Prime power is the continuous everyday power that powers the data center, as opposed to backup power There is also "bridge power" which is local generation which acts as prime power until a grid connection is put in place, and then becomes either backup or just a part of the supply portfolio.

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clean, faster, and cheaper to deploy than other generation and helpful for hyperscaler emissions commitments. In addition, the combined resource is more reliable, with fewer large points of failure than a handful of fossil units – a good Plan B if load never fully materializes or decreases. Included energy park resources would reflect a microcosm of trends in the wider U.S. market where the large majority of generation coming online[44] and waiting in interconnection queues are renewables and batteries.[45]

Figure 6 Solar, battery storage to lead new U.S. generating capacity additions in 2025. US EIA.



Data source: U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory*, December 2024

Providing new electricity supply for data centers from the bulk power grid

Given that most data centers will need to get some, if not all, of their power from the bulk power system, it is helpful to review how large commercial or industrial loads do this. The power grid is a system of systems including physical transmission and distribution poles and wires, the generation and loads they connect, operations and dispatch, power markets, and power purchase agreements.

As soon as a large new load decides to connect to the bulk power system, its needs can be disaggregated and met in many ways.

The grid resources a new data center project must collect to successfully draw from the bulk power system fall into three broad buckets: connection, grid services, and bulk electricity.

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New large data centers will require connection and network upgrades

How data centers connect to the grid depends on their size: scale matters. Smaller enterprise and co-location data centers (tens of MW or less) will often connect to a distribution system's high-end network (i.e., somewhere between 13.8 and 69 kilovolts) and may tie into an existing distribution substation with a new feeder. The utility typically owns and operates the primary substation equipment, while the data center customer owns the step-down transformer to its facility. The local utility conducts the impact studies and plans local upgrades to ensure compliance with NERC standards. Too many connections in the same area may trigger transmission upgrades and inclusion in transmission planning studies. In some geographies, like Virginia, this may involve an independent system operator (ISO) such as PJM [xvii] in planning and approving upgrades.

Larger data center campuses will have their own complex internal grid that connects directly to a bulk power system transmission substation. The data center must file a large load interconnection request with the local transmission owner or ISO. Tariffs and agreements will include matters like covering study costs, equipment ownership, and who pays for upgrades. The state may also require approvals for siting, environmental review, and cost recovery. The connection process can become long and painstaking once local capacity on the grid becomes tight. In Virginia's Dominion utility territory, data centers larger than 100 MW face up to a seven- year wait for power hookups.[46]

One important feature of new connection costs is that they are usually covered by the new load because cost causality is clear. Unfortunately, this may not hold true for more upstream transmission impacts where transmission upgrade costs are traditionally socialized more widely. A recent Natural Resources Defense Council (NRDC) report[47] tells the story in PJM: "Tight supply conditions led PJM to approve a $5 billion transmission expansion project to meet new data center demand in Virginia, where data centers already account for around a quarter of the state's electricity demand. The costs for this project were distributed by the Federal Energy Regulatory Commission (FERC), PJM, and utilities using varying cost allocation methods. Maryland residential customers were left with a bill of approximately $330 million, and Virginia residents had to foot $1.25 billion for transmission designed largely for a handful of data center customers in only a small region of the state."

Data centers create new stresses on a bulk power system planned around peak demand; they also consume other grid services

The main grid service data centers require regardless of size is peak capacity: the ability to serve up to their maximum interconnection rating during periods of system peak.

[xvii] Also referred to as a regional transmission operator, PJM covers 13 states in the mid-Atlantic and is one of the largest power markets in the world.

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Going back to PJM (often a source of current examples because it already serves so many data centers), the ISO's board chair communicated about future reliability concerns because: "PJM's 2025 long-term load forecast shows a peak load growth of 32 GW from 2024 to 2030. Of this, approximately 30 GW is projected to be from data centers."[48]

PJM's conundrum is how to keep the grid reliable as data center demand grows faster than new generation. Its "non-capacity-backed load" proposal would classify very large new loads (less than 50 MW) as customers outside the capacity market.[49]. The idea is to avoid shifting costs to others, but critics say that the 50 MW cutoff is arbitrary, curtailment rules could distort market signals, and contract and siting decisions may be disrupted.[50]. PJM is still debating whether the non-capacity-backed load should be voluntary or mandatory in shortage zones before filing at FERC for the 2028/29 delivery year.[51]

One challenge with resources like peak capacity is that once a project has been approved for interconnection, been built, and paid its share of costs, it becomes a load like any other. At that point, it is very difficult for the market to discriminate against it without creating efficiency concerns or legal risks. Data centers do more than strain peak supply; like all large loads with some variation, they also draw on ancillary services and other grid management resources.

If incremental demand is not met with increased supply, prices and emissions will rise

As the recent Nicholas Institute report[52] points out, some amount of flexibility from data centers could significantly reduce costs and delays associated with connection and peak demand constraints from new data centers. The report estimates peak load bottlenecks could be avoided for around 100 GW of so-called "curtailment-enabled headroom" on the U.S. grid. However, even if data centers avoid consumption during the most problematic hours, they still need power the rest of the time. Absent new supply on those same grids, the extra generation available off-peak will be from more expensive, and typically dirtier, marginal generation units.

Data centers' need to draw most of their power from existing units is thus a problem for other electricity customers because absent new matching supply, it will drive up their wholesale electricity costs. It is also problematic for the data centers themselves, which frequently are tied to corporations that have carbon reduction goals which are incompatible with increased emissions from existing fossil power plants. Conversely, new supply (especially cheap and clean supply) arriving quickly enough to offset data center consumption without requiring a large amount of new grid infrastructure creates potential for "beneficial electrification[53]" where more power over the same wires reduces other consumers' costs[54].

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Further consequences: Challenges and barriers specific to data centers

Connecting large new data center loads through the lens of three resource buckets faces three broad challenges required by all such loads. But these resource buckets also interact with the six more specific data center demand characteristics outlined in the preceding section.

Connection challenges specific to data centers

Because the source of many connection issues—or at least more expensive upgrades—come down to a limited set of hours and circumstances, flexibility is often cited as a master key for easing or speeding up connection. But flexibility is not always as simple to implement as first imagined, and other connection challenges specific to data centers are not necessarily circumvented with a touch of flexibility.

- **Agency:** Especially for co-location data centers, the operator is stuck between wanting to be more flexible to satisfy grid constraints and the imperative to be as generic as possible in contracts with tenants to accommodate as broad a class of customers as possible. Typical quality of service and service-level agreements also act as a barrier for to tapping flexibility.[55] Intervenors in public utility cases also question whether policies for ensuring new data centers cover all their incremental costs are effective[56].
- **Clustering:** Clustering leads to many data centers on the same part of the grid, necessitating more upstream transmission upgrades, as in the Virginia case mentioned cited by NRDC, mentioned above.
- **Consumption profile:** Big swings in power demand and power quality impacts on other consumers make data centers trickier for utilities and transmission providers to study and interconnect than simple 24/7 constant loads. Standard protection schemes and the collective behavior of 60 data centers recently caused a large reliability problem in Virginia in July 2024 when these data centers all dropped off the grid at once and caused a sudden surge in excess electricity that strained grid resources.[57]
- **Flexibility:** Some data centers are not flexible at all; others could be flexible but not in a manner consistent or predictable enough to satisfy the engineers running interconnection studies. These engineers are only likely to be satisfied after adding sophisticated energy management systems and large batteries, along with the promise of judicious backup power.
- **Backup:** As mentioned, backup power could be leveraged to facilitate connection or provide so-called "bridge power"[58] for data centers that cannot wait for interconnection. Unfortunately, backup power (used either for

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flexibility or bridge power) tends to be dirty, leading to siting and local community environmental concerns.[5960]

- **Modularity:** With a modular or phased build-out, a data center may ask up front for a large enough connection to accommodate all future phases, leading to stranded asset risk if all phases do not materialize.

Grid services challenges specific to data centers

Just as for solving connection issues, flexibility can help tamper the impact of new data centers on system-wide needs like peak capacity issues. A large overlap exists between local grid and larger grid issues with peak planning. However, as described in the prior section, flexibility is not always easy to implement or deploy in a manner which solves all challenges. Furthermore, the specific features of data centers tend to create additional challenges beyond help from simple load flexibility measures.

- **Agency:** Utilities often see new fossil resources like gas peakers as the easiest way to resolve new peak demand issues from data centers.[61] Because gas turbines are increasingly expensive, this may not be a good deal for other utility customers and may also entrench future emissions, working against many data center providers' and host states' clean power goals. Because eventual data center owner/operators tend to build where developers have prepared the ground, the fact that these developers may perceive emissions goals as secondary to "speed-to-power," and that utilities choose their own procurement path creates an agency mismatch.
- **Clustering:** The clustering of data centers tends to amplify their effects on the regional grid, with sharper surges in demand for grid services that cannot be accommodated fast enough through new resources builds.
- **Consumption profile:** While data centers don't run all the time, they plan their infrastructure for peak computing demand. This creates a knock-on effect for the bulk power system, which plans for peak power demand.
- **Flexibility:** Flexibility is not always a simple feature to implement or deploy.
- **Backup:** On-site backup power is a poor substitute for system resources because of expense as well as siting and local environmental concerns.
- **Modularity:** While the broader grid is in a good position to adjust to a phased build out of data center demand, this requires either coordination with the local utility or strong forward signals in the market to avoid disruptive demand shocks for grid services.

Bulk electricity challenges specific to data centers

Certain subcategories here (consumption profile, flexibility, modularity) concern time domains that do not apply when considering total annual consumption.

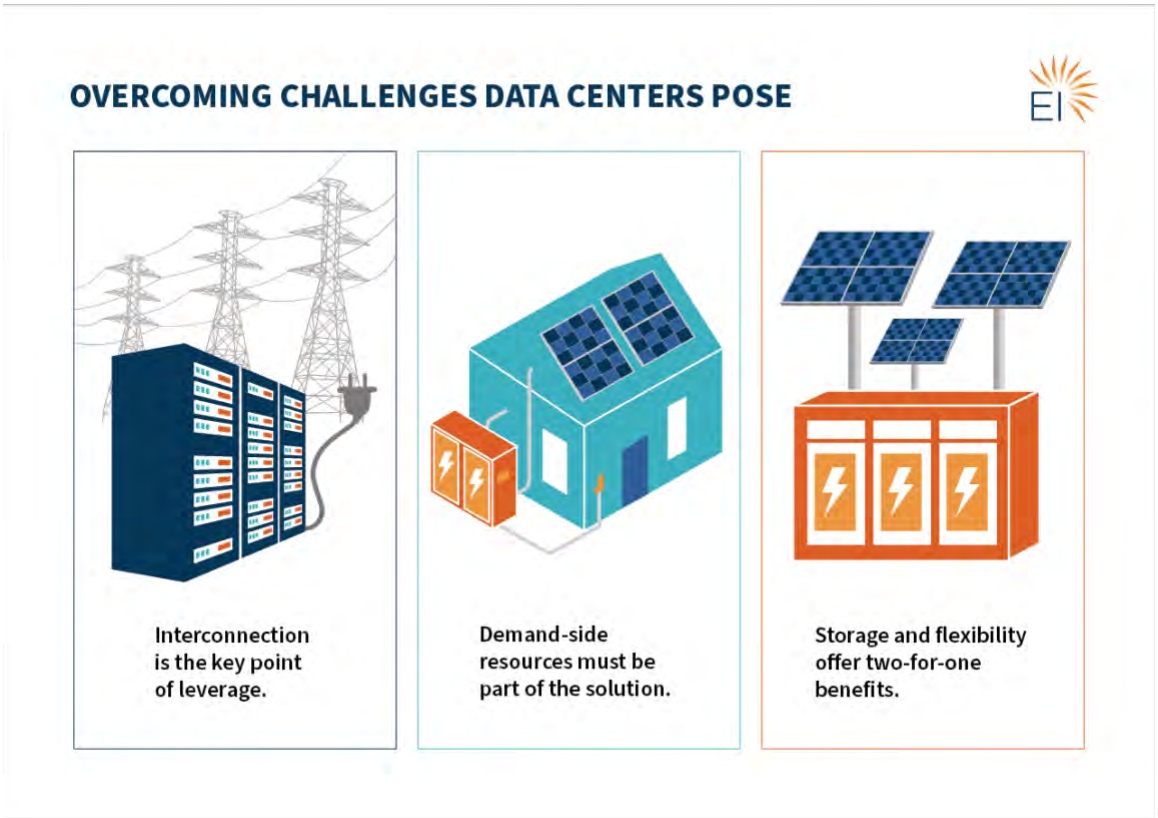
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- **Agency:** As with grid connection and services, intermediate entities between electricity provisioners and data center owner/operators with emissions goals may not consider the environmental impacts of reliance on using spare capacity from existing marginal resources.
- **Clustering:** Clustering means more annual electricity drawn from the same grid. This creates a greater need for new supply, amplifying the problems of price and emissions increases.
- **Consumption profile:** A variable but not necessarily predictable profile for large data center loads could create new challenges for grid operators, even at off-peak times.
- **Flexibility:** Data center demand flexibility could potentially alleviate emission concerns by targeting off-peak consumption more towards time periods with lower marginal emissions. This requires an extra layer of control on top of whatever that data center might have already committed to ease grid connection and mitigate impacts on grid operational resources.
- **Backup:** Supplying too much of the actual annual electricity use from backup power creates problematic environmental impacts.

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TAKEAWAYS FOR POLICYMAKERS AND OTHER STAKEHOLDERS

Figure 7 Three key takeaways



Many organizations (Clean Air Task Force/Brattle,[62] GridLab,[63] NRDC,[64] the Bipartisan Policy Center,[65] and the Regulatory Assistance Project[66]) have provided detailed and useful guides for coping with the challenges of meeting new data center loads.

This section distills the key lessons from the features and challenges discussed above.

Interconnection is the key point of leverage to influence when and how data centers join the grid

Accommodating large, dense new loads affects every grid participant, and the challenges show up at multiple scales. Geographically, they range from the substation where the data center connects to the entire interconnected system. In time, they span from sub-second transients to hours of local and bulk stress to the accumulation of annual demand.

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When issues are tied directly to a data center's load or its immediate connection, cost-causation principles are easier to apply. But at larger scales, like meeting new annual demand or rising peaks across a region, the problem is less about the nature of data centers than the pace and size of their growth. At that point, they can reasonably argue for being treated like any other customer buying power "at the pump," without special obligations.

This tension is what policymakers need to keep in mind. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the infrastructure costs they trigger, and to nudge them toward implementing solutions like flexible demand or local storage that relieve local bottlenecks and support the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

Using other demand-side resources

In one of our earlier reports on meeting the load growth challenge,[67] we pointed out the importance of using demand-side resources to meet this challenge most efficiently. Often the discussion of demand-side solutions focuses on direct measures at a data center, especially in the wake of the efficiencies revealed in the DeepSeek announcement.[68] However, data centers can meet their resource needs with other demand-side resources elsewhere on the grid. Recently, Voltus, an aggregator of distributed energy resources (DERs), announced a deal with Cloverleaf Infrastructure—a data center developer—to meet new capacity needs from data centers with market-accredited capacity from DERs.[69] This kind of transaction compensates other existing customers and thus helps accommodate the rapid rise of data center loads fairly, speedily, and equitably. Since connecting to the grid can involve mixing and matching resources to relieve bottlenecks, once a data center has invested in the flexibility and extra equipment needed to resolve local connection issues, there is no reason why more upstream connection issues, grid services bottlenecks, and the need for a large amount of annual electricity delivery cannot be resolved with demand-side solutions from other grid users.

A recent Rewiring America report proposes many of the resources to meet data center load growth could come from sponsoring household upgrades.[70] The report finds that if hyperscalers paid 50 percent of the up-front cost of installing heat pumps in the tens of millions of U.S. households that currently use inefficient electric heating, cooling, and water heating, they could free up a total 30 GW of capacity on the grid. In addition, if hyperscalers paid 30 percent of the up-front cost of rooftop solar and storage in every single-family household in the U.S., they could add 109 GW of capacity on the grid. The cost of these upgrades would be comparable to the report's estimate of $315/kW-year to build and operate a new gas power plant.

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Storage and flexibility relieve data center challenges; they can also ease interconnection of new variable renewables

On-site prime generation solutions built around renewables and flexibility (modulating demand and using batteries) may provide cheaper, cleaner, and faster means for meeting new and existing data center demand. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—offering a two-for-one advantage.

Furthermore, these renewable-plus-battery solutions can take advantage of existing surplus interconnection[71] to more quickly connect data centers to the grid in "power couples."[72]

By exploring the nuanced solutions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. Doing so will support both the digital economy's explosive growth and the clean energy transition.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-46:
R Street Institute Commentary: DOE "Zombies" Are Eating Competitive Power Mark

REAL SOLUTIONS

Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets

BY MICHAEL GIBERSON

ISSUES: ELECTRICITY POLICY, ENERGY AND ENVIRONMENT

NOV 13, 2025

This past May, the U.S. Department of Energy (DOE) used emergency authority to stop two scheduled power plant retirements. As we explained in July, these emergency orders are not a good way to boost grid reliability. That's not the only problem, though—the DOE's emergency orders also threaten to undermine competition in regional power markets.

The case invoked Section 202(c) of the Federal Power Act, which limits most orders to just 90 days. The DOE used this law to block the coal-fired J.H. Campbell Power Plant in Michigan and two units at the gas- and oil-fired Eddystone Generation Station in Pennsylvania from retiring. When those 90-day orders expired in August, the DOE issued new orders to keep the plants online. When these orders expire later in November, the DOE is expected to order the plants to stay online for *another* 90 days. Both currently operate with a safety net: If they lose money, the law makes area consumers cover those losses. And with losses covered no matter what, the plants have little reason to run efficiently. The result isn't grid reliability—it's creeping zombification of the market.

Markets require profits *and* losses to steer investment where it's needed (and away from where it's not). When a unit can't cover its costs at market prices, it should retire. When older, inefficient plants exit, space opens on the grid and in the market for better resources to jump in. Prices may initially rise, but consumers benefit in the end as competition grinds down average costs. Serial "emergency" orders break the economic feedback loop and undermine competitive forces.

The DOE's decision to keep two fossil-fueled power plants running raised speculation that the administration would block any fossil-fueled plant from retirement. However, a New Hampshire coal unit retired in October without federal intervention. That's good, because a plant that doesn't contribute to reliability and energy supplies at a competitive price *should* retire. But the lack of clear policy heightens uncertainty.

The economic damage shows up in three places:

- **Crowding out.** When zombie power plants are ordered to stay in the market, customers are stuck with the bill from any losses. Market revenues that would support efficient resources get skimmed by units the market has already rejected. The effect is subtle but

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important: Energy market prices flatten, clean and firm resources see less upside in tight hours, and generation turnover slows.

- **Planning.** Reliability planning depends on credible schedules—retirements that can be believed, new power plants that can be counted, and rules that don't change unnecessarily. A plant yo-yoing between "retired," "ordered to run," and "maybe extended" in 90-day increments can't fit into long-run reliability plans.

- **Policy-driven uncertainty.** States and stakeholders are suing the DOE over the emergency orders because the law is being employed in a manner different from what Congress intended. The DOE has not articulated a clear policy for how they will use their authority in the future, which leaves plant owners and potential investors in the dark.

Emergency orders do have their place. If a hurricane hits, fuel freezes, or a wildfire takes out a major power line, use 202(c) for the days or weeks necessary and then stand down. Utilities regularly ask for these emergency orders when they need them. The difference with zombie plant orders is that neither the plant owners nor the grid operators responsible for reliability in their regions requested them.

Nothing in this discussion denies reality—demand for electricity is rising, interconnection queues are clogged, and grid operators face tough winters and hot summers. The way forward is in policies that make better use of the existing grid, drive economical additions to transmission infrastructure, and let market forces drive power plant entry *and* exit. Competitive power markets are not responsible for rising electricity rates; in fact, a recent study pointed to increased spending on transmission and distribution wires as key factors in driving up customer rates.

Should the DOE continue to undermine market competition, consumers may get hit with the double-whammy of rising energy costs and rising infrastructure spending. Zombification of the electricity industry is no way to support a reliable, efficient power system.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-47:
Palgrave Handbook



The Palgrave Handbook of International Energy Economics

Edited by Manfred Hafner · Giacomo Luciani

OPEN ACCESS

palgrave
macmillan

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ISBN 978-3-030-86883-3 ISBN 978-3-030-86884-0 (eBook)
https://doi.org/10.1007/978-3-030-86884-0

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rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

3.4 Location

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

3.5 Expected Service Life

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-48:
IEA Report



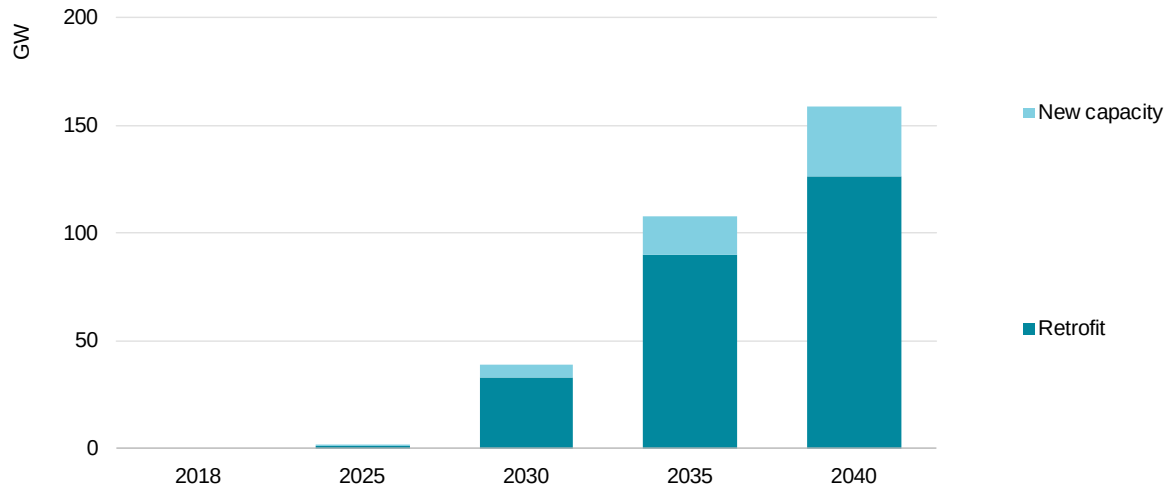
International Energy Agency

The role of CCUS in low-carbon power systems

Without carbon capture, meeting climate goals would ultimately mean almost eliminating the use of fossil fuels for power.

In the Sustainable Development Scenario, 120 GW of existing coal-fired capacity is retrofitted with carbon capture by 2040, accounting for some 80% of the coal plants equipped with these technologies. More than 110 GW of these retrofits are in China, representing a capital investment of around USD 160 billion. A further 10 GW are in the United States. Without carbon capture available at scale in power, coal-fired power generation, and eventually also gas-fired generation, would need to be virtually eliminated to meet long-term climate goals, with significant early retirements and potential stranding of assets.

Figure 4 **Coal-fired power plants equipped with carbon capture in the Sustainable Development Scenario**



Source: IEA (2019), World Energy Outlook 2019.

Over 750 GW of existing coal plants reduce operations to cut emissions in this Scenario, limiting electricity production but still providing system adequacy and flexibility. About one-quarter of the existing fleet would be retired before reaching the typical 50-year lifespan. Shutdowns and reduced operating hours are likely to lead to balance sheet write-downs for some owners of existing facilities. Coal plant retirements also imply greater investment in other low-carbon sources of electricity and associated network infrastructure.

Carbon capture retrofits also play an important role for the gas-fired power plant fleet, which currently has an average age of only around 19 years. In the SDS 155 GW of natural gas-fired power plants are equipped with carbon capture, utilisation and

IEA. All rights reserved.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-49:
2011 BART Order

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST:	]	
	]	FIRST REVISION:
TransAlta Centralia Generation LLC	]	ORDER NO. 6426
	]	

TO: Mr. Bob Nelson,
TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the state visibility protection program (WAC 173-400-151), which is implemented consistent with the requirements of the federal visibility protection program (40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitute Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event may the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

A. The TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant is a coal fired power plant larger than 750 MW output subject to BART. The power plant is comprised of 2 identical coal fired units referred to as BW21 and BW22.

B. BART emission limitations for sulfur dioxide and particulate matter were determined by the Environmental Protection Agency in 2003. The Centralia Power Plant's Operating Permit incorporates the BART emission limitations determined by EPA.

C. BART for nitrogen oxides at the Centralia Power Plant is based on:

   a. Use of selective noncatalytic reduction (SNCR) for nitrogen oxides control.
   b. Use of low NO_x burners with separated and close coupled over fire air systems (aka LNC3).
   c. Use of a sub-bituminous Powder River Basin coal or other coal that will achieve similar emission rates.

d. Use and installation of additional boiler heat recovery equipment and boiler tube cleaning equipment to maximize the extraction of fuel energy into boiler steam.

D. RCW 80.80.040 was amended in 2011 (Chapter 180, Laws of 2011) adding greenhouse gas emission requirements applicable to this facility that reduce the remaining useful life of each coal fired unit at the plant to approximately 8 and 13 years, starting from June 2011. The greenhouse gas emission requirements are:

a. Amendments to Chapter 80.80, Revised Code of Washington passed in 2011 require both coal fired units at the Centralia Power Plant to comply with the greenhouse gas emission performance standard requirements of Revised Code of Washington 80.80.040. One unit is required to comply by December 31, 2020. The other unit is required to comply by December 31, 2025. The plant owner, the Governor's office, and environmental organizations anticipate that compliance with this requirement will be accomplished by decommissioning the units.
b. The requirement to meet the greenhouse gas emission performance standard does not apply if the Department of Ecology determines that a state or federal requirement requires the installation of selective catalytic reduction for Nitrogen oxides control on the coal units.

Additional information and analysis is available in the BART Determination Support Document for the Centralia Power Plant, by the Washington State Department of Ecology, November 2008 (revised April 2010 and May 2011); and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008, and supplemental information dated March 2010; and Chapter 180, Laws of 2011.

YOU ARE ORDERED: To install and operate in accordance with the following conditions:

BART Emission Limitations

1. Nitrogen Oxides Emissions

1.1. Starting no later than the dates in Condition 1.1.1 and 1.1.2, emissions of nitrogen oxides from the two coal-fired utility steam generating units (known as BW21 and BW22) at the Centralia Power Plant are limited to a maximum of:

1.1.1. From the date of issuance of this Order, until 30 operating days after December 31, 2012, the nitrogen oxides emission limitation is 0.24 lb/MMBtu, 30 operating day rolling average, both units averaged together, including all emissions during unit start-up and shut-down.

1.1.2. Beginning on the 31st operating day after December 31, 2012, the nitrogen oxides emission limitation is 0.21 lb/MMBtu, 30 operating day rolling average, both units averaged together, including all emissions during unit start-up and shut-down.

1.1.3. The 30 day rolling average will be determined per Condition 7.

1.2. Beginning January 1, 2013, injection of ammonia or urea to control nitrogen oxides from a specific boiler must:

1.2.1. Commence when the flue gas at the point(s) of injection in the boiler has reached the minimum SNCR operating temperature as identified by the system vendor in the system specific operation manual.

1.2.2. End no sooner than the time coal is no longer introduced to the furnace of the boiler or the flue gas temperature at the injection point(s) is below the minimum SNCR operating temperature.

1.3. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75.

1.4. Coal used is required to be a sub-bituminous coal from the Powder River Basin or other coal that will achieve similar emission rates.

1.5. Nitrogen oxides emission reduction through the use of SNCR will be optimized as required in Condition 5. At the conclusion of the SNCR optimization study, the nitrogen oxides emission limitation contained in Condition 1.1.2 may be revised based on the results of the SNCR optimization study.

2. Ammonia emissions

2.1. Starting no later than the date in Condition 2.2, emissions of ammonia from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

2.1.1. Starting on January 1, 2013, the ammonia emission limitation is 10 parts per million, dry volume (ppmdv) 30 operating day rolling average, both units averaged together.
EXCEPTION: During the portion of the optimization study directed by Condition 5.2.3.1, the ammonia emission limitation is 20 ppmdv daily average, both units averaged together.

2.1.2. In the event that during a given day, only one unit operated, the average of both units will be the calendar day average of the operating boiler. The emission rate of zero for the unit that did not operate must not be included in calculating the average emissions.

2.2. Determination of compliance with the 30 operating day rolling average for ammonia will commence at midnight on the end of the 30th operating day after January 1, 2013.

2.3. Ammonia emission resulting from the use of SNCR will be optimized as required in Condition 5. The ammonia emission limitation contained in Condition 2.1.1 may be revised based on the results of the SNCR optimization study.

Schedule for Compliance

3. Compliance with the 30 operating day rolling average nitrogen oxides limitations begin on the dates given in Condition 1.1.1 and 1.1.2. Compliance with the 30 operating day rolling average ammonia emission limitations begins on the date given in Condition 2.1.

4. Coal units BW21 and BW22 will permanently cease burning coal and be decommissioned as follows:

4.1. One coal fired unit must permanently cease burning coal no later than December 31, 2020.

4.2. The second coal fired unit must permanently cease burning coal no later than December 31, 2025.

4.3. Conditions 4.1 and 4.2 do not apply in the event the Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit.

Nitrogen Oxides and Ammonia Reduction Optimization

5. The operation of the selective noncatalytic reduction (SNCR) system for control of nitrogen oxides will be optimized to produce both the lowest nitrogen oxides emission rate and the lowest ammonia emission concentration possible at the same time.

5.1. The nitrogen oxides control system will be optimized to achieve both the lowest 30 operating day average pound nitrogen oxides/MMBtu emission rate and the lowest 30 day average concentration of ammonia in the flue gas that is reasonably achievable without significant adverse effect on mercury capture, boiler cleaning processes (aka soot blowing) or byproduct salability .

5.2. To achieve the goal of Condition 5.1, The owner of the Centralia Power Plant will:

5.2.1. Develop an SNCR optimization plan and submit it by April 30, 2013 to Ecology and the SWCAA for their joint review and acceptance.

5.2.1.1.A draft optimization plan will be submitted to Ecology and SWCAA by January 30, 2013 for their review and comment. Ecology and/or SWACAA will respond with written comments within 45 days of receipt of the draft optimization plan. If a request for a copy of this draft optimization plan is

received, the agency receiving the request will provide the requester a copy of the draft optimization plan.

5.2.1.2. TransAlta will submit a final optimization plan reflecting all comments provided by Ecology and SWCAA. The plan must be submitted no later than April 30, 2013. The plan will be deemed to be accepted and the owner will immediately implement the plan if Ecology and/or SWCAA do not respond by May 30, 2013. If TransAlta, Ecology, or SWCAA receive a request for a copy of the final optimization plan, the entity receiving the request will provide a copy of the optimization plan to the requestor.

5.2.2. The optimization plan will:

5.2.2.1. Provide for all optimization testing to be complete and a report on the findings submitted to Ecology and SWCAA not later than December 31, 2014.

5.2.2.2. Identify the start and end dates of the optimization study.

5.2.2.3. Describe the optimization process to be followed, including:

5.2.2.3.1. The overall schedule.

5.2.2.3.2. The specific dates for each stage of the optimization program, especially the start and end dates of the testing to determine how low of a nitrogen oxides emission rate can be achieved per condition 5.2.3.1.

5.2.2.3.3. Whether testing will be done on only one boiler at a time or both together.

5.2.2.4. Identify acceptable maximum ammonia content of fly ash used for cement and gypsum used to produce wallboard, including the basis for those maximums.

5.2.2.5. Identify all additional flue gas monitoring that will be used to determine optimum urea or ammonia injection rates for maximum nitrogen oxides reduction.

5.2.2.6. Evaluate the effect of ammonia injection on mercury capture effectiveness, fly ash ammonia content, and gypsum product ammonia content. This includes a description of the sampling and analysis processes.

5.2.3. The focus of the optimization plan, is to determine :

5.2.3.1. The maximum nitrogen oxides reduction possible with an ammonia emission rate of up to 20 ppmdv, daily average, each unit individually;

5.2.3.2. The maximum nitrogen oxides reduction with which compliance can be reasonably achieved within an ammonia emission rate of 5 ppm; and

5.2.3.3. Determine the lowest nitrogen oxides emission rate reasonably achievable that coincides with the minimum ammonia emission rate.

5.2.3.4. The ability to achieve a nitrogen oxides emission rate of less than 0.19 lb/MMbtu, 30 operating day rolling average, each unit individually.

5.3. Ecology and SWCAA will review the optimization study report for 60 days. At the end of the 60 days the two agencies will either request TransAlta make changes to the report or accept the report in writing.

5.4. Within 90 days of receiving written acceptance of the optimization study report by Ecology and SWCAA, the plant operations and maintenance manual(s) will be amended to include the operating parameters reflecting the optimized ammonia or urea injection rates developed.

5.5. Revisions to this BART Order

.5.5.1. Within 30 days of acceptance of the optimization study report by Ecology and SWCAA, TransAlta will submit a request to Ecology to revise the emission limits in Conditions 1.1.2 and 2.1.1 to reflect the results of the optimization.

5.5.2. Upon receipt of the request to revise the emission limits, or within 60 days of acceptance of the optimization report by Ecology and SWCAA, Ecology will proceed to revise the emission limitations in Conditions 1.1.2 and 2.1.1 to reflect the results of the optimization study. Other approval conditions, including this condition, may be revised based on the final emission limitations.

5.5.3. The nitrogen oxides limitation will not be raised above the level in Condition 1.1.2 as it existed on the date of issuance of this Revised Order.

5.5.4. The ammonia limitation will not be raised above the level in Condition 2.1.1 as it existed on the date of issuance of this Revised Order.

Monitoring and Recordkeeping Requirements

6. Ammonia:

6.1. Ammonia emissions for compliance will be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing shall occur on the following frequency:

6.1.1. Testing shall occur once each calendar quarter, with no consecutive tests less than 80 or more than 110 calendar days apart.

6.1.2. If 3 consecutive tests are each less than the ammonia limitation, then the testing frequency reduces to once every 6 calendar months, provided the nitrogen oxides emission limit is complied with during the test.

6.1.3. If, after there are 3 consecutive tests less than the ammonia limitation, the next 2 consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

6.1.4. If at any time there is a test showing emissions above the emission limitation, then the testing frequency reverts to quarterly until the requirements in Conditions 6.1.2 and 6.1.3 are met.

6.1.5. The ammonia concentration measured during the periodic emissions testing is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test.

6.1.6. During the ammonia testing using BAAQMD Method ST1B (or CTM-027), the 30 rolling ammonia emission limit is to be treated as an hourly average for the purpose of Conditions 6.1. and 6.2.

6.2. For use as a routine indicator of compliance between the tests required in Condition 6.1, ammonia emissions will be estimated. The estimate will be based on a calculation which uses as inputs the reagent concentration and flow rate, a calculation or measurement of the uncontrolled nitrogen oxides rate, the continuous nitrogen oxides monitoring results measured in the stack, and other parameters as necessary.

6.3. At TransAlta's option, an ammonia continuous monitoring system may be used instead of periodic emissions tests. A continuous ammonia monitoring system used for compliance must meet the monitor location requirements contained in 40 CFR Part 60 Appendix B, Performance Specification 1 or 2, and the quality assurance and quality control requirements of 40 CFR Part 60 Appendix F as applicable.

7. Nitrogen oxides monitoring and averaging

7.1. For any hour in which coal is combusted in a unit, the owner/operator of each unit shall calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu times unit heat input) from all operating units and dividing that by the sum of the hourly heat inputs in million Btu for all operating units. At the end of each boiler operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler operating day and the previous 29 successive boiler operating days.

7.2.). An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR Part 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate.

7.3. Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

7.4. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period.

8. Ammonia emission limitation compliance based on periodic stack sampling and parameter monitoring.

8.1. Compliance with the ammonia emission limitation is demonstrated by meeting the limitation during the stack testing period. The average of the 3 discrete sampling runs will be used to determine compliance with the ammonia emission limitation until the next periodic stack testing occurs.

8.2. During each periodic stack test on each boiler, the ammonia or urea reagent injection rate and the ammonia to nitrogen oxides ratio for each sampling run shall be determined, recorded and reported as part of the testing report.

8.3. During plant operation between periodic stack testing, compliance with the ammonia emission limitation will be indicated by:

8.3.1. Injecting ammonia or urea reagent at the injection rate for ammonia or urea reagent used during the most recent stack sampling at the appropriate operating rate; and

8.3.2. Meeting the nitrogen oxides emission limit.

9. Coal Quality Monitoring

9.1. Coal nitrogen and sulfur content will be determined by taking a sample of the coal from the transfer belts between the coal pile and coal silos. An alternate location that provides a sample representative of the coal fired by the boilers may be proposed to Ecology by TransAlta for approval for use.

9.2. A sample of coal for nitrogen and sulfur content analysis will be taken at least once per week when at least one coal fired boiler is in operation. The sample must be taken following ASTM Method D2234/D2234M-07.

9.3. Coal nitrogen and sulfur content will be determined using ASTM Method D3176-89 (as reapproved in 2002). Note, other ASTM methods related to sample collection and preparation may need to be followed in order to perform this test.

9.4. As an alternate to coal nitrogen and sulfur content testing at the plant, certified results of testing by the coal mine operator of coal actually sent to the Centralia Power Plant may be used. Testing frequency should be no less frequent than required above.

Reporting Requirements

10. A letter reporting of achievement of each compliance date in the schedule in Conditions 3 and 4 must be submitted to the Washington State Governor, Ecology, and SWCAA within 30 days of achieving the milestone.

11. Emissions above the emission limitations in this order due to malfunctions must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with the emissions monitoring data per Condition 12. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA or Ecology regulation. Excess emissions that TransAlta believes are unavoidable must be documented as required in WAC 173-400-107 (or section 109 after that section is approved into the Washington SIP) and SWCAA's unavoidable excess emissions requirements.

12. Emission monitoring data will be reported to Ecology and to the SWCAA.

12.1. Continuous emission monitoring reports will be submitted within 30 days after the end of each calendar quarter. The reports must contain the following information:

12.1.1. The 30 operating day rolling average pound nitrogen oxides/MMBtu for each operating day in the reporting period. The 30 day rolling average nitrogen oxides emission rate shall be reported in units of lb/MMBtu, utilizing at least 2 significant figures;

12.1.2. The cumulative short tons of nitrogen oxides per unit and combined that has been emitted during the current calendar year. The cumulative tons shall be rounded to the nearest ton;

12.1.3. Periodic stack testing for ammonia emissions shall be submitted within 45 days of completion of the test.

If TransAlta elects to use continuous emission monitoring of ammonia instead of periodic stack testing, the quarterly report shall contain the 30 operating day rolling average ammonia concentration for both units averaged together for each operating day in the reporting period. Average ammonia concentrations shall be reported in units of ppmdv to 2 significant figures.

12.1.4 For each hour of boiler operation, the ammonia or urea injection rate in units of pounds of ammonia or urea/hour, , the boiler temperature at the point of injection, injection level in use, and the estimated ammonia emission concentration.

12.2. The emission monitoring report will be sent to SWCAA and Ecology electronically in a format acceptable to the SWCAA. Reporting to Ecology under this condition will end January 1, 2018.

13. Coal nitrogen and sulfur content information must be submitted to SWCAA and Ecology within 30 days of the end of each calendar quarter.

13.1. Coal nitrogen and sulfur reporting must include the date each coal sample is taken, the nitrogen and sulfur content of each coal sample analyzed, the average sulfur and nitrogen concentrations for the calendar quarter, and the maximum and minimum concentrations found during the calendar quarter.

13.2. After June 30, 2011, the report will include the rolling annual averages for nitrogen and sulfur content plus the maximum and minimum concentrations in the prior year.

13.2.1. The weekly coal sample test results will be retained for at least 5 years and available for review by Ecology or SWCAA upon request.

13.2.2. Coal quality reporting to Ecology will end the earlier of:

13.2.2.1. January 1, 2018, or
13.2.2.2. The decommissioning of either unit BW21 or BW22, or
13.2.2.3. The date monitoring of the quality of coal fired in units BW21 and BW22 is required by a regulation issued by EPA under the authority of Section 112 of the federal Clean Air Act.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order. Ecology shall enforce the terms of this Order only until such time as SWCAA incorporates the terms of the Order into the Centralia Power Plant's Air Operating Permit or except as provided by RCW 70.94.785.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.
- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:

The Pollution Control Hearings Board
PO Box 40903
Olympia, WA 98504-0903

OR

Deliver your appeal in person to:

The Pollution Control Hearings Board
4224–6th Avenue SE Rowe Six, Bldg 2
Lacey, WA 98503

To serve your appeal on the Department of Ecology:

Mail appeal to:

Department of Ecology
Appeals Coordinator
PO Box 47608
Olympia, WA 98504-7608

OR

Deliver your appeal in person to:

Department of Ecology
Appeals Coordinator
300 Desmond Drive SE
Lacey, WA 98503

And send a copy of your appeal packet to:

Alan Newman
Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at http://www.eho.wa.gov.

To find laws and agency rules, go to the Washington State Legislature website at http://www1.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this 13 day of Dec, 2011 at Olympia, Washington.

Jeff Johnston, Ph.D.
Manager, Science and Engineering Section
Department of Ecology
Air Quality Program

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-50:
2020 BART Order

STATE OF WASHINGTON
DEPARTMENT OF ECOLOGY

IN THE MATTER OF AN ADMINISTRATIVE ORDER AGAINST:	]	
	]	SECOND REVISION:
TransAlta Centralia Generation LLC	]	ORDER NO. 6426
	]	

TO: Mr. Mickey Dreher TransAlta Centralia Generation LLC
913 Big Hanaford Road
Centralia, WA 98531

This is an Administrative Order requiring your company to comply with WAC 173-400-151 by taking the actions that are described below. Chapter 70.94 RCW authorizes the Washington State Department of Ecology's Air Quality Program (Ecology) to issue Administrative Orders to require compliance with the requirements of Chapter 70.94 RCW and regulations issued to implement it.

Ecology has determined that portions of your facility are subject to the provisions of the state visibility protection program (WAC 173-400-151), which is implemented consistent with the requirements of the federal visibility protection program (40 CFR Part 51, Subpart P). The rules require that the State determine what technologies and level of emission control constitute Best Available Retrofit Technology (BART) for the eligible emission units at your facility. The rules also require the installation and use of those emission controls on the BART-eligible emission units. The emission controls are to be installed as expeditiously as possible, but in no event may the State allow them to start operation later than five years after the State's Regional Haze SIP amendment is approved by the United States Environmental Protection Agency (EPA).

FINDINGS

A. The TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant is a coal fired power plant larger than 750 MW output subject to BART. The power plant is comprised of two identical coal fired units referred to as BW21 and BW22.

B. BART emission limitations for sulfur dioxide and particulate matter were determined by the Environmental Protection Agency in 2003. The Centralia Power Plant's Operating Permit incorporates the BART emission limitations determined by EPA.

C. BART for nitrogen oxides at the Centralia Power Plant is based on:

   a. Utilization of the selective non-catalytic reduction (SNCR) for nitrogen oxides control as appropriate.
   b. Low NO_x burners with separated and close coupled over fire air systems (aka LNC3).

c. Utilization of the Combustion Optimization System with Neural Network on BW22 as appropriate.
d. Use and installation of additional boiler heat recovery equipment and boiler tube cleaning equipment to maximize the extraction of fuel energy into boiler steam.

D. RCW 80.80.040 was amended in 2011 (Chapter 180, Laws of 2011) adding greenhouse gas emission requirements applicable to this facility that reduce the remaining useful life of each coal fired unit at the plant to approximately 8 and 13 years, starting from June 2011. The greenhouse gas emission requirements are:

a. Amendments to Chapter 80.80, Revised Code of Washington passed in 2011 require both coal fired units at the Centralia Power Plant to comply with the greenhouse gas emission performance standard requirements of Revised Code of Washington 80.80.040. One unit is required to comply by December 31, 2020. The other unit is required to comply by December 31, 2025.

b. The requirement to meet the greenhouse gas emission performance standard does not apply if the Department of Ecology determines that a state or federal requirement requires the installation of selective catalytic reduction (SCR) for nitrogen oxides control on the coal units.

Additional information and analysis is available in the BART Determination Support Document for the Centralia Power Plant, by the Washington State Department of Ecology, November 2008 (revised April 2010 and May 2011); and the BART Analysis for the Centralia Power Plant, June 2008 and the BART Analysis Supplement, December 2008, and supplemental information dated March 2010; and Chapter 180, Laws of 2011.

YOU ARE ORDERED: To install and operate in accordance with the following conditions:

BART Emission Limitations

1. Nitrogen Oxides emissions

1.1. Emissions of nitrogen oxides from the two coal-fired utility steam generating units (known as BW21 and BW22) at the Centralia Power Plant are limited, from the date of issuance of this Order, to:

1.1.1. 0.21 lb/MMBtu on the unit that does not have the Combustion Optimization System with Neural Network installed. This is a 30 operating day rolling average and includes all emissions during unit start-up and shut-down.
1.1.2. 0.18 lb/MMBtu on the unit that does have the Combustion Optimization System with Neural Network. This is a 30 operating day rolling average and includes all emissions during unit start-up and shut-down.

1.1.3. 0.18 lb/MMBtu on the unit that continues coal fired power generation starting January 1, 2021.

1.2. The 30 day rolling average will be determined per Condition 5.

1.3. TransAlta may use a variety of means as necessary to control emissions of nitrogen oxides to meet the prescribed NOx limit for BW21 and BW22 including the Combustion Optimization System with Neural Network, the SNCR, Low NOx Burners, boiler control, variety (source) of coal, or any combination thereof. Compliance with the nitrogen oxides emission limitation will be determined by use of a continuous emission monitoring system meeting the requirements of 40 CFR Part 75.

2. Ammonia emissions

2.1. Starting no later than the effective date of this order, emissions of ammonia from the two coal-fired utility steam generating units at the Centralia Power Plant are limited to a maximum of:

2.1.1. 10 parts per million, dry volume (ppmdv). This is a 30 operating day rolling average of both units averaged together.

2.1.2. In the event that during a given day, only one unit is operated, the average of both units will be the calendar day average of the operating boiler. The emission rate of zero for the unit that did not operate must not be included in calculating the average emissions.

2.2. The injection rate of urea (as the source of ammonia) to meet the nitrogen oxides emission in Section 1.1.1 and 1.1.2 is solely determined by TransAlta.

Schedule for Compliance

3. Coal units BW21 and BW22 will permanently cease coal-fired power generation operations as follows:

3.1. One of the units must cease no later than December 31, 2020.

3.2. The other unit must cease no later than December 31, 2025.

3.3. The unit that continues coal-fired power generation operations starting January 1, 2021, must comply with section 1.1.3.

3.4. Conditions 3.1 and 3.2 do not apply in the event the Department of Ecology determines as a requirement of state or federal law or regulation that the selective catalytic reduction technology must be installed on either coal fired unit.

[First amendment of the December 23, 2011, Memorandum of Agreement between the State of Washington and TransAlta Centralia Generation LLC, dated July 13, 2017.]

Monitoring and Recordkeeping Requirements

4. Ammonia

TransAlta is required to meet the nitrogen oxides emission limits of 1.1.1 and 1.1.2. Ammonia monitoring is only required when urea injection is used to meet those limits. The entirety of Section 4 applies in any calendar year (CY) in which urea injection is used by TransAlta to meet the emission limits of 1.1.1 or 1.1.2. TransAlta is not required to perform any of the monitoring and recordkeeping requirements in Section 4 if urea is not injected in the CY.

4.1. Ammonia emissions for compliance will be monitored by means of periodic emissions testing utilizing Bay Area Air Quality Management District (BAAQMD) Method ST1B or Environmental Protection Agency Conditional Test Method 027 (CTM-027). The sampling point will be in the stack following the wet scrubber. Stack testing shall occur on the following frequency:

4.1.1. Testing shall occur once each calendar year if the ammonia feed-rate exceeds 1.5 gpm during that calendar year. Testing will be performed while the SNCR is in operation and the feed-rate is above 1.5 gpm during testing, with no consecutive tests less than 80 or more than 110 calendar days apart.

4.1.2. If two consecutive tests are each more than the ammonia limitation (in 2.1.1), then the testing frequency decreases to once every six calendar months, provided the nitrogen oxides emission limit is complied with during the test.

4.1.3. If, after there are three consecutive tests less than the ammonia limitation, the next two consecutive tests are less than 50% of the ammonia emission limitation, then the testing frequency reduces to once annually, provided the nitrogen oxides emission limit is complied with during the tests.

4.1.4. The ammonia concentration measured during the periodic emissions testing is the 30 operating day rolling average value used for compliance starting on the date of the completion of the test until the completion of the next required periodic emission test.

5. Nitrogen oxides monitoring and averaging

5.1. For any hour in which coal is combusted in a unit, the owner/operator of that unit shall calculate the hourly nitrogen oxides concentration in lb/MMBtu at the CEMS installed in accordance with the requirements of 40 CFR Part 75. The 30-day average lb/MMBtu rate is calculated by summing the hourly emissions in pounds (unit lb/MMBtu multiplied

by unit heat input) from that operating unit and dividing that by the sum of the hourly heat inputs in million Btu for that operating unit. At the end of that boiler's operating day, the owner/operator shall calculate and record a new 30-day rolling average emission rate in lb/MMBtu from all valid hourly data for that boiler's operating day and the previous 29 successive boiler operating days.

5.2. An hourly average nitrogen oxides emission rate is valid only if the minimum number of data points, as specified in 40 CFR Part 75, is acquired as necessary to calculate nitrogen oxides emissions and heat rate.

5.3. Data reported to meet the requirements of this section shall not include data substituted using the missing data substitution procedures of subpart D of 40 CFR part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR part 75.

5.4. A boiler operating day is a 24-hour period between 12 midnight and the following midnight during which coal is combusted at any time in the boiler. It is not necessary for coal to be combusted for the entire 24-hour period.

Reporting Requirements

6. A letter reporting achievement of each compliance date in the schedule in Condition 3 must be submitted to the Washington State Governor, Ecology, and SWCAA within 30 days of achieving the milestone.

7. A letter reporting TransAlta used urea injection must be sent to Ecology and SWCAA within 30 days of the first urea injection occurring during each calendar year. The letter must contain, at a minimum, the dates of urea injection, urea concentration, and the urea injection rate. No letter is required for any calendar year in which no urea injection occurred.

8. Emissions above the emission limitations in this order due to malfunctions must, at a minimum, be documented in writing and submitted to SWCAA and Ecology with 30 days after the end of each calendar quarter. Additional recordkeeping and notifications related to excess emissions may also be required by SWCAA or Ecology regulation. Excess emissions that TransAlta believes are unavoidable must be documented as required in WAC 173-400-107 (or section 109 after that section is approved into the Washington SIP) and SWCAA's unavoidable excess emissions requirements.

9. Emission monitoring data will be reported to Ecology and to the SWCAA.

9.1. Continuous emission monitoring reports will be submitted within 30 days after the end of each calendar quarter. The reports must contain the following information:

9.1.1. The 30 operating day rolling average pound nitrogen oxides/MMBtu for each operating day in the reporting period. The 30 day rolling average nitrogen oxides emission rate shall be reported as lb/MMBtu, with at least two significant figures;

9.1.2. The cumulative short tons of nitrogen oxides per unit and for both units combined that has been emitted during the current calendar year. The cumulative tons shall be rounded to the nearest ton;

9.1.3. The results of Section 4 testing for ammonia emissions, if they are required, shall be submitted within 45 days of completion of the test.

9.2. The emission monitoring report will be sent to SWCAA and Ecology electronically in a format acceptable to SWCAA.

Failure to comply with this Order may result in the issuance of civil penalties or other actions, whether administrative or judicial, to enforce the terms of this Order. Ecology shall enforce the terms of this Order only until such time as SWCAA incorporates the terms of the Order into the Centralia Power Plant's Air Operating Permit or except as provided by RCW 70.94.785.

You have a right to appeal this Order. To appeal you must:

- File your appeal with the Pollution Control Hearing Board within 30 days of the "date of receipt" of this document. Filing means actual receipt by the Board during regular office hours.
- Serve your appeal on the Department of Ecology within 30 days of the "date of receipt" of this document. Service may be accomplished by any of the procedures identified in WAC 371-08-305(10). "Date of receipt" is defined at RCW 43.21B.001(2).

If you appeal you must:

- Include a copy of this document with your Notice of Appeal.
- Serve and file your appeal in paper form; electronic copies are not accepted.

To file your appeal with the Pollution Control Hearing Board:

Mail appeal to:

The Pollution Control
Hearings Board
PO Box 40903
Olympia, WA 98504-0903

OR

Deliver your appeal in person to:

The Pollution Control
Hearings Board
1111 Israel Rd. SW, STE 301
Tumwater, WA 98501

To serve your appeal on the Department of Ecology:

Mail appeal to:

Department of Ecology
Appeals Coordinator
PO Box 47608
Olympia, WA 98504-7608

OR

Deliver your appeal in person to:

Department of Ecology
Appeals Coordinator
300 Desmond Drive SE
Lacey, WA 98503

And send a copy of your appeal packet to:

Philip Gent
Department of Ecology
Air Quality Program
PO Box 47600
Olympia, WA 98504-7600

For additional information, go to the Environmental Hearings Office website at https://www.eluho.wa.gov.

To find laws and agency rules, go to the Washington State Legislature website at http://www.leg.wa.gov/CodeReviser.

Your appeal alone will not stay the effectiveness of this Order. Stay requests must be submitted in accordance with RCW 43.21B.320. These procedures are consistent with Chapter 43.21B RCW.

DATED this _29th__ day of _July_, 2020 at Olympia, Washington.



Martha Hankins
Manager, Policy and Planning Section
Department of Ecology
Air Quality Program

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-51:
2020 BART Order Technical Support

DEPARTMENT OF ECOLOGY
State of Washington

Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision

TransAlta Centralia Generation Plant

July 2020

Publication and Contact Information

For more information, contact:

Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600
360-407-6800

Washington State Department of Ecology — www.ecology.wa.gov

- Headquarters, Olympia 360-407-6000
- Northwest Regional Office, Bellevue 425-649-7000
- Southwest Regional Office, Olympia 360-407-6300
- Central Regional Office, Union Gap 509-575-2490
- Eastern Regional Office, Spokane 509-329-3400

ADA Accessibility

To request ADA accommodation, email phil.gent@ecy.wa.gov or call 360-407-6810, 711 (relay service), or 877-833-6341 (TTY).

July 2020

Technical Support Document for Second BART (Best Available Retrofit Technology) Order Revision

TransAlta Centralia Generation Plant

Air Quality Program

Washington State Department of Ecology

Olympia, Washington

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Executive Summary

TransAlta requested a revision to their existing BART order to mitigate fouling of their electrostatic precipitators (ESPs) with ammonia sulfate. In 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. The proposed mitigation is for TransAlta to install and operate a Combustion Optimization System with Neural Network (Neural Net) and have a lower nitrogen oxides (NOx) emission limit on the unit that is operational beyond 2020.

TransAlta was previously required to install Selective Non-Catalytic Reduction (SNCR) for control of nitrogen oxides emitted from their Centralia Power Plant. As a condition of the BART order issued to the facility, an optimization study was required to be performed and the results of that study implemented by the facility. After conducting the optimization study, TransAlta discovered that the ESPs were fouled from ammonia use required in the current BART order (Revision 1).

Southwest Clean Air Agency agreed to use enforcement discretion in 2019 on the urea injection rate while TransAlta was tuning the Neural Net. At the end of Calendar Year 2019, TransAlta had enough data to agree that the Neural Net system would be able to meet a 0.18 lb/MMBtu emission standard. TransAlta submitted a request to revise their BART order in January 2020.

TransAlta, Southwest Clean Air Agency, and Ecology agreed on the conditions for Revision 2 for the BART order to include lower nitrogen oxides limits, changes to the use and monitoring of ammonia, and removal of the requirement to analyze the coal sulfur and nitrogen content.

Reason for this Revision

Trans Alta requested a revision to their existing BART order to mitigate fouling of their electrostatic precipitators (ESPs) with ammonia sulfate. The proposed mitigation is for TransAlta to install in one boiler unit a Combustion Optimization System with Neural Network (Neural Net) in order to reduce the urea injection rate (the source of the ammonia). The other boiler unit is currently slated to cease coal-fired power generation on December 31, 2020 and is not scheduled to have the Neural Net installed. Ecology and Southwest Clean Air Agency are willing to accept a lower urea injection rate if TransAlta is willing to accept a lower nitrogen oxides emission limit. Ecology has determined that the nitrogen oxides reduction resulting from lowering the emission limit to 0.18 lb/MMBtu nitrogen oxides will be slightly beneficial for the environment and reduce regional haze.

Ecology will modify the BART order by:

- Lowering the nitrogen oxides emission limit on one unit to 0.18 lb/MMBTU
- Requiring the unit that continues to provide coal-fired power production after 2020 to meet the 0.18 lb/MMBtu nitrogen oxides.
- Changing the language to "Permanently cease coal-fired 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" to match the new language in the MOA.
- Removing the requirement to sample the coal for nitrogen and sulfur content.
- Removing the requirement to report to Southwest Clean Air Agency results of coal test.
- Removing the requirement of a specific urea injection rate to allow TransAlta to inject urea as required (or if required) to meet the new emission standard.
- Changing the requirement for ammonia emission monitoring only to require monitoring when using a urea injection rate of greater than 1.5 gallons per minute

Ecology is also modifying the compliance schedule to eliminate the requirement to demolish the coal units to align the BART order's language with language in the Memorandum of Understanding (MOA) between the State of Washington and TransAlta.

SNCR and Other Related Changes

The requirement to install SNCR along with the requirement to meet Washington's greenhouse gas emission performance standard was enacted by the legislature in 2010. The legislative requirement resulted in the first BART order revision. This first revision was finalized in December 2011 and approved by EPA December 16, 2012.

Originally, Revision 2 was intended to incorporate the results of the SNCR Optimization Study required by Condition 5 of the First Revision of the amended 2012 BART order. The study was to demonstrate the proper use of ammonia in controlling emissions of nitrogen oxides generated by the combustion of coal in the TransAlta boilers. Goals of the study were to determine how low nitrogen oxides emissions could be attained while meeting an ammonia slip limit of 10 ppm.

TransAlta completed the required ammonia injection optimization testing in two phases. The first phase was completed and the required report submitted in September 2014. Ecology and Southwest Clean Air Agency requested additional testing. This additional testing was performed and updated test results were submitted in August 2016. The updated test results were accepted by Ecology and Southwest Clean Air Agency on November 7, 2016. Ecology's letter accepting the final report included a requirement for urea injection in Unit 1 at 1.2 gallons per minute and 2.0 gallons/minute in unit 2. The prescribed urea injection level was constant for all power generation levels.

Condition 5 of the First Revision of the BART order required TransAlta to submit a request to revise the BART order to reflect the results of the study. In a letter dated November 28, 2016, TransAlta requested specific revisions to the BART order to reflect the findings of the study.

Before Ecology was able to take action on TransAlta's request, TransAlta started a third optimization study in response to a compliance order with Southwest Clean Air Agency. The intent of the third optimization study was to fine-tune certain plant operating parameters and verify the result of the second optimization study. The results of the third study would augment or replace the results of the previous studies. An initial SNCR optimization test plan was submitted to Ecology by email on February 6, 2019.

In the summer of 2019, TransAlta experienced emission opacity readings that would have exceeded the opacity limits if TransAlta had not reduced plant capacity to compensate. During a maintenance shut-down of the facility, the electrostatic precipitators (ESPs) were examined. The ESPs had a visual fouling of all interior components, which dramatically reduced their efficiency. Samples of the material in the ESPs were analyzed and identified as ammonia sulfate. The source of ammonia in the system was from the reactions of urea in the SNCR system.

To decrease the ammonia slip in the SNCR, TransAlta installed a computerized emission control system called a Combustion Optimization System with Neural Network program (Neural Net). The Neural Net is able to monitor and adjust more system variables at the same time than the manual control system. TransAlta notified Ecology and Southwest Clean Air Agency by email on July 8, 2019 of the installation of the Neural Net and the start of tuning the system.

TransAlta submitted a request on January 30, 2020 to modify Revision 1 of the BART order. The modification proposes the installation of the Neural Net and eliminates the mandatory urea injection requirements.

Revision 2 incorporates those changes and removes outdated requirements.

Compliance schedule related change

On July 13, 2017, the Memorandum of Agreement (MOA) between the State of Washington and TransAlta was amended. Subsection D(5) of the Recitals was modified. The 2011 MOA stated, "permanently cease power generation…" The 2017 MOA amendment reads:

> (5) permanently cease coal-fired 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, in each case pursuant to the terms and subject to the conditions of this MOA.

The change in the MOA does not require decommissioning of the units as envisioned (but not explicitly required) in 2011 with the passage of Chapter 180 (see Laws of 2011 - ESSB 5769 in 2011, codified in several locations). The change in the order reflects the pertinent portions of this law as codified in Chapters 80.80 and 80.82 RCW.

Ecology used the 2011 expectation that the plant would close to comply with the greenhouse gas emissions performance standard in RCW 80.08.040(3). Ecology also used the planned closure of the plant in the 2011 Regional Haze State Implementation Plan to project visibility benefits from the plant meeting the standard according to the schedule in the law. If power generation of the coal plant is replaced with a different form of combustion power generation (e.g., natural gas), the impact to regional haze would have to be analyzed separate from this BART order modification.

If TransAlta decides to switch to non-coal power generation, a Notice of Construction application would need to be submitted to Southwest Clean Air Agency by the company. Ecology would require the company to do, at a minimum, emissions modeling that would be required under the BART process to quantify the visibility impacts resulting from the operation as a natural gas boiler plant (EGU). This is similar to what we would require of a new power plant to determine if it meets the requirements of WAC 173-400-117, special protection requirements for federal Class I areas.

Basis for Decision

SNCR related changes and optimization study

As directed by BART order revision 1 and RCW 80.80.040, TransAlta installed an SNCR system to reduce nitrogen oxides emissions from the boilers. The installation was based on a design study by the system vendor, NALCO-NOx Mobotec.

NALCO/Mobotec took system measurements adequate to model the combustion process and optimize the locations of ammonia injection into the boilers. Modeling indicated that due to the configuration of the boilers, the lowest nitrogen oxides emission rate anticipated would be approximately 0.195 lb/MMBtu, assuming that modifications to optimize combustion in the fireboxes for Powder River Basin (PRB) sub-bituminous coal were completed.

Only Unit 2 (aka BW22) was modified for optimizing the combustion of PRB coals. These modifications, proposed in 2007, are known as the Flex Fuels Project. Unit 1 (aka BW21) is not modified and the company indicates that it is unlikely that the modifications will be installed on this unit.

The installed SNCR system includes three levels of injection lances in each boiler. The actual lances used depends on the firing rate. In general, to avoid making nitrogen oxides by oxidizing ammonia, the higher lances are used at high firing rates and the lower lances are used at low firing rates.

Ammonia is supplied by using urea. Urea is received as a 40 percent by weight urea solution. The urea is supplied to the lances via a variable speed pump that can supply up to 6 gallons per minute of the 40 percent urea solution to an eductor system. The water provides some cooling to the hot flue gas and carries the urea well beyond the lance ports allowing the nitrogen oxides reduction to occur over more volume of the boiler. At maximum injection rates, the system is capable of injecting ammonia at approximately the stoichiometric rate for the SNCR reaction at maximum heat input.

The modeling by NALCO/Mobotec on maximum reduction of nitrogen oxides has proven to be accurate in practice. Boiler/SNCR system modeling indicated that the maximum expected nitrogen oxides reduction would give an emission rate of 0.195 lb/MMBtu. Testing indicates that on Unit 2, the maximum reduction is to 0.19 lb/MMBtu and for Unit 1, 0.20 lb/MMBtu.

The initial reduction testing (reported in the September 2014 Optimization Study report) indicated that at low injection rates, the installed SNCR systems did not reduce nitrogen oxides beyond the levels being achieved by the use of the installed combustion controls. There was no significant nitrogen oxides reduction when the SNCR and combustion controls were both operated concurrently. The 2014 Optimization Study report indicated that the combination of SNCR and combustion control could achieve 0.21 lb nitrogen oxides/MMBtu. The current

nitrogen oxides emission limit has been set to the achievable emission level of 0.21 lb nitrogen oxides/MMBtu.

Ecology and Southwest Clean Air Agency required TransAlta to complete additional urea injection studies to determine the effects of injection rates of up to 6 gpm of 40 percent urea solution on nitrogen oxides reduction. Two test series on each boiler were done at 2 boiler operating rates:

- A series of 15-minute tests at an operating rate of 686 MW, gross, and
- A series of 15-minute and 4 hours tests were done at an operating rate of 600 MW, gross.

Conclusions of TransAlta's optimization study

In conclusion, the 2014 and 2016 test results indicate that the injection rates developed by NALCO/Mobotec as their optimum injection rates are very close to what has been demonstrated in the most current study. TransAlta presented rationale for why the emission limits in the BART order should not be adjusted downward.

TransAlta's rationale included a conclusion that the effectiveness of the SNCR system is affected by numerous operational parameters. The plant operators have control over some, while others are out of their control. Operating parameters include market driven operating rates, fuel blend, physical condition of the boiler and auxiliary equipment, fuel staging at burners, air flow distribution, burner tilt, soot blowing intervals, tube fouling, water wall slagging, and temperature in the convective pass of the boiler. TransAlta argued that because the uncertainties listed above, the BART order should not be adjusted.

Ecology's evaluation of the optimization data

Test results indicate that a small reduction in average nitrogen oxides emissions may be achievable. The actual reduction depends on several operating parameters. Ecology has evaluated the possibility of reducing the 30-day average limitation from 0.21 to 0.20 lb/MMBtu. We note that if both units operated at full rate for every hour of the year (i.e., the potential to emit), a 0.01 lb/MMBtu reduction equates to about 590 tons per year out of a potential to emit rate of 12,900 tons.

TransAlta's current permits require the operation of the SNCR system with urea injection and emission limits of 0.21 lb/MMBtu. The urea injection rate is creating ammonia slip. The ammonia generation is reacting with sulfur to create ammonia sulfate that is plating the surfaces in the ESPs. This creates conditions where the facility has to run at a reduced rate to continuing meeting emission requirements.

Neural Net

TransAlta initial proposal was to substitute the Neural Net to reduce the urea injection rate for each unit. Ecology and Southwest Clean Air Agency were willing to accept a lower urea injection rate, but wanted TransAlta to meet the short-term emission values of 0.18 lb/MMBtu for the unit with the Neural Net installed on it. In July 2019, TransAlta did not know the effectiveness of the Neural Net system. TransAlta requested a delay in agreement until more testing was done.

Southwest Clean Air Agency agreed to use enforcement discretion in 2019 on the urea injection rate while TransAlta was tuning the Neural Net. At the end of Calendar Year 2019, TransAlta had enough data to agree that the Neural Net system would be able to meet a 0.18 lb/MMBtu emission standard. TransAlta submitted a request to revise their BART order in January 2020.

The main elements of the request are to:

- Install the Neural Net on Unit 2.
- Change the emission standard on Unit 2 to 0.18 lb/MMBtu from 0.21 lb/MMBtu.
- Allow TransAlta to use all methods and options they have available in any combination to meet the 0.18 lb/MMBtu standard.
- Change the ammonia monitoring requirements to reflect both historical readings and the change in urea injection rates.
- Remove the testing of coal for nitrogen and sulfur content as the facility would have to meet emission standards regardless of the coal used.
- Remove the reporting requirements for the coal nitrogen and sulfur content, as the test would no longer be performed.
- Change the permit language to reflect the new MOA language.

Compliance schedule related changes

The requirements of Chapter 80.80 RCW that sets the compliance schedule simply requires that to continue operation as a baseload power plant after the schedule in RCW 80.80.040(3)(c) and the BART order, each boiler must meet the greenhouse gas emission performance standard in effect on the day after the compliance dates. The standard is set by Washington Department of Commerce based on the emissions of combined cycle combustion turbines offered for sale and installed in the United States. This standard is currently 970 pounds of greenhouse gases/MWh. The standard is currently under review by Commerce for potential revision downward.

To continue operation after 2020 and 2025 with emissions above the greenhouse gas emission performance standard would require the plant owners to take an enforceable limit that keeps

operations annually below a 60 percent capacity factor to avoid being classified as a baseload power plant under Chapter 80.80 RCW.

Ecology Analysis

The change in MOA language does not exclude the possibility that TransAlta could retrofit the facility to natural gas and continue operation. As the current BART order revision request does not address the future operation of the plant after 2025, any changes of this nature will require a separate action on the part of TransAlta. Until such time, it is assumed that TransAlta will cease all power generation activities by 2025.

Chapter 80.82 RCW was enacted in the same legislation that enacted special requirements for the Centralia Power Plant in Chapter 80.80 RCW. This law was drafted with the explicit understanding that the coal units would be decommissioned and demolished rather than repowered.

Ecology is aware that if TransAlta repowers the units on natural gas the visibility improvements anticipated by the current BART order and state implementation plan limits would not be met. Repowering would change the emission reduction used in determining the 2028 further progress goals for the nearby Class I Areas (Mt. Rainier and Olympic National Parks, and the Goat Rocks and Alpine Lakes Wilderness Areas) under the 2021 Regional Haze State Implementation Plan.

Proposed revision to emission limit in BART order

Ecology has determined that the small nitrogen oxides reduction resulting from lowering the emission limit to 0.18 lb/MMBtu nitrogen oxides will be slightly beneficial for the environment and reduce regional haze.

Ecology has determined that a change in ammonia monitor is applicable with the change from a mandatory urea injection rate to a rate dependent on meeting a specific nitrogen oxides emission standard. TransAlta historic ammonia emission sampling at their current urea injection rate has never indicated excessive ammonia emissions. A large part in this finding is that the SNCR is upstream in the emission pathway from the wet scrubber. Free ammonia in the exhaust stream would be absorbed by the slurry stream in the wet scrubber, as ammonia is hydrophilic. These two factors allow for modification of the ammonia monitoring.

Ecology will modify the BART order by:

- Lowering the nitrogen oxides emission standard on the second unit to 0.18 lb/MMBTU
- Requiring the unit that continues to provide coal-fired power production after 2020 to meet the 0.18 lb/MMBtu nitrogen oxides.

- Change the language to “permanently cease coal-fired 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.” This to match the new language in the MOA.
- Remove the requirement to sample the coal for nitrogen and sulfur content.
- Remove the requirement to report to Southwest Clean Air Agency results of coal test.
- Removing the requirement a specific urea injection rate to allow TransAlta to inject urea as required (or if required) to meet the new emission standard.
- Change the requirement for ammonia emission monitoring to reflect monitoring when using a urea injection rate of greater than 1.5 gallons per minute.

Proposed revision to compliance schedule in BART order

Ecology is proposing to modify the compliance schedule for coal units BW21 and BW22 to permanently cease coal-fired power generation operations by 2020 and 2025. This much more closely matches the requirement in the underlying state law.

Any request to repower one or both units at the Centralia plant would require that the impact of repowering on visibility be modeled. The modeling would have to meet both the requirements of BART modeling and satisfy the requirement of WAC 173-400-117. Since TransAlta has not requested repowering at this time, this issue will not be addressed in this BART order revision.

References

TransAlta’s SNCR Optimization Study Report, September 20, 2014

TransAlta’s SNCR Optimization Study Report, August 15, 2016

Ecology’s SNCR Optimization Study Report acceptance letter dated November 7, 2016

Letter to Nancy Pritchett and Uri Papish, dated November 28, 2016

Southwest Clean Air Agency Regulatory Order #16-3202, issued December 13, 2016

TVW recording of March 15, 2011 House Environment Committee

Emission calculation

Appendix:

Response to Comment

From: Gent, Philip (ECY)
To: emissol@emissol.co
Subject: Response to submitted comment on TransAlta"s proposed BART Revision
Date: Monday, July 27, 2020 4:39:00 PM

To whom it may concern,

You submitted a comment in regards to a proposed revision to the TransAlta Centralia Generation LLC ("TransAlta") Centralia Power Plant's Best Available Retrofit Technology (BART) Order on 5/19/2020 at 1420. Below you will find your submitted comment and Ecology's response to your comment.

Submitted Comment

"Neural Network (NN) is a complex method and requires substantial testing, development and validation in order to make it work for any given environment. We trust the applicant has gone thru its due process for this development and demonstration. It is imperative that sufficient evidence is provided, showing a certain NN algorithm has been developed and specifically shown to work for the said environment in the powerplant."

Response to comment

Thank you for your comment. TransAlta along with Neuendorfer and Griffin Open Systems installed a temporary neural network interfacing with the plant distributed control system starting July 8, 2019. The system had no control elements and was only learning and modeling the systems. Griffin engineers built a model to perform predictive modeling and started to collect tuning data.

The neural network interface continued to collect tuning data and in October, 2019, TransAlta Corporate approved and issued an authorization for expenditure for the entire neural network installation. The installation plan was to have the neural network operational the first week of November. The actual transition time took longer than planned and the commission date was extended to December 19, 2019.

The months of installation and modification of the neural network in order to reduce and optimize NOx emissions gave TransAlta the confidence to request a change to their existing BART Order. From the time of control system commissioning (December 19, 2019 being the day Griffin and Neuendorfer left the site) until the unit came offline for the spring outage on February 11, 2020, average NOX emissions have been below 0.18 lb/MMBtu. As the request to lower the NOx emission limit came from the Permittee (TransAlta), it is incumbent on TransAlta to meet the limits.

No change was made to the BART Order as a result of this comment.

Philip Gent, PE
Senior Engineer
Policy & Planning Section
Washington Department of Ecology
(360) 407-6810
Philip.Gent@ecy.wa.gov

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-52:
Centralia Hazardous Substances Releases: Preliminary Determination (Sept. 2025)

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

September 4, 2025

Mickey Dreher
TransAlta Centralia Generation LLC
913 Big Hanaford Rd,
Centralia, WA 98531-9101

Re: Preliminary Determination of Liability for Release of Hazardous Substances at the following Contaminated Site:

- **Site Name:** Centralia Steam Plant
- **Site Address:** 913 Big Hanaford Rd, Centralia, WA 98531-9101
- **Cleanup Site ID:** 17302
- **Facility/Site ID:** 94772166

Dear Mickey Dreher:

Based on credible evidence, the Department of Ecology (Ecology) is proposing to find TransAlta Centralia Generation LLC liable under the Model Toxics Control Act (MTCA), Chapter 70A.305 RCW, for the release of hazardous substances at the Centralia Steam Plant (Site). Any person whom Ecology finds, based on credible evidence, to be liable is known under MTCA as a "potentially liable person" or "PLP."

This letter identifies the basis for Ecology's proposed finding and your opportunity to respond to that finding. This letter also describes the scope of your potential liability and next steps in the cleanup process at the Site.

Proposed Finding of Liability

Ecology is proposing to find TransAlta Centralia Generation LLC liable under RCW 70A.305.040 for the release of hazardous substances at the Site. This proposed finding is based on the following evidence:

1. TransAlta Centralia Generation LLC is the current owner and operator of the TransAlta Steam Plant (Site) located at 913 Big Hanaford Rd, Centralia Washington 98531 including Lewis County Parcels 23340001000,23340002002,23340003000,23340004000,23340005001,233400

05002,
23340005003,23340005004,23436000000,23345000000,23355001006,23355001007,
23355001008,23355002002.

2. The property is and has been historically operated as a coal-fired electric plant with associated energy production activities.

3. The owner has provided a draft remedial investigation (TRC Environmental Corporation, Remedial Investigation Report, TransAlta Centralia Generation LLC, 913 Big Hanaford Road, Centralia WA, May 13, 2025) that identifies releases including metals, volatile organic compounds, semi-volatile organic compounds (SVOCs), and total petroleum hydrocarbons, to soil, groundwater, and sediment above MTCA cleanup levels. The facility's operation as a coal burning power generation plant likely released particulate containing dioxins and furans, SVOCs, and select metals including mercury from its smokestacks into the environment surrounding the facility.

Opportunity to Respond to Proposed Finding of Liability

In response to Ecology's proposed finding of liability, you may either:

1. Accept your status as a PLP without admitting liability and expedite the process through a voluntary waiver of your right to comment. This may be accomplished by signing and returning the enclosed form or by sending a letter containing similar information to Ecology; or

2. Challenge your status as a PLP by submitting written comments to Ecology within thirty (30) calendar days of the date you receive this letter; or

3. Choose not to comment on your status as a PLP.

Please submit your waiver or written comments to the following address:

Thomas Middleton
Southwest Regional Office
Toxics Cleanup Program
PO Box 47775
Olympia, WA 98504-7775

After reviewing any comments submitted, or after 30 days if no response has been received, Ecology will make a final determination regarding your status as a PLP and provide you with written notice of that determination.

Identification of Other Potentially Liable Persons

If you are aware of any other persons who may be liable for the release of hazardous substances at the Site, Ecology encourages you to provide us with their identities and the reason you believe they are liable. Ecology also suggests you contact these other persons to discuss how you can jointly work together to most efficiently clean up the Site.

Responsibility and Scope of Potential Liability

Ecology may either conduct or require PLPs to conduct remedial actions to investigate and clean up the release of hazardous substances at a site. PLPs are encouraged to initiate discussions and negotiations with Ecology and the Office of the Attorney General that may lead to an agreement on the remedial action to be conducted.

Each liable person is strictly liable, jointly and severally, for all remedial action costs and for all natural resource damages resulting from the release of hazardous substances at a site. If Ecology incurs remedial action costs in connection with the investigation or cleanup of real property and those costs are not reimbursed, then Ecology has the authority under RCW 70A.305.060 to file a lien against that real property to recover those costs.

Next Steps in Cleanup Process

In response to the release of hazardous substances at the Site, Ecology intends to conduct the following actions under MTCA:

1. Ecology has completed the Initial Investigation/Site Hazard Assessment (II/SHA) and prepared an Early Notice Letter (ENL). Ecology will engage with TransAlta Generation Centralia LLC to develop an Agreed Order at the Site.

2. Ecology will continue to work with TransAlta Generation Centralia LLC to complete its closure requirements and obligations under RCW Chapter 80.82 and the Memorandum of Agreement between TransAlta and the State of Washington dated December 23, 2011.

For a description of the process for cleaning up a contaminated site under MTCA, please refer to the enclosed fact sheet.

Ecology's policy is to work cooperatively with PLPs to accomplish the prompt and effective cleanup of contaminated sites. Please note that your cooperation in planning or conducting remedial actions at the Site is not an admission of guilt or liability.

Contact Information

If you have any questions regarding this letter or if you would like additional information regarding the cleanup of contaminated sites, please contact me at 360-999-9594 or thomas.middleton@ecy.wa.gov. Thank you for your cooperation.

Sincerely,



Thomas Middleton
Cleanup Project Manager
Toxics Cleanup Program, SWRO

Enclosures (2)

1. FOCUS: MODEL TOXICS CONTROL ACT CLEANUP REGULATION: PROCESS FOR CLEANUP OF HAZARDOUS WASTE SITES (#94-129)
2. PLP WAIVER FORM TEMPLATE

By certified mail: 9489 0090 0027 6341 0492 85

cc: Conrad Wieclaw, Vincent Light, (Transalta): Conrad_Wieclaw@transalta.com
Dan Lawler,Office of the Attorney General:dan.lawler@atg.wa.gov
Ivy Anderson, Office of the Attorney General: Ivy.Anderson@atg.wa.gov
Marian Abbett, SWRO TCP Section Manager: marian.abbett@ecy.wa.gov
Bobbak Talebi, SWRO Regional Director: bobbak.talebi@ecy.wa.gov
Ecology Site File

WASHINGTON STATE DEPARTMENT OF ECOLOGY

Focus

Model Toxics Control Act Cleanup Regulation: Process for Cleanup of Hazardous Waste Sites

In March of 1989, an innovative, citizen-mandated toxic waste cleanup law went into effect in Washington, changing the way hazardous waste sites in this state are cleaned up. Passed by voters as Initiative 97, this law is known as the Model Toxics Control Act, chapter 70.105D RCW. This fact sheet provides a brief overview of the process for the cleanup of contaminated sites under the rules Ecology adopted to implement that Act (chapter 173-340 WAC).

How the Law Works

The cleanup of hazardous waste sites is complex and expensive. In an effort to avoid the confusion and delays associated with the federal Superfund program, the Model Toxics Control Act is designed to be as streamlined as possible. It sets strict cleanup standards to ensure that the quality of cleanup and protection of human health and the environment are not compromised. At the same time, the rules that guide cleanup under the Act have built-in flexibility to allow cleanups to be addressed on a site-specific basis.

The Model Toxics Control Act funds hazardous waste cleanup through a tax on the wholesale value of hazardous substances. The tax is imposed on the first in-state possessor of hazardous substances at the rate of 0.7 percent, or $7 per $1,000. Since its passage in 1988, the Act has guided the cleanup of thousands of hazardous waste sites that dot the Washington landscape. The Washington State Department of Ecology's Toxic Cleanup Program ensures that these sites are investigated and cleaned up.

What Constitutes a Hazardous Waste Site?

Any owner or operator who has information that a hazardous substance has been released to the environment at the owner or operator's facility and may be a threat to human health or the environment must report this information to the Department of Ecology (Ecology). If an "initial investigation" by Ecology confirms further action (such as testing or cleanup) may be necessary, the facility is entered onto either Ecology's "Integrated Site Information System" database or "Leaking Underground Storage Tank" database. These are computerized databases used to track progress on all confirmed or suspected contaminated sites in Washington State. All confirmed sites that have not been already voluntarily cleaned up are ranked and placed on the state "Hazardous Sites List." Owners, operators, and other persons known to be potentially liable for the cleanup of the site will receive an "Early Notice Letter" from Ecology notifying them that their site is suspected of needing cleanup, and that it is Ecology's policy to work cooperatively with them to accomplish prompt and effective cleanup.

November 2007 (revised) Focus No. 94-129 *printed on recycled paper*

Who is Responsible for Cleanup?

Any past or present relationship with a contaminated site may result in liability. Under the Model Toxics Control Act a potentially liable person can be:

- A current or past facility owner or operator.
- Anyone who arranged for disposal or treatment of hazardous substances at the site.
- Anyone who transported hazardous substances for disposal or treatment at a contaminated site, unless the facility could legally receive the hazardous materials at the time of transport.
- Anyone who sells a hazardous substance with written instructions for its use, and abiding by the instructions results in contamination.

In situations where there is more than one potentially liable person, each person is jointly and severally liable for cleanup at the site. That means each person can be held liable for the entire cost of cleanup. In cases where there is more than one potentially liable person at a site, Ecology encourages these persons to get together to negotiate how the cost of cleanup will be shared among all potentially liable persons.

Ecology must notify anyone it knows may be a "potentially liable person" and allow an opportunity for comment before making any further determination on that person's liability. The comment period may be waived at the potentially liable person's request or if Ecology has to conduct emergency cleanup at the site.

Achieving Cleanups through Cooperation

Although Ecology has the legal authority to order a liable party to clean up, the department prefers to achieve cleanups cooperatively. Ecology believes that a non-adversarial relationship with potentially liable persons improves the prospect for prompt and efficient cleanup. The rules implementing the Model Toxics Control Act, which were developed by Ecology in consultation with the Science Advisory Board (created by the Act), and representatives from citizen, environmental and business groups, and government agencies, are designed to:

- Encourage independent cleanups initiated by potentially liable persons, thus providing for quicker cleanups with less legal complexity.
- Encourage an open process for the public, local government and liable parties to discuss cleanup options and community concerns.
- Facilitate cooperative cleanup agreements rather than Ecology-initiated orders. *Ecology can, and does, however use enforcement tools in emergencies or with recalcitrant potentially liable persons.*

What is the Potentially Liable Person's Role in Cleanup?

The Model Toxics Control Act requires potentially liable persons to assume responsibility for cleaning up contaminated sites. For this reason, Ecology does not usually conduct the actual cleanup when a potentially liable person can be identified. Rather, Ecology oversees the cleanup of sites to ensure that investigations, public involvement and actual cleanup and monitoring are done appropriately. Ecology's costs of this oversight are required to be paid by the liable party.

When contamination is confirmed at the site, the owner or operator may decide to proceed with cleanup without Ecology assistance or approval. Such "independent cleanups" are

allowed under the Model Toxics Control Act under most circumstances, but must be reported to Ecology, and are done at the owner's or operator's own risk. Ecology may require additional cleanup work at these sites to bring them into compliance with the state cleanup standards. Most cleanups in Washington are done independently.

Other than local governments, potentially liable persons conducting independent cleanups do not have access to financial assistance from Ecology. Those who plan to seek contributions from other persons to help pay for cleanup costs need to be sure their cleanup is "the substantial equivalent of a department-conducted or department-supervised remedial action." Ecology has provided guidance on how to meet this requirement in WAC 173-340-545. Persons interested in pursuing a private contribution action on an independent cleanup should carefully review this guidance prior to conducting site work.

Working with Ecology to Achieve Cleanup

Ecology and potentially liable persons often work cooperatively to reach cleanup solutions. Options for working with Ecology include formal agreements such as consent decrees and agreed orders, and seeking technical assistance through the Voluntary Cleanup Program. These mechanisms allow Ecology to take an active role in cleanup, providing help to potentially liable persons and minimizing costs by ensuring the job meets state standards the first time. This also minimizes the possibility that additional cleanup will be required in the future – providing significant assurances to investors and lenders.

Here is a summary of the most common mechanisms used by Ecology:

- **Voluntary Cleanup Program**: Many property owners choose to cleanup their sites independent of Ecology oversight. This allows many smaller or less complex sites to be cleaned up quickly without having to go through a formal process. A disadvantage to property owners is that Ecology does not approve the cleanup. This can present a problem to property owners who need state approval of the cleanup to satisfy a buyer or lender.

  One option to the property owner wanting to conduct an independent cleanup yet still receive some feedback from Ecology is to request a technical consultation through Ecology's Voluntary Cleanup Program. Under this voluntary program, the property owner submits a cleanup report with a fee to cover Ecology's review costs. Based on the review, Ecology either issues a letter stating that the site needs "No Further Action" or identifies what additional work is needed. Since Ecology is not directly involved in the site cleanup work, the level of certainty in Ecology's response is less than in a consent decree or agreed order. However, many persons have found a "No Further Action" letter to be sufficient for their needs, making the Voluntary Cleanup Program a popular option.

- **Consent Decrees:** A consent decree is a formal legal agreement filed in court. The work requirements in the decree and the terms under which it must be done are negotiated and agreed to by the potentially liable person, Ecology and the state Attorney General's office. Before consent decrees can become final, they must undergo a public review and comment period that typically includes a public hearing. Consent decrees protect the potentially liable person from being sued for "contribution" by other persons that incur cleanup expenses at the site while facilitating any contribution claims against the other persons when they are responsible for part of the cleanup costs. Sites cleaned up under a consent decree are also exempt from having to obtain certain state and local permits that could delay the cleanup.

- ***De Minimus* Consent Decree:** Landowners whose contribution to site contamination is "insignificant in amount and toxicity" may be eligible for a de minimus consent decree. In these decrees, landowner typically settle their liability by paying for some of the cleanup instead of actually conducting the cleanup work. Ecology usually accepts a de minimus settlement proposal only if the landowner is affiliated with a larger site cleanup that Ecology is currently working on.
- **Prospective Purchaser Consent Decree:** A consent decree may also be available for a "prospective purchaser" of contaminated property. In this situation, a person who is not already liable for cleanup and wishes to purchase a cleanup site for redevelopment or reuse may apply to negotiate a prospective purchaser consent decree. The applicant must show, among other things, that they will contribute substantial new resources towards the cleanup. Cleanups that also have a substantial public benefit will receive a higher priority for prospective purchaser agreements. If the application is accepted, the requirements for cleanup are negotiated and specified in a consent decree so that the purchaser can better estimate the cost of cleanup before buying the land.
- **Agreed Orders:** Unlike a consent decree, an agreed order is not filed in court and is not a settlement. Rather, it is a legally binding administrative order issued by Ecology and agreed to by the potentially liable person. Agreed orders are available for remedial investigations, feasibility studies, and final cleanups. An agreed order describes the site activities that must occur for Ecology to agree not to take enforcement action for that phase of work. As with consent decrees, agreed orders are subject to public review and offer the advantage of facilitating contribution claims against other persons and exempting cleanup work from obtaining certain state and local permits.

Ecology-Initiated Cleanup Orders

Administrative orders requiring cleanup activities without an agreement with a potentially liable person are known as **enforcement orders**. These orders are usually issued to a potentially liable person when Ecology believes a cleanup solution cannot be achieved expeditiously through negotiation or if an emergency exists. If the responsible party fails to comply with an enforcement order, Ecology can clean up the site and later recover costs from the responsible person(s) at up to three times the amount spent. The state Attorney General's Office may also seek a fine of up to $25,000 a day for violating an order. Enforcement orders are subject to public notification.

Financial Assistance

Each year, Ecology provides millions of dollars in grants to local governments to help pay for the cost of site cleanup. In general, such grants are available only for sites where the cleanup work is being done under an order or decree. Ecology can also provide grants to local governments to help defray the cost of replacing a public water supply well contaminated by a hazardous waste site. Grants are also available for local citizen groups and neighborhoods affected by contaminated sites to facilitate public review of the cleanup. See Chapter 173-322 WAC for additional information on grants to local governments and Chapter 173-321 WAC for additional information on public participation grants.

Public Involvement

Public notices are required on all agreed orders, consent decrees, and enforcement orders. Public notification is also required for all Ecology-conducted remedial actions.

Ecology's Site Register is a widely used means of providing information about cleanup efforts to the public and is one way of assisting community involvement. The Site Register is published every two weeks to inform citizens of public meetings and comment periods, discussions or negotiations of legal agreements, and other cleanup activities. The Site Register can be accessed on the Internet at: www.ecy.wa.gov/programs/tcp/pub_inv/pub_inv2.html.

How Sites are Cleaned Up

The rules describing the cleanup process at a hazardous waste site are in chapter 173-340 WAC. The following is a general description of the steps taken during the cleanup of an average hazardous waste site. Consult the rules for the specific requirements for each step in the cleanup process.

1. Site Discovery: Sites where contamination is found must be reported to Ecology's Toxics Cleanup Program within 90 days of discovery, unless it involves a release of hazardous materials from an underground storage tank system. In that case, the site discovery must be reported to Ecology within 24 hours. At this point, potentially liable persons may choose to conduct independent cleanup without assistance from the department, but cleanup results must be reported to Ecology.

2. Initial Investigation: Ecology is required to conduct an initial investigation of the site within 90 days of receiving a site discovery report. Based on information obtained about the site, a decision must be made within 30 days to determine if the site requires additional investigation, emergency cleanup, or no further action. If further action is required under the Model Toxics Control Act, Ecology sends early notice letters to owners, operators and other potentially liable persons inviting them to work cooperatively with the department.

3. Site Hazard Assessment: A site hazard assessment is conducted to confirm the presence of hazardous substances and to determine the relative risk the site poses to human health and the environment.

4. Hazard Ranking: The Model Toxics Control Act requires that sites be ranked according to the relative health and environmental risk each site poses. Working with the Science Advisory Board, Ecology created the Washington Ranking Method to categorize sites using data from site hazard assessments. Sites are ranked on a scale of 1 to 5. A score of 1 represents the highest level of risk and 5 the lowest. Ranked sites are placed on the state Hazardous Sites List.

5. Remedial Investigation/Feasibility Study: A remedial investigation and feasibility study is conducted to define the extent and magnitude of contamination at the site. Potential impacts on human health and the environment and alternative cleanup technologies are also evaluated in this study. Sites being cleaned up by Ecology or by potentially liable persons under a consent decree, agreed order or enforcement order are required to provide for a 30 day public review before finalizing the report.

6. Selection of Cleanup Action: Using information gathered during the study, a cleanup action plan is developed. The plan identifies preferred cleanup methods and specifies cleanup standards and other requirements at the site. A draft of the plan is subject to public review and comment before it is finalized.

7. Site Cleanup: Actual cleanup begins when the cleanup action plan is implemented. This includes design, construction, operation and monitoring of cleanup actions. A site may be taken off the Hazardous Sites List after cleanup is completed and Ecology determines cleanup standards have been met.

PLP Waiver Form Template

[PLP SIGNATORY]
[PLP COMPANY]
[STREET ADDRESS]
[CITY, STATE] [POSTAL CODE]

Pursuant to WAC 173-340-500 and WAC 173-340-520(1)(b)(i), I [NAME], a duly authorized representative of [COMPANY NAME], do hereby waive the right to the thirty (30) day notice and comment period described in WAC 173-340-500(3) and accept status of [COMPANY NAME] as a Potentially Liable Person at the following contaminated site:

- Site Name: [CLEANUP SITE NAME]
- Site Address: [CLEANUP SITE ADDRESS]
- Cleanup Site ID: [CLEANUP SITE NUMBER]
- Facility/Site ID: [FACILITY/SITE NUMBER]
- [OPTIONAL: County Assessor's Parcel Number(s): [NUMBERS]]

By waiving this right, [COMPANY NAME] makes no admission of liability.

_____ _____

Signature Date

Relation to the Site: [for example, owner or operator]

For More Information / Special Accommodation Needs

If you would like more information about the state Model Toxics Control Act, please call us toll-free at **1-800-826-7716**, or contact your regional Washington State Department of Ecology office listed below. Information about site cleanup, including a listing of ranked hazardous waste sites, is also accessible through our Internet address: http://www.ecy.wa.gov/programs/tcp/cleanup.html

- **Northwest Regional Office** **425/649-7000**
  (Island, King, Kitsap, San Juan, Skagit, Snohomish, Whatcom Counties)
- **Southwest Regional Office** **360/407-6300**
  (Southwestern Washington, Olympic Peninsula, Pierce, Thurston and Mason Counties)
- **Central Regional Office** **509/575-2490**
  (Benton, Chelan, Douglas, Kittitas, Klickitat, Okanogan, Yakima Counties)
- **Eastern Regional Office** **509/329-3400**
  (Adams, Asotin, Columbia, Ferry, Franklin, Garfield, Grant, Lincoln, Pend Oreille, Spokane, Stevens, Walla Walla, Whitman Counties)

If you need this publication in an alternative format, please contact the Toxics Cleanup Program at (360) 407-7170. Persons with a hearing loss can call 711 for the Washington Relay Service. Persons with a speech disability can call 877-833-6341.

Disclaimer Notice: This fact sheet is intended to help the user understand the Model Toxics Control Act Cleanup Regulation, chapter 173-340 WAC. It does not establish or modify regulatory requirements.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-53:
Centralia Pollution Inspection (June 2025)

DEPARTMENT OF ECOLOGY
State of Washington

☐ Check this box if you have attached any documents to this form (using the paperclip icon on the left).

ERTS #(s):	**None**
Parcel # (s):	**See additional info box**
County:	**Lewis**
FSID #:	**94772166**
CSID #:	**17302**
UST #:	**8710**

SITE INFORMATION

Site Name (Name over door): **TransAlta Centralia**	Site Address (including City, State, and Zip): 913 Big Hanaford Rd, Centralia, WA 98531	Phone Click to enter text. Email **Click to enter text.**
Site Contact, Title, Business: **Conrad Wieclaw**	Site Contact Address (including City, State, and Zip): **913 Big Hanaford Rd, Centralia, WA 98531**	Phone **360-807-8093** Email **Conrad_Wieclaw@transalta.com** **Click to enter text.**
Site Owner, Title Business: **TransAlta Centralia Generation LLC**	Site Owner Address (including City, State, and Zip): **913 Big Hanaford Rd, Centralia, WA 98531**	Phone **360-736-9901** Email **Centralia@transalta.com**
Site Owner Contact, Title, Business: **Trans Alta Corporation**	Site Owner Contact Address (Including City, State, and Zip **TransAlta Place, Suite 1400, 1100 1 St SE, Calgary, Alberta Canada T2G 1B1**	Phone **403-267-7110** Email **Click to enter text.**
Previous Site Owner(s):	Additional Info (for any Site Information Item): **23340001000,23340002002,23340003000,23340004000,23340005001,23340005002, 23340005003,23340005004,23436000000,23345000000,23355001006,23355001007, 23355001008,23355002002.**	
Alternate Site Name(s): **Click to enter text.**		

Latitude (Decimal Degrees):	**46.75487**
Longitude (Decimal Degrees):	**-122.8636**

INSPECTION INFORMATION

☒ Please check this box if there is relevant inspection information, such as data or photos, in an existing site report for this site.

Inspection Conducted? Yes ☐ No ☒	Date/Time: Click to enter text.	Entry Notice:	Announced ☐ Unannounced ☐
Photographs taken?	Yes ☐	No ☒	Note: Attach photographs or upload to PIMS
Samples Collected?	Yes ☐	No ☒	Note: Attach record with media, location, depth, etc.

RECOMMENDATION

No Further Action (Check appropriate box below):		**LIST on Contaminated Sites List:** ☒
Release or threatened release does not pose a threat	☐	
No release or threatened release	☐	**LIST on NFA Sites List:** ☐
Refer to program/agency (Name: **Click to enter text.**)	☐	
Independent Cleanup Action Completed (contamination removed)	☐	

COMPLAINT (Brief Summary of ERTS Complaint):

Property representatives reported contamination above MTCA cleanup standards during Site investigations

CURRENT SITE STATUS (Brief Summary of why Site is recommended for Listing or NFA):

I recommend this Site for a listing on the Contaminated Sites List. The submitted report indicates contamination above MTCA cleanup standards.

Investigator: **Thomas Middleton, L.HG**	Date Submitted: 6/2/2025

OBSERVATIONS ☐ **Please check this box if you included information on the Supplemental Page at end of report.**

Description (If site visit made, please be sure to include the following: site observations, site features and cover, chronology of events, sources/past practices likely responsible for contamination, presence of water supply wells and other potential exposure pathways, etc):

There are six COCs for soil at the Site. These COCs are further divided into nine Remedial Areas (RAs) for discussion of vertical and horizontal distribution of COCs in soil. The RAs are summarized below:

- **Arsenic:** Remedial Areas 1, 2, and 8. The distribution of arsenic impacts is displayed on Figures 12 and 13.
- **Barium:** Remedial Areas 1, 5, 6, 8, and 9. The distribution of barium impacts is displayed on Figures 14 and 15.
- **Cadmium:** Remedial Areas 3, 5, 6, and 8. The distribution of cadmium impacts is displayed on Figures 16 and 17.
- **Copper:** Remedial Areas 1, 4, and 7. The distribution of copper impacts is displayed on Figures 18 and 19.
- **Selenium**: Remedial Area 8. The distribution of selenium impacts is displayed on Figure 20.
- **Zinc**: Remedial Area 2. The distribution of zinc impacts is displayed on Figure 21.

As identified above, there are nine Remedial Areas (RAs) with COCs at concentrations exceeding CULs.

There are nine COCs for groundwater at the Site. These COCs are summarized below and are based on groundwater samples collected from February 2023 to December 2024:

- **Arsenic (dissolved and total):** The distribution of arsenic impacts is displayed on Figures 23 through 27 in both the shallow and deep aquifers. The area of impacts in the shallow aquifer is predominantly near the Surge Pond, North Effluent Pond, and South Effluent Pond, with isolated pockets near the bottom ash pile and north of the North Coal Pile Runoff Ditch.

  The highest arsenic concentration in the deeper aquifer was from the off-property monitoring well CMWD-2 in both May and December 2024. Groundwater flow in the deeper aquifer is consistently toward the southeast. Based on the redox potential analysis of groundwater at the Site, these higher concentrations may be the result of anoxic groundwater conditions. Anoxic groundwater conditions significantly influence the mobility and concentration of naturally occurring arsenic and manganese at depth, especially where organic matter or other reducing agents are present.

- **Chromium (total):** The distribution of chromium impacts is displayed on Figures 28 through 30 in the shallow aquifer. No samples exceeded the chromium CUL from the deeper aquifer. Chromium impacts in the shallow aquifer exceeded CULs in monitoring wells CMW-16 (February 2023 and May 2024), CMW-32 (February 2023), and CMW-43 (December 2024). Corresponding chromium impacts to soil were not observed at levels exceeding CULs in these areas.

- **Copper (total):** While copper was retained as a COC for groundwater, only one sample exceeded the CUL in the shallow aquifer. Monitoring well CMW-16 exceeded the CUL in May 2024 at a concentration of 19 µg/L. The CUL for protection of surface water aquatic life is 11 µg/L. No samples exceeded the respective CUL from the deeper aquifer.

- **Manganese (dissolved and total):** The distribution of manganese impacts is displayed on Figures 31 through 35 in both the shallow and deep aquifers. Impacts to the shallow and deep aquifers were not fully delineated in May and December 2024 but the highest concentrations were observed upgradient of the facility, north of the CPRO Ponds and north of Hanaford Creek. This is most likely due to the naturally occurring metals at depth and the anoxic and hydric soil conditions to the north of the facility. As described in the 2019 Environmental Science & Technology, *Elevated Manganese Concentrations in United States Groundwater, Role of Land Surface- Soil- Aquifer Connections* (McMahon et al. 2018), the concentration of manganese is significantly higher in wells where hydric soils are present within a 500-meter buffer around the well.

- **Selenium (dissolved and total):** The distribution of selenium impacts is displayed on Figures 36 through 38 in the shallow aquifer. Selenium impacts exceeding the CUL of 5 µg/L were observed in the area surrounding the coal pile and the CPRO Ponds in February 2023 and December 2024. In May 2024, the selenium exceedances in the shallow aquifer were restricted to only monitoring well CMW-43, near Cooling Tower 1B.

  Selenium was not detected at a concentration exceeding the CUL of 80 µg/L in the deeper aquifer. The highest concentration in the deeper aquifer was 1.9 µg/L in December 2024 from monitoring well CMWD-1.

- **Zinc (dissolved and total):** The distribution of zinc impacts is displayed on Figures 39 through 41 in the shallow aquifer.

- **1-Methylnaphthalene:** 1-methlnaphthalene was detected in one monitoring well, CMW-16, exceeding the CUL of 0.86 µg/L. No other samples exceeded the MDL in both the shallow and deep aquifers.

- **TPH – Diesel-Range Organics:** The distribution of TPH-DRO impacts is displayed on Figures 42 through 44 in the shallow aquifer. Samples collected from monitoring well CMW-16, exceeded the CUL of 500 µg/L during all three sampling events. Based on the silica gel cleanup results collected in December 2024, there are other sources of polar organic compounds contributing to the weathered petroleum mixture, most likely from naturally occurring organic matter. Use of silica gel cleanup is recommended going forward to distinguish the non-petroleum polar organics in the samples. No TPH-DRO was detected exceeding the MDL in the deeper aquifer.

Vinyl Chloride: Vinyl chloride was only detected in two monitoring wells at a concentration exceeding the CUL of 0.02 µg/L for protection of surface water: temporary monitoring well CTMW-2 located south of the South Effluent Pond, and monitoring well CMW-27. The exceedance in temporary well CTMW-2 in February 2023 has not been encountered in surrounding groundwater monitoring wells CMW-6, CMW-8, and CMW-17.

There are six COCs for sediment at the Site. The spatial distribution of these COCs exceeding the SCO is restricted to the CPRO Ponds, the North Effluent Pond, the South Effluent Pond, and the Coal Pile Runoff Ditches.

The sediment samples collected from Hanaford Creek were either less than the MDL or less than the sediment cleanup objective for all constituents analyzed and are not discussed further in this section.

Chemical concentrations that are less than or equal to the CSL but greater than the sediment cleanup objective correspond to sediment quality that results in minor adverse effects to the benthic community. The

only constituents that exceeded the sediment screening level for protection of the benthic community were chromium and mercury. The distribution of COCs in sediment exceeding the SCO is as follows:

- **Arsenic:** The distribution of arsenic impacts is displayed on Figure 45. Sediment sample result\s exceeding the SCO were observed in the CPRO Ponds 2 through 8, the North Effluent Pond, and the East Coal Pile Runoff Ditch.

- **Cadmium:** The distribution of cadmium impacts is displayed on Figure 46. Sediment sample results exceeding the SCO were observed in the CPRO Ponds 3 through 8 and the North Effluent Pond. The sediment samples collected in the Coal Pile Runoff Ditches were all less than the MDL.

- **Chromium:** The distribution of chromium impacts is displayed on Figure 47. Sediment samples that exceeded the SCO were observed in CPRO Ponds 3, 4, 6, 7, and 8 and the North Effluent Pond. Six of the eight samples that exceeded the SCO also exceeded the SCL for chromium.

- **Mercury:** The distribution of mercury impacts is displayed on Figure 48. Sediment samples that exceeded the SCO were observed in the CPRO Pond 5, the North Effluent Pond, the South Effluent Pond, and the East Coal Pile Runoff Ditch. All samples that exceeded the SCO also exceeded the SCL for mercury.

- **Nickel:** The distribution of nickel impacts is displayed on Figure 49. Sediment samples that exceeded the SCO were observed in the CPRO Pond 3, the North Effluent Pond, the South Effluent Pond, and the West Coal Pile Runoff Ditch.

- **Selenium:** The distribution of selenium impacts is displayed on Figure 50. Sediment samples that exceeded the SCO were observed in the CPRO Ponds 3 through 7 and the North Effluent Pond.

Suspected off-property contaminants:

Investigation of potential impacts from smoke stack deposition has not occurred and suspected contaminants of concern off-property include, dioxins and furans (D/F), semi-volatile organic compounds (SVOCs) and select metals.

Documents reviewed:

2025-05-13 ECY Draft RI Report_TransAlta_Centralia.pdf

CONTAMINANT GROUP	CONTAMINANT	*SOIL*	*GROUNDWATER*	*SURFACE WATER*	*AIR*	*SEDIMENT*	DESCRIPTION
Non-Halogenated Organics	Phenolic Compounds	Select	Select	Select		Select	Compounds containing phenols (Examples: phenol; 4-methylphenol; 2-methylphenol)
	Non-Halogenated Solvents	Select	Select	Select	Select	Select	Organic solvents, typically volatile or semi-volatile, not containing any halogens. To determine if a product has halogens, search HSDB (http://toxnet.nlm.nih.gov/cgi-bin/sis/htmlgen?HSDB) and look at the Chemical/Physical Properties, and Molecular Formula. If there is not a Cl, I, Br, F in the formula, it's not halogenated. (Examples: acetone, benzene, toluene, xylenes, methyl ethyl ketone, ethyl acetate, methanol, ethanol, isopropranol, formic acid, acetic acid, stoddard solvent, Naptha). *Use this when TEX contaminants are present independently of gasoline.*
	Polynuclear Aromatic Hydrocarbons (PAH)	Select	**C**	Select	Select	Select	Hydrocarbons composed of two or more benzene rings.
	Tributyltin	Select	Select	Select		Select	The main active ingredients in biocides used to control a broad spectrum of organisms. Found in antifouling marine paint, antifungal action in textiles and industrial water systems. (Examples: Tributyltin; monobutyltin; dibutyltin)
	Methyl tertiary-butyl ether	Select	Select	Select	Select	Select	MTBE is a volatile oxygen-containing organic compound that was formerly used as a gasoline additive to promote complete combustion and help reduce air pollution.
	Benzene	Select	Select	Select	Select	Select	Benzene
	Other Non-Halogenated Organics	Select	Select	Select	Select	Select	TEX
	Petroleum Diesel	Select	**C**	Select		Select	Petroleum Diesel
	Petroleum Gasoline	Select	Select	Select	Select	Select	Petroleum Gasoline
	Petroleum Other	Select	**B**	Select		Select	Oil-range organics
Halogenated Organics (see notes at bottom)	PBDE	Select	Select	Select	Select	Select	Polybrominated di-phenyl ether
	Other Halogenated Organics	Select	Select	Select	Select	Select	Other organic compounds with halogens (chlorine, fluorine, bromine, iodine). search HSDB (http://toxnet.nlm.nih.gov/cgi-bin/sis/htmlgen?HSDB) and look at the Chemical/Physical Properties, and Molecular Formula. If there is a Cl, I, Br, F in the formula, it is halogenated. (Examples: Hexachlorobutadiene; hexachlorobenzene; pentachlorophenol)
	Halogenated solvents	Select	**C**	Select	Select	Select	PCE, chloroform, EDB, EDC, MTBE
	Polychlorinated Biphenyls (PCB)	Select	Select	Select	Select	Select	Any of a family of industrial compounds produced by chlorination of biphenyl, noted primarily as an environmental pollutant that accumulates in animal tissue with resultant pathogenic and teratogenic effects
	Dioxin/dibenzofuran compounds (see notes at bottom)	**B**	Select	Select	Select	Select	A family of more than 70 compounds of chlorinated dioxins or furans. (Examples: Dioxin; Furan; Dioxin TEQ; PCDD; PCDF; TCDD; TCDF; OCDD; OCDF). *Do not use for 'dibenzofuran', which is a non-chlorinated compound that is detected using the semivolatile organics analysis 8270*
Metals	Metals – Other	**C**	**C**	Select		**C**	Cr, Se, Ag, Ba, Cd
	Lead	Select	Select	Select		Select	Lead
	Mercury	Select	Select	Select	Select	**C**	Mercury
	Arsenic	**C**	**C**	Select		Select	Arsenic
Pesticides	Non-halogenated pesticides	Select	Select	Select	Select	Select	Pesticides without halogens (Examples: parathion, malathion, diazinon, phosmet, carbaryl (sevin), fenoxycarb, aldicarb)
	Halogenated pesticides	Select	Select	Select	Select	Select	Pesticides with halogens (Examples: DDT; DDE; Chlordane; Heptachlor; alpha-beta and delta BHC; Aldrin; Endosulfan, dieldrin, endrin)

CONTAMINANT GROUP	CONTAMINANT	*SOIL*	*GROUNDWATER*	*SURFACE WATER*	*AIR*	*SEDIMENT*	DESCRIPTION
Other Contaminants	Radioactive Wastes	Select	Select	Select	Select	Select	Wastes that emit more than background levels of radiation.
	Conventional Contaminants, Organic	Select	Select	Select		Select	Unspecified organic matter that imposes an oxygen demand during its decomposition (Example: Total Organic Carbon)
	Conventional Contaminants, Inorganic	Select	Select	Select	Select	Select	Non-metallic inorganic substances or indicator parameters that may indicate the existence of contamination if present at unusual levels (Examples: Sulfides, ammonia)
	Asbestos	Select	Select	Select	Select	Select	All forms of Asbestos. Asbestos fibers have been used in products such as building materials, friction products and heat-resistant materials.
	Other Deleterious Substances	Select	Select	Select		Select	Other contaminants or substances that cause subtle or unexpected harm to sediments (Examples: Wood debris; garbage (e.g., dumped in sediments))
	Benthic Failures	Select	Select	Select		Select	Failures of the benthic analysis standards from the Sediment Management Standards.
	Bioassay Failures	Select	Select	Select		Select	For sediments, a failure to meet bioassay criteria from the Sediment Management Standards. For soils, a failure to meet TEE bioassay criteria for plant, animal or soil biota toxicity.
Reactive Wastes	Unexploded Ordinance	Select	Select	Select	Select	Select	Weapons that failed to detonate or discarded shells containing volatile material.
	Other Reactive Wastes	Select	Select	Select	Select	Select	Other Reactive Wastes (Examples: phosphorous, lithium metal, sodium metal)
	Corrosive Wastes	Select	Select	Select	Select	Select	Corrosive wastes are acidic or alkaline (basic) wastes that can readily corrode or dissolve materials they come into contact with. Wastes that are highly corrosive as defined by the Dangerous Waste Regulation (WAC 173-303-090(6)). (Examples: Hydrochloric acid; sulfuric acid; caustic soda)

(fill in contaminant matrix above with appropriate status choice from the key below the table)

Status choices for contaminants	
Contaminant Status	**Definition**
B— Below Cleanup Levels (Confirmed)	The contaminant was tested and found to be below cleanup levels. (Generally, we would not enter each and every contaminant that was tested; for example if an SVOC analysis was done we would not enter each SVOC with a status of "below". We would use this for contaminants that were believed likely to be present but were found to be below standards when tested
S— Suspected	The contaminant is suspected to be present; based on some knowledge about the history of the site, knowledge of regional contaminants, or based on other contaminants known to be present
C— Confirmed Above Cleanup Levels	The contaminant is confirmed to be present above any cleanup level. For example—above MTCA method A, B, or C; above Sediment Quality Standards; or above a presumed site-specific cleanup level (such as human health criteria for a sediment contaminant).
RA— Remediated - Above	The contaminant was remediated, but remains on site above the cleanup standards (for example—capped area).
RB— Remediated - Below	The contaminant was remediated, and no area of the site contains this contaminant above cleanup standards (for example—complete removal of contaminated soils).

Halogenated chemicals and solvents: Any chemical compound with chloro, bromo, iodo or fluoro is halogenated; those with eight or fewer carbons are generally solvents (e.g. halogenated methane, ethane, propane, butane, pentane, hexane, heptane or octane) and may also be used for or registered as pesticides or fumigants. Most are dangerous wastes, either listed or categorical. Organic compounds with more carbons are almost always halogenated pesticides or a contaminant or derivative. Referral to the HSDB is recommended if you are unfamiliar with a chemical name or compound, as it contains useful information about synonyms, uses, trade names, waste codes, and other regulatory information about most toxic or potentially toxic chemicals.

Dibenzodioxins and dibenzofurans are normalized to a combined equivalent toxicity based on 2,3,7,8-tetrachloro-p-dibenzodioxin as set out in WAC 173-340-708(8)(d) and in the Evaluating the Toxicity and Assessing the Carcinogenic Risk of Environmental Mixtures using Toxicity Equivalency Factors Focus Sheet (https://fortress.wa.gov/ecy/clarc/FocusSheets/tef.pdf). Results may be reported as individual compounds and isomers (usually lab results), or as a toxic equivalency value (reports).

FOR ECOLOGY II REVIEWER USE ONLY (For Listing Sites):

How did the Site come to be known ☒ **Site Discovery (received a report)** **5/14/2025** (Date Report Received)
☐ **ERTS Complaint**
☐ **Other (please explain):** Click to enter text.

Does an Early Notice Letter need to be sent: ☒ Yes ☐ No
If *No*, please explain why: Click to enter text.

NAICS Code (if known): **221112**
Otherwise, briefly explain how property is/was used (i.e., gas station, dry cleaner, paint shop, vacant land, etc.):
Power Generation Facility – Coal burning

Site Unit(s) to be created (Unit Type): ☒ Upland (includes VCP & LUST) ☒ Sediment
If multiple Unites needed, please explain why: Click to enter text.

Cleanup Process Type (for the Unit):
☐ No Process ☐ Independent Action
☐ Voluntary Cleanup Program ☒ Ecology-supervised or conducted
☐ Federal-supervised or conducted

Site Status:
☒ Awaiting Cleanup ☐ Construction Complete – Performance Monitoring
☐ Cleanup Started ☐ Cleanup Complete – Active O&M/Monitoring
☐ No Further Action Required

Model Remedy Used? ☐
If yes, was this a transformer spill? ☐

Site Manager (Default Tom Middleton) Click to enter text.

Specific confirmed contaminants include:
Metals in Soil
Metals, DRO, VOCs in Groundwater
Metals, in Other (specify matrix: Sediment

Facility/Site ID No. (if known):
94772166
Cleanup Site ID No. (if known):
Click to enter text.

COUNTY ASSESSOR INFO: Please attach to this report a copy of the tax parcel/ownership information for each parcel associated with the site, as well as a parcel map illustrating the parcel boundary and location.

Additional or Supplemental Information for Observations Page

Please use this box for any text that requires special formatting

Click to enter text.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-54:
Centralia Hazardous Substances Liability Determination (Oct. 2025)

COPY

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

Tuesday, October 14, 2025

Mickey Dreher
TransAlta Centralia Generation LLC
913 Big Hanaford Rd,
Centralia, WA 98531-9101

Re: Final Determination of Liability for Release of Hazardous Substances at the following Contaminated Site:

- **Site Name:** Centralia Steam Plant
- **Site Address:** 913 Big Hanaford Rd, Centralia, WA 98531-9101
- **Cleanup Site ID:** 17302
- **Facility/Site ID:** 94772166

Dear Mickey Dreher:

On September 4, 2025, the Department of Ecology (Ecology) sent you written notice of our preliminary determination that TransAlta Centralia Generation LLC is a potentially liable person (PLP) for a release of hazardous substances at the Centralia Steam Plant facility (Site). On October 8, 2025, Ecology received your written notice accepting your status as a PLP for the Site and waiving your opportunity to comment.

Based on available information, Ecology finds that credible evidence exists that TransAlta Generation LLC is liable for a release of hazardous substances at the Site. On the basis of this finding, Ecology has determined that TranAlta Generation LLC is a PLP with regard to the Site.

The purpose of the Model Toxics Control Act (MTCA) is to identify, investigate, and cleanup facilities where hazardous substances have been released. Liability for environmental contamination under MTCA is strict, joint and several (RCW 70.105D.040(2)). Ecology ensures that contaminated sites are investigated and cleaned up to the standards set forth in the MTCA statue and regulations. Ecology has determined that it is in the public interest for remedial actions to take place at this Site. Ecology will contact you regarding the actions necessary for the TransAlta Generation LLC to bring about the prompt and thorough cleanup of hazardous substances at this Site. Failure to cooperate with Ecology or comply with MTCA in this matter will result in Ecology employing enforcement tools as it deems necessary and appropriate. This includes, but is not limited to, the issuance of an administrative order. Failure to comply with such an order may result in a fine of up to $25,000 per day and liability for up to three times the costs incurred by the state (RCW 70.105D.050(1)).

Your rights and responsibilities as a PLP are outlined in Chapter 70.105D RCW, and Chapters 173-340 and 173-204 WAC. Ecology's cleanup project manager for the Site, Thomas Middleton, will contact you with information about how Ecology intends to proceed with the cleanup.

If you have any questions regarding this notice, please contact Thomas Middleton at (360) 999-9594 or Thomas.middleton@ecy.wa.gov.

Sincerely,

Marian L. Abbett

Marian Abbett
Section Manager
Toxics Cleanup Program, SWRO

By certified mail:9489 0090 0027 6341 0494 07

cc: Conrad Wieclaw, Vincent Light, (Transalta): Conrad_Wieclaw@transalta.com
Dan Lawler,Office of the Attorney General: dan.lawler@atg.wa.gov
Ivy Anderson, Office of the Attorney General: Ivy.Anderson@atg.wa.gov
Tom Middleton, SWRO TCP Cleanup Project Manager: thomas.middleton@ecy.wa.gov
Bobbak Talebi, SWRO Regional Director: bobbak.talebi@ecy.wa.gov
Ecology Site File

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-55:
Emissions Performance Standard



Emissions Performance Standard (EPS)

Energy Policy, Standards and Reports

Energy Policy, Standards and Reports Electricity Policy and Standards

Feedback

Emissions Performance Standard (EPS)

The emissions performance standard (EPS) is a set of state-imposed rules to a limit the amount of CO2 that each power station may emit to atmosphere.

The emissions performance standard (EPS) is a set of state-impose rules to limit the amount of greenhouse gas emissions each baseload power plant can release into the air.

Every five years, our office adopts rules on the average available greenhouse gas emissions output by surveying new combined-cycle natural gas thermal electric generation turbines. The turbines need to be commercially available, offered for sale by manufacturers and purchased in the United States. Then we determine the average rate of emissions of greenhouse gases for them.

Baseload generation limits and utility investment restrictions

Baseload generation, which refers to the minimum amount of continuous electricity supply that is needed to meet the basic demand of the power grid over a 24-hour period, is considered to be a generating unit operating at a capacity factor of 60 or greater percent. This means a facility that produces energy each year equaling at least 60 percent of the energy it could produce at continuous full power operation for the same period.

Utilities may not enter into long-term contracts (five or more years) with a baseload generating facility, nor can utilities invest in a facility, when the greenhouse gas emissions of the facility exceed the standard.

The standard applies to all investor and consumer-owned utilities in the state. Renewable and nuclear-powered electricity are exempt, as are long-term commitments with the Bonneville Power Administration.

The performance standard was last updated in January 2025. The new rule lowers the average estimated greenhouse gas emissions rate of combined-cycle natural gas power plants from 925 to 876 pounds per megawatt-hour. This updated emissions rate of greenhouse gas emissions will be used by the Department of Ecology (Ecology) and Energy Facility Site Evaluation Council (EFSEC) to

Feedback

apply Washington's emissions standard as required by state law (**Chapter 80.80 RCW**).

Power plants must meet the greenhouse gas emission standards or capture and store their carbon pollution under this rule. The Department of Ecology and local clean air agencies regulate small plants that generate megawatts of electricity (MWe), but less than 350 MWe. The Energy Facility Site Evaluation Council (EFSEC) regulates larger plants that generate more than 350 MWe.

Rulemaking

Commerce began its most recent rulemaking process in February 2024, and since then, the agency held three public workshops and three technical advisory group meetings. Commerce received and responded to comments, incorporating changes based on them into the rulemaking process. The public workshops and advisory team meetings were well-attended. Commerce received two public comments.

The latest rule lowers the average available greenhouse gas emissions output estimate of combined-cycle natural gas facilities from 925 lb/MWh to 876 lb/MWh. The updated average rate of greenhouse gas emissions will be used by the Department of Ecology (Ecology) and Energy Facility Site Evaluation Council (EFSEC) to implement Washington's baseload electric generation emissions performance standard as provided for under **Chapter 80.80 RCW**.

- **Final rules for WAC 194-26-020**

For questions related to the rulemaking process, please contact Aaron Tam, Energy Utility Data Specialist, at **energydata@commerce.wa.gov** or by calling 206-454-2251.

Resources

- **Final rules for WAC 194-26-020**
- **RCW 80.80.040**
- **WAC 194.26.010 – Authority**
- **WAC 194.26.020 – Average available greenhouse gas emissions output**
- **Department of Ecology's power plant greenhouse gas standards webpage**

Feedback

Page last updated: May 21, 2025

Contact

Austin Scharff, Senior Energy Policy Specialist
Austin.Scharff@commerce.wa.gov

Aaron Tam, Data Specialist
Aaron.Tam@commerce.wa.gov

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Subscribe to receive emails or SMS/text messages from Commerce or to access subscriber preferences.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-56:
Puget 2024 Annual EEI Report

PUGET SOUND ENERGY

Annual Energy and Emissions Intensity ("EEI") Metrics Report

Pursuant to WAC 480-109-300

May 31, 2025

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Appendix 1: Estimation of PSE Service Territory Population

Appendix 2: Emissions Reporting Methodology

Attachment A – EEI Raw Data and Charts

PSE's Annual Energy and Emissions Intensity (EEI) Metrics Report for operating year 2024

Section 1: Executive Summary

Compared to the 2023 operating year, Puget Sound Energy's (PSE's) 2024 carbon dioxide equivalent (CO_2e) emissions intensity from total electricity delivered to customers decreased from 877.5 lb/MWh to 830.3 lb/MWh.[1] This report provides the metrics, analyses, and descriptions behind that change. Further, it demonstrates that PSE delivers electricity to customers from a combination of sources that the Company owns and purchases from other providers via firm contracts or the spot market.

Per the requirements of WAC 480-109-300, PSE submits the following report outlining its energy and emissions intensity metrics for the previous ten years (reporting period). This report includes the following metrics for all PSE generating resources serving customers:

- Average megawatt-hours (aMWh) per residential customer
- Average megawatt-hours (aMWh) per commercial customer
- Megawatt-hours (MWh) per capita
- Annual carbon dioxide equivalent (CO_2e) emissions measured in metric tons
- Comparison of annual CO_2e emissions to CO_2 emissions in 1990

PSE and the other utilities purchase a percentage of their energy to serve native load from the spot market. The generation sources from purchases made on the spot market are unknown. Therefore, this report also includes a subset of metrics for spot market purchases based on the unspecified emission rate factor provided by the Washington State Department of Ecology ("Ecology"). Those metrics include:

- Annual CO_2e emissions (metric tons) from unknown generation sources
- Annual megawatt-hours (MWh) delivered to retail customers from unknown generation sources
- Percentage of load served by unknown generation sources

In addition to the raw data included in Attachment A to this report, the tables and sections below provide trend analysis, narrative descriptions, and graphics to help contextualize PSE's data and trends for the reporting period. Table 1 below summarizes PSE's greenhouse gas

[1] Beginning in 2022, adjusted to apply Bonneville Power Administration (BPA) Asset-Controlling Supplier (ACS) System emission factors for BPA specified purchases. See Sections 3 and 4 for more information.

(GHG) emissions intensity and energy metrics for the calendar year 2024. Summaries of the previous nine years in the reporting period are included in Attachment A to this report. Section 2 below provides a 10-year "lookback" analysis of the reporting period (to the operating year 2015) of the metrics mentioned above and benchmarks those metrics to a 1990 emissions baseline. Section 3 provides a discussion of the trends observed in the metrics and the broader regional market. Section 4 includes appendices that provide more detail on the methodologies used in this report.

Summarized in Table 1 and narrative below are PSE's 2024 energy and emissions intensity metrics. The energy intensity metrics represent the metered sale of energy to customers (by class) as reported under the Federal Energy Regulatory Commission (FERC) Form-1 protocols, i.e., Total Load Served. Busbar energy tallies represent the total load PSE served (to Washington) generated and purchased, net of bilateral sales, as reported in PSE's Energy Accounting (EA) database, i.e., Busbar MWh.

Table 1. 2024 Energy and Intensity Metrics

Utility :	Puget Sound Energy	
Reporting for year :	2024	**MWh per Capita**
Population Served :	2,712,488	**7.80**

Energy Intensity Metrics

	MWh at Meter	MWh Proportion	Customer Count	**MWh per Customer**
Residential Customers	11,462,977	54.2%	1,091,599	**10.5**
Commercial Customers	8,570,573	40.5%	134,993	**63.5**
Industrial Customers	1,057,368	5.0%		
Other Customers	77,822	0.4%		
Total Load Served	21,168,740	100.0%		

Emissions Intensity Metrics

	Busbar MWh	Percent of Total Load	**Metric Tons CO_2e**	
Known Resources Serving WA				
EPA Methodology	25,508,769	114.9%	9,623,768	
EIA Methodology	0	0.0%	0	
Unknown Resources Serving WA	(3,299,563)	**-14.9%**	(1,259,530)	**% of 1990 CO_2**
Total Busbar MWh	**22,209,206**	Total Metric Tons:	**8,364,238**	**132.7%**

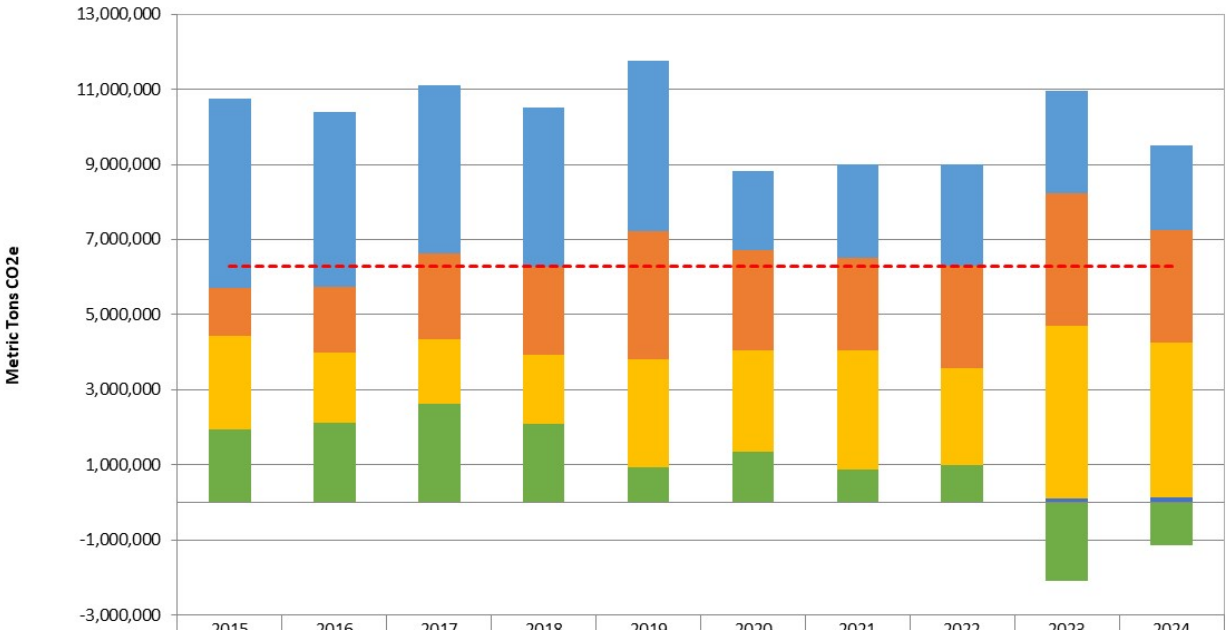
1990 Metric Tons CO_2	6,301,363

Section 2: Prior 10-year annual metrics for all generating resources serving Washington customers

Figure 1 provides a comparison of annual PSE CO_2e emissions measured in metric tons from generation sources for the previous 10 years. Figure 1 also includes a 1990 emissions baseline.

Until 2020, WAC 480-109-300 specified that the EEI report only include CO_2 output. In 2020, as a result of rulemaking conducted to implement the Clean Energy Transformation Act (CETA), revised WAC 480-109-300 now requires all greenhouse gas emissions in the EEI report be based on CO_2e. This change means the inclusion of methane (CH4) and nitrous oxide (N2O) as CO_2e[2] for all resources and years presented in this report.

Figure 1. Total Emissions by Resource Type

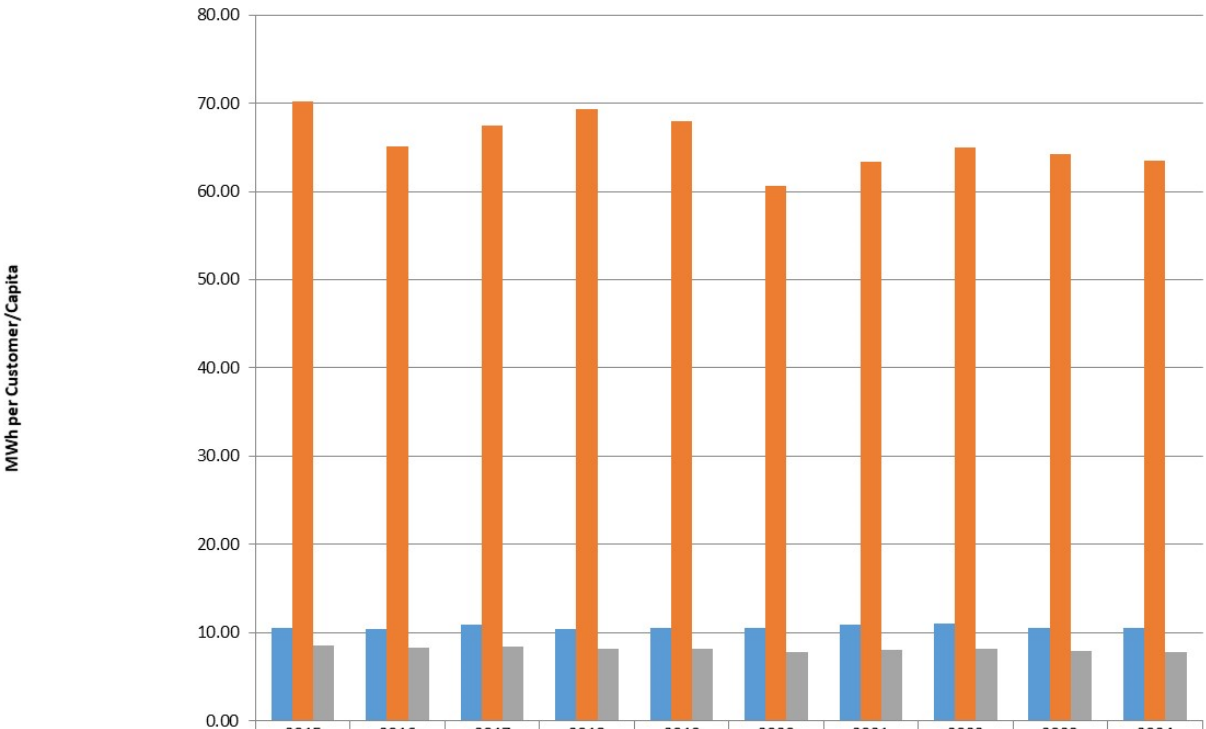


	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Owned Coal	5,034,544	4,642,921	4,486,832	4,255,201	4,531,772	2,089,805	2,508,424	2,684,409	2,741,750	2,230,496
Firm Coal	1,280,440	1,746,188	2,271,968	2,348,792	3,395,867	2,671,660	2,459,358	2,750,063	3,536,340	3,015,251
Owned Diesel	253	155	335	62	155	514	439	747	34	305
Owned Gas	2,487,336	1,872,826	1,730,673	1,825,412	2,874,183	2,703,673	3,170,392	2,566,071	4,578,453	4,118,746
Firm Gas	167	86							113,329	131,152
Unspecified	1,935,514	2,119,604	2,625,679	2,097,895	950,430	1,348,716	873,099	999,377	-2,100,695	-1,131,712
1990 Baseline	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363	6,301,363

[2] Principle combustible constituents in natural gas and coal are carbon, hydrogen, and their compounds, and in the combustion process, these compounds and elements oxidize to CO_2 and water vapor. However, small amounts of methane (CH_4) result from incomplete fuel combustion, and nitrous oxide (N_2O) formation results from post-combustion thermal reactions.

Figure 2 provides a comparison of the average MWh per residential customer, average MWh per commercial customer, and MWh per capita delivered in each of the years during the reporting period in PSE's service territory.

Figure 2. Energy Intensity Metrics



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
MWh / Residential Customer	10.47	10.40	10.89	10.39	10.49	10.56	10.90	11.03	10.57	10.50
MWh / Commercial Customer	70.25	65.07	67.49	69.33	68.01	60.66	63.37	64.99	64.28	63.49
MWh per capita	8.48	8.29	8.41	8.18	8.15	7.75	8.04	8.17	7.91	7.80

Figure 3 provides a comparison of the ratios of PSE's annual CO_2e emissions from known sources for the reporting period compared to CO_2 emission in 1990.

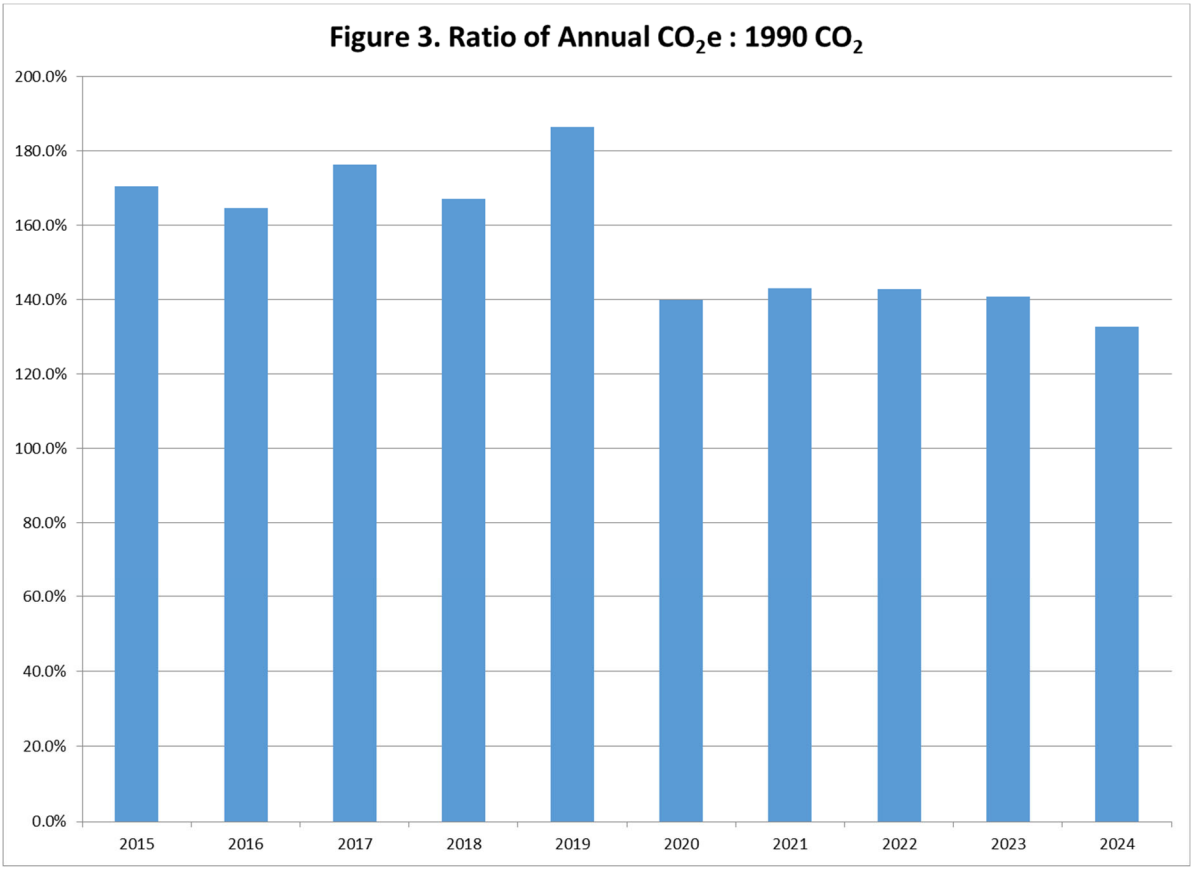
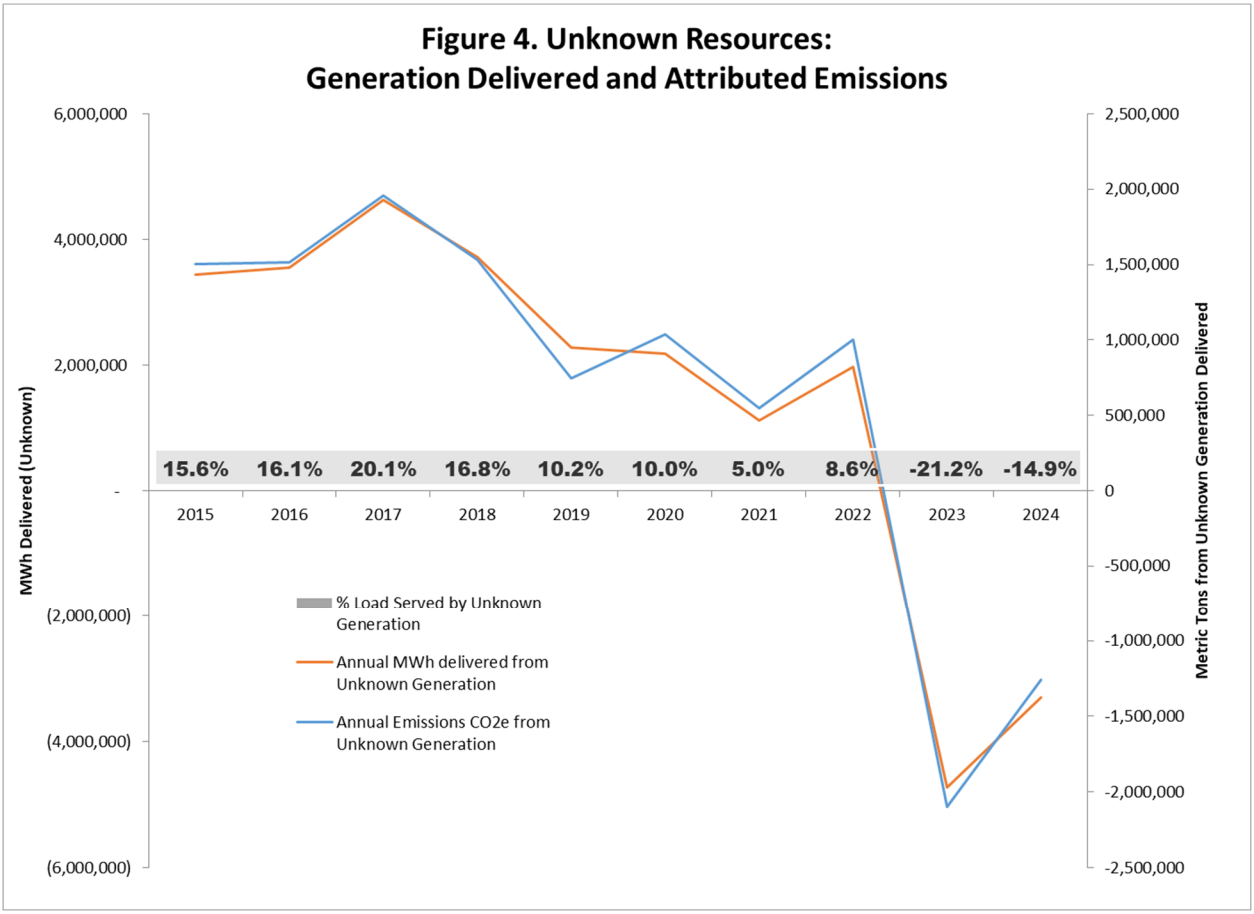


Figure 4 provides a 10-year comparison of generation delivered to PSE from unknown sources and the attributed emissions. Those metrics include annual CO_2e emissions (metric tons), annual MWh delivered to retail customers, and the percentage of load served. As discussed in the executive summary, the generation sources and attributed emissions for spot market purchases are unknown. Therefore, emissions factors for each of the previous ten years in the reporting period were applied according to methodology provided by the Department of Ecology.



Section 3: Trend Analysis

This section addresses the requirement in WAC 480-109-300(5) to include narrative text describing trends and an analysis of the likely causes of changes, or lack of changes, in the metrics.

Electric Supply

In 2024, PSE's electric power resources, which include company-owned or controlled resources and those under long-term contract, had a total capacity of approximately 6,524 megawatts (MW). PSE purchases electric energy under long-term firm-purchased power contracts with other utilities and marketers in the Western Interconnection. PSE is generally not obligated to make payments under these contracts unless power is delivered.

Energy supply and demand balance across the Western Interconnection is maintained on a second-to-second basis, and PSE dispatches its resources based on market prices and other system constraints in the Interconnection. Generally speaking, when the dispatch cost of a specific PSE-owned unit is lower than the market price, it is economic for the unit to run. Net revenue resulting from sales of electricity from PSE-dispatched resources result in net revenue that is credited back to customers to reduce rates. When the cost to run the PSE-owned unit is greater than the market price, the units are not dispatched. PSE may also dispatch resources in real-time based on dispatch operating instructions issued by the California Independent System Operator (CAISO) in its Energy Imbalance Market (EIM). Dispatch decisions are independent of the demand by PSE's customers. If PSE's customers need power when its units are uneconomic to run, PSE purchases the energy from wholesale markets – other utilities or registered power marketers with energy to sell. If PSE's generation is dispatched and there is a surplus above PSE's customers' needs, that surplus will be sold in the wholesale market (net revenue from such sales is credited back to customers through rates), meaning whatever is happening to PSE's load is unrelated. The primary driver of generation dispatch is whether a generator's variable cost of dispatch is lower than the market price.

PSE tracks its firm and non-firm power transactions in its Energy Accounting (EA) database on a calendar year basis. Table 2 shows all firm energy transactions made in 2024, including the total dispatch of all of PSE-owned units. Emissions from PSE's units and from each firm purchase are calculated using the methodologies described in Appendix 2.1 and 2.2, respectively. For unspecified electricity purchases, PSE uses the emissions intensity metrics according to WAC

480-109-300(4)[3]. PSE employed Commission Staff's net-by-counterparty approach to calculate emissions from its non-firm (unspecified) power transactions. Details of these transactions are presented in Table 3, and the calculation methodology is described in Appendix 2.3. Staff requested in its compliance letter to PSE's 2017 EEI report that the Company explain how PSE determines whether a source is known or unknown. Staff correctly assumes that PSE classifies non-unit specific purchases as unknown sources. PSE-owned resources and unit-specific firm deliveries are classified as known sources because their fuel source is known and reported in the U.S. Energy Information Administration (EIA) databases, described in Appendix 2.1 and 2.2.

Table 2. Known Resources Serving WA Customers

Resource	Generation / Purchase WA MWh	Sales WA MWh	Metric Tons CO_2e	Type	Fuel
Lower Baker	326,698		0	Own	Hydro
Snoqualmie Falls #1	65,857		0	Own	Hydro
Snoqualmie Falls #2	158,872		0	Own	Hydro
Upper Baker	317,830		0	Own	Hydro
Colstrip 3 & 4	2,195,159		2,230,496	Own	Coal
Crystal Mountain	366.2		305	Own	Diesel
Encogen	763,946		364,444	Own	Gas
Ferndale	1,684,142		804,020	Own	Gas
Freddie #1	856,249		333,786	Own	Gas
Fredonia	555,781		367,670	Own	Gas
Frederickson	88,924		63,613	Own	Gas
Goldendale	2,099,550		780,985	Own	Gas
Mint Farm	2,695,425		924,443	Own	Gas
Sumas	674,253		316,436	Own	Gas
Whitehorn	230,887		163,349	Own	Gas
Hopkins Ridge (W184)	411,010		0	Own	Wind
Lower Snake River	873,275		0	Own	Wind
Wild Horse (W183)	636,124		0	Own	Wind
Sierra Pacific Industries	128,427		0	Bundled PPA	Biomass
Bio Energy Washington (BEW)	77		0	Qualifying Facility	Biogas

[3] Bonneville Power Administration (BPA) Asset-Controlling Supplier (ACS) System emission factors are used for BPA specified purchase claims beginning in reporting year 2022 (https://apps.ecology.wa.gov/publications/documents/2302002.pdf). For all other unspecified electricity purchases, the default emission factor provided by the Washington State Department of Ecology is used (RCW 19.405.070).

Resource	Generation / Purchase WA MWh	Sales WA MWh	Metric Tons CO_2e	Type	Fuel
Edaleen Dairy LLC	3,508		0	Qualifying Facility	Biogas
Emerald City Renewables	32,053		0	Qualifying Facility	Biogas
Farm Power Rexville LLC	3,099		0	Qualifying Facility	Biogas
Rainier Bio Gas	832		0	Qualifying Facility	Biogas
VanderHaak Dairy Digester	2,451		0	Qualifying Facility	Biogas
Transalta Centralia Generation LLC	2,700,452		3,015,251	Unbundled PPA	Coal
Transalta Centralia Generation LLC	292,490		127,818	Unbundled PPA	Market
Chelan County PUD #1	123,200		0	Bundled PPA	Hydro
Chelan PUD - RI & RR	1,632,424		0	Bundled PPA	Hydro
Chelan PUD - Slice 35	323,790		0	Bundled PPA	Hydro
Chelan PUD - Slice 38	334,072		0	Bundled PPA	Hydro
Black Creek Hydro Inc	11,311		0	Qualifying Facility	Hydro
Koma Kulshan Associates	24,725		0	Qualifying Facility	Hydro
Nooksack	20,084		0	Qualifying Facility	Hydro
Skookumchuck Hydro	2,157		0	Qualifying Facility	Hydro
Sygitowicz Creek	594		0	Qualifying Facility	Hydro
Twin Falls Hydro	62,947		0	Qualifying Facility	Hydro
Weeks Falls	11,521		0	Qualifying Facility	Hydro
Douglas PUD - Wells Project	535,293		0	Unbundled PPA	Hydro
Grant PUD - Priest Rapids Project	336,069		0	Unbundled PPA	Hydro
KERR DAM-ENERGY KEEPER	351,282		0	Unbundled PPA	Hydro
Powerex Seasonal Capacity	1,216,000		0	Unbundled PPA	Hydro
HF Sinclair (Mar Pt)	656,794		223,636	Qualifying Facility	Gas
CAMAS SOLAR	9,844		0	Community Solar	Solar
Penstemon Solar	10,843		0	Community Solar	Solar
URTICA SOLAR	10,646		0	Community Solar	Solar
Bonney Lake CS	514		0	CS Generation	Solar
Olympia High School CS	245		0	CS Generation	Solar
Pine Lake Middle School CS	145		0	CS Generation	Solar
Lund Hill Solar, LLC	361,485		0	Green Direct	Solar
CC Solar 1 and CC Solar 2	28		0	Qualifying Facility	Solar

Resource	Generation / Purchase WA MWh	Sales WA MWh	Metric Tons CO_2e	Type	Fuel
Ikea Solar	13		0	Qualifying Facility	Solar
Lake Washington -- Finn Hill	287		0	Qualifying Facility	Solar
Port of Coupeville	49		0	Qualifying Facility	Solar
Schedule 667 Solar Energy Credit	168		0	Qualifying Facility	Solar
TACOMA GLASS	174		0	Qualifying Facility	Solar
Avangrid Renewable (Golden Hills)	685,096		0	Bundled PPA	Wind
Clearwater Wind	1,304,894		0	Bundled PPA	Wind
Klondike Wind Power III	123,482		0	Bundled PPA	Wind
Skookumchuck Wind PPA	416,933		0	Green Direct	Wind
Swauk Wind	2,363		0	Green Power Program	Wind
California ISO		-374,270	0	EIM Sales and Purchases	Hydro
California ISO		-212,412	-92,484	EIM Sales and Purchases	Gas
California ISO		-271,754	0	EIM Sales and Purchases	Wind

Table 3. Unknown Resources Serving WA Customers

Counterparty	Type	Energy Purchased (MWh)	Energy Sold (MWh)	Net Purchase (MWh)	Rate $mtCO_2e/MWh$	Metric Tons CO_2e
BPA Purchases	Market	792,762	0	792,762	--	208,238.7
BPA Sales	Market	0	-358,111	-358,111	--[4]	-156,495
Avista Corp. WWP Division	Market	14,754	-76,585	-61,831	0.377	-23,327
Avista Nichols Pump	Interchange In	13,837	0	13,837	0.437	6,046.8
BASIN ELECTRIC POWER	Market	0	-4,022	-4,022	0.377	-1,517
BC Hydro (Point Roberts)	Unbundled PPA	20,596	0	20,596	0.437	9,000.4
BHE Power Watch, LLC	Market	0	-3	-3	0.377	-1
BP Energy Co.	Market	1,805	-547,122	-545,317	0.377	-205,733
British Columbia Transmission Corp	Market	0	-8	-8	0.377	-3
Brookfield Energy Marketing	Market	61,600	-242,601	-181,001	0.377	-68,287

[4] BPA specified purchases use 0.0174; BPA unspecified purchases use 0.437.

Counterparty	Type	Energy Purchased (MWh)	Energy Sold (MWh)	Net Purchase (MWh)	Rate $mtCO_2e/MWh$	Metric Tons CO_2e
California ISO	EIM Purchases	1,230,919	0	1,230,919	0.437	537,911.7
California ISO	EIM Sales	0	-37,873	-37,873	0.377	-14,288
California ISO	EIM Sales to CA	0	-173	-173	0.377	-65
California ISO	Purchases	108,868	0	108,868	0.437	47,575.3
California ISO	Sales	0	0	0	0.377	-0.1
California ISO	Sales to CA	0	-2,244	-2,244	0.377	-847
Chelan County PUD #1	Market	19,602	-3,606	15,996	0.437	6,990.3
Citigroup Energy Inc	Market	47,676	-773,028	-725,352	0.377	-273,656
Clatskanie PUD	Market	2,671	-3,322	-651	0.377	-246
Conoco, Inc.	Market	809,406	-594,187	215,219	0.437	94,050.7
CONSTELLATION ENERGY	Market	53,713	-58,364	-4,651	0.377	-1,755
CP Energy Marketing (Epcor)	Market	6,209	-6,572	-363	0.377	-137
Deviation	System Deviation	0	-3,994	-3,994	0.377	-1,507
DYNASTY POWER INC	Market	597	-312,664	-312,067	0.377	-117,734
EDF Trading NA LLC	Market	22,537	-6,288	16,249	0.437	7,100.8
Energy Keepers Inc.	Market	400	-1,000	-600	0.377	-226
Eugene Water & Electric	Market	7,736	-40,653	-32,917	0.377	-12,419
Grant County PUD #2	Market	6	0	6	0.437	2.6
GRIDFORCE ENERGY MANAGEMENT, LLC.	Market	10	-761	-751	0.377	-283
Iberdrola Renewables (PPM Energy)	Market	268,684	-802,903	-534,219	0.377	-201,546
Idaho Power Company	Market	5,669	-9,479	-3,810	0.377	-1,437
J. Aron & Company	Market	0	-400	-400	0.377	-151
MERCURIA ENERGY	Market	20,852	-228,460	-207,608	0.377	-78,325
Merrill Lynch Commodities	Market	354,833	-790,692	-435,859	0.377	-164,438
Morgan Stanley CG	Market	320,484	-351,762	-31,278	0.377	-11,800
Natur Ener USA	Market	0	-20	-20	0.377	-8
Nevada Energy	Market	0	0	0	0.377	0.0
Nevada Power Company	Market	50	-155	-105	0.377	-40
New Mexico, Public Service Company	Market	90	0	90	0.437	39.3
Northwestern Energy	Market	6,944	-23,827	-16,883	0.377	-6,369
NRG Business Marketing LLC DECM	Market	0	-400	-400	0.377	-151
Pacific Gas & Elec - Exchange	Interchange In-0ut	413,000	-413,000	0	0.377	0.0

Counterparty	Type	Energy Purchased (MWh)	Energy Sold (MWh)	Net Purchase (MWh)	Rate $mtCO_2e/MWh$	Metric Tons CO_2e
Pacificorp	Market	8,216	-57,809	-49,593	0.377	-18,710
PHILLIPS 66 ENERGY	Market	7,194	-268,574	-261,380	0.377	-98,612
Portland General Electric	Market	24,398	-149,315	-124,917	0.377	-47,128
Powerex Corp.	Market	46,199	-965,399	-919,200	0.377	-346,789
Rainbow Energy Marketing	Market	2,137	-4,796	-2,659	0.377	-1,003
Sacramento Municipal	Market	50	-60	-10	0.377	-4
Salt River Project Power	Market	6	-5	1	0.437	0.4
Seattle City Light Marketing	Market	27,681	-51,598	-23,917	0.377	-9,023
Shell Energy (Coral Pwr)	Market	109,261	-160,998	-51,737	0.377	-19,519
Snohomish County PUD #1	Market	7,005	-24,295	-17,290	0.377	-6,523
Tacoma Power	Market	14,683	-4,292	10,391	0.437	4,540.9
The Energy Authority	Market	26,603	-127,731	-101,128	0.377	-38,153
TransAlta Energy Marketing	Market	447,332	-1,097,517	-650,185	0.377	-245,297
TransCanada Energy Sales Ltd	Market	176	-9,679	-9,503	0.377	-3,585
Turlock Irrigation District	Market	988	0	988	0.437	431.8
Vitol Inc.	Market	33,504	-44,959	-11,455	0.377	-4,322

Columbia River Energy Supply Contracts

During 2024, approximately 14.8 percent of PSE's energy supply requirement was obtained through long-term contracts with three Washington Public Utility Districts (PUDs) that own and operate hydroelectric projects on the Columbia River (Mid-Columbia). PSE's portion of the power output of the PUD projects is shown in Table 4.

Table 4. Columbia River Electric Energy Supply Contracts

Project	Contract Expiration	Percent of Output (PSE Share)	MW Capacity (PSE Share, approx.)
Rock Island Project (Chelan County PUD)	2031	25%	156
Rocky Reach Project (Chelan County PUD)	2031	25%	325
Wells Project (Douglas County PUD)	2028	27.1%	228
Priest Rapids Development (Grant County PUD)	2052	0.6%	6
Wanapum Development (Grant County PUD)	2052	0.6%	7

2024 Carbon Dioxide Emissions - Results & Discussion

Overall, PSE's CO_2e emissions intensity from total electricity delivered to customers decreased from 877.5 lb/MWh in 2023 to 830.3 lb/MWh in 2024 (as seen in Table 6). As shown in Table 5, in 2024, 65.9 percent of electricity delivered to PSE customers was generated by the company, 34.1 percent of electricity was purchased via firm contracts (49.0 percent) and non-firm contracts, i.e., spot market (-14.9 percent)[5]. Of the CO_2e emissions associated with electric delivery, 75.9 percent were from electricity generated by PSE, and 24.1 percent were from purchased electricity (39.1 percent via firm contracts and -15.1 percent via non-firm contracts).

It is important to remember that CO_2e emissions vary based on the fuel source or technology used to generate the electricity. Some sources are more emissions intense than others. "Intensity" is the relationship between emissions and production, and utilities can measure that intensity using a metric called pounds of CO_2e per megawatt-hour (lb/MWh) of electricity produced. For instance, in 2024 (as seen in Table 5), about 15.0 percent of the electricity generated by PSE came from coal combustion, but this fuel source represented about 35.1 percent of the CO_2e emissions from electricity generated by PSE. Natural gas accounted for 65.9 percent of the electricity generated by PSE; however, this fuel source represented 64.9 percent of the CO_2e emissions from electricity generated by PSE. Renewable energy accounted for 19.1 percent of the electricity generated by PSE-owned generation resources and produced zero CO_2e emissions.

Compared to 2023 (as seen in Table 7), total electricity delivered to customers in 2024 decreased slightly, by 0.3 percent, and total emissions decreased slightly, by 5.7 percent. This trend is due primarily to a decrease in PSE coal generation and purchases. Coal generation decreased significantly, by 18.4% in 2024 compared to 2023, which resulted in 1.1 MM metric tons of fewer emissions compared to the previous year.

[5] This is net of all unspecified purchases.

Table 5. Summary of Total Energy Delivered (MWh) and Total Emissions (metric ton CO_2e)

2024	Total Energy Delivered (MWh)				Total Emissions (CO_2e)			
Source	MWh Total	MWh % of PSE All-owned Total	MWh % of PSE Thermal Only	MWh % of Total	Metric Ton Total	Metric Ton % of PSE All-owned Total	Metric Ton % of PSE Thermal Only	Metric Ton % of Total
PSE Owned Coal	2,195,159	15.0%	18.5%	9.9%	2,230,496	35.1%	35.1%	26.7%
PSE Owned Gas	9,649,521	65.9%	81.5%	43.4%	4,119,051	64.9%	64.9%	49.2%
PSE Owned Renewable	2,789,666	19.1%		12.6%	0	0.0%		0.0%
Firm Coal	2,700,452			12.2%	3,015,251			36.0%
Firm All Other	8,173,971			36.8%	258,970			3.1%
Unspecified	-3,299,563			-14.9%	-1,259,530			-15.1%
Total (from energy)	22,209,206				8,364,238			
PSE Own plus Firm PPA	25,508,769				9,623,768			
Total PSE Only	14,634,346			65.9%	6,349,547			75.9%
Total Firm Only	10,874,423			49.0%	3,274,221			39.1%
Total Unspecified Only	-3,299,563			-14.9%	-1,259,530			-15.1%

Table 6. 2023 and 2024 Total Energy Delivered (MWh), Total Emissions (metric ton CO_2e), and Emission Intensity (lb/MWh)

	2024					***2023***				
	Energy MWh	%	Emissions Metric Ton	%	Intensity (lb/MWh)	Energy MWh	%	Emissions Metric Ton	%	Intensity (lb/MWh)
PSE Owned Coal	2,195,159	9.9%	2,230,496	26.7%	2,240.1	3,326,355	15%	2,741,750	31%	1,817.2
Firm Coal	2,700,452	12.2%	3,015,251	36.0%	2,461.6	2,673,671	12%	3,536,340	40%	2,916.0
PSE Owned Gas	9,649,521	43.4%	4,119,051	49.2%	941.1	9,954,456	45%	4,578,487	52%	1,014.0
PSE Owned All Other	2,789,666	12.6%	0	0.0%	0.0	2,265,369	10%	0	0%	0.0
Firm All Other	8,173,971	36.8%	258,970	3.1%	69.8	8,794,954	39%	113,329	1%	28.4
Unspecified	-3,299,563	-14.9%	-1,259,530	-15.1%	841.6	-4,732,543	-21%	-2,100,695	-24%	978.6
PSE Owned Plus Firm PPA	25,508,769		9,623,768		831.7	27,014,805		10,969,906		895.2
PSE Owned	14,634,346	65.9%	6,349,547	75.9%	956.5	15,546,180	69.8%	7,320,237	82.5%	1,038.1
Firm	10,874,423	48.96%	3,274,221	39.1%	663.8	11,468,625	51.5%	3,649,669	41.1%	701.6
Unspecified	-3,299,563	-14.86%	-1,259,530	-15.1%	841.6	-4,732,543	-21.2%	-2,100,695	-23.7%	978.6
Total (Own, Firm, Unspecified)	22,209,206		8,364,238		830.3	22,282,262		8,869,210		877.5

Table 7. Comparison to Previous Year: Total Energy Delivered (MWh), Total Emissions (metric ton CO_2e), and Emission Intensity (lb/MWh)

	2024 vs. 2023				
	Energy MWh	%	Emissions Metric Ton	%	Intensity (lb/MWh)
PSE Owned Coal	-1,131,196	-34.0%	-511,254	-18.6%	423.0
Firm Coal	26,781	1.0%	-521,088	-14.7%	-454.3
PSE Owned Gas	-304,935	-3.1%	-459,436	-10.0%	-72.9
PSE Owned All Other	524,296	23.1%	0	0.0%	0.0
Firm All Other	-620,983	-7.1%	145,641	0.0%	41.4
Unspecified	1,432,980	-30.3%	841,165	-40.0%	-137.0
PSE Owned	-911,834	-5.9%	-970,690	-13.3%	-81.6
Firm	-594,202	-5.2%	-375,447	-10.3%	-37.8
Unspecified	1,432,980	-30.3%	841,165	-40.0%	-137.0
Total (Own, Firm Unspecified)	-73,056	-0.3%	-504,972	-5.7%	-47.2

Trends Discussion

The relative amount of GHG emissions from the electricity sources did not align with the amount of power produced from each electricity source. This trend is due to factors related to the intensity of emissions from each source, which reflects the relationship between CO_2e and power production of each source.

For example, about 15.0 percent of the electricity generated by PSE came from coal combustion, which has a high CO_2e emission intensity compared to natural gas and oil combustion sources. Of CO_2e emissions from electricity generated by PSE (direct emissions), about 35.1 percent were from coal-combustion generation. The high CO_2e emission intensity of coal-combustion generation made the overall CO_2e emission intensity of PSE's electric operations high.

Another example highlighting this trend occurs in purchased electricity. Roughly 74.3 percent[6] of firm contract electricity purchased by PSE came from renewable plants in the Pacific Northwest (primarily hydroelectric), while the remaining purchases were sourced from thermal plants. Since hydroelectric generation is considered a non-GHG emitting source, almost all of the CO_2e emissions generated from firm contract purchased electricity come from coal and natural gas generated electric operations.

A third example relates to how emissions are calculated for electricity purchased by PSE on the spot market (i.e., non-firm contracted electricity purchases). Again, these purchases are sourced from different utilities and non-utilities via the "grid" system of electric distribution, making the source of energy challenging to track and measure. Therefore, regional average emission factors were used to estimate non-firm contract purchased electricity. For instance, electricity purchased by a utility from an energy trader could have been purchased by the energy trader from a hydroelectric facility near the utility's operational territory or from a second utility generating electricity using coal outside the utility's operational territory. The emissions associated with the generation are not known because they could be significantly different for each source. Therefore, the emissions associated with non-firm contract purchased electricity were calculated using the unspecified emission rate factor provided by Ecology that generally reflects the suite of generation sources that produced the purchased electricity.

[6] Calculated, Attachment A (Known Resources)

Centralia Coal Transition Power

It is important to distinguish between emissions from PSE's owned thermal resources above and the contract PSE signed with TransAlta for coal transition power from the Centralia power station ("Centralia"). In this report, PSE incorporates a breakdown of energy and emissions from Centralia and differentiates Centralia generation and Centralia supply, which is power purchased by the owner of Centralia (i.e., TransAlta), and supplied to PSE. PSE's report will apply different emissions factors for energy supplied versus generated from Centralia to reflect known sources of emissions more accurately.

PSE reports the difference between supplied and generated power each year from Centralia in its Annual Report of Energy Delivery to PSE from TransAlta-Centralia Transition Coal in Docket No. UE-121373 ("Coal Transition Report").

PSE's sources of Centralia generation and supply in this report are consistent with its Coal Transition Report.

For power generated from Centralia coal, PSE applied the emission factor following the methodology and data reported to the Environmental Protection Agency (EPA). For power supplied by the Centralia market option, PSE applied the Ecology unspecified rate, 963 lbs per CO_2e/MWh. PSE determined the Ecology unspecified rate was reasonable because it provides consistency given the uncertainty of sources purchased by TransAlta from other Balancing Authority Areas. PSE plans to use this same methodology to differentiate Centralia generation and supply in this report for the Centralia coal transition contract duration.

Population Data

PSE tracks customers served by class of service but does not track the number of people (population) served. Therefore, population data in this report is estimated based upon methodology agreed to by PSE, UTC Staff, and the other utilities.

The total service area population was estimated by multiplying the total residential customers in PSE's service area by the average household size (AHS) of occupied homes, using data from the most recent five-year estimates from the U.S. Census Bureau's American Community Survey (ACS).

For more detailed information, see Appendix 1: Estimation of PSE Service Territory Population.

Unspecified Market Purchases

This report includes energy that PSE has purchased from the spot market associated with the corresponding generation year where the actual generating unit is unknown (unspecified). As stipulated in this rule, PSE uses an unspecified emissions rate for these spot market purchases where the energy source is unknown (WAC 480-109-300(4))[7]. The net system mix emissions rates for PSE and the other utilities during the reporting period have been calculated and provided by Ecology.

[7] Bonneville Power Administration (BPA) Asset-Controlling Supplier (ACS) System emission factors are used for BPA specified purchase claims beginning in reporting year 2022 (https://apps.ecology.wa.gov/publications/documents/2302002.pdf). For all other unspecified electricity purchases, the default emission factor provided by the Washington State Department of Ecology is used (RCW 19.405.070).

Section 4. Appendices

Appendix 1: Estimation of PSE Service Territory Population

This appendix documents how PSE estimated the population within its service territory to meet the reporting requirement of WAC 480-109-300(2)(c): Megawatt-hours per capita. The estimated population for each reporting year is the product of PSE residential customer count for the year multiplied by the weighted average household size of the counties that PSE provides electric service. The methodology is consistent with the preferred Per Capita Methodology described in the UTC Staff's final report[8] and the Commission's Final Order[9] on the estimation of population in an electric utility service territory. As prescribed in the Commission's Final Order paragraph 17, "To produce the reports required by WAC 480-109-300(2)(c), the utilities should use the methodology agreed upon by stakeholders and described in the final report and this order." [10]

PSE's customer information system is the ultimate source of the annual residential customer count data, which represents the number of households within PSE service territory. These customer count data are as reported in PSE's FERC financial reporting Form No. 1: Annual Report of Major Electric Utilities, Licensees, and Others. Not all residents in a multi-family or mixed-use commercial and residential building are included in PSE's residential customer count at this time. PSE does not have reliable data to make a separate adjustment to account for the persons residing in master-metered residential buildings.

The average household size used in PSE's WAC 480-109-300: Energy and emissions intensity metrics is 2.48. This number is the overall average of persons per household for PSE's service territory weighted by the population size for each county.

The source of the five-year average of county-level data is the United States Census Bureau's American Communities Survey, which can be accessed using the Bureau's web-based application QuickFacts at www.census.gov/quickfacts/table/PST045215/00.

The following table details the data and the calculation of the 2.48 persons average household size that used in the determination of PSE service territory population for megawatt hours per capita (WAC 480-109-300(3)(c)).

[8] UE-131732 Proposed EE Metrics Workgroup Results – Final Report, August 7, 2015, (Report at2-3).
[9] UE-131732, Final Order, General Order R-581: Order Adopting Rule Permanently, September, 10, 2015, (Order at 6 §17).
[10] UE-131732, Final Order, General Order R-581: Order Adopting Rule Permanently, September, 10, 2015, (Order at 6 §17).

2016-2020 Census Bureau, Updated July 2021			
County	Population	Per House	Total
Skagit	130,696	2.55	333,275
Pierce	925,708	2.64	2,443,869
Island	87,432	2.31	201,968
King	2,252,305	2.43	5,473,101
Kitsap	274,314	2.46	674,812
Kittitas	45,499	2.32	105,558
Thurston	297,977	2.5	744,943
Whatcom	228,831	2.47	565,213
		Weighted Average	2.48

Appendix 2: Emissions Reporting Methodology

1. Owned Thermal Resources

PSE wholly owns three dual-fuel combustion turbine generation facilities (Frederickson, Fredonia, and Whitehorn), five natural gas combined cycle generation facilities (Encogen, Goldendale, Mint Farm, Ferndale and Sumas), and one internal diesel combustion generation facility (Crystal Mountain). Also, PSE partially owns one coal-combustion generation facility (Colstrip) and one natural gas combined cycle generation facility (Freddy 1).

PSE's CO_2e emissions from electric operations are calculated using the EPA GHG Mandatory Reporting Rule Subparts C and D (Tiers 2 & 4) calculation methodologies. Utilizing Subparts C & D, carbon dioxide mass is calculated based on the amount of fuel consumed by each generation facility.

Thermal facilities utilizing the Subpart C method include Frederickson, Fredonia Units 1 & 2 and Whitehorn. Annual CO_2e mass emissions using Subpart C are calculated with these plant measurements: 1) fuel heat content (HHV), 2) the amount of fuel burned (volume)[11] and, 3) a default specific emission factor (EF). An example calculation is provided below.

> Example = Volume gas x fuel heat content HHV x EF =
>
> (334,172,000 scf natural gas measured) x (0.0010920 MMBtu/scf measured) x (53.06 kg CO_2/MMBtu) = 21,343 short ton CO_2

Thermal facilities utilizing the Subpart D method include Encogen, Goldendale, Mint Farm, Ferndale, Sumas, Fredonia Units 3 & 4, Freddy 1 and Colstrip. This method utilizes direct continuous emissions measurement systems (CEMS) as prescribed in Part 75 of the EPA Acid Rain Program. Stack gas and flow measurements are measured continuously, and this data is used in prescribed equations (via the CEMS system) to determine total GHG mass. Part 75 also includes certification and Quality Assurance (QA)/Quality Control (QC) requirements to ensure that data validity is confirmed at the beginning of a monitoring program.

2. Firm Contract Purchases

PSE calculated firm contract purchased emissions using the Ecology methodology outlined in WAC 177-444-040(2).

- Step 1: Obtain plant GHG emissions. GHG emissions for this method are defined as the sum of all Subpart C and Subpart D emissions from the individual power plant as

[11] Measured in standard cubic feet (scf).

published by EPA based on 40 CFR[12] Part 98 reporting consistent with the methods adopted in WAC 173-441-120. Emissions are on a calendar year basis and in units of metric tons CO_2e. Use emissions values specific to the calendar year in the calculation.

- Step 2: Obtain plant net electric generation. Net electric generation is the sum of all annual net generation (MWh) from Form EIA-923 for the power plant for the calendar year for all reported fuel type codes.
- Step 3: Calculate transmission losses using the following method as directed by the regulatory agency. Transmission losses are zero MWh if utility claims are reported on a plant net output basis, like utility claims measured at the Busbar.
- Step 4: Obtain cogeneration correction factor. Account for nonelectric heat use at the power plant by dividing the sum of annual electric fuel consumption (MMBtu) by the sum of annual total fuel consumption MMBtu from Form EIA-923.
- Step 5, Firm Contract Plant Emission Rate Equation (Ecology Method) =

$$\frac{\text{EPA plant GHG emissions} \times \text{cogeneration correction factor}}{\text{plant net electric generation}} \times (\text{utility claims} + \text{transmission losses})$$

3. Non-Firm Contract Purchases

PSE's emissions from non-firm contract purchased electricity were estimated using the net-by-counterparty methodology for purchases and sales of non-firm contract purchased electricity pursuant to the Staff directive described below:

> *" 3. Unknown Sources – Purchase and sales reporting methodology: After several rounds of discussion last year and after reviewing analysis performed by the utilities, Staff believes the appropriate methodology for reporting purchases and sales is the net-by-counterparty approach:*
> *(a) for each transaction partner whose generation is from an unknown resource, subtract the total annual sales to this party from the total annual purchases from this party;*
> *(b) if the result is positive, apply the Ecology unspecified intensity factor to calculate emissions associated with the net purchase;*
> *(c) if the result is negative, apply an aggregate, fleet-wide emissions intensity factor for the utility's known sources to calculate emissions associated with the net sale.*
> *Staff understands that this approach has largely been implemented by PSE in prior reports. Staff contends that the net-by-counterparty approach represents an optimal*

[12] CFR stands for Code of Federal Regulations.

balance among the three competing priorities of accuracy, consistency, and burden on company and commission resources."[13]

4. Non-Firm Purchases in the Energy Imbalance Market (EIM)

    1. For non-PSE units:
        - Apply net-by-counterparty calculus described in 3) above

    2. For PSE units:
        - If end-of-year net (by plant) is greater than zero, then PSE was a net purchaser (from the California Independent System Operator, CAISO); assign Commerce rate. If end-of-year net (by plant) is less than zero, then PSE had excess generation.
        - For excess generation from PSE units, will assign "zero" emission rate because emissions are accounted for under "Generation" (to avoid double counting).

[13] UE-170696. *PSE 2007-2016 EEI report Staff Compliance Letter* (June 26, 2018). Staff compliance letter recommending that the Commission acknowledge Puget Sound Energy's compliance with WAC 480-109-300. ATTACHMENT Staff feedback re: PSE's 2007-2016 EEI Report, page 1 of 2.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-57:
Wash. Utils. Comm'n Rejection of Colstrip Investments in Puget Rates

Service Date: December 19, 2025

BEFORE THE WASHINGTON
UTLITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY Respondent.	DOCKET UE-240729 FINAL ORDER 05 REJECTING TARIFF SHEETS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis: *The Washington Utilities and Transportation Commission rejects the tariff sheets field by Puget Sound Energy (PSE or the Company) filed on September 30, 2024, and allowed to provisionally go into effect subject to refund. The Commission has considered the full record and requires PSE to file tariff sheets that will result in a decrease in revenue of approximately $6,843,705 or 0.08 percent in accordance with the decisions in this Order summarized below, subject to the true-up required by this Order. The Commission concludes that Colstrip Units 3 and 4 will be "retired" within the meaning of CETA when PSE transfers its ownership in those units to NorthWestern Energy Corporation (NorthWestern) on January 1, 2026. The Commission further determines that the Abandonment and Acquisition Agreement (A&A Agreement) is not subject to Commission approval because Colstrip is not useful or necessary for PSE's service in Washington at the time of transfer. However, the Commission establishes a condition to facilitate review of future property transfers to comply with CETA. The Commission determines that PSE's Colstrip investments are not used and useful after December 31, 2025, and that such investments should be prorated, with the exception of six investments in support of human health and safety. The Commission further requires PSE to establish the in-service dates of two other investments, the U4 Generator Exciter and the Northern Cheyenne AAQ System, to establish the prorated level of recovery, if any. The Commission determines that PSE has demonstrated that the prorated portion of its Colstrip investments are prudent, other than its investment in the TOFA SmartBurn component and four projects that lack a capital justification. The Commission further finds that the annual amortization amount associated with the 2024 Colstrip outage should be adjusted to $1,603,174. The Commission finds that PSE should be required to refund over-collected amounts in the manner described in this Order. The Commission further requires PSE to file an accounting of its 2025 Colstrip investments as part of its Sch. 141COL annual filing,*

consistent with the decisions in this Order, to allow for review of its 2025 Colstrip investments.

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PROCEDURAL HISTORY

1 On September 30, 2024, Puget Sound Energy (PSE or Company) filed with the Washington Utilities and Transportation Commission (Commission) a proposed revision to rates under the established Colstrip Adjustment Rider Schedule 141COL. PSE requested an annual revenue increase of $4.1 million, or 0.14 percent, which for the typical residential customer using 800 kWh per month would be a rate increase of $.18 or 0.16 percent.

2 On December 19, 2024, this matter came before the Commission at the Open Meeting. Commission staff (Staff) raised concerns about a number of capital investments reflected in the filing that are potentially unrecoverable by law or imprudent for Washington ratepayers. The Commission entered Order 01 Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication (Order 01) in this docket, requiring PSE to file revised tariff pages no later than December 23, 2024, with an effective date of January 1, 2025, indicating that the increased rates would go into effect on January 1, 2025, subject to refund.[1] The Company was directed by Order 01 to file revised tariff pages, which the Company complied with on December 20, 2024.

[1] On December 23, 2024, the Commission issued an errata to Order 01 and a revised Order 01. The revision did not affect the substantive terms or determinations in Order 01.

3 On February 27, 2025, Alliance of Western Energy Consumers (AWEC) filed its Petition to Intervene, arguing that it has a substantial interest in this proceeding based on its participation in the establishment of the Colstrip Adjustment Rider Schedule and the impacts of proposed rate increases on AWEC members who purchase power from PSE.[2]

4 On March 6, 2025, NW Energy Coalition (NWEC) filed its Petition to Intervene arguing that it has a substantial interest in this proceeding based upon its historic and ongoing work with utility companies to promote a clean, reliable, affordable, and equitable energy future.

5 On March 12, 2025, the Commission convened a virtual prehearing conference before Administrative Law Judges (ALJ) Harry Fukano and Jessica Kruszewski. At the hearing the presiding ALJ granted AWEC and NWEC's unopposed petitions to intervene in this matter.

6 On March 26, 2025, the Commission entered Order 03, Prehearing Conference Order and Notice of Hybrid Evidentiary Hearing (Order 03), which set an evidentiary hearing for September 3, 2025, at 9:30 a.m.

7 On April 4, 2025, the Commission issued a Notice of Revised Procedural Schedule at the request of PSE to revise the date of the initial settlement conference to April 16, 2025, and for PSE's initial testimony to be due on April 22, 2025. No party opposed PSE's request to modify the procedural schedule.

8 On August 28, 2025, the Commission held a combined virtual public comment hearing in Dockets UE-240729 and UG-240884. Eight participants voiced opposition to PSE's requests for cost recovery in this docket.[3]

9 In addition to the virtual public comments, the Commission and Public Counsel received a total of forty-six written comments with forty opposed, two in favor, and four undecided. Of these commenters, many PSE customers raised concerns about increases in rates while living on a fixed income.[4]

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[2] *WUTC v. Puget Sound Energy*, Dockets UE-220066 & UG-220067 (*consolidated*), and Docket UG-210918 Order 24/10 (Dec. 22, 2022).

[3] *WUTC v. Puget Sound Energy*, Docket UE-240729, Virtual Public Comment Hearing Recording (Aug. 29, 2025).

[4] *WUTC v. Puget Sound Energy*, Docket UE-240729, Comment Matrix Attachment A (Sept. 17, 2025).

10 On September 3, 2025, the Commission convened a hybrid evidentiary hearing before the Commissioners that was presided over by ALJ's Harry Fukano and Jessica Kruszewski.

11 On September 5, 2025, the Commission issued Notice of Bench Requests (BR) 1-4 requesting additional information from the parties with a deadline for responses to BR 1-3 set for September 10, 2025, at 5:00 p.m., and set a deadline for replies from non-company parties to the company's response to BR 1 for September 17, 2025. The deadline for responses to BR 4 was set for September 17, 2025. The Company submitted supplemental responses to BRs 3 and 4 on October 2, 2025.

12 On October 10, 2025, the Commission issued a Notice requesting supplemental briefing from the parties in relation to the interpretation of RCW 19.405.020 to aid the Commission in its decision-making with a deadline for set for October 24, 2025, at 5:00 p.m.

13 On October 21, 2025, the Commission issued BR 5-6 asking the Company to clarify additional questions it had in relation to the Company's investment into SmartBurn and its NOx control system.

14 **PARTY REPRESENTATIVES.** Donna L. Barnett of Perkins, Coie LLP, represents PSE. Nash Callaghan and Josephine Strauss, Assistant Attorneys General, represent Staff.[5] Tad Robinson O'Neill, Jessica Johanson-Kubin, and Robert Sykes, Assistant Attorneys General, represent the Public Counsel Unit of the Attorney General's Office (Public Counsel). Sommer Moser and Michelle Madsen of Pepple Moser, P.C., represent AWEC. Yochanan Zakai and Orran Balagopalan of Shute, Mihaly & Weinberger, represent NWEC.

BACKGROUND

15 **Clean Energy Transformation Act (CETA).** In 2019, the Washington State Legislature passed the Clean Energy Transformation Act (CETA),[6] codified in chapter 19.405 of the Revised Code of Washington (RCW). In the face of immediate and significant threats posed by climate change, CETA requires that each Washington electric utility "eliminate coal-fired resources from its allocation of electricity" no later than December 31, 2025,[7] that all retail sales of electricity are "one hundred percent carbon-neutral by January 1,

[5] In formal proceedings such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To ensure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

[6] Laws of 2019, ch. 288, §§ 1–13 and 26. Codified as chapter 19.405 RCW.

[7] RCW 19.405.030(1). *See also* RCW 19.405.020(1)

2030,"[8] and that by January 1, 2045 "one hundred percent of all sales of electricity to Washington retail customers" are supplied by either non-emitting or renewable electricity generation resources.[9] CETA promotes a transition to a clean energy economy,[10] provides incentives for clean alternative energy sources,[11] and expands the meaning of "public interest" under Title 80 RCW.[12] However, CETA's requirement for each utility to eliminate coal-fired resources from its allocation of electricity "does not include costs associated with decommissioning and remediation of these facilities" provided the Commission deems these costs to be prudently incurred.[13]

16 **Colstrip, Ownership and Operations Agreement (O&O Agreement), and Development of the Abandonment and Acquisition Agreement (A&A Agreement).** This case concerns the recovery of PSE's portion of investments in the Colstrip Steam Electric Station (Colstrip). Colstrip was a four-unit coal-fired electric generation facility operated by Talen MT (Talen) and located in Colstrip, Montana.[14] Colstrip Units 1 and 2 were closed in January 2020.[15] At present, PSE owns 25 percent of the remaining Colstrip Units 3 and 4, with the other 75 percent divided among other entities as follows:[16]

	Colstrip Unit 3	**Colstrip Unit 4**
Avista Corporation	15%	15%
NorthWestern Energy Corporation	--	30%
PacifiCorp	10%	10%
Puget Sound Energy	25%	25%
Portland General Electric Company	20%	20%
Talen MT	30%	--

[8] RCW 19.405.010(2); RCW 19.405.040(1).

[9] RCW 19.405.010(2); RCW 19.405.050(1).

[10] RCW 19.405.010(1).

[11] RCW 19.405.010(4).

[12] RCW 19.405.010(6). In enacting CETA, the Legislature found that the public interest includes: (a) the "equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacts communities;" (b) "long-term and short-term public health, economic, and environmental benefits;" and (c) "the reduction of costs and risks and energy security and resiliency."

[13] RCW 19.405.030(1)(a)-(b).

[14] Atwood, Exh. NLA-1T at 2:9, 7:3-4, 8:19.

[15] Atwood, Exh. NLA-1T at 7:3-4, 12-13.

[16] Atwood, Exh. NLA-1T at 7:3-9.

17 The owners of Colstrip Units 3 and 4 operate under the terms of the Common Facilities Agreement which describes ownership interests, among other things.[17] Contracts relating to Colstrip Units 1 and 2 expired when the units were closed.[18] Additionally, the owners of Colstrip Units 3 and 4 operate under the O&O Agreement, which was entered into in 1981 and continues to govern the operation of the Colstrip units.[19] Under the O&O Agreement, PSE must fund costs to operate and maintain Colstrip Units 3 and 4 as long as the Company holds any ownership shares. [20] This includes requiring each owner to provide the plant with enough coal to generate the owner's share of the plant's minimum operating capacity.[21] Each year, the owners of the Colstrip units must approve a budget, but because PSE holds 25% ownership, it is not the sole entity approving or denying a budget with a minority vote.[22]

18 To comply with CETA's mandate to have coal-fired generation removed from its allocation of electricity by December 31, 2025, PSE has made several prior attempts to sell or dispose of Colstrip Units 3 and 4. PSE first entered into an agreement with NorthWestern in 2019 to sell Colstrip Units 3 and 4 with a purchase price and an exchange of rights on the Colstrip transmission system, but withdrew the agreement after pushback.[23] In a second attempt, in 2022, PSE and Talen worked out an abandonment agreement but the transfer did not occur as Talen went through a bankruptcy in 2024.[24] Talen did not get approval of the PSE abandonment agreement in the bankruptcy, so the agreement was invalidated.[25] PSE then entered into the A&A Agreement with NorthWestern to transfer its interest in Colstrip Units 3 and 4.[26] PSE entered into this agreement without seeking Commission approval.[27] The transfer will occur at 12:00 a.m. on January 1, 2026, Pacific Standard Time.[28]

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[17] Atwood, Exh. NLA-1T at 7:12-13.

[18] Atwood, Exh. NLA-1T at 7:12-14.

[19] Atwood, Exh. NLA-1T at 7:16-18; Atwood, Exh. NLA-4.

[20] Atwood, Exh. NLA-1T at 8:3-4.

[21] Atwood, Exh. NLA-1T at 8:3-7.

[22] Atwood, Exh. NLA-1T at 9:14-20, 16:12-21.

[23] TR Roberts at 94:20-25, 95:1-8; Atwood, Exh. NLA-1T at 19:8-10.

[24] TR Roberts at 95:9-20; Atwood, Exh. NLA-1T at 19:11-22.

[25] Atwood, Exh. NLA-1T at 19:11-22.

[26] Atwood, Exh. NLA-1T at 19:6-22.

[27] Mullins Exh. BGM-1T at 2:10-16.

[28] PSE's Response to BR 3.

I. Applicable Law

19 The Legislature has entrusted the Commission with broad discretion to regulate and set rates in the public interest[29] that are just, fair, reasonable and sufficient,[30] and to balance the needs of the public to have safe, reliable, and appropriately priced services, while also assuring that the utilities earn enough to remain in business.[31] The Commission has previously interpreted the fair, just, reasonable, and sufficient standard to mean that "rates that are *fair* to customers and to the Company's owners; *just* in the sense of being based solely on the record developed in a rate proceeding; *reasonable* in light of the range of possible outcomes supported by the evidence; and *sufficient* to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms."[32]

20 However, if after hearing the Commission finds that the rates charged by the utility are:

> . . . unjust, unreasonable, unjustly discriminatory or unduly preferential, or in any wise in violation of the provisions of the law, or that such rates or charges are insufficient to yield a reasonable compensation for the service rendered, the commission shall determine the just, reasonable, or sufficient rates, charges, regulations, practices or contracts to be thereafter observed and in force, and shall fix the same by order.[33]

21 For proposed rates, as in this case, the Commission may enter an order under this same standard as if the proposed rates were already effective.[34]

22 As a general matter, the burden of proving that a proposed increase is just and reasonable is upon the public service company,[35] and the burden of proving that the presently effective rates are unreasonable rests upon any party challenging those rates.[36]

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[29] RCW 80.01.040(3).

[30] RCW 80.28.010.

[31] *People's Org. for Wash, Energy Res. v. WUTC*, 104 Wn.2d 798, 808 (1985).

[32] *WUTC v. Avista Corp.*, Dockets UE-160228 & UG-160229, Order 06 at 47 ¶ 79 (Dec. 15, 2016) (emphasis in original).

[33] RCW 80.28.020.

[34] RCW 80.04.130(1).

[35] *Id*.

[36] *WUTC v. Pacific Power and Light Company*, Cause No. U-76-18 (Dec. 29, 1976) (internal citations omitted).

23 As discussed above, in 2019, the Legislature expanded the traditional definition of the public interest standard. As Washington state transitions to a clean energy economy, the Legislature provided that the public interest includes: "The equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks; and energy security and resiliency."[37] In achieving these policies, "there should not be an increase in environmental health impacts to highly impacted communities."[38]

24 Following the passage of RCW 80.28.425, which requires utilities to file multi-year rate plans when filing a general rate case (GRC), the Commission indicated its commitment to considering equity while regulating in the public interest: "So that the Commission's decisions do not continue to contribute to ongoing systemic harms, we must apply an equity lens in all public interest considerations going forward."[39] The Commission also explained that regulated companies should be prepared to address equity considerations in future cases: "Recognizing that no action is equity-neutral, regulated companies should inquire whether each proposed modification to their rates, practices, or operations corrects or perpetuates inequities."[40]

II. Application of RCW 19.405.030 - Interpretation of "*Retirement*"

25 CETA requires the following:

> The commission must allow in rates, directly or indirectly, amounts on an investor-owned utility's books of account that the commission finds represent prudently incurred undepreciated investment in a fossil fuel generating resource that has been retired from service when:
>
> (a) The retirement is due to ordinary wear and tear, casualties, acts of God, acts of governmental authority, inability to procure or use fuel, termination or expiration of any ownership, or an operation agreement affecting such a fossil fuel generating resource; or
>
> (b) The commission finds that the retirement is in the public interest.

[37] RCW 19.405.010(6).

[38] RCW 19.405.010(6).

[39] *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755, Order 10 ¶ 58 (Aug. 23, 2022).

[40] *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755, Order 10 ¶ 58 (Aug. 23, 2022).

26 The Company has argued that a transfer of its ownership rights in Colstrip Units 3 and 4 is a retirement under RCW 19.405.030(3) and is the type of transfer the Legislature had in mind when the statute was drafted.[41] PSE argues that it has done exactly what the statute intended and because the "long-lived plant will be retired by PSE upon transfer of ownership . . . the Commission must allow the cost to invest in that plant to be recovered either directly or indirectly in rates, as the law requires."[42] PSE alleges that this treatment applies to 2024 and 2025 plant additions, which will become unrecovered plant as of December 2025.[43]

27 NWEC argues that the Commission should apply the dictionary definition of "retirement" so that in the context of this case, retirement would mean that Colstrip ceases to produce electricity. To support its contention that the Company interprets "retirement" similarly to NWEC, NWEC points to PSE's Colstrip FACTS Frequently Asked Questions webpage, in which PSE states that "there are no plans to retire Colstrip Units 3 & 4" and that only Units 1 and 2 have been.[44] Further, NWEC contends that RCW 19.405.030(3) does not apply to PSE's investments in Colstrip Units 3 and 4 because the statute intended a "financial assurance" that if a company retires a fossil fuel generating resource, as in the resource is no longer working and causing pollution, shareholders would not be asked to write off undepreciated investment.[45] Specifically, NWEC takes the position that CETA intended to incentivize companies to retire fossil fuel plants and that it does not apply to investments that extend the life of the plant beyond 2025.[46] NWEC supports this assertion by noting that "those financial incentives were carefully written in the past tense, so that they only apply after the plant 'has been retired from service.'"[47] Because Colstrip Units 3 and 4 will continue to operate beyond 2025, NWEC argues that they will not be retired as intended by CETA, so RCW 19.405.030(3) does not apply to this proceeding.[48]

28 In applying the language of RCW 19.405.030(3)(a), NWEC contends that "termination or expiration of any ownership" does not independently constitute retirement and that the

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[41] Steuerwalt, Exh. MS-1T at 8:13-16.

[42] Steuerwalt, Exh. MS-1T at 8:13-19.

[43] Steuerwalt, Exh. MS-1T at 8:19-20, 9:1-2.

[44] McCloy, Exh. LCM-1T at 6:6-8.

[45] McCloy, Exh. LCM-1T at 6:11-14.

[46] McCloy, Exh. LCM-1T at 6:14-21.

[47] McCloy, Exh. LCM-1T at 6:20-21, 7:1.

[48] McCloy, Exh. LCM-1T at 7:1-6.

statute lists causes of retirement and does not "define or alter the plain meaning of the word retired."[49] Similarly, NWEC alleges that section (3)(b) of the statute that allows "such treatment if the retirement of the facility is in the public interest[]" does not apply because Colstrip Units 3 and 4 have not been retired, but even if they had, life extending investments are not prudent nor in the public interest [50]

29 Additionally, NWEC argues that CETA requires electric utilities to "eliminate coal-fired resources from their 'allocation of electricity' by December 31, 2025," but "makes an explicit exception for decommissioning and remediation costs."[51] NWEC interprets this to mean that "CETA did not authorize the recovery of undepreciated investment in fossil resources that remain in-service beyond December 31, 2025."[52]

30 Public Counsel takes a similar position to NWEC and argues that Colstrip Units 3 and 4 will not be retired as intended by RCW 19.405.030(3) after December 31, 2025.[53] Further, Public Counsel alleges that RCW 19.405.030(3) does not apply to this proceeding and the Commission should construe the word "retire" according to its plain language meaning, in which case there are no identifiable retirement dates for Colstrip Units 3 and 4.[54]

31 In response to NWEC's assertion that retirement means "cease to work", PSE asserts that NWEC has misapplied the definition of "retire" and that the "accounting definition of retire related to physical assets that is more relevant here."[55] Specifically, PSE contends that an accounting definition is more appropriate and what was contemplated in the legislation because the statute references "depreciation schedules" which utilize the accounting definition of "retirement."[56] PSE offers two accounting definitions of retirement:

> (1) . . . that asset is no longer under the control of that entity . . . [57] , and

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[49] McCloy, Exh. LCM-1T at 7:11-21.

[50] McCloy, Exh. LCM-1T at 8:3-6.

[51] Cebulko, Exh. BTC-1CT at 10:17-20, 11:1-2.

[52] Cebulko, Exh. BTC-1CT at 11:2-6.

[53] Dreyer, Exh. JMD-1CTr at 4:12-18.

[54] Dreyer, Exh. JMD-1CTr at 4:12-16.

[55] Free, Exh. SEF-1T at 2:15-19, 3:1-3.

[56] Free, Exh. SEF-1T at 3:13-17; RCW 19.405.030(2).

[57] Free, Exh. SEF-1T at 4:3-17 (*citing* the master glossary of the Financial Accounting Standards Board's (FASB) Accounting Standards Codification, and Generally Accepted Accounting Principles (GAAP), that defines "retirement" as: "The other-than-temporary removal of a long-lived asset from service. That term encompasses sale, abandonment, recycling, or disposal in some

(2) Retirement of a tangible asset (retirement encompasses its sale, abandonment, recycling or disposal in some other manner) . . .[58]

PSE argues that NWEC's definition of "retire" as "cease to work" is not found within the CETA statute and that NWEC's interpretation "ignores its plain language, and it utilizes a general dictionary definition rather than the specific accounting and regulatory framework that governs utility asset treatment."[59] Further PSE explains that the Financial Accounting Standards Board (FASB) as the authoritative Generally Accepted Accounting Principles (GAAP) source, controls over dictionary definitions in a regulatory context.[60] PSE further asserts that under RCW 19.405.030(3)(a) the term retirement includes "termination or expiration of any ownership"[61] and that the Commission should not be swayed by the restrictions NWEC places on the term retirement as it is used in the statute. [62]

32 The Company argues that CETA intended for coal to be retired from a utility's portfolio with the "financial assurance that shareholders would not be asked to write-off any undepreciated plant investment."[63] The Company asserts that the Legislature expressly included the termination or expiration of ownership to be a cause of retirement and did not include physical cessation of generation as a condition.[64]The Company contends that the central mandate of CETA is to eliminate coal-fired resources from a utility's "'allocation of electricity' by December 31, 2025."[65] To support this contention, the Company asserts that by referencing CETA's use of "depreciation schedules" and "books of account" the Legislature intended for an accounting definition of "retire."[66] The Company also referred to the definition of retirement under Generally Accepted Accounting Principles and by the

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other manner. However, it does not encompass the temporary idling of a long-lived asset. After an entity retires an asset, that asset is no longer under the control of that entity, no longer in existence, or no longer capable of being used in the manner for which the asset was originally acquired, constructed, or developed." https://asc.fasb.org/MasterGlossary).

[58] Free, Exh. SEF-1T at 4:9-17 (*citing* the definition for "retirement" as used by the State of Washington, Office of the Washington State Auditor).

[59] Free, Exh. SEF-1T at 5:1-9.

[60] Free, Exh. SEF-1T at 5:7-9.

[61] Steuerwalt, Exh. MS-1T at 9:18-20; RCW 19.405.030(3)(a)

[62] Steuerwalt, Exh. MS-1T at 9:23-24, 10:1-5.

[63] Brief of PSE at 8 ¶ 17.

[64] Brief of PSE at 8-9 ¶ 18.

[65] Brief of PSE at 9 ¶ 18.

[66] Brief of PSE at 9 ¶ 19.

Washington State Auditor to support CETA's intent for the accounting definition to be used to interpret the term "retire."[67]

33 Public Counsel argues, first, that the Commission should look to the plain language to interpret the word "retirement" in the CETA statute, which is not the accounting definition. Next, Public Counsel emphasizes that the Commission should look to the complete statute and that CETA is concerned with eliminating coal-fired power from Washington's electricity supply and that the primary concern is not depreciation schedules. Using these methods of statutory interpretation, Public Counsel construes "retirement" as used in CETA to mean "end of working life of coal-fired power."[68] The language of RCW 19.405.030(3) allows for recovery of an investment ". . . in a fossil fuel generating resource that has been retired from service . . ." which Public Counsel argues, gives utilities the opportunity to recover on their investments at the time CETA was enacted rather than allowing "companies to accrue millions of dollars of additional life extending costs after CETA was enacted only then to administratively 'retire' the assets on December 31, 2025[.]"[69] Public Counsel stresses that the plain language and spirit of CETA is to provide cost recovery to Washington utilities that close plants, not for transferring assets.[70]

34 In response to the Company's arguments, NWEC asserts "that allowing recovery of undepreciated investment only in fossil resources that *actually cease operations* was 'intended to remove a disincentive for PSE and other Washington owners to retire fossil plants.'"[71] Similar to Public Counsel, NWEC explains that the financial incentives to retire fossil plants were "'carefully written in the past tense' to reflect the Legislature's intention" that recovery of undepreciated investment only occur if the plant "ceased operations."[72]

Commission Determination

35 To understand what the Legislature meant by the word "retire" in CETA, we look to the canons of statutory interpretation. Although NWEC argues that the starting point to interpret a statutory term is to look to its "plain language and ordinary meaning", a technical term should be given its technical meaning rather than its general purpose

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[67] Brief of PSE at 9 ¶ 19; Free, Exh. SEF-1T at 4:3-17.

[68] Brief of Public Counsel at 16 ¶ 50.

[69] Brief of Public Counsel at 16-17 ¶ 52; RCW 19.405.030(3).

[70] Brief of Public Counsel at 16-17 ¶ 52.

[71] Brief of NWEC at 3-4 ¶ 9 (*citing* McCloy, Exh. LCM-1T at 6:14-16).

[72] Brief of NWEC at 3-4 ¶ 9 (*citing* McCloy, Exh. LCM-1T at 6:20-21, 7:1).

dictionary definition.[73] NWEC has provided a narrow scope for defining the term "retire" for the purposes of statutory interpretation and has not considered a technical meaning. In this case, we must also consider "the context of the statute in which that provision is found, related provisions, and the statutory scheme as a whole."[74] Further, we also consider "'all the terms and provisions of the act in relation to the subject of the legislation, the nature of the act, the general object to be accomplished and consequences that would result from construing the particular statute in one way or another.'"[75]

36 Although NWEC has maintained its position that the Commission should apply the dictionary and plain language meaning to the word "retire", NWEC looks to RCW 19.405.010(2) to provide context to the statute. However, RCW 19.405.010(2) refers to transforming Washington's electrical system, which will be accomplished even if Colstrip Units 3 and 4 cease to operate. The Company argues that the statute refers to depreciation schedules to provide context to the intent of the Legislature, and that this is an accounting term. Further, the Company contends that CETA allows for recovery of undepreciated investment when the retirement is caused by the termination or expiration of ownership which demonstrates the Legislature's intent that retirement not be narrowly construed to only mean that the plant is no longer in operation.

37 The Company provided two sources for the accounting definitions for the word "retirement" to guide the Commission in interpreting CETA and identifying whether the Company is able to recover undepreciated investments in Colstrip Units 3 and 4 under RCW 19.405.030(3). Because the statute references depreciation schedules and books of account, the Company has provided the definition used by GAAP, which we find to be a credible source in determining the technical definition of "retire" because it provides the definition as used in regulatory accounting. Further, the Company provides the definition of "retirement" used by the Washington State Auditor's Office, which also considers retirement to be when an asset is no longer controlled by the entity, or controlled by another entity. The Company argues that Colstrip Units 3 and 4 will be retired for PSE under both of these definitions as of January 1, 2026, thus the provisions of RCW 19.405.030(3) apply, and permit the Company to recover its undepreciated investments in Colstrip Units 3 and 4.

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[73] *Tingey v. Haisch,* 159 Wn.2d 652, 658 (2007).

[74] *Taylor v. Burlington N. R.R. Holdings, Inc.*, 193 Wn.2d 611, 614 (2019).

[75] *Burns v. City of Seattle,* 161 Wn.2d 129, 146 (2007) (*citing State v. Krall,* 125 Wn.2d 146, 148 (1994) and *State v. Huntzinger*, 92 Wn.2d 128, 133 (1979)).

38 Because CETA is a relatively new statute without much context and related provisions to help us understand what the Legislature intended with the word "retire", we also consider the object to be accomplished by CETA, which is, among other things, to remove coal-fired resources from Washington's electricity supply by the end of 2025, and perhaps more importantly, the impacts of construing the statute one way or another. Public Counsel has argued that CETA intends to provide incentives to utility companies to close coal-fired plants, which Public Counsel argues is demonstrated by the use of past tense, which means the Company cannot recover any undepreciated investments until after the coal-fired plants are no longer operational. Public Counsel further argues that CETA could not have intended for companies to accrue millions of dollars of additional life extending costs after CETA was enacted only to then transfer the plants rather than fully decommission them. However, we have concerns when we look to the reality of the position the Company is placed in if CETA required it to fully decommission Colstrip Units 3 and 4.

39 The Company is required to maintain the plants and fulfill its contractual obligations to other entities. The Company would be faced with the impossible scenario where CETA requires it to not invest in the plants and to not meet its contractual obligations, which could result in a situation where the Company is required to turn to the market to provide power at a much higher cost to customers. The alternative for the Company is to invest in the plant to ensure its safe and reliable operation until it no longer owns its portion of the plant and meet its contractual obligations, but then to absorb the costs to maintain the plants. We are not persuaded that the Legislature intended for electric utility companies to be responsible for the costs to maintain coal-fired plants to provide electricity to Washington customers and then fully decommission coal-fired plants by the end of December 31, 2025.

40 First, we must determine whether the Company can recover undepreciated investments under RCW 19.405.030(3). NWEC and Public Counsel have both argued that because Colstrip Units 3 and 4 will still be operational as of January 1, 2026, the plant will not be retired by the end of December 31, 2025, and the Company cannot recover its undepreciated investment in the plant. The Company has argued that the Legislature intended the accounting definition of "retire" to apply because the statute references depreciation schedules, books of accounts, and sets a condition of retirement to include termination or expiration of ownership. We find this argument persuasive when we look at the context of the statute. We also agree that the Legislature expressly identified termination or expiration of ownership, but did not include language specifically requiring coal-fired plants to no longer be operational, and find this persuasive in demonstrating that the Legislature intended for an accounting definition of the word "retirement." We do not

agree with NWEC and Public Counsel that the Legislature intended a dictionary definition for the word "retirement" because the statute calls for a technical definition.

41 Next, we consider that the purpose of CETA is to remove coal-fired electricity from Washington's electricity supply by the end of December 31, 2025. That is still accomplished if Colstrip Units 3 and 4 are transferred to NorthWestern and are no longer providing electricity in Washington, even if the plants are not entirely shut down. We have great concern about interpreting RCW 19.405.030(3) to mean the Colstrip Units must cease to operate in order for the Company to recover the investments it made into the plant for which it had a contractual obligation to maintain. If we decide otherwise the Company shareholders would be left having to absorb all of the investments made, which we do not believe was the Legislature's intent. Colstrip Units 3 and 4 are jointly owned so PSE cannot unilaterally choose to "retire" or decommission the plant. Specifically, if the Company had not invested in the maintenance of the plant, the Company would have been in breach of its O&O Agreement with its co-owners and would have had to turn to the market for power, which, based on the evidence presented in this case, likely would have been more costly for PSE's customers than maintenance of the plant.[76] For these reasons, we find it reasonable that the accounting definition should apply in the interpretation of RCW 19.405.030(3). As the Company is under contract to transfer its interest in Colstrip Units 3 and 4 on January 1, 2026, we find that PSE will have retired coal-fired electricity from its electrical supply in Washington and that RCW 19.405.030(3) does not preclude the Company from recovering at least some of the undepreciated investments in Colstrip Units 3 and 4.

III. Asset Transfer

42 PSE entered into the A&A Agreement with NorthWestern on July 30, 2024, to comply with the CETA requirement to no longer include coal-fired power in its allocation of electricity after December 31, 2025. The A&A Agreement transfers PSE's ownership interest in Colstrip Units 3 and 4 by way of abandonment to NorthWestern without a purchase price at 12:00 a.m. on January 1, 2026, Pacific Standard Time.[77] Public Counsel, NWEC, and AWEC raised concerns about the transfer, primarily that the transfer has no purchase price and has not been reviewed or approved by the Commission.[78] Specifically,

[76] Atwood, Exh. NLA-1T at 16:12-21, 17:5-18; Atwood, Exh. NLA-4.

[77] Mullins, Exh. BGM-3 at 19-20; PSE's Response to BR 3.

[78] See Dreyer, Exh. JMD-1CTr at 7:8-22; Cebulko, Exh. BTC-1CT at 5:17-20; Mullins, Exh. BGM-1T at 2:10-20, 3:1-6.

Public Counsel asserts that the investments PSE seeks to recover in this docket may have been covered with a purchase price.[79] NWEC maintains that the Commission should rule on the prudence of the transfer.[80] AWEC argues that NorthWestern should be obligated to pay a fair value because the capital additions will benefit its customers and not PSE customers.[81] AWEC further contends that PSE could have elected to operate its share of Colstrip as a merchant plant.[82]

43 PSE maintains that its decision to enter into the A&A Agreement transferring its ownership share of Colstrip to NorthWestern was reasonable considering the circumstances confronting the Company at the time that it entered into the agreement. PSE states that at the time it signed the A&A Agreement in July 2024, PSE anticipated substantial costs related to bringing Colstrip into compliance with Mercury and Air Toxics Standards (MATS).[83] PSE asserts that the potential MATS compliance costs ultimately caused its planned transfer of Colstrip to the plant operator, Talen to fail.[84] PSE further argues that the Commission should afford little weight to Public Counsel's questioning of PSE witness Roberts regarding an exemption to MATS compliance, based on the lack of documentary evidence in the record regarding the exemption, contending that prudence is concerned with what the utility knew at the time it made a decision.[85]

44 The Company contends that its decision to transfer its Colstrip ownership interest to NorthWestern for no purchase price was reasonable because the potential MATS compliance obligations rendered Colstrip a value-negative asset.[86] PSE also argues that the CETA deadline to remove coal power from the Company's allocation of electricity undermined PSE's bargaining leverage because potential buyers knew that PSE was unable

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[79] Dreyer, Exh. JMD-1CTr at 8:1-4.

[80] Cebulko, Exh. BTC-1CT at 5:17-20.

[81] Mullins, Exh. BGM-1T at 2:10-20, 3:1-6.

[82] Mullins, Exh. BGM-1T at 9:3-21.

[83] Brief of PSE at 24 ¶ 43; Roberts, Exh. RJR-1T at 3:18 – 4:8 (noting July 2024 MATS compliance estimates of $459,000,000 to $594,000,000).

[84] Brief of PSE at 24 ¶ 43; Roberts, TR. at 95:9-20.

[85] Brief of PSE at 24 ¶ 43.

[86] Brief of PSE at 25-26 ¶¶ 44-45; Roberts, Exh. RJR-1T at 4:9-18 (stating "no rational purchaser would ascribe positive value to [Colstrip]" and "[Colstrip]'s fair market value was already demonstrably negative, and any attempt to monetize it would have imposed a greater burden on PSE's Washington ratepayers than an outright abandonment.").

to retain long-term ownership in Colstrip.[87] PSE states that its bargaining power regarding Colstrip was further limited by the Company's need to maintain its Colstrip transmission rights, reducing the number of potential acquirers.[88] Based on these factors, PSE maintains that NorthWestern was the only purchaser who was willing and operationally capable of acquiring PSE's Colstrip ownership interest and that PSE's lack of bargaining power, combined with the need to quickly transfer Colstrip ownership, made a no-value transfer prudent under the circumstances.[89] The Company asserts that no other party has demonstrated that another entity was willing to purchase PSE's Colstrip ownership or identified an appropriate selling price that PSE should have acquired.[90] Furthermore, the Company states that the A&A Agreement is not subject to Commission approval pursuant to RCW 80.12.020 because as of December 31, 2025, Colstrip is not necessary or useful in the performance of any PSE duties to the public.[91]

45 PSE argues that AWEC's proposal that PSE could have retained its ownership interest in Colstrip and operated as a merchant plant would be unreasonably risky for the Company and contrary to Washington clean energy policy. PSE states that while it could have conceivably operated its share of Colstrip as a merchant plant, it would not be able to control dispatch or capital project decisions, which creates a risk that PSE would be forced into uneconomical decisions due to its minority ownership share.[92] PSE contends retaining ownership in Colstrip would have required PSE to participate in a new long term coal fuel contract for the plant, which creates risk that the Company would not be able to recover associated fuel costs.[93] The Company further suggests that its net present value (NPV) analysis demonstrates that the primary risk to Colstrip is an outage event that necessitates the acquisition of power at higher costs, and that merchant plant operation increases this risk.[94] PSE also maintains that it could face potential litigation over an attempt to operate

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[87] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 4:20 – 5:15.

[88] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 6:14 – 7:8. *See also* Roberts, TR. at 94:20 – 95:8 (explaining that the first attempted sale of PSE's Colstrip ownership was withdrawn in part because other parties to the proceeding objected to PSE's proposal to sell part of its Colstrip transmission system rights).

[89] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 6:3 – 8:6.

[90] Brief of PSE at 25-26 ¶ 45; Roberts, Exh. RJR-1T at 8:9-18. *See also* Roberts, TR. at 94:20 – 96:22 (explaining that PSE had previously failed to sell or transfer its ownership interest in Colstrip two times prior to entering into the A&A Agreement with NorthWestern).

[91] Roberts, Exh. RJR-1T at 11:3-14.

[92] Brief of PSE at 27 ¶ 48; Roberts, Exh. RJR-1T at 9:3-14.

[93] Brief of PSE at 27 ¶ 48; Roberts, Exh. RJR-1T at 10:4-8.

[94] Brief of PSE at 27 ¶ 48; Atwood, NLA-11T at 14:7-12.

Colstrip as a merchant plant because its incorporation agreements prohibit the Company from creating subsidiaries.[95] PSE states that, even if it were able to operate Colstrip as a non-regulated subsidiary, such operation would either only benefit shareholders or lead to potential cost allocation disputes.[96] Finally, PSE asserts that operating Colstrip as a merchant plant would conflict with the intent of CETA and Washington's clean energy policy.[97]

46 NWEC argues that the A&A Agreement between PSE and NorthWestern requires Commission approval pursuant to RCW 80.12.020. NWEC asserts that PSE's argument that Colstrip will no longer be necessary or useful in its duties to the public as of December 31, 2025, is circular, because PSE is abandoning Colstrip to NorthWestern as of the date of that agreement and suggests that if PSE's interpretation is correct, then every abandonment agreement would evade Commission review.[98] NWEC contends that, even if PSE's interpretation is correct, the Commission is still required to approve the agreement because PSE agreed to align its voting with NorthWestern as part of the A&A Agreement.[99] While NWEC states that it is not asking the Commission to void the A&A Agreement, it maintains that the Commission should not allow PSE to both avoid review of the A&A Agreement and fully recover costs that allow Colstrip to continue operating beyond December 31, 2025.[100]

47 AWEC argues that the Commission has authority to review the A&A Agreement pursuant to RCW 80.12.020. AWEC asserts that Colstrip cannot both be a regulatory asset subject to ratemaking treatment and not subject to the Commission's approval under RCW 80.12.020 with respect to its transfer to NorthWestern.[101] AWEC maintains that, if PSE's transfer of Colstrip is not subject to Commission approval, then Colstrip is a merchant power plant that is not eligible for recovery of undepreciated investment under RCW 19.405.030.[102] AWEC contends that it is unreasonable for PSE to request full recovery of its investments in Colstrip while also transferring its ownership of Colstrip to NorthWestern without

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[95] Brief of PSE at 27-28 ¶ 49; Roberts, TR. at 106:15-18.

[96] Brief of PSE at 27-28 ¶ 49; Roberts, Exh. RJR-1T at 9:15 – 10:3.

[97] Brief of PSE at 27 ¶ 47; Roberts, Exh. RJR-1T at 10:9-12.

[98] Brief of NWEC at 11-12 ¶ 27.

[99] Brief of NWEC at 12 ¶ 28.

[100] Brief of NWEC at 12 ¶¶ 29-30.

[101] Brief of AWEC at 3 ¶ 7.

[102] Brief of AWEC at 3 ¶ 7.

Commission oversight.[103] AWEC further cautions against relying on the timing of the Colstrip ownership transfer as a basis to not approve the transaction, as the timing may imply that Colstrip is operating as a merchant plant.[104]

48 AWEC maintains that the Commission should find PSE's reasons for entering into the A&A Agreement unpersuasive and states that if PSE is correct that Colstrip is of no value, then the plant should be immediately retired.[105] AWEC states that PSE's transfer of its Colstrip ownership to NorthWestern at no cost is not supported by economic analysis and is undermined by the decommissioning and remediation obligations that PSE retains under the A&A Agreement.[106] AWEC argues that the A&A Agreement is not in the public interest because it provides no value to Washington customers and requires PSE to surrender its discretion to NorthWestern for the benefit of NorthWestern's ratepayers.[107] AWEC further asserts that PSE could have elected to operate Colstrip as a merchant plant, that the Commission should not find the Company's arguments about the risks of operating Colstrip as a merchant plant persuasive, and that PSE chose to not operate Colstrip as a merchant plant to protect its shareholders.[108]

49 Both AWEC and Public Counsel recommend that the Commission require PSE to submit a separate filing to approve the A&A Agreement.[109]

Commission Determination

50 RCW 80.12.020(1) provides:

> No public service company shall sell, lease, assign or otherwise dispose of the whole or any part of its franchises, properties or facilities whatsoever,

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[103] Brief of AWEC at 3 ¶ 7.

[104] Brief of AWEC at 4 ¶ 8. The Commission declines to consider the testimony filed in another docket cited by AWEC. This evidence is not part of this record in this proceeding and the Commission has already rejected a prior attempt to refer to related testimony that has not been made part of the record. *See WUTC v. Avista Corp*., Docket UE-240891, Order 06 (Sept. 30, 2025) (striking reference to testimony in Docket UE-240729 because the testimony had not been made part of the record).

[105] Brief of AWEC at 5-6 ¶¶ 10-11; Mullins, Exh. BGM-1T at 3:2-4.

[106] Brief of AWEC at 5-6 ¶ 11.

[107] Brief of AWEC at 5-6 ¶ 11; Mullins, Exh. BGM-1T at 7:10-17.

[108] Brief of AWEC at 6 ¶ 12.

[109] Dreyer, Exh. JMD-2CT at 3:11 – 4:12; Mullins, Exh. BGM-1T at 12:21 – 13:3.

> which are necessary or useful in the performance of its duties to the public, and no public service company shall, by any means whatsoever, directly or indirectly, merge or consolidate any of its franchises, properties or facilities with any other public service company, without having secured from the commission an order authorizing it to do so. The commission shall not approve any transaction under this section that would result in a person, directly or indirectly, acquiring a controlling interest in a gas or electrical company without a finding that the transaction would provide a net benefit to the customers of the company.

51 For RCW 80.12.020(1) to apply, the property that a public service company seeks to "sell, lease, assign or otherwise dispose of," must be "necessary or useful in the performance of [the public service company's] duties to the public." Pursuant to RCW 19.405.030(1)(a), each electric utility must eliminate coal-fired resources from its allocation of electricity on or before December 31, 2025, such that the costs and benefits associated with coal resources are removed from the electric utility's retail customer rates.[110]

52 During this proceeding, PSE updated its A&A Agreement to make the transfer of its Colstrip ownership to NorthWestern effective as of 12:00 a.m. Pacific Time, January 1, 2026.[111] As such, PSE's transfer of its Colstrip ownership to NorthWestern will occur after CETA's requirement to remove coal from the Company's allocation of electricity takes effect. Importantly, PSE has preserved its Colstrip transmission rights through the A&A Agreement.[112]

53 In general, every transfer of property that is useful and necessary from a public service company to another entity is subject to Commission approval pursuant to RCW 80.12.020. However, by prohibiting the use of certain resources for service in Washington, CETA has a unique interaction with the transfer of property statute, insofar as CETA effectively makes certain generating resources neither necessary or useful for service after a specific point in time. For coal-fired resources, that point in time is December 31, 2025.[113] Consequently, the Commission determines that the A&A Agreement is not subject to Commission approval pursuant to RCW 80.12.020 because, at the time PSE's Colstrip ownership is transferred to NorthWestern, Colstrip will not be "necessary or useful in the

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[110] *See* RCW 19.405.020(1).

[111] PSE's Supplemental Response to BR 3 (October 2, 2025).

[112] Roberts, Exh. RJR-1T at 6:14-15; Roberts, TR. at 98:15 – 99:1.

[113] RCW 19.405.030(1)(a).

performance of [PSE's] duties to the public," other than the Colstrip transmission rights, which the Company has retained.[114]

54 The Commission is cognizant of the fact that this conclusion is unique and unusual. However, as will be addressed elsewhere in this Order, the fact that the Commission is not reviewing the A&A Agreement for approval does not mean that the Commission will refrain from examining actions taken pursuant to the A&A Agreement under other Commission standards. The Commission's determination that the A&A Agreement is not subject to review because Colstrip's generation will not be necessary or useful in the performance of PSE's duties to the Washington public is consistent with RCW 19.405.030(3)'s requirement that coal-fired resources be removed from PSE's allocation of electricity. Moreover, the Commission is not without recourse to fashion alternative review mechanisms pursuant to its statutory duty to regulate in the public interest.[115]

55 In order to facilitate future review of the transfer of property that will become unable to serve Washington customers in the future due to the requirements of CETA, including but not limited to RCW 19.405.030-.050, the Commission shall require PSE to comply with the following condition:

> Going forward from the date of this Order, where PSE executes an agreement transferring assets for the purpose of complying with a requirement in CETA, PSE must file that agreement with the Commission for review and, if deemed necessary by the Commission, approval within five days of entering into the agreement, even where the resource may no longer be necessary or useful in the performance of its duties to the public by operation of CETA. In its review of the agreement, the Commission will consider whether the agreement is consistent with the public interest and equity concerns of CETA.

56 As the Commission has determined that the A&A Agreement is not subject to approval under RCW 80.12.020, it is unnecessary to resolve the arguments regarding whether PSE could have operated its portion of Colstrip as a merchant plant. However, the Commission observes that PSE presented credible evidence that the Company faced financial and legal risks if it elected to operate Colstrip as a merchant plant, PSE had a difficult bargaining position with respect to Colstrip, and PSE had made previous efforts to transfer its Colstrip

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[114] *See also* Mullins, Exh. BGM-1T at 10:7-12 ("If the transaction occurs prior to 12:00 Midnight on January 1, 2026, the deadline to remove coal from rates, then the transaction must, without question, be considered to involve utility plant subject to the property disposition requirements. If it occurs after 12:00 Midnight on January 1, 2026, then the transaction could potentially, but not necessarily, be viewed as a transaction of a merchant plant not subject to the approval process.").

[115] RCW 80.01.040.

ownership prior to the A&A Agreement.[116] Furthermore, insofar as CETA prohibits the cost and benefits from coal-fired resources to be included in retail electric customer rates, it is unclear how the operation of Colstrip as a merchant plant would have any direct or indirect value to PSE's Washington customers. There is no analysis in the record before the Commission regarding what those benefits could be, and the Commission will not presume that such benefits exist in the absence of supporting evidence. Finally, issues regarding decommissioning and remediation costs are not properly before the Commission in this case and will be reviewed in a later proceeding when such costs are proposed for inclusion in rates.

IV. Investments in Colstrip

57 As an initial matter, the discussion of PSE's Colstrip investments is somewhat complicated by the fact that different parties propose different categorizations of investments based on their respective positions. While there is some overlap between the parties' organization of investments and issues, the parties' organizations do not necessarily follow a uniform pattern. Therefore, the Commission will proceed by giving a brief overview of the parties' various positions and identify what assets each party has grouped under their respective categories in the interest of clarity.

PSE – Initial Position

58 PSE states that the purpose of this filing is to seek a determination of prudence and cost recovery for capital investments placed into service in 2024 through Schedule 141COL that are currently subject to refund.[117] PSE explains that it attempted to avoid including any capital investments that were expected to close in 2025 to minimize forecasting, although its filing does contain four projects that had closings in 2024 that are anticipated to be in service in 2025.[118] The Company further indicates that a final reporting of capital

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[116] Roberts, Exh. RJR-1T at 3:19 – 8:6, 9:3 – 10:8; Roberts, TR. at 94:20 – 96:22. However, the Commission expresses concern that PSE omitted the fact that Colstrip had received an exemption to the MATS compliance obligations from its testimony. Roberts. TR. at 90:1-3. ("Q: Okay. And Colstrip received an exemption from the EPA's MATS, correct? A: After the abandonment agreement was reached, yes."). The Commission expects a greater degree of candor from the utilities that it regulates, and the lack of documentation regarding the MATS exemption for Colstrip is unavailing when PSE's own witness verified that an exemption had been granted. A lack of forthrightness may subsequently impact a party's credibility before the Commission.

[117] Atwood, Exh. NLA-1T at 2:7-11, 5:22-23.

[118] Atwood, Exh. NLA-1T at 5:23-25 fn. 11. *See also* Atwood, Exh. NLA-5C; Cebulko, Exh. BTC-1CT at 19:6-11 (identifying the four projects with 2025 in service dates as (1) U4 Generator Exciter; (2) Replacement 3X3 Startup Transformer; (3) 3-5 Feedwater Heater; and (4) Northern Cheyenne AAQ System).

investments that are placed into service beyond the investments included in this filing will be made in its annual reports filed on or before September 30, 2025, and in 2026 after PSE has applied unrecovered plant against Production Tax Credits (PTC).[119]

59 PSE further argues that it has demonstrated that the costs the Company seeks to include in rates are prudent. The Company argues that it has demonstrated the need for its Colstrip investments based on its contractual obligations, the Colstrip operator's evaluation of the plan and cost benefit analysis, and the relatively high cost of replacement power.[120] The Company asserts that its decision to vote "no" on certain 2024 Colstrip budget items reflects PSE's attempt to consider alternatives to further capital additions, but that it cannot control the budgeting process based on its minority ownership share in Colstrip.[121] PSE further testifies that it coordinated with and kept its management reasonably informed about the investments at Colstrip.[122] Finally, PSE states that it has provided relevant contemporaneous documentation regarding the Colstrip costs in this proceeding.[123]

Staff

60 Staff does not challenge PSE's recovery of three categories of costs associated with Colstrip, totaling 25 projects. First, Staff does not contest ten projects with de minimis costs, defined by Staff as projects included in the Colstrip tracker that were less than $50,000, because these projects are not likely to have a material impact on rates.[124] Second, Staff does not challenge six projects associated with human health and safety concerns because "Staff accepts that the near-term benefits of those projects exceed the costs of the investments."[125] Third, Staff declines to challenge seven routine maintenance projects with

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[119] Atwood, Exh. NLA-1T at 6:1-5.

[120] Atwood, Exh. NLA-1T at 7:10 – 8:11, 10:17 – 11:9, 14:15 – 15:6; Exh. NLA-7C.

[121] Atwood, Exh. NLA-1T at 16:10 – 18:19.

[122] Atwood, Exh. NLA-1T at 20:8-17.

[123] Atwood, Exh. NLA-1T at 21:1-8; Exh. NLA-7C; Exh. NLA-10C.

[124] McGuire, Exh. CRM-1T at 8:1 – 9:5. Staff further explains that while at least one other project, the Northern Cheyenne AAQ system, met Staff's criteria for de minimis projects, Staff is contesting that project because the Company has not demonstrated that it is used and useful for service. McGuire, Exh. CRM-1T at 8:7-12. Staff states that the 10 de minimis projects consist of: (1) Opacity Monitor Replacement; (2) PLC to DCS Obsolescence; (3) Paste Plant Overflow Structure Mod; (4) Mercury Monitor Replacement U3; (5) Mercury Monitor Replacement U4; (6) River Pump Motor; (7) Boiler Feed Pump Rebuild; (8) PA Fan Motor Rewind; (9) Boiler Feed Booster Pump; and (10) Motor Circ Water Pump Cap. McGuire, Exh. CRM-1T at 8:14-20.

[125] McGuire, Exh. CRM-1T at 9:9 – 11:5. Staff identifies the six human health and safety projects as: (1) Switchgear modification; (2) U4 Boiler Snubber Rebuild; (3) Coal Pipe Replacement; (4) U4

an expected service life of four years or less,[126] reasoning that the Commission has previously distinguished between life-extending investments and routine capital maintenance and arguing that routine capital maintenance may be more appropriate for inclusion in rates.[127] Staff confirms that all of the projects that it is not contesting were placed into service during 2024.[128]

61 Staff challenges 13 of the 38 projects that PSE seeks to recover in this proceeding across three categories of assets.[129] First, Staff argues that the Commission should disallow one project related to the SmartBurn NOx Control System.[130] Second, Staff contends the Commission should disallow two projects that will not be used and useful in Washington in 2025.[131] Third, Staff asserts that the Commission should prorate ten projects that represent investments in long-lived plant.[132]

Projects Not Used and Useful

62 Staff maintains that the Commission should disallow recovery of the Unit 4 Generator Exciter and Northern Cheyenne AAQ System because the Company has not demonstrated that those investments are used and useful for service in Washington. Staff asserts that PSE has only identified estimated in-service dates for these two capital projects, which is insufficient to establish that the capital assets will be used and useful in Washington.[133]

Hot Reheat Elbow Replacement; (5) U4 Boiler Scaffolding; and (6) U4 Boiler Elevator. McGuire, Exh. CRM-1T at 9:15-20.

[126] McGuire, Exh. CRM-1T at 12:3-7 (identifying the routine maintenance projects as: (1) U4 Auxiliary Turbine Overhaul; (2) U4 Turbine/Generator Base Overhaul; (3) U4 Boiler Coutant Bottom; (4) U4 Air Preheater Basket Replacement; (5) U4 Boiler Waterwall Replacement; (6) U4 Boiler Economizer Tube Replacement; and (7) U4 Air Preheater Seal Replacement).

[127] McGuire, Exh. CRM-1T at 11:9 – 13:3. Staff further clarifies that while 18 of PSE's projects met its criteria for routine maintenance, 11 of the projects either have de minimis costs (four projects), were human health and safety projects (four), or were related to SmartBurn (three). McGuire, Exh. CRM-1T at 11:16 – 12:2. Staff subsequently revised its position and determined that two of the three investments that were originally categorized as SmartBurn should be recovered in full through rates as expenses related to routine maintenance. Brief of Staff at 5 ¶ 13.

[128] McGuire, Exh. CRM-1T at 7:17-20.

[129] McGuire, Exh. CRM-1T at 6:19 – 7:3.

[130] Brief of Staff at 3 ¶ 9.

[131] McGuire, Exh. CRM-1T at 13:11-12.

[132] McGuire, Exh. CRM-1T at 13:13-15.

[133] Brief of Staff at 6-7 ¶ 15; Atwood, Exh. NLA-11T at 19:15-20 (*citing* Atwood, Exh. NLA-14); Atwood, TR. at 77:10 – 79:12.

Alternatively, Staff argues that, if the Company demonstrates that these projects are in service after the close of evidence in this proceeding, the Commission should only allow a prorated portion of those investments into rates based on the length the projects are in service prior to the CETA cut-off relative to the total service life of the assets.[134]

63 Staff further disagrees that the Commission's Used and Useful Policy Statement supports PSE's argument for full recovery of the capital investments in this proceeding. Staff contends that simply because the capital investments may be used and useful for some time prior to CETA's requirement to remove coal power from PSE's allocation of electricity does not mean that PSE is entitled to recover the full cost of the investment.[135] Moreover, Staff states that allowing PSE to recover costs in rates associated with projects in service after 2025 would be unreasonable and contrary to Washington law.[136] Staff further argues that it is not unfair for the Commission to require PSE to pay for costs that it is obligated to pay under its O&O Agreement, because PSE, rather than the ratepayers, had full control over whether to enter such an agreement and there is nothing unfair about requiring PSE to honor its contractual commitments.[137]

Long-Lived Plant Assets

64 Staff contends that the Commission should prorate the costs associated with ten long-lived assets because PSE has not demonstrated that the ten long-lived assets were prudent and not life extending.[138] First, Staff asserts that while the investments provide some benefit to Washington customers, the investments will not be able to provide the full benefit associated with their respective useful lives due to CETA's prohibition on coal power in PSE's allocation of electricity.[139] For support, Staff refers to the Commission's final order in Avista's 2020 GRC, where the Commission rejected Avista's request to recover costs of its Dry Ash Disposal Project because Avista had not shown that the project was not life-

[134] Brief of Staff at 6-7 ¶ 15.

[135] Brief of Staff at 7-8 ¶ 16.

[136] Brief of Staff at 7-8 ¶ 16.

[137] Brief of Staff at 8 ¶ 17.

[138] Brief of Staff at 8-9 ¶ 19 fn. 37 (identifying the ten long-lived assets as: (1) CEM Monitor replacement for U4; (2) Scrubber Chiller replacement; (3) Windows 11 Workstation Upgrades; (4) CRO Simulator replacement, (5) Mobile Equipment replacements for 2024; (6) Replacement 3x3 Startup Transformer; (7) 3-5 Feedwater Heater; (8) Vehicle replacements for 2024; (9) EHP G Cell Liner Purchase; and (10) Cooling Tower Fill replacement for U4).

[139] Brief of Staff at 10 ¶ 22.

extending.[140] Staff maintains that because CETA prohibits coal in the Company's allocation of electricity beginning in 2026, the Company should only be authorized to recover a proportional share of costs associated with long-lived assets because they will only benefit Washington customers for a portion of their overall useful life.[141]

65 Second, Staff argues that PSE has not demonstrated a need for the ten long-lived investments. Staff notes that even though PSE voted against several capital additions during the Colstrip budgeting process, which indicates a lack of need, the Company is nonetheless seeking full recovery of those investments in this proceeding.[142] According to Staff, although PSE was obligated to pay for its proportional share of approved investments pursuant to the O&O Agreement, the existence of the agreement is not determinative as to the need for a particular investment.[143] Staff further contends that the lack of discretion to fund approved budget items under the O&O Agreement is insufficient to demonstrate need and that PSE's decision to vote against including certain long-lived assets in the Colstrip budget shows that such investments were unnecessary.[144]

66 Third, Staff maintains that PSE has not identified a valid cost-benefit analysis demonstrating that the projects are likely to produce sufficient benefits relative to the costs of the projects. Staff argues that the Commission's prior decisions in PacifiCorp's 2005 GRC and Avista's 2015 GRC establish that a utility must provide a cost-benefit analysis that quantifies tangible and intangible benefits to demonstrate that an investment is prudent.[145] Staff notes that PSE testified that whether benefits exceed costs is a relevant consideration for utility management when choosing to pursue investments and that such analysis should be from the perspective of Washington ratepayers.[146]

67 Staff also contends that, while PSE did provide a NPV calculation to demonstrate that the Company considered the costs and benefits of investments, the NPV analysis is flawed because it assumes a 100 percent probability of asset failure that will result in an outage if

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[140] Brief of Staff at 10 ¶ 23 fn. 46 (*citing WUTC v. Avista Corp*., Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 100 ¶ 279 (Sept. 27, 2021)).

[141] Brief of Staff at 11 ¶ 24.

[142] Brief of Staff at 12-13 ¶¶ 27-28.

[143] Brief of Staff at 12-13 ¶ 27.

[144] Brief of Staff at 13 ¶ 28.

[145] Brief of Staff at 13-14 ¶ 30 (*citing WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 69 ¶ 193 (Jan. 6, 2016); *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 27-28 ¶ 68 (Apr. 27, 2006)).

[146] Brief of Staff at 15 ¶ 32 (*citing* Atwood, TR. at 37:17-21, 38:4-7).

the investment is not pursued.[147] Staff asserts that assuming a 100 percent probability of failure if a replacement is not acquired overstates the actual probability of failure, thereby artificially increasing the benefits associated with a particular investment.[148] Staff states that PSE is unable to identify the actual probability of failure because Talen does not model the probability of failure.[149] Staff also states that PSE's NPV analysis is unreasonable because it is not from the perspective of Washington ratepayers.[150] Staff further maintains that PSE has not adequately supported its assertion that the cost of short term power would exceed the cost of further capital investment in Colstrip.[151] Finally, Staff argues that PSE has not demonstrated that it adequately presented data to management regarding decisions to pursue investments at Colstrip.[152]

SmartBurn

68 Staff initially recommended that the Commission disallow recovery of the Unit 4 Boiler Burner AuxAir Replacement (Boiler Burner), the Unit 4 separated air over fire (SOFA) Bucket Replacement, and the Unit 4 Top Over Fire Air Bucket Replacement (TOFA), which Staff initially identified as SmartBurn components that were disallowed in PSE's 2019 GRC.[153] However, after receiving PSE's answer to BR 2, Staff revised its recommendation to support recovery for the SOFA and Boiler Burner but to disallow recovery for the TOFA component because it had been previously disallowed in PSE's 2019 GRC as a SmartBurn component.[154]

Public Counsel

69 Public Counsel asserts that PSE's attempt to seek full cost recovery of "life-extending" investments at Colstrip is improper because these investments will support Colstrip operations beyond 2025, after which CETA prohibits inclusion of coal-fired resources in PSE's allocation of electricity. Public Counsel recommends that the Commission broadly prorate all of PSE's 2024 Colstrip investments so that customers only pay for a share of

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[147] Brief of Staff at 15 ¶ 33; McGuire, Exh. CRM-1T at 20:4 - 24:4.

[148] Brief of Staff at 15-16 ¶ 34.

[149] Brief of Staff at 15-16 ¶ 34; McGuire, Exh. CRM-4 at 2.

[150] McGuire, CRM-1T at 19:6-10, 20:16 – 21:19.

[151] Brief of Staff at 17-18 ¶ 36.

[152] Brief of Staff at 16-17 ¶ 35.

[153] McGuire Exh. CRM-1T at 3:8-10, 13:22-23, 14:1-2, 14:13-18.

[154] Brief of Staff at 3 ¶ 9.

each plant addition proportional to their share of that plant's additional expected service life prior to the deadline to remove coal-fired resources from rates.[155] Public Counsel further argues that the Commission should entirely disallow the TOFA project related to SmartBurn.[156]

Used and Useful

70 Public Counsel argues that Colstrip will not be used and useful to Washington ratepayers after December 31, 2025, and that costs associated with capital additions related to Colstrip operations after that date must be excluded from rates. Stated another way, Public Counsel contends that Colstrip "capital additions can only be placed into rates to the extent they were in service to Washington customers through the end of 2025."[157] Public Counsel maintains that while the Legislature modified the Commission's ratemaking authority when it enacted CETA to allow the Commission to consider rate base that will be used and useful up to 48-months after the rate effective date, the assets must still be capable of being used for service in Washington to be included in rate base.[158]

Life-Extending Investments

71 Public Counsel states that PSE has failed to demonstrate that its investment in life-extending capital additions to Colstrip were prudent. Public Counsel argues that several capital additions that extend the useful life of Colstrip beyond December 31, 2025, when Colstrip can no longer provide coal power to PSE's Washington customers, are unreasonable and therefore imprudent.[159] Public Counsel further asserts that including costs associated with Colstrip capital assets in service beyond 2025, when Washington customers cannot benefit from those assets, results in rates that are not fair, just, reasonable, and sufficient. Public Counsel contends that including the full costs of PSE's Colstrip investments is unfair because they cannot benefit Washington customers after 2025, unjust because inclusion is contrary to CETA and the used and useful principle, and unreasonable because Colstrip provides no value to Washington customers and is harmful to the

[155] Dreyer, Exh. JMD-1CTr at 5:19 – 6:6. *See also* Dreyer, Exh. JMD-2CT at 5:1-7 (supporting AWEC's general proposal to prorate PSE's 2024 capital additions).

[156] Brief of Public Counsel at 23 ¶¶ 69-70.

[157] Brief of Public Counsel at 14-15 ¶ 45.

[158] Brief of Public Counsel at 14-15 ¶¶ 44-45.

[159] Brief of Public Counsel at 18 ¶ 55; Dreyer, Exh. JMD-1CTr at 4:23 – 5:18.

environment.[160] Public Counsel also maintains that the Company has not presented any evidence that allowing only a prorated portion of its Colstrip capital additions into rates will result in insufficient revenue for the Company to continue operating.[161] Based on its above arguments, Public Counsel recommends that the Commission allow recovery of PSE's Colstrip assets on a prorated basis.[162]

SmartBurn

72 Public Counsel recommends that the Commission disallow recovery for all four of the NOx components, including the Boiler Burner, SOFA, TOFA, and Control Room Operator (CRO) because the Commission had previously found SmartBurn to be imprudent.[163] After review of PSE's response to BR 2, Public Counsel maintains its position that SmartBurn investments that were disallowed in PSE's 2019 GRC cannot be recovered in this matter.[164] However, because only the TOFA component was disallowed in the 2019 GRC, Public Counsel now recommends the Commission disallow recovery only of the TOFA investment.

NWEC

73 NWEC makes six general recommendations regarding PSE's Colstrip investments at issue in this proceeding. First, NWEC argues that the Commission should disallow costs associated with projects that extend the life of Colstrip such that it will continue to operate past December 31, 2025.[165] Second, NWEC states that the Commission should disallow

[160] Brief of Public Counsel at 18-19 ¶¶ 57-59.

[161] Brief of Public Counsel at 19-20 ¶ 60.

[162] Brief of Public Counsel at 24-26 ¶¶ 74-80; Dreyer, Exh. JMD-1CTr at 5:19 – 6:6.

[163] Dreyer, Exh. JMD-2CT at 3:4-8.

[164] Brief of Public Counsel at 23 ¶¶ 69-70.

[165] Cebulko, Exh. BTC-1CT at 22:1-10, 25:8-9 (identifying nine life-extending investments as (1) Scrubber Chiller Replacement; (2) CEM Monitor Replacement – U4; (3) Opacity Monitor Replacement; (4) Cooling Tower Fill Replacement U4; (5) Mercury Monitor Replacement – Unit 3; 6) Mercury Monitor Replacement – Unit 4; 7) EHP G Cell Liner Purchase; (8) PLC to DCE Obs. (Water Treatment Conversion); and (9) River Pump Motor). *See also* Brief of NWEC at 4 ¶ 10 (clarifying that NWEC also considers the four projects not used and useful prior to 2025 to also be life extending investments, bringing the total number of life-extending investments that NWEC recommends the Commission disallow to thirteen).

projects that lack a capital justification.[166] Third, NWEC asserts that the Commission should allow PSE to recover only a prorated portion of costs associated with eleven major maintenance projects.[167] Fourth, NWEC contends that the Commission should disallow costs associated with the TOFA and SOFA investments related to SmartBurn.[168] Fifth, NWEC maintains that the Commission should disallow recovery of four investments that were not placed into service in 2024.[169] Finally, similar to Staff, NWEC recommends that the Commission allow full recovery of six projects associated with human health and safety.[170]

Life-Extending Investments

74 NWEC argues that the Commission should not allow PSE to recover costs associated with life-extending investments at Colstrip. NWEC contends that PSE has not demonstrated that 13 life-extending projects are used and useful for service in Washington.[171] NWEC further asserts that the fact that PSE has entered into the A&A Agreement with NorthWestern should not influence the Commission's analysis regarding whether the assets are used and useful.[172] NWEC maintains that PSE's decision to vote against various Colstrip capital additions undermines the Company's assertion that those assets are prudent.[173] NWEC

[166] Cebulko, Exh. BTC-1CT at 26:1-2 (identifying projects lacking capital justification as (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare).

[167] Cebulko, BTC-1CT at 28:15 – 29:1 (identifying major maintenance projects as: (1) Auxiliary Turbine Overhaul U4; (2) Turbine/Generator Base OH U4; (3) Boiler Coutant Bottom U4; (4) Air Preheater Basket Repl U4; (5) Boiler Waterwall Repl/Maint U4; (6) Air Preheater Seal Repl; (7) Workstation Upgrades (Windows 11); (8) Mobile Equipment replacements (2024); (9) Paste Plant Overflow Structure Modifications; (10) Boiler Economizer Tube Repl U4; and (11) Vehicle Replacements (2024)). Seven of NWEC's major maintenance projects are the same as the "routine maintenance" projects identified by Staff. *Compare* McGuire, Exh. CRM-1T at 23:3-7 *with* Cebulko, Exh. BTC-9CT at 8:1.

[168] Brief of NWEC at 8 ¶ 19.

[169] Cebulko, Exh. BTC-1CT at 19:6-11 (identifying the four projects as (1) U4 Generator Exciter; (2) Replacement 3X3 Startup Transformer; (3) 3-5 Feedwater Heater; and (4) Northern Chyenne AAQ System).

[170] *Compare* McGuire, Exh. CRM-1T at 8:14-20 *with* Cebulko, Exh. BTC-1CT at 27:7-8.

[171] Brief of NWEC at 4-5 ¶¶ 11-12. Cebulko, Exh. BTC-1CT at 9:10 – 10:2, 12:10 – 13:6.

[172] Brief of NWEC at 5 ¶ 12.

[173] Brief of NWEC at 5 ¶ 12.

requests that the Commission should articulate a prudence standard that will apply to future investments that extend the life of fossil fuel resources.[174]

Investments Lacking Capital Justification

75 NWEC additionally recommends that the Commission disallow four projects that have no capital justification in the record. NWEC notes that PSE's request for recovery in this case contains four projects that were initially non-capital projects that were subsequently transferred to capital based on financial review that do not have specific capital justification summaries.[175] NWEC inquired further about the justification for these four projects in discovery, but received a similar response from PSE, who indicated that no capital justifications were available.[176] NWEC recommends that the Commission disallow costs associated with these four projects because PSE has neither demonstrated the need for nor provided contemporaneous documentation regarding these projects.[177]

Major Maintenance

76 NWEC also recommends that the Commission prorate major maintenance projects associated with Colstrip capital investments and disallow costs amortized after 2025, consistent with the term in the Settlement Agreement in PSE's 2022 GRC regarding major maintenance, for three reasons.[178] First, NWEC states that plant investments have generally been recovered based on the expected life of the investment, and that prorating recovery of maintenance costs appropriately matches the investments costs with its expected benefits.[179] Second, NWEC contends that allowing full recovery of maintenance costs would conflict with PSE's 2014 and 2022 settlement terms regarding the amortization of major maintenance costs, which provide that major maintenance will be amortized over three years and, in the case of the 2022 settlement, that costs amortized after 2025 will not

[174] Supp. Brief of NWEC at 4 ¶ 11.

[175] Cebulko, Exh. BTC-1CT at 25:13-18 (*citing* Atwood, Exh. NLA-1T at 11:1 fn. 17).

[176] Cebulko, Exh. BTC-7 at 1 (stating for each of the four projects "No Capital Justification available, inspection based work after removal.").

[177] Cebulko, Exh. BTC-1CT at 26:6-8.

[178] Cebulko, Exh. BTC-9CT at 6:1-19; Brief of NWEC at 7-8 ¶ 17 (*citing WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022)).

[179] Cebulko, Exh. BTC-9CT at 6:2-11.

be recovered.[180] Finally, NWEC argues that the NPV analysis overstates the benefits from Colstrip because it overestimates the availability of Colstrip power, fails to consider the cost of capital investments in its comparison of benefits to costs, and improperly assumes that PSE's only reasonable alternative was to purchase replacement power from the market.[181] NWEC supports Staff's argument that the NPV analysis improperly assumes a 100 percent probability of failure in the event that a capital asset is not pursued.[182] NWEC further maintains that the Commission should not rely on the late disclosed analysis provided by PSE in response to BR 1 because that analysis is not risk adjusted and PSE has not shown that it was prepared contemporaneously with its decisions to invest in Colstrip.[183]

SmartBurn

77 NWEC argues that the Company has not provided any new evidence demonstrating that its SmartBurn investments have been prudently incurred.[184] NWEC also raises concerns about the Company requesting relief for an investment that has been previously disallowed by the Commission and alleged that the request places an "undue and significant burden on the Commission and intervenors" as it makes it difficult to obtain a reasonable settlement.[185]

78 NWEC contends that the Company has not provided support that distinguishes the SOFA component from the TOFA component. NWEC raises concern that "the arrows in PSE's schematic[186] identify the same part of the boiler system in attempting to delineate between TOFA and SOFA, making it impossible for the viewer to determine what, if any, difference exists between the TOFA and SOFA components."[187] NWEC recommends that the

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[180] Cebulko, Exh. BTC-1CT at 29:2 – 30:2 (*citing WUTC v. Puget Sound Energy*, Docket UE-141141, Order 04 at 3-5 ¶ 8 (Nov. 3, 2014)); Cebulko, Exh. BTC-9CT at 6:12-17 (*citing WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022)).

[181] Brief of NWEC at 5-6 ¶ 13; Cebulko, Exh. BTC-1CT at 13:15 – 16:16.

[182] Brief of NWEC at 6 ¶ 14 (*citing* McGuire, Exh. CRM-1T at 22:1 – 24:4).

[183] Brief of NWEC at 6-7 ¶ 16.

[184] Cebulko, Exh BTC-1CT at 18:12-15.

[185] McCloy, Exh. LCM-1T at 12:16-20.

[186] The schematic identified by NWEC was filed September 10, 2025, by the Company in response to BR 2 Attachment A and is marked confidential.

[187] Brief of NWEC at 9-10 ¶ 22.

Commission should disallow the SOFA and TOFA components as SmartBurn that has been previously disallowed.[188]

Investments Not Used and Useful in 2024

79 NWEC maintains that the Commission should fully disallow four projects with in-service dates in 2025 because PSE cannot demonstrate that these investments provided benefits to Washington ratepayers in 2024.[189] NWEC asserts that projects that come online on December 31, 2025, will never provide benefits to Washington ratepayers due to CETA's requirement to remove coal-fired resources from the allocation of electricity.[190] NWEC also argues that, if the Commission determines that the four investments not used and useful in 2024 are in fact used and useful, that the Commission should classify the projects as life-extending and disallow recovery of those investments because their useful lives exceed the three to four year useful life for major maintenance projects.[191]

Human Health and Safety Investments

80 NWEC recommends that the Commission allow PSE to recover six projects associated with human health and safety concerns.[192] NWEC states that it has reviewed the project justifications for each of the projects and found that the projects included economic metrics, including such as the internal rate of return and estimated payback period, and verified that the project descriptions supported a safety designation.[193] As such, NWEC recommends full recovery of the six human health and safety projects.[194]

AWEC

81 AWEC recommends that the Commission should prorate PSE's recovery of assets based on the portion of their service life prior to December 31, 2025, because after that date the

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[188] Brief of NWEC at 9-10 ¶ 22.

[189] Cebulko, Exh. BTC-1CT at 19:1 – 20:6. *See also* Cebulko, Exh. BTC-1CT at 19:10-11 (identifying the projects with in service dates in 2025 as: (1) U4 Generator Exciter; (2) Replacement 3X3 Startup Transformer; (3) 3-5 feedwater heater; and (4) Northern Cheyenne AAQ System).

[190] Cebulko, Exh. BTC-1CT at 20:7-13.

[191] Brief of NWEC at 10 ¶ 24.

[192] Cebulko, Exh. BTC-1CT at 26:11 – 27:10.

[193] Cebulko, Exh. BTC-1CT at 27:1-6.

[194] Cebulko, Exh. BTC-1CT at 27:9-10.

assets are not used and useful in Washington and the Commission should disallow costs associated with the previously disallowed SmartBurn investment.

Used and Useful

82 AWEC asserts that the Commission should exclude capital projects that have an in-service date of December 31, 2025, or later under the used and useful standard, because those capital projects will not be used for service during the rate effective period.[195] Additionally, AWEC argues that the Commission should prorate PSE's recovery of life-extending investments, routine maintenance, and human safety projects, because those investments will not provide benefits to ratepayers after 2025.[196] AWEC further contends that a disallowance is appropriate given PSE's decision to enter into the A&A Agreement because the A&A Agreement obligated PSE to invest in life-extending assets that provide minimal benefit to Washington ratepayers.[197] AWEC states that any disallowance should be not be subject to cost recovery by using PTCs.[198]

SmartBurn

83 AWEC recommends that the Commission disallow all capital additions associated with SmartBurn that had been previously disallowed.[199] Specifically AWEC recommends disallowance for previously disallowed SmartBurn investments by a total of $1,039,987, which reflects only a disallowance for the TOFA component.[200]

PSE - Rebuttal

Used and Useful

84 The Company maintains that its capital investments in Colstrip satisfy the Commission's used and useful standard. Specifically, PSE argues that its investments comply with the Commission's Used and Useful Policy Statement and suggests that prorating its investments would be unjust given the Commission's prior approval of the settlement term

[195] Brief of AWEC at 7-8 ¶ 15.

[196] Brief of AWEC at 8-9 ¶ 17.

[197] Brief of AWEC at 4-5 ¶ 9.

[198] Brief of AWEC at 4-5 ¶ 9; Mullins, Exh. BGM-1T at 4:5-9.

[199] Mullins, Exh. BGM-1T at 3:16-18.

[200] Brief of AWEC at 8 ¶ 16; Mullins, Exh. BGM-4C.

related to terminal depreciation of Colstrip assets.[201] The Company further asserts that proration of the Colstrip capital investments would be unfair, because the investments were necessary and provided a benefit to customers.[202] PSE maintains that the proposals to prorate the capital additions in this case contradict the settlement agreement in Dockets UE-170033 and UG-170034, as well as the settlement agreement in Dockets UE-220066, UG-220067, and UG-210918, because those agreements provide for terminal depreciation of the Colstrip assets.[203]

Live-Extending Investments

85 PSE asserts that the NPV analysis included in the Company's filing satisfies the Commission's prudence standard. The Company maintains that the NPV analysis reasonably reflects the costs associated with each project, risks associated with not performing the work, and the reasoning for each project.[204] PSE argues that the risk assessment reflected in the NPV analysis is appropriate because of the comparatively high cost of purchasing replacement power in the event of a temporary shut-down of Colstrip.[205] The Company further contends that, under its O&O Agreement, PSE's failure to pay its portion of Colstrip capital addition costs would have resulted in the Company defaulting on its contract and losing access to its share of electricity from Colstrip.[206] As a result of the threat of default, the Company argues that it effectively faced a 100 percent probability of failure if it failed to pay for its share of Colstrip capital addition costs. PSE further states that the Commission's prudence standard does not require a risk adjusted cost-benefit analysis in the manner proposed by Staff.[207]

Projects Not In Service Before 2025

86 PSE additionally argues that the Commission should allow the Company to recover assets that may not be in service before 2025. PSE suggests that the Commission's Used and Useful Policy Statement supports the Company's argument that the Commission has

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[201] Brief of PSE at 14-15 ¶ 26; Free, Exh. SEF-1T at 6:1 – 8:11, Atwood, Exh. NLA-11T at 18:6 – 19:20.

[202] Brief of PSE at 14-15 ¶ 26; Atwood, Exh. NLA-11T at 2:7-10.

[203] Brief of PSE at 12-14 ¶¶ 23-25; Free, Exh. SEF-1T at 6:1-21.

[204] Brief of PSE at 15 ¶ 27; Atwood, Exh. NLA-1T at 10:17 – 11:9, Exh. NLA-11T at 14:1 – 15:16.

[205] Brief of PSE at 15-16 ¶ 28; Atwood, Exh. NLA-1T at 15:7 – 16:8; Exh. NLA-11T at 14:7-12.

[206] Brief of PSE at 16-17 ¶ 29; Atwood, Exh. NLA-9.

[207] Brief of PSE at 17 ¶ 30; Atwood; Exh. NLA-11T at 11:1 – 13:6.

sufficient flexible authority under RCW 80.04.250 to permit recovery of its investments in the U4 Generator Exciter and Northern Cheyenne AAQ System.[208] The Company states that the Commission's rejection of more restrictive approaches to the inclusion of provisional capital in rates as part of the Used and Useful Policy Statement indicates that the Commission may include capital additions that are not in service by 2025 in rate base.[209]

Major Maintenance

87 PSE argues that the Commission should reject NWEC's argument to prorate or disallow major maintenance capital costs based on PSE's 2014 and 2022 settlements because those settlements do not apply to major maintenance capital costs. PSE maintains that major maintenance events result in two types of costs, capital costs and operations and maintenance (O&M) costs.[210] PSE asserts that the 2014 settlement only pertains to the O&M costs associated with major maintenance events, and that NWEC is attempting to improperly apply that settlement term to major maintenance capital costs.[211] However, while PSE contends that the 2014 settlement term does not apply to the capital maintenance costs, it states that the major maintenance amortization treatment in the 2014 settlement has the same effect as prorating the major maintenance capital costs.[212] PSE further argues that the 2022 settlement term regarding major maintenance amortization only pertains to the amortization of major maintenance O&M costs, not major maintenance capital costs, similar to the 2014 settlement.[213]

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[208] Brief of PSE at 21-22 ¶¶ 38-39; Atwood, NLA-11T at 17:18 – 19:20.

[209] Brief of PSE at 22 ¶ 39.

[210] Free, Exh. SEF-1T at 12:10-11.

[211] Free, Exh. SEF-1T at 13:3-8.

[212] Free, Exh. SEF-1T at 13:14-17 ("In other words – the treatment Mr. Cebulko and parties recommend for pro-rating PSE's capital costs is the same as the major maintenance *amortization* treatment agreed to in PSE's 2014 PCORC. Therefore, no correction to the calculation of Mr. Cebulko's proposed adjustment is needed.") (emphasis in original).

[213] Brief of PSE at 14-15 ¶ 26 fn.61; Free, TR. at 115:25 – 118:8. *See also* Free, TR. at 119:5-14 ("A: I believe that the way my exhibits were laid out in [PSE's 2022 GRC], the contested adjustment was only related to the O&M portion of major maintenance. That's deferred. Not the capital. And we settled that adjustment. So in my mind that makes it clear. Q: All right. So what you're saying is you only settled the operation/maintenance portion, not the capitalized portion? A: Correct.").

SmartBurn

88 The Company is seeking recovery of investments to components of its NOx control system. Specifically, the Boiler Burner, SOFA, and TOFA components of the combustion control system, which are commonly referred to as SmartBurn by the Colstrip operator and within plant budgets.[214] PSE alleges that there has been a misunderstanding as to what is the SmartBurn equipment that was disallowed in PSE's 2019 GRC because SmartBurn is a company and not a singular piece of equipment. [215] For regulatory purposes, PSE clarifies that the only components of the NOx control system that was disallowed as SmartBurn in PSE's 2019 GRC was the TOFA. The SOFA and Boiler Burners existed prior to the SmartBurn technology installation.[216] The Boiler Burner was installed prior to 2007, the SOFA on Unit 3 was installed in 2007, and on Unit 4 in 2009.[217] PSE concedes that the Company incorrectly identified the SOFA, TOFA, and Boiler Burners as SmartBurn in a data request response to Staff.[218] On cross-examination, although the Boiler Management System (BMS) was updated by SmartBurn in 2017, the plant would still need a BMS, regardless of who installed it.[219] PSE is not seeking any recovery related to the BMS in this docket.[220] Atwood alleges that the "CRO Simulator is not specific to the operation of SOFA-installed SmartBurn equipment only" and that the CRO would have been installed without a SmartBurn investment so it should not be disallowed.[221]

89 PSE is seeking recovery for the TOFA SmartBurn component even though it had previously been disallowed because the TOFA is "an integrated part of the Combustion Control system, and the plant cannot run without it."[222] Specifically:

> [t]he pieces of the combustion system work together to operate the Units efficiently by avoiding slagging, maintaining steam temperature, avoiding metal heat fatigue, and other goals, while also maintaining environmental compliance standards. TOFA, SOFA, burners, and other equipment all have to be maintained on a regular basis when in constant contact with heat and

[214] Atwood, Exh. NLA-11T at 4:12-18.

[215] Atwood, Exh. NLA-11T at 5:4-8.

[216] Atwood, Exh. NLA-11T at 5:15-22; Atwood, TR. at 39:21-25; Atwood, Exh. NLA-12.

[217] PSE's Response to BR 2.

[218] Atwood, Exh. NLA-11T at 5:22, 6:1-3; Exh. NLA-7C.

[219] Atwood, TR. at 40:14-20.

[220] Atwood, Exh. NLA-19X at 1.

[221] Atwood, Exh. NLA-11T at 7:3-5, 13-15.

[222] Atwood, Exh. NLA-11T at 6:5-9.

> corrosive conditions. Consequently, PSE should be allowed to recover the investment made in these systems and equipment.[223]

90 PSE argues that its investments in SmartBurn are prudent and are used and useful, and requests that the Commission grant full recovery.[224] Although the Commission previously disallowed the TOFA component, the Company argues that a previous disallowance is not a "blanket, forward-looking" ban and that the Commission should base its decision on the record in this proceeding and asks the Commission to consider whether the SmartBurn investments in "2024 were prudently incurred and confer commensurate benefits to Washington customers in the rate period[.]"[225]

Commission Determination

91 Before investments may be recovered in rates, the Commission must determine that the costs associated with investments a utility seeks to recover are used and useful for service in this state.[226] Similarly, costs may only be included in rates if the Commission determines those investments are prudent.[227] As such, the Commission review of a utility's requested rate recovery encompasses both the question of whether investments are used and useful and the question of whether the associated costs are prudent.[228] The Commission now proceeds to consider whether the investments that PSE has included in rates for recovery are used and useful and then considers whether the costs that it seeks to recover are prudent.

A. Used and Useful

92 RCW 80.04.250 states in part:

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[223] Atwood, Exh. NLA-11T at 6:10-16.

[224] Brief of PSE at 17-18 ¶ 31.

[225] Brief of PSE at 17-18 ¶ 31.

[226] *WUTC v. PacifiCorp,* Docket UE-050684, Order 04 at 21-22 ¶ 50 (Apr. 17, 2006).

[227] *WUTC v. Puget Sound Energy*, Docket UE-031725, Order 14 at 20-21 ¶ 37 (May 13, 2004) ("Any costs determined to be unreasonable or imprudent in such proceedings are subject to disallowance.").

[228] *See also* Policy Statement on Property that Becomes Used and Useful After the Rate Effective Date, Docket U-190531 at 14-15 ¶ 43 (Jan. 31, 2020) ("In sum, this Policy Statement establishes a two-step approval process. The first step involves provisional approval for the inclusion in rates of identified rate-effective period investment. The second step involves final approval after the investments are reviewed and confirmed to be used and useful and prudent.").

> (1) The provisions of this section are necessary to ensure that the commission has sufficient flexible authority to determine the value of utility property for rate making purposes and to implement the requirements and full intent of chapter 288, Laws of 2019.
>
> (2) The commission has power upon complaint or upon its own motion to ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state by or during the rate effective period and shall exercise such power whenever it deems such valuation or determination necessary or proper under any of the provisions of this title. The valuation may include consideration of any property of the public service company acquired or constructed by or during the rate effective period, including the reasonable costs of construction work in progress, to the extent that the commission finds that such an inclusion is in the public interest and will yield fair, just, reasonable, and sufficient rates.
>
> (3) The commission may provide changes to rates under this section for up to forty-eight months after the rate effective date using any standard, formula, method, or theory of valuation reasonably calculated to arrive at fair, just, reasonable, and sufficient rates. The commission must establish an appropriate process to identify, review, and approve public service company property that becomes used and useful for service in this state after the rate effective date.

The Commission further observes that this language reflects amendments the Legislature made during consideration of CETA, and those amendments are found in chapter 288, Laws of 2019, the same legislation that enacted CETA.[229]

93 In interpreting the phrase "used and useful," the Washington State Supreme Court has explained "'Used' is defined as 'employed in accomplishing something'; 'useful' is defined as 'capable of being put to use: having utility: advantageous: producing or having the power to produce good: serviceable for a beneficial end or object.'"[230] The Court further explained "RCW 80.04.250 empowers the Commission to determine, for ratemaking purposes, the fair value of property which is employed for service in Washington *and* capable of being put to use for service in Washington."[231] By extension, "[w]hen calculating a utility's rate base for ratemaking, if the WUTC considers utility plant that 'is neither employed for service nor capable of being put to use for service; . . . such plant is

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[229] See, e.g., RCW 19.405.010 (reflecting the title "Findings – Intent – 2019 c 288").

[230] *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984) (*citing Webster's Third New International Dictionary* 2524 (1976)).

[231] *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984).

not 'used and useful' for service' and the [Commission] exceeds its statutory authority."[232] The Commission has also previously interpreted "the phrase 'used and useful for service in this state' to mean benefits to ratepayers in Washington, either directly (e.g., flow of power from a resource to customers) and/or indirectly (e.g., reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits)."[233]

94 However, the Commission's inquiry regarding the used and useful standard is further informed by the requirements of CETA. Specifically, RCW 19.405.030(1) states that "[o]n or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity. This does not include costs associated with decommissioning and remediation." RCW 19.405.020(1) further defines "allocation of electricity" as, "for the purpose of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state." As such, RCW 19.405.030(1) prohibits a utility from including the benefits and costs associated with coal power in its retail customer electricity rates after December 31, 2025, other than costs associated with decommissioning and remediation.

95 As CETA requires that PSE remove the benefits and costs of coal power from its retail customer rates as of January 1, 2026, the Commission determines that costs associated with capital investments in Colstrip based on benefits that are realized after 2025 must be excluded from rates. The Commission generally agrees with the non-company parties that this outcome may be achieved by prorating the Company's recovery of costs based on the portion of their useful lives in service prior to the CETA deadline to remove coal power from PSE's allocation of electricity.

96 The Commission disagrees with PSE's argument that the 2017 and 2022 GRC settlements support the Company's request for full recovery of its assets or that proration would be unjust because it contradicts those settlements. Regarding the 2017 GRC settlement, the Commission observes that this settlement was approved prior to the enactment of CETA. Insofar as the 2017 GRC settlement did not contemplate the additional requirements under CETA, the Commission is not persuaded that settlement controls the Commission's analysis in this proceeding. Furthermore, review of the order approving the 2017 GRC settlement indicates that the terms regarding depreciation only apply to those investments that were known at the time of the settlement:

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[232] *Ofc. of the Atty. Gen., Pub. Counsel Unit v. Wash. Utils. & Transp. Comm'n*, 4 Wn. App. 2d 657, 682 (2018) (quoting *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984)).

[233] *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 21-22 ¶ 50 (Apr. 17, 2006).

> Balancing PSE's interest in recovering **all of the net plant amounts remaining on its books for the Colstrip units as of September 30, 2016**, against the Settling Parties' common interest in protecting ratepayers from significant rate impacts and avoiding intergenerational inequities, the Settlement Stipulation establishes two new accounts.
>
> . . .
>
> In the final analysis, we determine that the Settlement Stipulation takes advantage of the unique circumstances in which PSE, without significant rate impacts, is able to recover fully the undepreciated Colstrip plant balances **on the Company's books** on significantly shortened depreciation schedules tied to the known retirement date for Units 1 & 2 and a well-considered change for Units 3 & 4.[234]

As such, as the assets on issue in this proceeding were not "on the Company's books" at the time of the 2017 GRC settlement, the Commission does not interpret that settlement as presently controlling.

97 Turning to the 2022 GRC settlement, while PSE is correct that the record reflects that the settling parties in that case contemplated terminal depreciation,[235] the settlement also expressly provides for additional review of investments related to Colstrip:

> j. Colstrip. PSE will move Colstrip rate base and expense into a separate tracker under Schedule 141-C, as proposed in the testimony of Susan E. Free (Exh. SEF-18). PSE agrees to exclude capital investments associated with the construction of PSE's Colstrip dry ash facilities from recovery in base rates in this case and PSE's proposed Schedule 141-C tracker. **The Settling Parties agree that Colstrip costs included in rates in 2023 and beyond (including major maintenance expense and new plant additions) are subject to review, including but not limited to an examination of prudence, in PSE's annual Schedule 141-C tariff filing.** Major maintenance costs incurred during the MYRP will be amortized over three years, regardless of the year incurred. Costs amortized after 2025 would not be recovered in rates. **The Settling Parties retain all rights to challenge Colstrip costs when PSE files tariff revision for the tracker**.[236]

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[234] *WUTC v. Puget Sound Energy*, Dockets UE-170033 & UG-170034 (*consolidated*), Order 08 at 40, 50-51 ¶¶ 111, 136 (Dec. 5, 2017) (emphasis added, internal citations omitted).

[235] Free, Exh. SEF-1T at 6:1-21; Free, TR. at 115:12 – 116:13.

[236] *WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022) (emphasis added).

Given that the 2022 GRC settlement clearly preserved the parties' ability to challenge the inclusion of subsequent costs related to Colstrip in a future proceeding, PSE cannot reasonably rely on the 2022 GRC settlement as requiring the inclusion of all Colstrip costs at issue in this proceeding. The 2022 GRC settlement did not preapprove any of the assets that are currently before the Commission for review and does not preclude the Commission from disallowing costs that fail to satisfy applicable legal standards on a prorated basis.

98 The Commission further disagrees with PSE's assertion that prorating its recovery in this case would be unfair and contrary to the Commission's Used and Useful Policy Statement. The Used and Useful Policy Statement states in part that "rates must be fair to both customers and the public service company[.]"[237] Although the Company maintains that it would be unfair to prorate the recovery of its Colstrip investments because it was obligated by its ownership agreement to fund its full share of those assets, that agreement was entered into at the discretion of PSE and PSE's customers had no control over whether to accept those terms. To the extent that PSE argues that it lacks discretion because of the O&O Agreement, that lack of discretion was created by PSE's own actions. The Commission also rejects PSE's argument that Washington customers will receive the full benefit of Colstrip costs associated with capital projects and maintenance regimes that extend past the CETA deadline to remove coal from the allocation of electricity.[238] As the Company stated at hearing, Colstrip provides no benefit to ratepayers after 2025:

> Q: So if you could look at your rebuttal testimony at Page 11, Lines 11 to 13. Actually, 13 to 14. And it indicates that, in response to AWEC's testimony, that as of December 31st, 2025, Colstrip is not necessary or useful in the performance of any PSE duties to the public; is that correct?
>
> A: That is correct.[239]

99 Witness Atwood similarly testified:

> Q: Just to clarify: CETA requires that coal be out of rates effective December 31st, 2025. Is that your understanding?
>
> A: Yes.

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[237] Policy Statement on Property that Becomes Used and Useful After the Rate Effective Date, Docket U-190531 at 14-15 ¶ 43 (Jan. 31, 2020).

[238] Atwood, Exh. NLA-1T at 20:4-6.

[239] Roberts, TR. at 103:23 – 104:4. *See also* Roberts, Exh. RJR-1T at 11:13-14 ("As of December 31, 2025, as AWEC knows, Colstrip is not necessary or useful in the performance of any PSE duties to the public.").

> Q: And so after that date, coal plant will not be used to serve Washington ratepayers; is that correct?
>
> A: It will not be operational to serve customers, PSE customers.
>
> Q: In Washington?
>
> A: Yes.
>
> . . .
>
> Q: Is the Colstrip plant after December 31st, 2025, worth anything to Washington customers?
>
> A: Puget Sound Energy cannot have it in its rates. By getting out of the plant at the end of the required timeline, Washington customers benefit from a cleaner portfolio.
>
> Q: Okay. So there's a benefit. But in terms of the actual output of Colstrip, is there any value to Washington customers after that date?
>
> A: There will not be benefit of operating after that date, no.[240]

100 While the Commission must carefully evaluate the needs of both customers and the Company, the Commission does not find that it would be fair to require Washington customers to bear the full costs of assets from which they will only receive a fraction of the benefits relative to those assets' useful lives. Rather, prorating the assets based on the portion of their useful lives in service prior to the CETA deadline to remove coal power from PSE's allocation of electricity appropriately assigns fair costs to ratepayers relative to the benefit they actually receive from the Colstrip assets.[241]

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[240] Atwood, TR. at 56:7-16, 76:1-12. The Commission notes that while the witness did further respond that "Well, the [Colstrip] power will be on the grid" and that "would potentially be a benefit in some way," this assertion is speculative and conflicts with the witness's earlier statement that Colstrip could not serve Washington customers after 2025. Atwood, TR. at 76:16 – 77:7.

[241] On the issue of fairness, the Commission also notes that the Company was aware of the possibility that certain Colstrip assets may be subject to disallowance as part of this proceeding. *See* Roberts, Exh. RJR-1T at 13:10-12 (explaining that PSE voted no on certain budget items in part because "PSE felt that the possibility of a disallowance by the Commission would leave the Company in a difficult negotiating position with NorthWestern should PSE not have some logic to its No votes.").

i. Human Health and Safety Investments

101 However, the Commission determines that the six human health and safety projects should be fully recovered by PSE because they provide a benefit beyond facilitating the generation of electricity.[242] As testified to by Staff, these projects were intended to address employee health and safety hazards related to Colstrip operations:

> Two of the projects (the Snubber Rebuild and the Hot Reheat Elbow Replacement) address risks associated with damaged or out-of-code high-pressure steam lines where failure of the existing equipment could result in the release of 1000 degree high-pressure steam onto the turbine deck, one of the projects (the switchgear mod) is necessary for code compliance and addresses the risks that plant personnel will be exposed to high-energy arc flash events, and one of the projects (the coal pipe replacement) addresses coal pipe leaks which increase the risks of explosions and create employee health hazards such as an elevated risk of silicosis, pneumonia, and black lung.
> . . .
> The boiler scaffolding provides a safe structural environment during boiler inspections and repairs, and the boiler elevator allows large and heavy equipment to be safely moved to various locations on the boiler.[243]

102 The Commission agrees with Staff's assessment that the "near-term benefits of th[e]se projects exceed the cost of their investment," and determines that they should be fully included in rates.[244] The Company's ratepayers benefit from reasonable human safety investments that reduce the Company's risk of liability in the event of an incident resulting in injury or death to plant workers. Absent such investment, investors may be led to perceive the Company as relatively riskier, which could in turn require a greater degree of compensation to investors to account for that risk, thereby increasing overall future rates to customers.[245] Although utilities must transition away from certain resources to comply with CETA, the Commission does not want to create an incentive for utilities to avoid reasonable safety investments for such resources that place workers in threat of harm,

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[242] Specifically, the six human safety projects are (1) Switchgear modification; (2) the U4 Boiler Snubber rebuild; (3) the Coal Pipe Replacement; (4) the U4 Hot Reheat Elbow Replacement; (5) the U4 Boiler Scaffolding; and (6) the U4 Boiler Elevator. McGuire, Exh. CRM-1T at 9:15-20.

[243] McGuire, Exh. CRM-1T at 10:4-19 (citations omitted). *See also* Cebulko, Exh. BTC-1CT at 26:9 – 27:10 (recommending full recovery of the same six human safety projects).

[244] McGuire, Exh. CRM-1T at 11:2-5.

[245] RCW 19.405.010(2) ("In implementing this chapter, the state must . . . provide safeguards to ensure that the achievement of this policy does not impair the reliability of the electricity system or impose unreasonable costs on utility customers."

which generally would be contrary to the public interest.[246] The Commission has no desire to see the transformation of Washington's energy supply to clean energy built upon a foundation of unnecessary hazards and risk of harm to workers.

ii. Assets with 2025 In-Service Dates

103 With respect to assets with in-service dates in 2025, the Commission determines that such assets should be prorated consistent with the Commission's used and useful analysis discussed above. Regarding the U4 Generator Exciter and the Northern Cheyenne AAQ System, the Commission finds that PSE should be required, as a condition of compliance with this order, to make a supplemental filing indicating when these two investments were placed into service. If these investments were placed into service on or before December 31, 2025, the Company should be allowed to recover a pro rata portion of these investments for two reasons. First, to the extent that these assets are placed into service on or before the deadline to remove coal from rates, they have provided some benefit to Washington customers that warrants proportional recovery in the interest of fairness. Second, because CETA requires that coal power be removed from PSE's allocation of electricity after 2025, PSE will not have another opportunity to recover these costs in a subsequent proceeding. As such, the Commission exercises its discretion to require PSE to file an update to the record as a condition of compliance with this order due to the requirements of CETA but cautions that this unique situation should not be interpreted as setting a general precedent for future GRCs.

B. Prudence

104 During GRC proceedings, the Commission determines the prudence of utility expenditures by reviewing whether the utility made reasonable business decisions in light of the facts and circumstances known or that reasonably should have been known to the utility at the time decisions were made.[247] What is reasonable requires assessment of choices made, in light of circumstances and possible alternatives, based on industry norms and practices.[248]

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[246] *See,* RCW 19.405.010(4)(" The legislature finds that Washington can accomplish the goals of chapter 288, Laws of 2019 while: . . . maintaining safe and reliable electricity to all customers at stable and affordable rates[.]"); RCW 80.28.425(1) (stating in part ""[i]n determining the public interest, the commission may consider such factors including, but not limited to, . . . health and safety concerns . . . to the extent such factors affect the rates, services, or practices of a[n] . . . electrical company.").

[247] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at 8-9 ¶ 19 (Apr. 7, 2004).

[248] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at 8-9 ¶ 19 (Apr. 7, 2004).

Prudence does not require a single, ideal decision, but requires the utility to make a reasonable decision among a number of alternatives that the Commission might find prudent.[249] The prudence review "requires evaluation of the Company's decisions not just from the perspective of management for the benefit of shareholders, but also for the benefit of customers."[250] The fundamental question for decision is whether management acted reasonably in the public interest, not merely in the interest of the company.[251]

105 The prudence standard applies to both the question of need and the appropriateness of the expenditure.[252] The Commission considers three broad questions when evaluating prudence: (1) Was the initiation of the project prudent; (2) Was the continued implementation of the project prudent; and (3) Were the expenses prudently incurred?[253] The second and third factors are examined using the same prudence test as the first factor, but applied at a different point in time and necessarily premised on a reevaluation of the project.[254] Consequently, the Commission's prudency review is not limited to a single point in time and encompasses the implementation and construction phases of a project to ensure that a regulated utility continues to reasonably control and evaluate a project.

106 As noted above, when evaluating prudence, the Commission reviews utility decision-making at the time decisions were made. Stated differently, the Commission will not use the benefit of hindsight when evaluating prudence.[255] Consequently, regulated utilities are required to maintain contemporaneous records of their decision-making process and analysis to satisfy the Commission's prudency standard.[256] A utility's "robust discussions" about a project, with a "consensus" on decisions, is not sufficient to demonstrate

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[249] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 & UG-090705 (*consolidated*), Order 11 at 119 ¶ 337 (Apr. 2, 2010).

[250] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14 at 34-35 ¶ 65 (May 13, 2004).

[251] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14 at 34-35 ¶ 65 (May 13, 2004) (*quoting* Goodman, The Process of Ratemaking, at 857).

[252] *WUTC v. PacifiCorp*, Docket UE-152253, Order 12 at 33 ¶ 94 (Sept. 1, 2016).

[253] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 95 (Sept. 1, 2016).

[254] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 95 (Sept. 1, 2016).

[255] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 94 (Sept. 1, 2016).

[256] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order, at 15-16 (Sept. 27, 1994) ("The company's lack of contemporaneous evaluation and documentation is, at best, poor management practice."); *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 36 ¶ 102 (Sept. 1, 2016) ("However, this memo was prepared after the final decision to proceed was made, and therefore cannot be shown to have played a part in the Company's decision-making.").

prudence.[257] Rather, "the parties and Commission should be able to follow the company's decision-making process, knowing what elements the company used, and the manner in which the company valued those elements. Such a process should certainly be documented."[258] "Documentation and evidence of prudence decision making must be kept contemporaneously with a company's decision making or the Commission's ability to evaluate prudence is thwarted."[259]

107 The Commission has previously explained that its review of prudence typically focuses on four factors:

> 1) *The Need for the Resource:* The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering the purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.
>
> 2) *Evaluation of Alternatives:* The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision. The acquisition process should be appropriate.
>
> 3) *Communication With and Involvement of the Company's Board of Directors:* The utility should inform its board of directors about the purchase decision and its costs. The utility should also involve the board in the decision process.
>
> 4) *Adequate Documentation:* The utility must keep adequate contemporaneous records that will allow the Commission to evaluate the Company's decision-making process. The Commission should be able to follow the utility's decision process; understand the elements that the utility used; and determine the manner in which the utility valued these elements.[260]

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[257] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order at 16 (Sept. 27, 1994).

[258] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order at 16 (Sept. 27, 1994).

[259] *In re Investigation Regarding Prudency of Outage and Replacement Power Costs*, Docket UE-190882, Order 5 at 12 ¶ 43 (Mar. 20, 2020).

[260] *WUTC v. Puget Sound Energy*, Dockets UE-111048 & UG-111049 (*consolidated*), Order 08 at 148 ¶ 409 (May 7, 2012) (citation omitted).

108 As stated above, the Commission has already disallowed the costs associated with Colstrip investment assets' remaining useful lives after 2025 based on those portions of the assets not providing any service or benefit to Washington customers. Consequently, the Commission's prudence review is limited to the remaining portions of those costs.

109 The Commission finds that the Company has sufficiently demonstrated that the remaining portions of the assets and costs it seeks to include in rates are prudent.[261] With regard to the question of need, PSE has made a reasonable showing of the need for the assets based on the analysis prepared by the Colstrip operator and the forecasted costs of replacement power.[262] The Commission is not persuaded that the Company's decision to vote "no" on certain capital investments is evidence of a lack of need, as the Company's voting strategy can be informed by several considerations, including CETA compliance and prior Commission orders.[263] The Commission also disagrees that investments that extend the life of Colstrip are categorically prohibited under the prudence standard. Both Staff and NWEC cite to the Commission's order in Avista's 2020 GRC to support their argument that investments that extend the life of Colstrip must be excluded from the Company's rates.[264] However, the Commission's consideration of whether the Dry Ash Disposal project was life extending was a product of Avista's settlement obligations from a prior GRC, not a component of the Commission's general prudence standard.[265]

110 The Commission also rejects the premise that the prudence standard requires a specific form of cost-benefit analysis. While a utility must include some form of analysis as part of its demonstration of need and consideration of alternatives, the Commission does not require a particular type of analysis under the general prudence standard, leaving the utility with discretion to develop a cost analysis that is reasonable under the circumstances. The Commission finds that the discussion of the prudence of Avista's advanced metering infrastructure investment in the first Avista 2015 GRC order is distinguishable, as in that

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[261] The Commission declines AWEC's invitation to articulate a prudence standard regarding all investments that extend the life of fossil fuel resources that departs from its longstanding prudence framework. The Commission is not persuaded that a modification of its well-established standard is necessary or warranted.

[262] Atwood, Exh. NLA-7C.

[263] Roberts, Exh. RJR-1T at 13:10-12.

[264] Brief of Staff at 10 ¶ 23; Brief of NWEC at 6 ¶ 15.

[265] *WUTC v. Avista Corp.*, Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 100 ¶ 279 (Sept. 27, 2021) ("Lastly, we are uncertain that Dry Ash is not a life-extending capital addition. Our 2019 Avista GRC Final Order approved a settlement that included an agreement by Avista not to support capital expenditures beyond routine capital maintenance costs that would extend Colstrip's operational life beyond December 31, 2025.").

case Avista had not yet implemented its AMI program and the prudence of AMI was not sufficiently ripe for adjudication.[266] However, the first Avista 2015 GRC order does highlight the fact that, while the Commission will not "preapprove" a particular type of analysis to support prudence, a utility risks a disallowance if it presents an analysis that has insufficient detail or otherwise lacks credibility.[267] Additionally, the Commission's discussion in PacifiCorp's 2005 GRC regarding the demonstration of "tangible and quantifiable benefits to Washington of resources in the system," was in the context of reviewing PacifiCorp's interjurisdictional allocation methodology, rather than as part of a prudence review.[268]

111 However, the Commission agrees that the O&O Agreement does not independently satisfy the required showing of need under the prudence standard. While the O&O Agreement creates an obligation for PSE to pay for its proportional share of budget items that are approved by the Colstrip owners, the owners' approval is not determinative of whether a utility has demonstrated a reasonable need. If the fact that PSE is required to fund its portion of investments pursuant to a contract were all that is necessary to demonstrate need, the need would be met for every Colstrip asset approved, which would effectively nullify the Commission's prudency review. Furthermore, the Commission has previously disallowed Colstrip assets that the owners voted to approve based on a finding of lack of need, such as the Commission's previous SmartBurn disallowance, which further supports a determination that the O&O Agreement's obligation to pay does not, by itself, satisfy the need component of the prudence standard.[269]

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[266] *WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 71 ¶ 199 (Jan. 6, 2016)("In conclusion, we decline to rule on the prudency of Avista's proposed AMI investment in this case because the issue is not ripe for our determination. This decision should not be interpreted as a rejection of AMI. The Company must decide what metering program provides ratepayers the most benefit at the least cost.").

[267] *WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 69 ¶ 193 (Jan. 6, 2016) ("While we do not make a decision regarding the prudence of this project in this proceeding, we note the considerable uncertainty surrounding the business case analysis Avista prepared. . . . We look forward to a more refined cost-benefit analysis in a future proceeding, including a fuller discussion of "non-quantifiable benefits" suggested by Mr. Kopzcynski.").

[268] *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 27-28 ¶ 68 (Apr. 27, 2006).

[269] *WUTC v. Avista Corp.*, Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 98 ¶ 274 (Sept. 27, 2021) (disallowing SmartBurn investment in Colstrip because the utility "failed to demonstrate that SmartBurn was necessary and failed to produce documentation sufficient to demonstrate that its costs were prudently incurred.").

112 Turning to the NPV analysis supporting PSE's Colstrip costs in this case, the Commission agrees with the non-company parties that the analysis is questionable in some respects. Although the Commission agrees that PSE's failure to fund an approved capital investment will result in default under the O&O Agreement, the record does not indicate that Talen's decision to assume 100 percent probability of failure was intended to reflect a shareholder's default.[270] However, while the persuasiveness of the NPV analysis is weakened by the fact that the analysis is not risk adjusted, the Commission is not persuaded that this condition makes the analysis wholly unreliable.

113 Additionally, in light of the Commission's above analysis excluding the portions of Colstrip investments not used and useful in Washington after 2025, the Commission finds that the NPV analysis is sufficiently reasonable even though it is not performed from the perspective of Washington ratepayers. While the Commission will not proscribe the type of analysis that a utility may utilize to support its showing of prudence, if such analysis is based on general rather than Washington-specific data, the utility should be able to explain how that data supports prudence from the perspective of Washington ratepayers. In some cases, there may be no distinction between the general benefit and the Washington specific benefit, insofar as the Washington benefit is a proportional share of the general benefit. But, in circumstances where the Washington benefit may materially diverge from the general benefit, such as when a resource may no longer be used to provide service in Washington, further analysis should be performed to verify that the investment is still prudent with respect to Washington ratepayers.

114 Based on the above discussion, the Commission finds that the Company has demonstrated a need for the prorated portions of the Colstrip assets in this case based on the NPV analysis and forecasted replacement power costs.[271] The same evidence also supports a finding that the Company considered alternatives to continuing to fund Colstrip and that it documented its reasoning contemporaneously. The record also demonstrates that the Company informed and consulted with its management about the investment decisions related to Colstrip.[272]

115 As to the equity considerations raised by Public Counsel regarding PSE's full inclusion of Colstrip costs, the Commission has addressed this issue by prorating PSE's recovery of

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[270] Atwood, Exh. NLA-7C; Exh. NLA-9.

[271] Atwood, Exh. NLA-7C.

[272] Atwood, Exh. NLA-1T at 20:8-17; De Villiers, Exh. SDV-3C, Attach. A.

Colstrip costs.[273] Prorating PSE's recovery of investments in Colstrip promotes equity by appropriately assigning costs to Washington customers relative to the benefits that they will receive before coal-fired resources can no longer be included in PSE's allocation of electricity. The Commission's analysis in this matter is also informed by the numerous public comments filed in this docket raising concerns about affordability and opposing continued support for coal-fired resource operations past 2025 despite CETA's mandate to remove coal from the allocation of electricity.[274]

i. SmartBurn

116 In this docket, PSE is seeking recovery for costs associated with four components of the NOx control system:

- Unit 4 Boiler Burner AuxAir Replacement (Boiler Burner)
- Unit 4 Separated Over Fire Air Bucket Replacement (SOFA)
- Unit 4 Top Over Fire Air Bucket Replacement (TOFA)
- Control Room Operator (CRO)[275]

117 Although the Commission finds general prudence in PSE's Colstrip investments, the Commission finds that specific Company investments labelled "SmartBurn" were not prudently incurred because the Company did not demonstrate that the investments were necessary, based on the Commission's prior disallowance of certain SmartBurn investments.[276]

118 In PSE's 2019 GRC, the Commission disallowed recovery of investments in SmartBurn technology that is associated with the NOx Combustion Control system after the Commission found that "PSE failed to demonstrate that the costs related to PSE's

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[273] Brief of Public Counsel at 20-22 ¶¶ 61-68; *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755, Order 09 at 19-20 ¶ 59 (Aug. 23, 2022) (retaining discretion to evaluate equity on a case-by-case basis). However, the Commission declines to consider the articles cited by Public Counsel in its briefing, as those articles are not part of the record in this case, and Public Counsel has not motioned for the Commission to take official notice of those articles or explained why they could not have been previously submitted to the record.

[274] *See generally* BR 5, Public Comment Exhibit.

[275] Atwood, Exh NLA-11T at 4:12-19, 7:3-12.

[276] *WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (consolidated), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (Consolidated), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶ 197 (Jul. 8, 2020).

SmartBurn investment were prudently incurred[,]"[277] In particular, the Commission found that PSE failed to demonstrate that SmartBurn was necessary and "failed to maintain appropriate documentation of its decision to install SmartBurn."[278] During the initial rounds of testimony in this docket, the parties were not clear on what components of the NOx control system were related to the SmartBurn investments the Commission previously disallowed in PSE's 2019 GRC. In response to DR 19 from NWEC, the Company identified the Boiler Burner, SOFA, and TOFA as SmartBurn technology.[279] However, PSE clarified that the only component of the NOx control system that had been previously disallowed was the TOFA component.[280] The Company confirms that the Boiler Burner and SOFA investments on Units 3 and 4 were installed prior to 2016 and were not part of the 2019 GRC.[281]

119 Because PSE's investment in the SmartBurn TOFA component of the NOx control system has been previously disallowed as imprudent, we analyze PSE's request for recovery for investment in replacing the TOFA component for prudence. The Company has argued that although the Commission disallowed recovery of its investment in the TOFA component in the 2019 GRC, that should not influence the Commission's decision in this matter, and the Commission should only look to the record in this docket and not a previous docket to determine prudence.

120 In determining whether an investment was prudently incurred, we consider what the Company knew at the time it made the investment. The Company was aware that the Commission had previously found its costs related to investment in SmartBurn/TOFA to be imprudently incurred at the time it invested in the replacement component.[282] We can understand the Company's concerns that that the TOFA component is an integrated part of the NOx control system and that the TOFA replacement was necessary because the plant

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[277] *WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (*consolidated*), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (*consolidated*), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶ 197 (Jul. 8, 2020).

[278] *WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (consolidated), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (Consolidated), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶ 197 (Jul. 8, 2020).

[279] Cebulko, Exh. BTC-6.

[280] PSE's Response to BR 2 at 2 (September 10, 2025); PSE's Revised Response to BR 6 at 1 (October 30, 2025).

[281] PSE's Response to BR 5 at 2 (October 27, 2025).

[282] *See WUTC v. Puget Sound Energy*, Dockets UE-190529, UG-190530 (*consolidated*), UE-190274, UG-190275 (*consolidated*), UE-171225, UG-171226 (*consolidated*), UE-190991 & UG-190992 (*consolidated*), Order 08/05/03 at 61 ¶¶ 197-199 (Jul. 8, 2020).

cannot run without it. However, the Company has not provided additional documentation to demonstrate prudence in its TOFA investment, thus there is not sufficient information in the record to persuade us that the Company's investment was prudently incurred. Because the Company's investment in relation to the SmartBurn TOFA component is not prudent, we find that the Commission should disallow cost recovery related to the TOFA component.

121 The Company clarified that the CRO, Boiler Burner, and SOFA components were installed in the NOx control system prior to its 2019 GRC and were not subject to the decision in that order. Further, the Company has conceded that the TOFA component was disallowed as imprudent.[283]

122 We find the installation timeline of the SOFA component provided by the Company sufficiently rebuts NWEC's argument because it demonstrates that SOFA was installed on Colstrip Units 3 and 4 in 2007 and 2009 respectively, and was not subject to the 2019 GRC decision.[284] Because the Boiler Burner, CRO, and SOFA components of the NOx control system were not subject to PSE's 2019 GRC, we do not find that recovery on investment for these components was disallowed in PSE's 2019 GRC. The Boiler Burner, CRO and SOFA are not subject to the same analysis as the TOFA component but are subject to the Commission's pro-rata analysis in the Used and Useful section of this order above.

ii. *Assets Lacking Capital Justification*

123 The Commission further determines that PSE has not demonstrated the prudence of four investments that lack capital justification.[285] As noted by NWEC, the Company has stated in both testimony and in response to discovery that there are no capital justifications for four projects, and those projects are not discussed in the Company's NPV analysis.[286] As such, the Commission determines that the Company has not demonstrated the need for these investments or provided contemporaneous documentation with respect to its decision to pursue these investments, and has not demonstrated that they are prudent.

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[283] Brief of PSE at 18-19 ¶ 32.

[284] PSE's Response to BR 2.

[285] Cebulko, Exh. BTC-1CT at 26:1-2 (identifying projects lacking capital justification as (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare).

[286] Cebulko, Exh. BTC-1CT at 25:13-18 (*citing* Atwood, Exh. NLA-1T at 11:1, fn. 17); Cebulko, Exh. BTC-7 at 1 (stating for each of the four projects "No Capital Justification available, inspection based work after removal.").

V. Operations & Maintenance Amortization

124 Staff contests a portion of PSE's major maintenance amortization expenses related to the 2024 Unit 4 outage. Staff explains that PSE has included a total major maintenance amortization expense of $4,201,653 related to four separate Colstrip outages, with the 2024 Unit 4 outage accounting for $1,609,006.[287] Staff contends that dividing the total 2024 Unit 4 outage cost of $4,471,694 by 36-months should result in a monthly amortization expense of $124,214, but PSE has included a monthly amortization expense of $134,048 in its filing.[288] Based on a monthly amortization cost of $124,214, Staff maintains that the annual amortization associated with the 2024 Unit 4 outage should be $1,490,565.[289] Staff recommends that the Commission reduce the annual major maintenance amortization expense included in rates from $1,609,006 to $1,490,565.[290]

125 PSE maintains that while Staff's methodology for calculating the annual amortization expense is correct, it is based on an incorrect total event cost for the 2024 Unit 4 outage.[291] The Company asserts that $4,471,694 included in its original filing was based on a preliminary amount rather than the final amount, and that the correct costs associated with the 2024 Unit 4 outage is $4,809,523.[292] Based on the correct amount, PSE argues that the correct total amortization for the 2024 Unit 4 outage is $1,603,174.[293]

Commission Determination

126 The Commission agrees with PSE's updated calculation of the annual amortization expense associated with the 2024 Unit 4 outage. PSE's updated calculation on rebuttal is based on the actual cost of the 2024 Unit 4 outage, rather than the preliminary estimate that was included in the Company's initial filing. As such, the amount associated with the annual amortization associated with the 2024 Unit 4 outage should be corrected from $1,609,006 to $1,603,174. The Commission further determines that major maintenance operations and

[287] McGuire, Exh. CRM-1T at 36:11-18.

[288] McGuire, Exh. CRM-1T at 37:10-16.

[289] McGuire, Exh. CRM-1T at 37:17-20.

[290] McGuire, Exh. CRM-1T at 37:22 – 38:4.

[291] Free, Exh. SEF-1T at 11:1-4.

[292] Free, Exh. SEF-1T at 11:4-10.

[293] Free, Exh. SEF-1T at 11:11 – 12:2.

maintenance expenses should be recovered consistent with the terms of PSE's 2022 GRC settlement.[294]

VI. Refund Process

127 Although PSE maintains that no refund is necessary, if the Commission does require a refund, the Company recommends that the Commission require the Company to either provide a refund directly to customers or apply the refund against PTCs.[295] PSE raises concerns that CETA's requirement to remove coal from its allocation of electricity after 2025 could be interpreted to prohibit a direct refund to customers through Schedule 141COL.[296] If the Commission determines that a direct refund is not permitted under CETA, the Company recommends applying the refund against its PTCs and states that customers would still be compensated for the time value of money because they would offset rate base in the Colstrip Tracker.[297]

128 Staff recommends that the Commission require the Company to directly refund any over collected amounts through PSE's Schedule 141COL beginning in 2026.[298] Specifically, Staff argues that the Commission should require PSE to refund over-collected amounts after 2024 plant additions are trued up to actuals, as PSE's original filing did not have actual costs for all of the 2024 projects.[299] Staff further asserts that the Commission should maintain currently effective rates through 2025 and order PSE to refund trued-up over-collected amounts over the course of 2026 through Schedule 141COL.[300] Staff contends that requiring PSE to file compliance tariff revisions to Schedule 141COL, with an effective date of Jan. 1, 2026 and containing trued-up 2024 plant amounts, would simplify the refund calculation, allow the trued-up amounts to be reflected in the refund, and reduce the number of tariff revisions required by PSE.[301]

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[294] *WUTC v. Puget Sound Energy*, Dockets UE-220066, UG-220067, & UE-210918 (*consolidated*), Order 24/10, Appendix A at 7-8 ¶ 23 j (Dec. 22, 2022) (stating in part "Major Maintenance costs incurred during the MYRP will be amortized over three years, regardless of the year incurred. Costs amortized after 2025 would not be recovered in rates.").

[295] Brief of PSE at 23 ¶¶ 40-41; Free, Exh. SEF-1T at 14:2 – 15:16.

[296] Free, Exh. SEF-1T at 14:6-17.

[297] Brief of PSE at 23 ¶ 41; Free, Exh. SEF-1T at 15:1-16.

[298] Brief of Staff at 19-20 ¶ 39; McGuire, Exh. CRM-1T at 39:19 – 40:5.

[299] McGuire, Exh. CRM-1T at 29:13-19; 39:3-17.

[300] McGuire, Exh. CRM-1T at 39:19 – 40:8.

[301] McGuire, Exh. CRM-1T at 31:12 – 32:4.

129 Public Counsel maintains that the Commission should require PSE to directly refund any over collected amounts either through a one-time bill credit or over a period not to exceed one year.[302] Public Counsel states that a direct refund is more appropriate than waiting to apply any refund against future decommissioning and remediation expenses because customers benefit more from a direct refund due to the time value of money.[303]

130 NWEC recommends that the Commission require PSE to refund over collected amounts directly to customers rather than apply that refund against PTCs.[304] While AWEC recommends that the Commission disallow various costs PSE included in its filing, it does not provide a recommendation regarding the mechanism for refunding the disallowance.[305]

Commission Determination

131 The Commission requires PSE to directly refund over collected amounts to customers consistent with the method identified by Staff, rather than apply those costs against future PTCs. Staff's proposed method is administratively efficient and will provide more immediate relief to PSE's customers, which is in the public interest and promotes equity. While the Commission appreciates PSE's concern regarding whether a refund complies with CETA's requirement to remove coal power from the allocation of electricity, the Commission does not interpret RCW 19.405.030(1) to prohibit a refund under these circumstances. When the Commission authorized rates to go into effect in this proceeding, it did so subject to refund based on further development of the record and adjudication.[306] As such, the refund required in this case represents an adjustment to rates that were in effect from the end of 2024 to the end of 2025, when the costs and benefits associated with coal power could still be included in rates.

VII. 2025 Colstrip Plant Filing

132 Staff recommends that the Commission clarify the anticipated process for review of PSE's offsetting of 2025 Colstrip plant additions against PTCs. Staff further suggests that the annual Schedule 141COL tariff revision docket filing on or before September 30, 2026, would be a reasonable venue to review PSE's use of PTCs and potentially contesting

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[302] Brief of Public Counsel at 24-25 ¶ 76.

[303] Brief of Public Counsel at 24-25 ¶¶ 74-76; Dreyer, Exh. JMD-1CTr at 8:15 – 9:3.

[304] Cebulko, Exh. BTC-1CT at 3:12-13.

[305] Brief of AWEC at 10 ¶ 20.

[306] *WUTC v. Puget Sound Energy*, Docket UE-240729, Order 01 at 3 ¶ 9 (Dec. 23, 2024).

certain plant additions.[307] AWEC similarly argues that the Commission should require PSE to submit a filing regarding the Company's final regulatory accounting for Colstrip as of December 31, 2025, that will involve a prudence determination for plant balances that the Company proposes to offset with PTCs.[308] AWEC also asks that the Commission clarify that the same principles that apply to the Commission's review in this case will apply to the Commission's review of PSE's 2025 Colstrip plant additions.[309] Public Counsel also indicates that it supports AWEC's recommendation that the Commission evaluate the prudency of the Company's 2025 Colstrip plant additions to be applied against PTCs.[310] PSE states that it agrees with Staff's proposal regarding the treatment of 2025 plant requirements in PSE's annual Schedule 141COL filings.[311]

Commission Determination

133 The Commission agrees that it is appropriate to provide further guidance regarding the review of 2025 Colstrip plant additions and agrees with Staff's recommended process. The Commission requires PSE to file as part of its annual Schedule 141COL filing on or before September 30, 2026, its final proposed regulatory accounting for Colstrip costs as of December 31, 2025. As part of this filing, all interested parties and the Commission will have an opportunity to review whether such costs should be offset by PTCs. While the Commission does not prejudge any issues that may arise in the context of reviewing PSE's 2025 Colstrip investments, this Order should be understood as guidance with respect to the Commission's review in that proceeding.

FINDINGS OF FACT

134 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

135 (1) The Commission is an agency of the state of Washington vested by statute with the authority to regulate rates, regulations, practices, accounts, securities, transfers

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[307] McGuire, Exh. CRM-1T at 34:13 – 36:7.

[308] Brief of AWEC at 9 ¶ 19; Mullins, Exh. BGM-1T at 12:11-20.

[309] Brief of AWEC at 10 ¶ 20.

[310] Brief of Public Counsel at 25-26 ¶ 78; Dreyer, Exh. JMD-2CT at 7:2-8.

[311] Free, Exh. SEF-1T at 16:2-5.

of property and affiliated interests of public service companies, including electric and companies.

136 (2) PSE is a "public service company," and an "electrical company," as those terms are defined in RCW 80.04.010 and used in Title 80 RCW. PSE provides electric utility service to customers in Washington.

137 (3) On September 30, 2024, PSE filed with the Commission a proposed revision to rates under the established Colstrip Adjustment Rider Schedule 141COL.

138 (4) PSE requested an annual revenue increase of $4.1 million, or 0.14 percent, which for the typical residential customer using 800kWh per month would be a rate increase of $.18 or 0.16 percent.

139 (5) On December 19, 2024, the Commission entered Order 01 Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication in this docket, requiring PSE to file revised tariff pages no later than December 23, 2024, with an effective date of January 1, 2025, indicating that the increased rates are subject to refund. The Company was directed by Order 01 to file revised tariff pages, which the Company complied with on December 20, 2024.

140 (6) On September 3, 2025, the Commission convened a hybrid evidentiary hearing before the Commissioners that was presided over by ALJ's Harry Fukano and Jessica Kruszewski.

141 (7) Colstrip Units 3 and 4 are coal-fired generating units.

142 (8) At 12:00 a.m. on January 1, 2026, Pacific Standard Time, PSE's ownership interest will transfer to NorthWestern and costs associated with coal-fired generation of electricity will be removed from rates for electricity for PSE's Washington State customers.

143 (9) As of January 1, 2026, Colstrip will provide no benefit to Washington electric retail customers.

144 (10) As of January 1, 2026, Colstrip will not be necessary or useful in PSE's provision of electric service to Washington customers.

145 (11) Six Colstrip projects related to human health and safety provide near-term, immediate benefits that exceed the cost of investment. Those six projects are: (1)

Switchgear modification; (2) the U4 Boiler Snubber rebuild; (3) the Coal Pipe Replacement; (4) the U4 Hot Reheat Elbow Replacement; (5) the U4 Boiler Scaffolding; and (6) the U4 Boiler Elevator.

146 (12) PSE has not demonstrated that its remaining investments in Colstrip, other than the six human health and safety projects previously identified, provide any benefits to Washington customers after December 31, 2025.

147 (13) The record developed in this proceeding does not indicate when the U4 Generator Exciter and the Northern Chyanne AAQ System were placed into service.

148 (14) PSE has not demonstrated a need for four projects that lack capital justification. Those four projects are: (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare.

149 (15) PSE's costs for capital improvements to the SmartBurn TOFA component of Colstrip Units 3 and 4 were not prudently incurred because the Company was aware at the time it made the decision to replace the TOFA components, that the Commission had previously found PSE's investment in the TOFA component for Colstrip Units 3 and 4 imprudent. Because PSE's investment in the TOFA components in this docket were not prudently incurred, recovery of costs associated with TOFA components are disallowed.

150 (16) The Boiler Burner, CRO, and SOFA are not SmartBurn components that were previously disallowed in PSE's 2019 GRC.

151 (17) The NPV analysis provided by PSE demonstrates a reasonable need for PSE's Colstrip investments, other than the four projects lacking capital justification and the SmartBurn TOFA component, up to December 31, 2025, after which the assets cannot provide any benefit to Washington customers.

152 (18) For its remaining Colstrip investments and costs, PSE has provided sufficient evidence demonstrating that it considered alternatives to its Colstrip investments and costs, consulted with its management, and contemporaneously documented its analysis.

153 (19) PSE's annual amortization of the 2024 Colstrip Unit 4 outage is $1,603,174, rather than $1,609,006, based on its updated actual costs associated with the outage.

154 (20) PSE's annual amortization cost associated with the 2024 Colstrip Unit 4 outage should be adjusted to $1,603,174.

155 (21) Based on the analysis in this proceeding, PSE has over-collected $6,843,705 that should be refunded to its customers, subject to the true up required by this Order. The computation of the over-collected amounts is attached to this Order as Appendix A (Confidential).[312]

156 (22) Staff's recommended process for implementing a refund of over-collected amounts, as described in Exh. CRM-1T at 39:1 – 40:8 is reasonable and not contrary to CETA.

157 (23) Staff's recommended process for reviewing PSE's 2025 Colstrip investments is reasonable.

CONCLUSIONS OF LAW

158 Having discussed above all matters material to this decision, and having stated the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

159 (1) The Commission has jurisdiction over the subject matter of, and Parties to, this proceeding.

160 (2) PSE is an electric company and a public service company subject to Commission jurisdiction.

161 (3) PSE bears the burden to demonstrate that its provisional rates subject to refund are fair, just, reasonable, and sufficient. The Commission's determination of whether the Company has carried its burden is adjudged based on the full evidentiary record.

162 (4) PSE has not demonstrated that the rates allowed to go into effect January 1, 2025, subject to refund, are fair, just, reasonable, and sufficient.

163 (5) Colstrip Units 3 and 4 are coal-fired resources as that term is defined in RCW 19.405.020(7)(a).

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[312] Appendix A (Confidential) shall be provided to PSE and parties that have signed the protective order agreement and shall be posted to the docket.

164 (6) After a careful analysis of the canons of Legislative intent, we find that the Legislature intended for a broad definition of the terms "retired" and "retirement" in RCW 19.405.030(3), which includes the accounting definition.

165 (7) We adopt the Generally Accepted Accounting Principles and Washington State Auditor's definitions of the terms "retired" and "retirement" in the application of RCW 19.405.030(3) in this docket.

166 (8) The provisions of CETA apply to the proceedings in this docket because we find that the Company will have retired Colstrip Units 3 and 4 pursuant to RCW 19.405.030(3) by 12:00 a.m. January 1, 2026.

167 (9) The A&A Agreement between PSE and NorthWestern is not subject to Commission approval under RCW 80.12.020 because, pursuant to RCW 19.405.030(1)(a)'s requirement that coal-fired resources be removed from PSE's allocation of electricity on or before December 31, 2025, Colstrip Units 3 and 4 cannot provide any benefit to PSE's Washington customers.

168 (10) The Commission should reject the request to have PSE file the A&A Agreement for Commission approval pursuant to RCW 80.12.020.

169 (11) The Commission should require PSE, as a condition of this order, to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 55.

170 (12) The six human health and safety investments in Colstrip are fully used and useful. The six projects are: (1) Switchgear modification; (2) the U4 Boiler Snubber rebuild; (3) the Coal Pipe Replacement; (4) the U4 Hot Reheat Elbow Replacement; (5) the U4 Boiler Scaffolding; and (6) the U4 Boiler Elevator.

171 (13) PSE has not demonstrated that its remaining capital investments in Colstrip are used and useful for service in Washington after December 31, 2025.

172 (14) The Commission should disallow a prorated portion of the Colstrip capital investments based on the portion of the investment's useful lives in service prior to December 31, 2025.

173 (15) PSE should be required to file an update to this docket detailing when the U4 Generator Exciter and the Northern Cheyenne AAQ System were placed into

service, including supporting documentation. If either asset was placed into service prior to December 31, 2025, PSE should be allowed to recovery a prorated portion of the costs associated with those investments, consistent with the proration methodology described in paragraph 95.

174 (16) PSE has not demonstrated that its investments in four projects that lack capital justification were prudent. Those four projects are: (1) Boiler Feed Pump Rebuild-Element; (2) PA Fan Motor Rewind/Refurb; (3) Boiler Feed Booster Pump RB; and (4) Motor Circ Wtr Pump Cap Spare.

175 (17) The TOFA component of the NOx control system is a SmartBurn component that was previously disallowed in PSE's 2019 GRC and therefore is imprudent.

176 (18) PSE's remaining investments and costs related to Colstrip that are not disallowed as not used and useful are prudent.

177 (19) PSE should be required to refund over-collected revenue through Schedule 141COL starting Jan. 1, 2026, consistent with Staff's recommended process as described in Exh. CRM-1T at 39:1 – 40:8.

178 (20) PSE should be required to file its final regulatory account for all Colstrip costs as of December 31, 2025, as part of its Schedule 141COL annual filing on or before September 30, 2026, consistent with the guidance in this Order. As part of such filing, other interested parties shall have the ability to review and contest PSE's investments.

ORDER

THE COMMISSION ORDERS:

179 (1) Puget Sound Energy's tariff revisions filed on September 30, 2024, further revised on December 20, 2024, and allowed to go provisionally into effect on January 1, 2025, by prior Commission order, are rejected and subject to refund with respect to the over-collected amounts.

180 (2) Puget Sound Energy is authorized and required to make compliance filings in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Order. PSE should file its compliance tariffs with an effective date of January 1, 2026, on or before December 24, 2025.

181 (3) As a condition of this order, Puget Sound Energy is required to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 55.

182 (4) As a condition of compliance with this order, Puget Sound Energy is required to submit an update to this docket indicating when the U4 Generator Exciter and the Northern Cheyenne AAQ System were placed into service, with supporting documentation, and the record should be reopened for the limited purpose of incorporating this information. If the assets were placed into service prior to December 31, 2025, Puget Sound Energy is authorized to recover a prorated portion of the value of those assets, consistent with the methodology described in paragraph 95.

183 (5) Puget Sound Energy is required to refund over-collection amounts consistent with the methodology described by Staff in Exh. CRM-1T at 39:1 – 40:8.

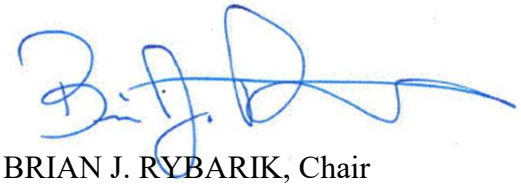
184 (6) Puget Sound Energy is required to file its final regulatory account for all Colstrip costs as of December 31, 2025, as part of its Schedule 141COL annual filing on or before September 30, 2026, consistent with the guidance in this Order. As part of such filing, other interested parties shall have the ability to review and contest PSE's investments.

185 (7) The Commission Secretary is authorized to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

186 (8) The Commission retains jurisdiction to effectuate the terms of this Order.

Dated at Lacey, Washington, and effective December 19, 2025.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION



BRIAN J. RYBARIK, Chair



ANN E. RENDAHL, Commissioner

MILTON H. DOUMIT, Commissioner

NOTICE TO PARTIES: This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-07-870.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-58:
EPA CEMS Data 2021-2025

State	Facility Nai	Facility ID	Year	Gross Load	Steam Loa	SO2 Mass (	CO2 Mass	NOx Mass (	Heat Input
WA	Centralia	3845	2021	3338498		794.285	3808194	3237.726	36310042
WA	Centralia	3845	2022	3800396		1261.793	4321275	3650.313	41199918
WA	Centralia	3845	2023	4436385		1161.237	4960494	4107.822	47296887
WA	Centralia	3845	2024	3039265		934.718	3510596	2804.53	33472505
WA	Centralia	3845	2025	2449289		683.202	2279285	1981.104	21732302

(mmBtu)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-59:
NERC 2025-26 Winter Assessment

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

2025–2026 Winter Reliability Assessment

November 2025



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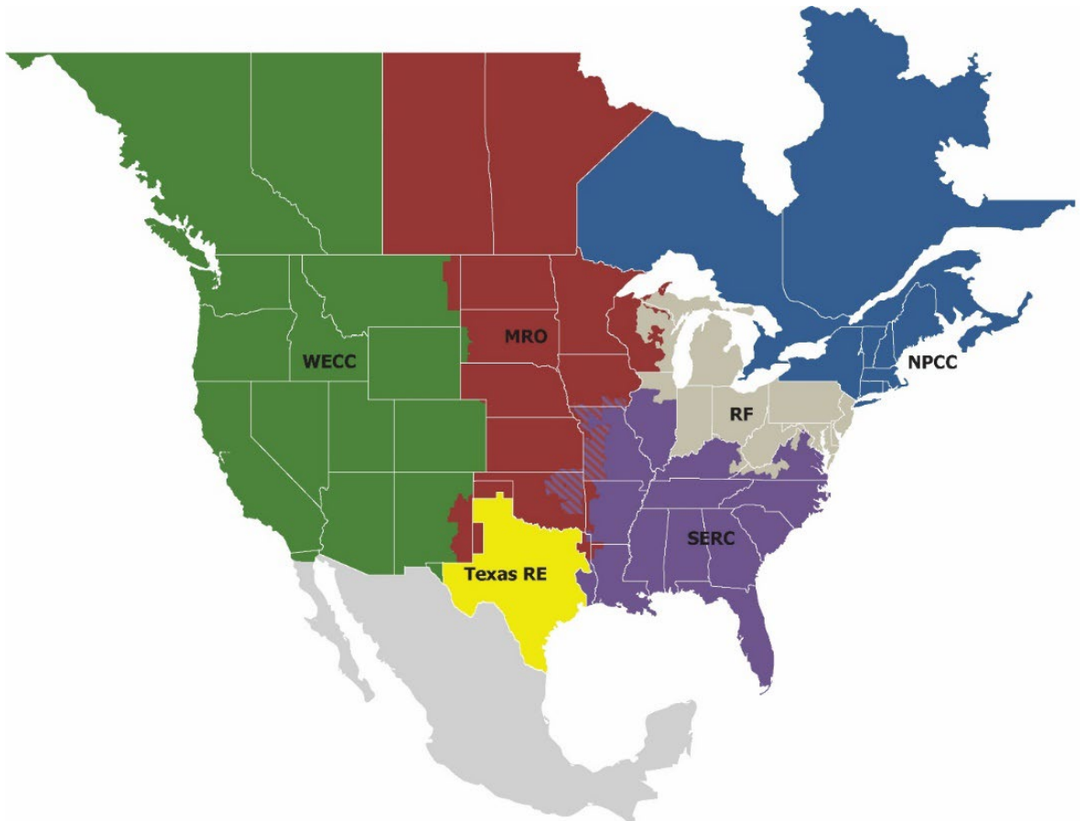
Preface

Electricity is a key component of the fabric of modern society, and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of NERC and the six Regional Entities, is a highly reliable, resilient, and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown in the map and 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	Western Electricity Coordinating Council

About this Assessment

NERC's *2025–2026 Winter Reliability Assessment* (WRA) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming winter season. In addition, the WRA 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 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 the ERO Enterprise (i.e., NERC and the six Regional Entities) and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to ensure BPS reliability. This report also provides an opportunity for industry to discuss plans and preparations to ensure reliability for the upcoming winter period.

Key Findings

This WRA covers the upcoming three-month (December–February) winter period, providing an evaluation of the generation resource and transmission system adequacy necessary to meet projected winter peak demands and operating reserves. This assessment identifies potential reliability issues of interest and regional risks. The following findings are the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as the potential operational concerns that may need to be addressed for the upcoming winter.

Two trends affecting resource adequacy across the BPS for the upcoming winter are rising electricity demand forecasts and a continued shift in the resource mix characterized by the retirement of thermal generators and growth in battery resources. After years of flat or low (~1%) peak demand growth, the aggregate peak demand for all NERC assessment areas has risen by 20 GW (2.5%) since the previous winter. Nearly all assessment areas are reporting year-on-year demand growth; some are forecasting increases near 10%. Total BPS resources have also increased since last winter, but by a smaller amount of 9.4 GW. This number includes the net change in generating capacity as well as additional demand response. These demand and resource changes are described in **Escalating Winter Demand** and **Resource Trends** sections.

The following findings are derived from NERC and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operating concerns that should receive attention for Winter 2025–2026:

1. **All areas are assessed as having adequate resources for normal winter peak-load conditions (i.e., the area's 50-50 peak forecast). However, more extreme winter conditions extending over a wide area could result in electricity supply shortfalls.** Prolonged, wide-area cold snaps can drive sharp increases in electricity demand and threaten reliable BPS generation and the availability of fuel supplies for natural-gas-fired generation. Four severe arctic storms have descended to cover much of North America since 2021, causing regional demand for electricity and heating fuel to soar and exposing generation and fuel infrastructure in temperate areas to freezing conditions.[1] The following areas face risks of electricity supply shortfalls during periods of more extreme conditions this winter (see **Figure 1**):

    - **NPCC-Maritimes**: The peak demand forecast has fallen slightly (-1.6%) in the NPCC-Maritimes assessment area, contributing to higher reserves compared to the 2024–2025 winter. Maritimes is projected to have an Anticipated Reserve Margin (ARM) of 16.9%, which is 270 MW below the area's Reference Margin Level of 20% . New Brunswick has long-term energy contracts that can be used to mitigate resource adequacy challenges through the purchase of energy on a day-ahead basis. NPCC's all-hours probabilistic assessment for the NPCC Region included the simulation of both a base case (i.e., normal 50/50 demand) and highest peak load scenario (having an approximate 7% chance of occurring), for both an expected and a low-likelihood, reduced-resource condition. The preliminary results of this assessment indicate that operators in Maritimes are likely to require emergency operating mitigations and/or energy emergency alerts (EEA) during above-normal demand or low-resource output conditions.
    - **NPCC-New England**: A lower peak demand forecast and additional resources from demand response and firm imports offset recent generator retirements, resulting in little change to the NPCC-New England ARM for this winter. New England continues to closely monitor regional energy adequacy, particularly during extended cold snaps where constrained natural gas pipelines contribute to rapid depletion of stored fuel supplies. ISO-NE's deterministic winter scenario analysis shows limited exposure to energy shortfalls this winter. In New England, winter energy concerns are highest in scenarios when stored fuels are rapidly depleted; during these periods, timely replenishment is critical to minimizing the potential for energy shortfalls.
    - **SERC-East**: The winter peak demand forecast has increased by 700 MW (1.6%) since last winter, while winter firm capacity has declined, resulting in lower reserves. SERC-East has changed from a summer-peaking area to potentially peaking during both summer and winter. This is due to the continued addition of solar photovoltaic (PV) generation that shaves off summer peak demand and a trend toward electrification of heating that drives up winter peak demand. All-hours probabilistic analysis from SERC found some load-loss hours (<0.1 hrs) and small amounts of expected unserved energy, with the highest risk occurring during above-normal peak demand and early morning hours when solar output is absent.
    - **SERC-Central:** Additional demand response and flat load growth since last winter is offsetting declining resource capacity (down 1,120 MW), resulting in little change to the ARM at 30.5%. There are adequate resources for normal winter peak demand; however, higher levels of demand that can occur during extreme cold temperatures can result in insufficient reserves that operators would need to manage with non-firm imports and potential energy emergencies.
    - **Texas RE-ERCOT:** Strong load growth from new data centers and other large industrial end users is driving higher winter electricity demand forecasts and contributing to continued risk of supply shortfalls. For the upcoming winter season, Texas RE-ERCOT is expected to continue facing reserve shortage risks during the peak load hour and high-

[1] See detailed reports on the January 2024 and January 2025 Arctic Storms, Winter Storm Elliott, and Winter Storm Uri.

net-load hours, particularly under extreme load conditions that accompany freezing temperatures. Elevated forced outage of thermal resources and reduced output from intermittent resources during these conditions exacerbates the risk of supply shortfalls. In winter, peak demands typically occur before sunrise and after sunset coinciding with the unavailability of solar generation making the system dependent on wind generation and dispatchable resources. Data centers are altering the daily load shape due to their round-the-clock operating pattern, lengthening peak demand periods. Additional battery storage and demand-response resources since last winter help mitigate shortfall risks. However, with the continued flattening of the load curve, maintaining sufficient battery state of charge will become increasingly challenging for extended periods of high loads, such as a severe multi-day storm like Winter Storm Uri.

- **WECC-Basin**: There is sufficient capacity in the area for expected peak conditions; however, Balancing Authorities (BA) are likely to require external assistance during extreme winter weather that causes thermal plant outages, adverse wind turbine conditions, and natural gas fuel supply issues for area internal resources. External assistance may not be available during region-wide extreme winter conditions. With an expected winter peak demand of 11.1 GW, under an extreme combination of generator derates and outages, the region could be short 1.6 GW before imports. Forecasted net internal demand has increased 1% since last year, with little change in winter capacity. Note that the WECC-Basin assessment area includes Utah, southern Idaho, and a portion of western Wyoming. In prior WRA reports, this part of the BPS was included as part of the WECC-NW assessment area. The *2025–2026 WRA* includes a new assessment area map for the Western Interconnection. The new assessment area boundaries provide reliability risk information in more geographic detail for the United States and Mexico.
- **WECC-NW**: Like WECC-Basin, there is sufficient capacity in the area for expected peak conditions; however, BAs 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. Over 3 GW of new resources have been in development for the assessment area this year, primarily battery storage, solar PV, and wind resources. Delays that threaten timely completion of these resource additions will make the area more reliant on imports to meet peak demand.

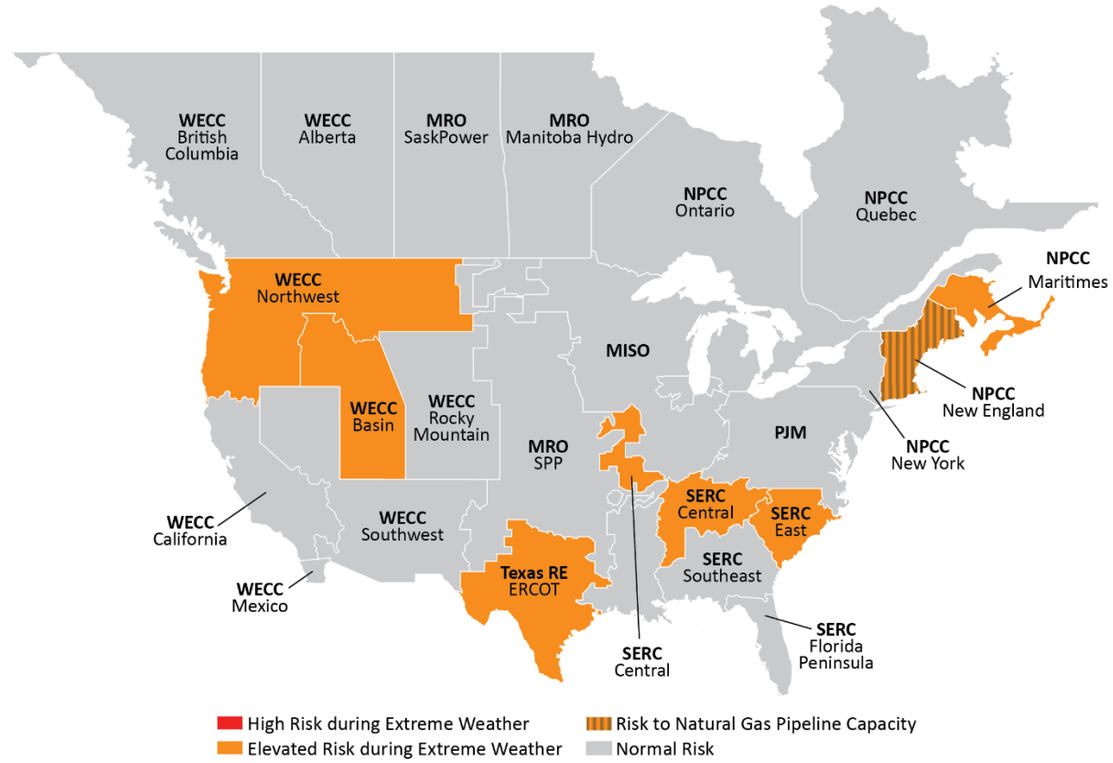


Figure 1: Winter Reliability Risk Area Summary

2. **The performance of natural gas production and supply infrastructure during peak winter conditions will again have a significant effect on BPS reliability.** Natural gas is an essential fuel for electricity generation in winter. Winter fuel supplies for thermal generators must be readily available during the periods of high electricity and natural gas demand that accompany extreme cold weather. Yet these periods are the most challenging for natural-gas-fired Generator Operators to obtain sufficient fuel and delivery. Natural gas production often falls off in extreme winter temperatures as supply infrastructure is affected by freezing issues, and Generator Operators that fail to secure firm fuel delivery are frequently unable to access fully subscribed pipelines. Evidence from the past two winters indicates notable improvement in the delivery of natural gas to BPS generators since winter storms Elliott and Uri with overall less natural gas production decline during cold weather and fewer natural gas infrastructure

force majeures.[2] Still, natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America, resulting in uneven application of protections and continued supply risks during extreme conditions. Furthermore, timing misalignments between the natural gas and electric markets continue to challenge generator fuel procurement in advance of severe winter conditions that occur over winter holiday weekends. As winter approaches, NERC encourages all entities across the gas-electric value chain—from production to the burner tip—to take all necessary preparations for extreme cold and keep natural gas flowing and the lights on.

3. **Cold weather Reliability Standards first introduced in 2023 have been improved prior to the upcoming winter and address recommendations from winter storms Elliott and Uri.** In September 2025, the Federal Energy Regulatory Commission (FERC) approved EOP-012-3 with an effective date of October 1, 2025, concluding the development of Reliability Standards for generator cold weather preparedness.[3] The EOP-012 Reliability Standard contains requirements for generator freeze protection measures, cold weather preparedness plans, and operator training. Among the improvements in the new version are enhanced and expanded requirements to ensure that Generator Owners (GO) are implementing corrective actions to address known issues affecting their ability to operate in cold weather in a timely manner. NERC collects data on the winterization of generating units, which, in conjunction with NERC's monitoring of BPS performance and analysis of cold weather events, helps determine the effectiveness of Reliability Standards. NERC submitted to FERC its first annual *Cold Weather Data and Analysis* informational filing in October 2025.[4] Based on the data reported this year, 96% of the total net winter capacity reported extreme cold weather temperatures (ECWT) at or below 32 degrees Fahrenheit, triggering winter preparedness measures under the Cold Weather Preparedness Standard, and 99% of total net winter capacity in the continental US reporting the ability to operate at the calculated ECWT. As the first such report, this *Cold Weather Data and Analysis* filing provides a benchmark for future analysis.

Recommendations

To reduce the risks of energy shortfalls on the BPS this winter, NERC recommends the following:

- Reliability Coordinators (RC), BAs, and Transmission Operators (TOP) in the elevated risk areas identified in the key findings should review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially high generator outages and extreme demand levels. Operators should review NERC's Resources on Cold Weather Preparations.
- GOs should complete winter readiness plans and checklists prior to December, deploy weatherization packages well in advance of approaching winter storms, and frequently check and maintain cold weather mitigations while conditions persist.
- BAs should be cognizant of the potential for short-term load forecasts to underestimate load in extreme cold weather events and be prepared to take early action to implement protocols and procedures for managing potential reserve deficiencies. Proactive issuance of winter advisories and other steps directed at generator availability contributed to improved reliability during cold weather events of the past two winters.
- RCs and BAs should implement generator fuel surveys to monitor the adequacy of fuel supplies. They should prepare their operating plans to manage potential supply shortfalls and take proactive steps for generator readiness, fuel availability, load curtailment, and sustained operations in extreme conditions.
- Generator Owners/Operators of natural-gas-fired units should maintain awareness of potential extreme cold weather developing over holiday weekends and the implications for fuel planning and procurement that may result given the natural gas purchase close dates that precede long holiday weekends.
- State and provincial regulators can assist grid owners and operators in advance of and during extreme cold weather by maintaining awareness of BA, natural gas pipeline, and gas local distribution company (LDC) operational public announcements and notices, amplifying public appeals for electricity and natural gas conservation, and supporting requested environmental and transportation waivers.

[2] See *January 2025 Arctic Events | A System Performance Review*, April 2025
[3] See NERC's Statement on FERC September Open Meeting for summary and link to FERC's order.
[4] See 2025 Cold Weather Data Collection and Analysis Informational Filing

Risk Highlights

Escalating Winter Demand

Winter electricity demand is rising at the fastest rate in recent years, particularly in areas where data center development is occurring. After several years of low (~1%) growth, total internal demand for the BPS is forecast to increase by 20.2 GW (2.5%) over last winter's forecast. The changes in forecasted net internal demand for each assessment area are shown in **Figure 2** below.[5] Assessment areas develop these forecasts based on historical load and weather information as well as future projections. Most assessment areas are projecting an increase in peak demand. SaskPower, PJM, the U.S. Southeast, and parts of the U.S. West have the largest increase in peak demand forecasts.

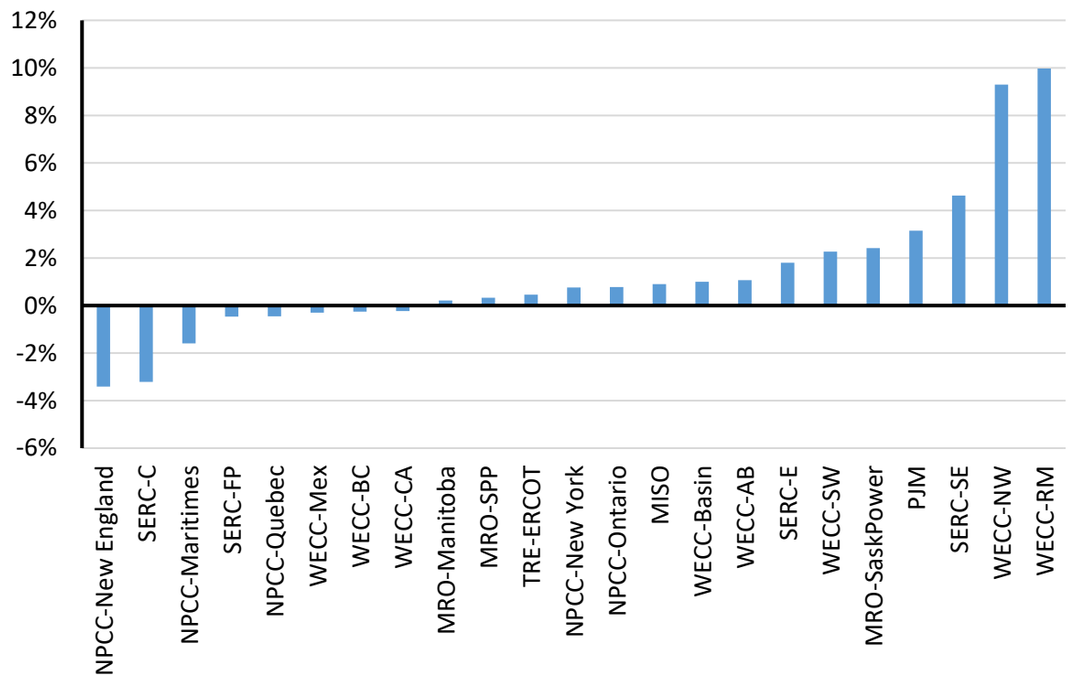


Figure 2: Change in Net Internal Demand—Winter 2025–2026 Forecast Compared to Winter 2024–2025 Forecast

[5] See **Data Concepts and Assumptions** section for demand definitions.

Resource Trends

BPS resources are growing, but at a slower rate than demand is rising. Battery and solar facilities were the leading resource types added to the BPS since last winter. Solar resources, however, often do not supply output during hours of peak winter demand. Growth in demand response is also contributing to BPS resources for the upcoming winter. **Table 1** shows the total change in BPS resources since last winter. For battery, solar, and wind resources, the table includes change in both nameplate (installed) capacity as well as the change in on-peak demand capacity, which is the capacity that resources are expected to provide in their area during the time of peak demand. For assessment-area specific information see **Variable Energy Resource Contributions** section.

Table 1: BPS Resource Change from Winter 2024–2025 to Winter 2025–2026

Resource	Net Change Nameplate Capacity (MW)	Net Change Peak Demand Capacity (MW)
Total Generator Capacity		1,335
Battery	19,659	11,121
Solar	11,097	1,176
Wind	-562	-14,238
Thermal and Hydro		3,276
Demand Response		8,112
Total Resources		9,447

Total BPS resources for serving winter peak demand, including generating capacity and demand response, have increased since last winter by 9,447 MW. Sizeable additions in battery resources and some new natural gas-fired generators contribute to the increase in resource capacity. However, the increase is offset by lower on-peak capacity values for wind resources, which are the result of revised valuations of wind resource capability at peak demand hours in some areas.[6] As a result, BPS generator capacity for winter peak demand makes up only a small portion of the total BPS increase. Generation accounts for 1,335 MW of the total 9,445 MW increase, while the larger share comes from demand response programs. Area specific information on demand response is provided in the **Demand and Resource Tables**.

The recent trend in resource additions is contributing to higher risk of electricity supply shortfalls in winter. BA operators are likely to face higher winter demand without a comparable increase in supply resources. Furthermore, the types of resources that are growing the most-- battery resources and

[6] Since last winter, ERCOT and MISO have implemented new methods for determining capacity contributions that result in lower wind and solar resources contributions at peak demand. See ERCOT's Resource Adequacy page and MISO's *Planning Year 2025-2026 Wind and Solar Capacity Credit Report*.

demand response—have unique characteristics that operators will need to account for and could limit the use of these resources in extreme winter conditions. Battery energy is reliable when it can be dispatched and has sufficient charge for the period it is needed, yet little time to recharge can be expected during extreme winter weather. System operators will need good visibility on battery state of charge and should anticipate that some extreme winter events will cause these resources to become depleted when needed. Demand response is limited by contract terms, which typically specify how often and for how long the resource may be used. Other resource types are also challenged in winter (see **Thermal Generator Fuel Adequacy and Security**). As BAs grapple with higher demand in most parts of the BPS, they will do so with resources that are becoming increasingly complex to dispatch especially in winter.

Thermal Generator Fuel Adequacy and Security

The performance of the thermal generator fleet remains critical to winter BPS operations. Winter fuel supplies for thermal generators must be readily available during periods of high demand and extreme cold weather. Generally, fuel adequacy for the thermal generating fleet is bolstered through strategic infrastructure investments and fuel stockpiling that increases the certainty of having fuel on hand that can be converted to electricity when needed. Because of this, winter performance of thermal generators is inextricably linked to extraction, processing, storage, and delivery infrastructure for a variety of fuels. Fuel supply risks have been noted in recent years' WRAs related to coal and natural gas availability and illustrate the interconnected nature of these critical energy infrastructure systems.

BPS stakeholders across North America note multiple fuel-related issues that are being monitored entering the winter season. For example, while coal represents a waning share of the overall resource mix, it continues to play an important role in meeting demand during extreme winter weather events, and oil inventories at dual-fuel gas-oil generators lessen risks related to natural gas deliverability in infrastructure-constrained regions, especially during the winter. Notably, it is infeasible or prohibitively costly to stockpile natural gas locally at power plants, and this exposes the BPS to the risk profile of the constituent systems that comprise the supply and delivery of this just-in-time fuel.

Natural Gas Generator Fuel Supplies

Natural gas generators remain a crucial part of on-peak resources meant to meet winter electricity demand across much of North America. While many Generator Owners and Operators secure backup fuel supplies at critical gas-fired generators, particularly in the northeastern United States and Florida, large contributions to the on-peak winter resource mix by single-fuel natural-gas-fired generators remain across North America (see **Figure 3**).

Natural gas generator performance can be threatened when natural gas supplies are insufficient or when natural gas infrastructure is unable to maintain the flow of fuel to critical generators. Grid operators continue to acknowledge and enhance their winter planning processes to firm up their fuel supplies and guard against natural gas disruptions, but winter storms Uri and Elliott demonstrated that combinations of natural gas flow restrictions and supply insufficiency can occur regardless of whether cold temperatures are common or uncommon in the region and can affect more than one BA area concurrently.

Many BPS areas that regularly experience cold weather events, like New England, have adopted mitigating technologies to lessen the impact of natural gas shortages through generator dual-fuel capability and stored backup fuel. In those areas, prolonged cold weather events present a risk of rapid depletion of stored backup fuel. Robust regional and distributed storage investments and winter planning for timely fuel replenishment are critical to minimizing potential energy shortfalls in the operational time frame in these areas.

Natural gas and electricity infrastructures have the added complexity of interdependence. Electricity is used to power some facilities, such as compressor stations and processing plants that make up natural gas infrastructure. These interdependencies mean that reliability events that originate on one system have the potential to affect the other and worsen the overall event magnitude or duration.

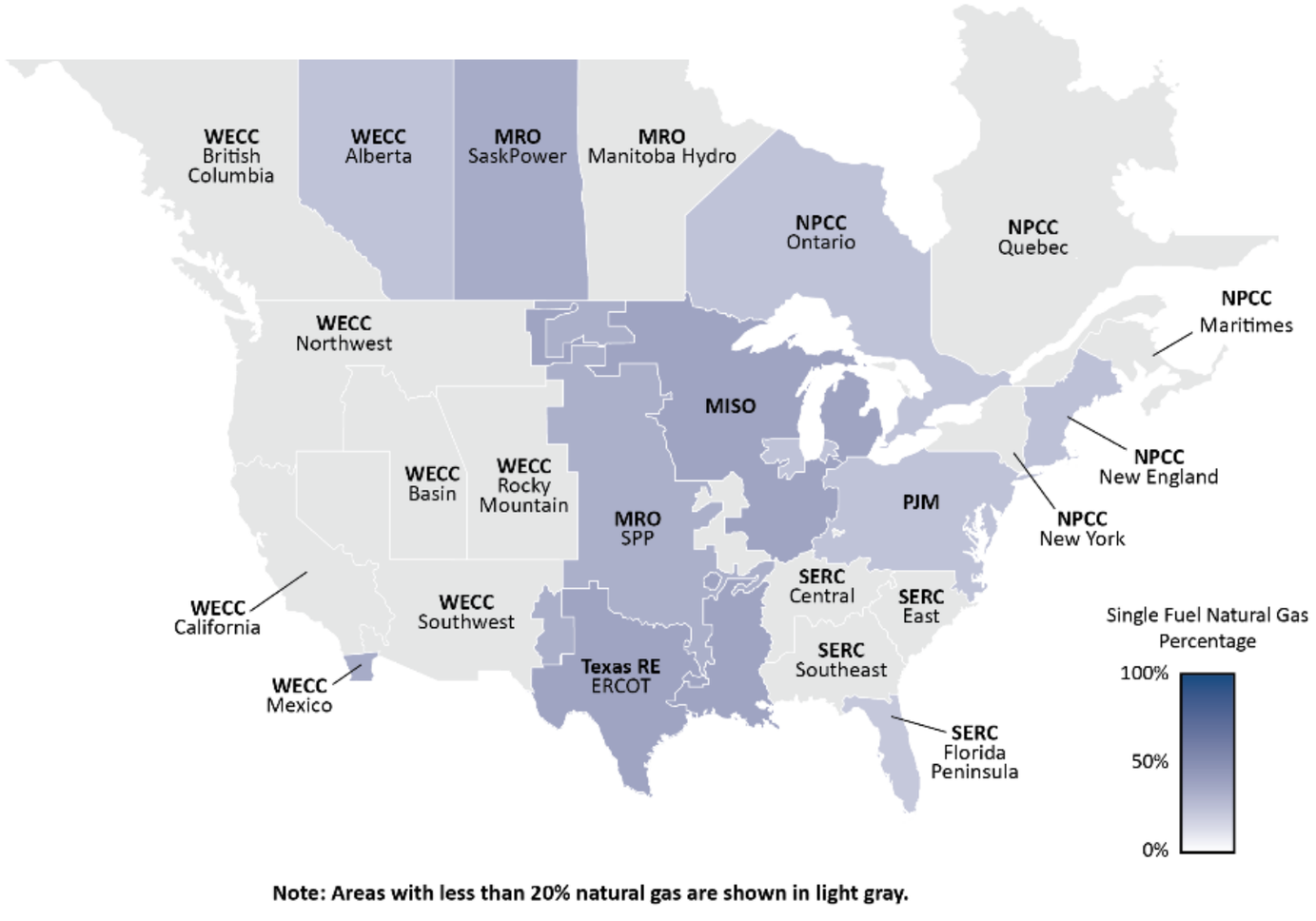
Natural gas infrastructure freeze protection mitigations are voluntary for the natural gas industry in most of North America. Texas is an exception, where the Railroad Commission of Texas adopted rules to require critical natural gas facilities to implement weather-related emergency preparation measures.[7] Lack of consistent standards for natural gas infrastructure protections will result in uneven application of freeze protections and continued supply risks during extreme conditions in many areas.

These considerations have driven higher levels of coordination to ensure sustained reliable operation of the natural gas and electricity systems. While a FERC and ERO staff review of system performance during the January 2025 arctic events[8] details improvements in electric and natural gas coordination since winter storms Uri and Elliott, the review also identifies continuing gaps between the electricity and natural gas industries that remain entering the 2025–2026 Winter season. These include natural gas scheduling challenges during winter holiday weekends, market time frame and process incompatibility, and electric power entities' lack of visibility into operational impact data from natural gas producers and suppliers.

[7] See Railroad Commission of Texas weatherization rule.

[8] FERC, NERC Issue Report on System Performance During the January 2025 Arctic Weather | Federal Energy Regulatory Commission

The U.S. Energy Information Administration (EIA)[9] anticipates a slightly milder winter than last year across much of the United States, especially in the Northeast, leading to a projection that households will consume approximately 2% less natural gas than last winter. Working natural gas storage inventories are about 5% above the previous five-year average in the United States heading into the winter season. The EIA attributes this relative surplus in part to robust production this summer and lower-than-expected natural gas consumption by power generators.



Single-Fuel Natural-Gas-Fired Generation

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

Figure 3: Single-Fuel Natural-Gas-Fired Generation Capacity Contribution to the 2025–2026 Winter Generation Mix

[9] See the U.S. Energy Information Administration's Winter Fuels Outlook 2025–26

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 (RML); or • Probabilistic indices exceed benchmarks, e.g., loss of load hours (LOLH) of 2.4 hours over the season; or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage 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 over the season); or • 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** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • 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 extreme 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 (ARM), which provide the Planning Reserve Margins for normal peak conditions, as well as reserve margins with typical forced outage levels and for the most extreme seasonal risk scenarios are provided in Table 3.

Table 3: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Reserve Margin with Typical Outages	Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	49.5%	22.3%	3.7%
MRO-Manitoba	13.7%	11.4%	6.1%
MRO-SaskPower	35.1%	29.0%	16.1%
MRO-SPP	56.5%	29.4%	16.9%
NPCC-Maritimes	16.9%	12.5%	-4.7%
NPCC-New England	58.9%	45.4%	8.7%
NPCC-New York	78.2%	52.4%	16.2%
NPCC-Ontario	28.6%	21.8%	13.2%
NPCC-Québec	15.2%	15.1%	5.0%
PJM	35.6%	24.8%	15.6%
SERC-C	30.5%	22.4%	-0.9%
SERC-E	21.9%	17.5%	3.0%
SERC-FP	41.7%	28.3%	25.6%
SERC-SE	39.7%	24.7%	17.7%
TRE-ERCOT	36.0%	25.2%	-20.0%
WECC-AB	35.2%	32.4%	10.0%
WECC-Basin	29.6%	19.7%	-21.1%
WECC-BC	25.9%	25.8%	15.4%
WECC-CA	82.3%	73.7%	57.9%
WECC-Mex	83.1%	79.4%	52.9%
WECC-NW	30.9%	29.5%	-8.5%
WECC-RM	61.7%	53.2%	10.0%
WECC-SW	104.4%	90.1%	50.1%

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 winter peak demand and resource condition information. 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 ARMs 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.

Areas highlighted in orange in **Figure 1** above have been identified as having resource adequacy or energy risks for the winter and are included in the **Key Findings** section's discussion that follows. The typical outage reserve margin includes anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced-outage margin is the same as the ARM, 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 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 winter season. Results are summarized in **Table 5**. 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 loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) declarations (see **Table 4** for a description of EEA levels).

Table 4: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	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 operating reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	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 operating reserve requirements.
EEA 3	Firm load interruption is imminent or in progress	• The energy-deficient BA is unable to meet minimum operating reserve requirements.

Energy Emergency Alerts

The combination of above-normal generation outages, low resource output, and peak loads as occurred during the extreme cold weather events of Winter Storm Uri in 2021 and Winter Storm Elliott in 2022 are ongoing winter reliability risks. When supply resources in an area fall below expected demand and operating reserve requirements, BAs may need to employ EEAs to maintain balance between available capacity and energy and real-time demand. A description of each EEA level is provided above.

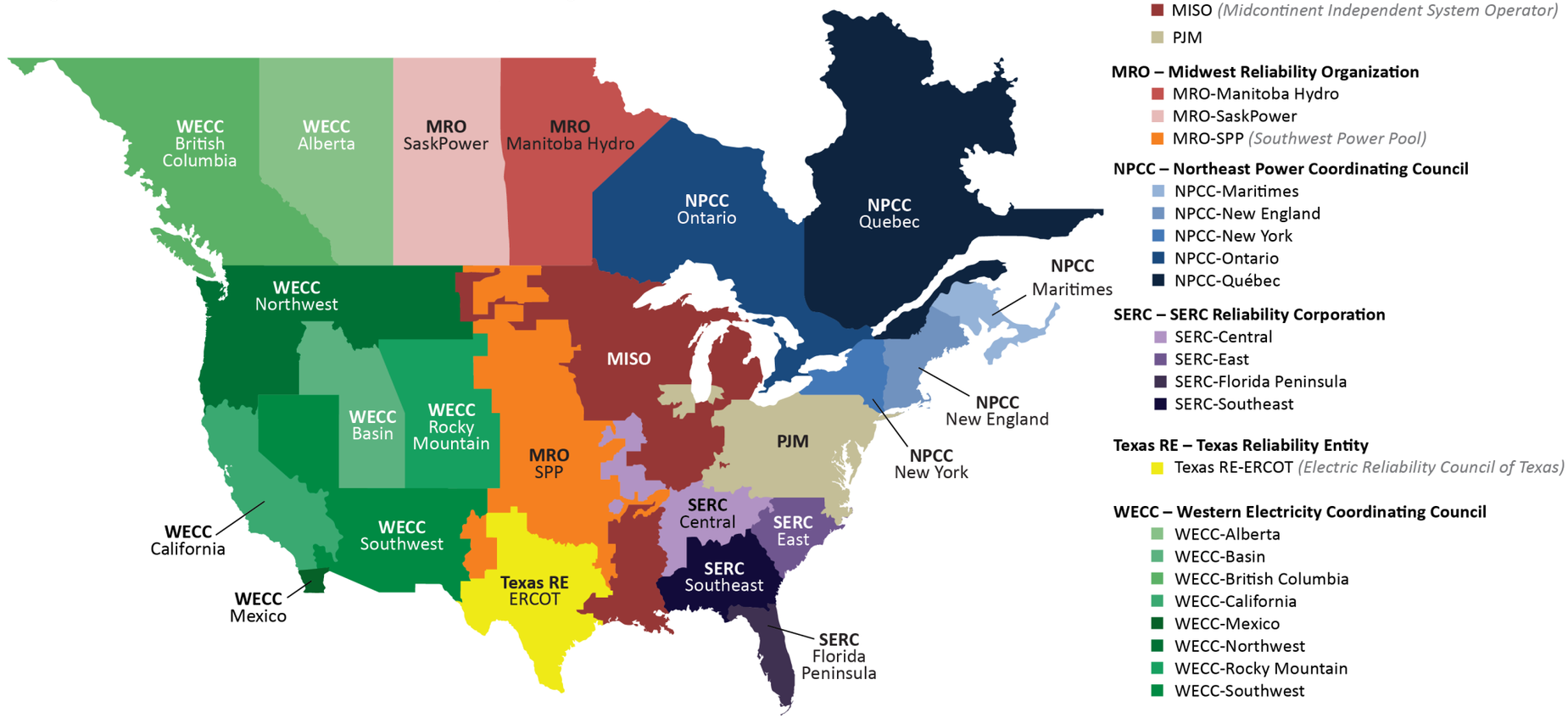
Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
MISO	Deterministic	MISO does not provide a probabilistic assessment for the WRA. MISO applies a deterministic look at expected system conditions, looking at generation availability under typical and extreme outages and looking at a typical 50/50 load forecast and an extreme 90/10 load forecast. For the upcoming winter season, under an extreme outage and extreme 90/10 load forecast, this is the riskiest scenario for the MISO footprint. This scenario produces the shortest actual reserve margin for January.
MRO-Manitoba	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 *Long-Term Reliability Assessment* (LTRA) found no load-loss or unserved energy hours for 2026.
MRO-SaskPower	Probability-based capacity adequacy assessment	SaskPower's probabilistic assessment for the 2025–2026 Winter indicates that risk of shortfalls is lower than the previous winter. LOLH for an elevated risk scenario for the 2025–2026 Winter season is 0.08 hours. The month with the highest LOLH is December (0.05 hours).
MRO-SPP	NERC 2024 ProbA	Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
NPCC	NPCC conducted an all-hour probabilistic reliability assessment that included detailed neighbor modeling and consisted of a base case and severe case examining low resources, reduced imports, and higher loads. The assessment evaluates the probabilistic indices of LOLE, LOLH, and EUE. The highest peak load scenario has an approximately 7% probability of occurring.	
NPCC-Maritimes	The Maritimes Area low-likelihood resource case assumed: wind derated by 50% for every hour in December through February and a 50% natural gas capacity curtailment for December through February (dual-fuel units assumed reverting to oil) and reduced transfer capabilities.	The preliminary assessment indicates that established operating procedures are not sufficient to maintain a balance between electricity supply and demand. Under highest peak load levels, the Maritimes Area shows a notable likelihood of utilizing its operating procedures such as reducing 30-minute reserves, initiating interruptible loads, and reducing 10-minute reserves to maintain system reliability during the upcoming winter period.
NPCC-New England	The New England Area low-likelihood resource case assumed: 500 MW of additional maintenance outages, ~4,513 MW of gas-fired generation unavailable due to fuel supply constraints, and 50% reduced import capabilities of external ties.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand
NPCC-New York	The New York Area low-likelihood resource case assumed: ~500 MW of extended maintenance in southeastern New York, 600 MW of cable transmission reduction across HVdc facilities, and ~5,000 MW of generation unavailable due to fuel delivery issues.	The preliminary results of this assessment indicate that operating procedures were not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period, for all the scenarios modeled.
NPCC-Ontario	An energy assessment for the Ontario Assessment Area was conducted for two scenarios: firm resources and firm demand with expected weather, and planned resources with planned demand with expected weather.	No cumulative LOLH or EUE risks were identified over the entire November-to-April winter season for both scenarios modeled.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
NPCC-Québec	The Québec Area low-likelihood resource case assumed 1,000 MW of generation reductions.	The preliminary results of this assessment indicate that established operating procedures are sufficient to maintain a balance between electricity supply and demand if needed. No cumulative LOLE, LOLH or EUE risks were indicated over the December–February winter period for all the scenarios modeled
PJM	Probabilistic study for the NERC Probabilistic Assessment (ProbA)	Probabilistic study for 2025–2026 Winter is not provided for the WRA. PJM performed probabilistic analysis for 2026-2027 winter as part of the 2024 ProbA summarized in NERC's 2024 LTRA. The results of this study indicate risk of load loss (<0.1 hours) and unserved energy during winter months. For the upcoming winter, load-loss hours are expected to be less than this value because forecasted load is lower and anticipated resource capacity is higher than the case studied for the 2024 ProbA.
SERC	Based on the 2024 NERC Probabilistic Assessment (ProbA) base-case result. SERC's assessment used 38 years of historical load shapes to assess the resource adequacy of years 2026 and 2028, primarily based on data from the 2024 Long Term Reliability Assessment (LTRA).	
SERC-Central		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
SERC-East		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found a small number of load-loss hours (<0.1) and EUE (61 MWh / 1 ppm) for 2026.
SERC-Florida Peninsula		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found negligible load-loss hours and EUE.
SERC-Southeast		Probabilistic analysis for the 2024 ProbA summarized in NERC's 2024 LTRA found no load-loss or unserved energy hours for 2026.
Texas RE-ERCOT	ERCOT Probabilistic Reserve Risk Model	ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
WECC	The resource adequacy work performed at WECC used the Multi-Area Variable Resource Integration Convolution (MAVRIC) model for the 2025 LTRA. The MAVRIC model is a convolution-based probabilistic model and is WECC's chosen method for developing probability metrics used for assessing demand and variable resource availability in every hour. In the resource adequacy environment, the reports produced support NERC's seasonal assessments, LTRA, and ProbA.	
WECC-AB		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Basin		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-BC		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

Table 5: Probability-Based Risk Assessment		
Area	**Type of Assessment**	**Results and Insight from Assessment**
WECC-CA		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Mexico		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-Rocky Mountain		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.
WECC-NW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026. Results for a case where new resource additions are not completed for the upcoming winter found some EUE and LOLH.
WECC-SW		The results of the probabilistic assessment reveal no EUE or LOLH for Winter 2025–2026.

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 ARM compared to a reference margin level (RML) that is established for each area 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**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme winter 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 WRA 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 vary by assessment area and provide further insights into the risk conditions forecasted for this upcoming winter period.



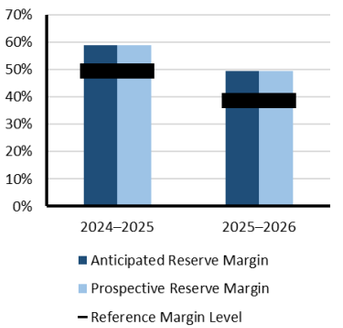


MISO

The Midcontinent Independent System Operator, Inc. (MISO) is an independent, not-for-profit organization responsible for operating the bulk electric power system and administering wholesale electricity markets across 15 U.S. states and the Canadian province of Manitoba. MISO ensures the reliable delivery of electricity to approximately 45 million people by managing regional transmission operations as well as energy and ancillary services markets and advising on long-term resource planning. The MISO footprint includes 39 Local BAs and more than 550 market participants. MISO operates one of the world's largest organized electricity markets, with its members operating a system that consists of over 77,000 miles of transmission lines and approximately 1,888 generating units. The peak electricity demand on the MISO system currently occurs during the summer season. MISO's footprint lies across three regional entities (MRO, RF, and SERC), but MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

- MISO expects limited risk in the 2025–26 Winter season as MISO was able to procure 6.1% more resources through the annual planning reserve auction than required by its minimum resource adequacy target. A further 3.3 GW of resources were available but not chosen to be committed for the winter season.
- Some risk has been identified for this upcoming winter season. In a high generation outage and high winter load scenario reliability is expected to be maintained by reliance upon operational mitigations that include non-firm energy transfers into the system, energy-only resources not subject to a must-offer requirement that may still offer into the energy markets, load-modifying resources, and internal transfers that exceed the Sub-Regional Import/Export Constraint (SRIC/SREC) between the MISO North/Central and South areas.
- MISO continues to coordinate with neighboring RCs and BAs to improve situational awareness and vet any needs for energy transfers to address extreme system conditions.
- MISO continues to survey and coordinate with its members on winter preparedness and fuel sufficiency.
- MISO has implemented a seasonal resource adequacy construct and seasonal unit accreditation to better affirm adequate supply in all seasons.

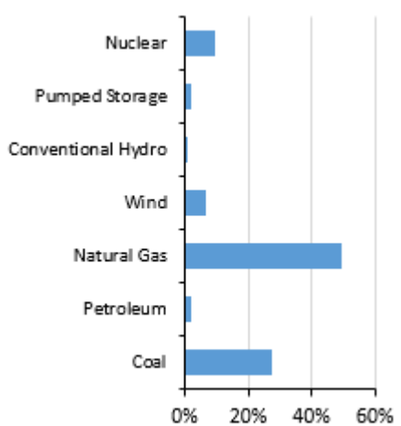
On-Peak Reserve Margin[10]



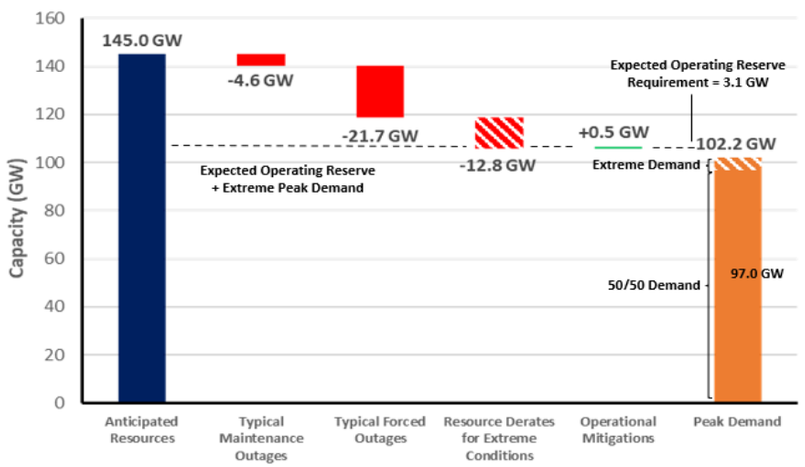
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with generator outages from freezing or fuel supply issues and low wind output result in the need to employ operating mitigations (i.e., demand response and transfers).

On-Peak Resource Mix



2025–2026 Winter 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 net internal demand and additional demand during extreme weather conditions (e.g., Winter Storm Enzo) using member submitted data and historical load data

Typical Maintenance Outages: Rolling three-year winter average of peak-day maintenance and planned outages

Typical Forced Outages: Three-year average of all peak-day outages that were not planned

Resource Derates for Extreme Conditions: Represents derates aligning with the most extreme hour of each of the past 3 years,

Operational Mitigations: Non-firm energy transfers into the system, energy-only resources that do not have a must-offer requirement, or internal transfers that exceed the SRIC/SREC between the MISO North/Central and South regions

[10] The MISO Risk Scenario Assessment for the 2025-26 Winter Season is not directly comparable to that for the 2024-25 Winter Season as methodology improvements have been implemented.



MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas. Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and natural gas to approximately 293,000 customers in southern Manitoba. Its service area is the province of Manitoba, which is 251,000 square miles. Manitoba Hydro is winter-peaking. Manitoba Hydro is its own Planning Coordinator (PC) and Balancing Authority (BA). Manitoba Hydro is a coordinating member of MISO, which is the RC for Manitoba Hydro.

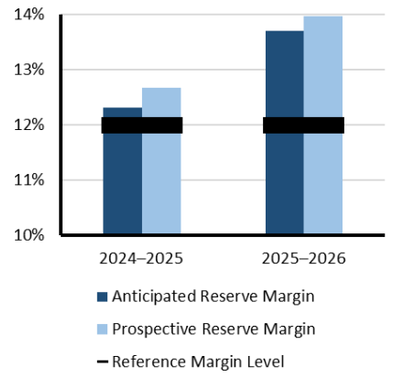
Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for Winter 2025–2026.
- Manitoba Hydro expects to reliably supply its internal demand and export obligations even under continued drought conditions.
- Manitoba Hydro is experiencing well below-average water supply conditions; however, the Manitoba Hydro system is designed and operated such that reliable operations can be maintained under extreme drought.
- The ARM for Winter 2025–26 exceeds the 12% RML.

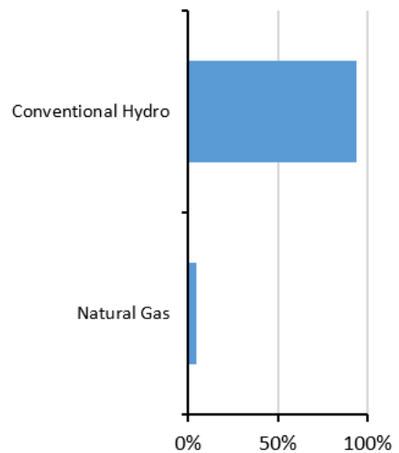
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

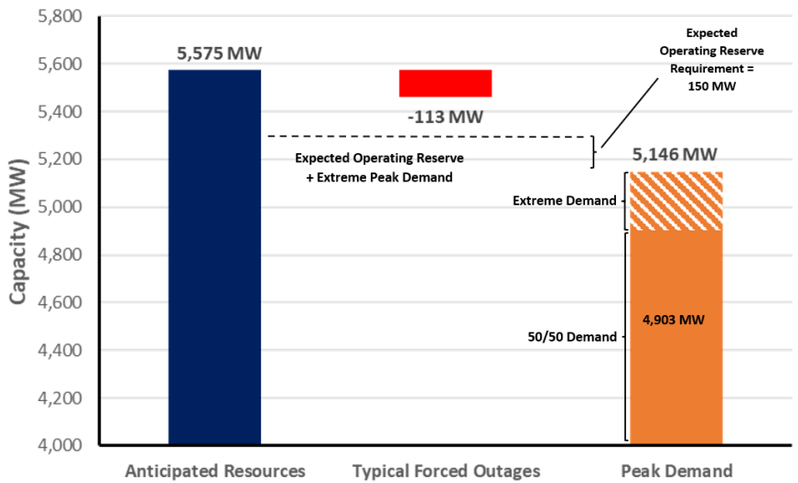
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario

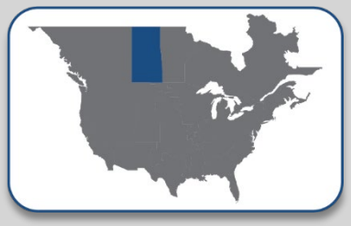


Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of weather data

Typical Forced Outages: Accounts for average forced outages



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 Bulk Electric System (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.

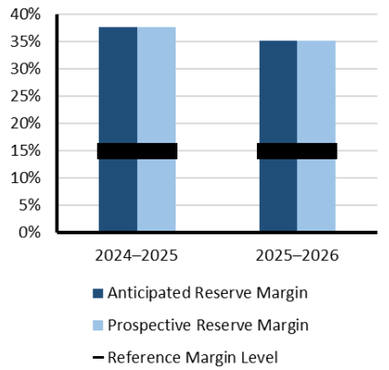
Highlights

- Saskatchewan experiences its peak load during the winter months due to extreme cold weather.
- Based on the planned maintenance, 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 the 2025–2026 Winter.
- During extreme winter conditions, SaskPower would utilize available demand-response programs, short-term power transfers from neighboring utilities, maintenance rescheduling, and/or short-term load interruptions to manage the situation.

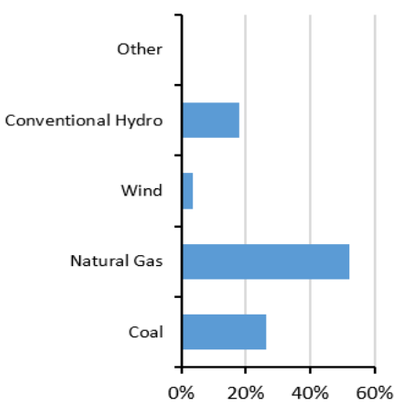
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

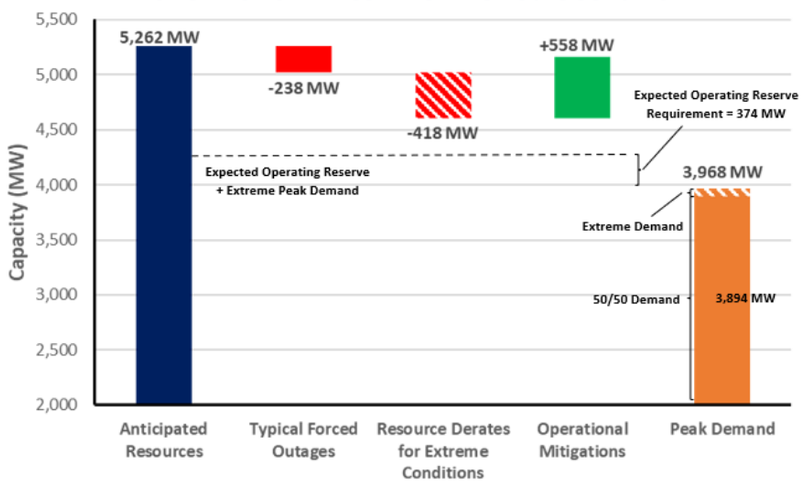
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Based on the historical load variability, SaskPower calculates a probability density function for load to simulate various scenarios that include extreme conditions.

Typical Forced Outages: Estimated using SaskPower forced outage model

Resource Derates for Extreme Conditions: Wind capacity is derated by 96% due to the cut-out of most wind farms below -30°C. Solar generation is expected to be fully unavailable under extreme conditions.

Operational Mitigations: Includes the non-firm import capability (360 MW) and generators in layup status (167 MW) that can be brought online with one to five days' notice; additional demand-side resources are estimated based on other demand response programs and non-firm loads that require 15 minutes to 2 hours of notification



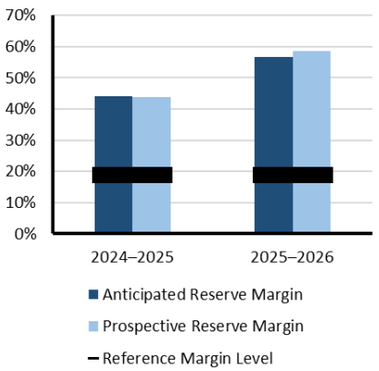
MRO-SPP

SPP's 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

- SPP anticipates that planning reserves are adequate for the upcoming winter season even as SPP continues to set new winter season load records.
- SPP does not anticipate any emerging reliability issues impacting the area for the 2025–2026 Winter season but realizes that interruptions to fuel supply combined with higher penetration of variable energy resources could create unique operation challenges.
- SPP continues to work at enhancing communications and operator preparedness with neighboring regions to address potential electric deliverability issues associated with extreme weather events.
- To minimize conservative operations, EEAs, and mid-range forecast error uncertainty response in wind forecasts, SPP implemented several new operational mitigation processes and procedures to deal with high-impact real-time areas of reliability concern.
- SPP has proposed numerous resource adequacy initiatives, including addressing EUE standards, fuel assurance, winter planning reserve margins, outage policies, demand response, and accreditation; all were recently approved by FERC.

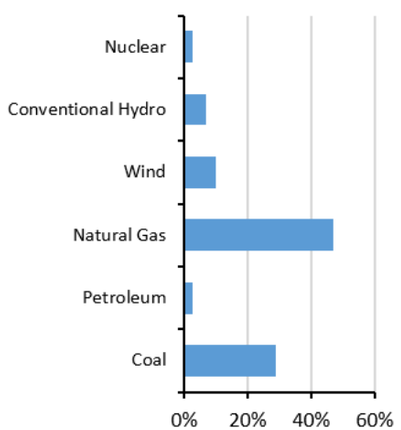
On-Peak Reserve Margin



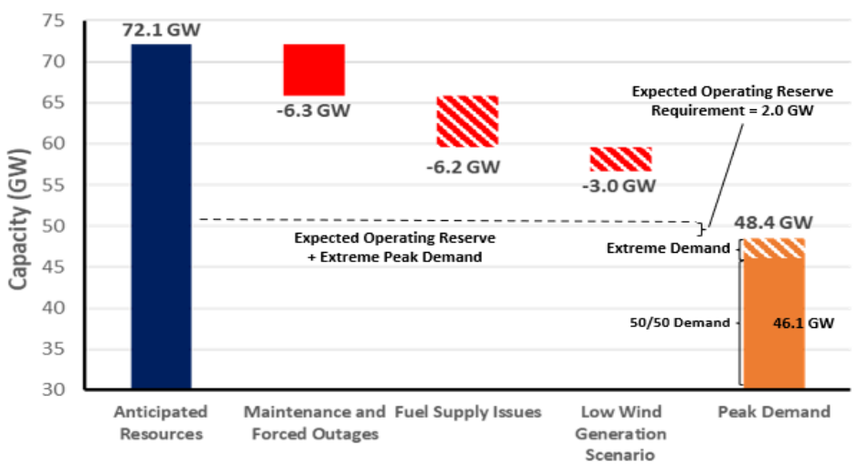
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter 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 using historical data

Maintenance and Forced Outages: A capacity derate of 6.3 GW for maintenance outages, forced outages, and performance in extreme weather based on historical data

Fuel Supply Issues: BA derate of 6.2 GW based on MW capacity of gas-fired generators experiencing fuel supply issues in winter storm Elliott.

Low Wind Generation Scenario: 3 GW of wind potentially off-line when temperatures fall below their cold weather performance packages



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 balancing authority for New Brunswick, Prince Edward Island, and the northern portion of Maine. Nova Scotia Power Inc. (NSPI) is the balancing authority 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.

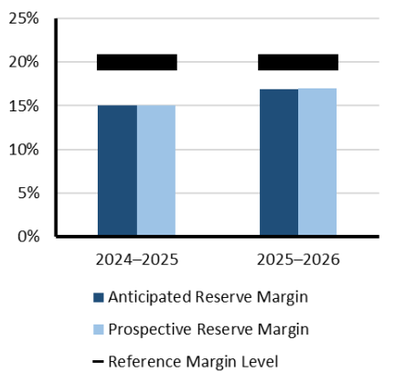
Highlights

- The Maritimes has a diversified mix of capacity resources fueled by oil, coal, hydro, nuclear, natural gas, wind, dual-fuel oil/gas, tie benefits, and biomass with no one type making up more than about 27% of the total capacity in the area.
- The Maritimes has long-term energy contracts in place for its winter supply and can purchase additional energy in the day-ahead and in real time as required.
- As part of the winter planning and preparation process, dual-fueled units will have sufficient supplies of heavy fuel oil stored on site to enable sustained operation in the event of natural gas supply interruptions.

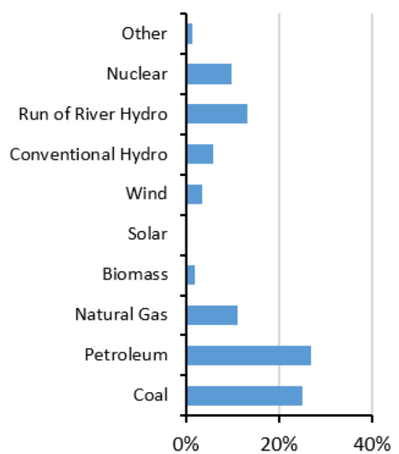
Risk Scenario Summary

Expected resources do not meet operating reserve requirements under normal peak-demand scenarios. Normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response, transfers, appeals) and EEAs. NPCC probabilistic analysis indicates some risk of unserved energy and LOLH under high demand or low resource scenarios.

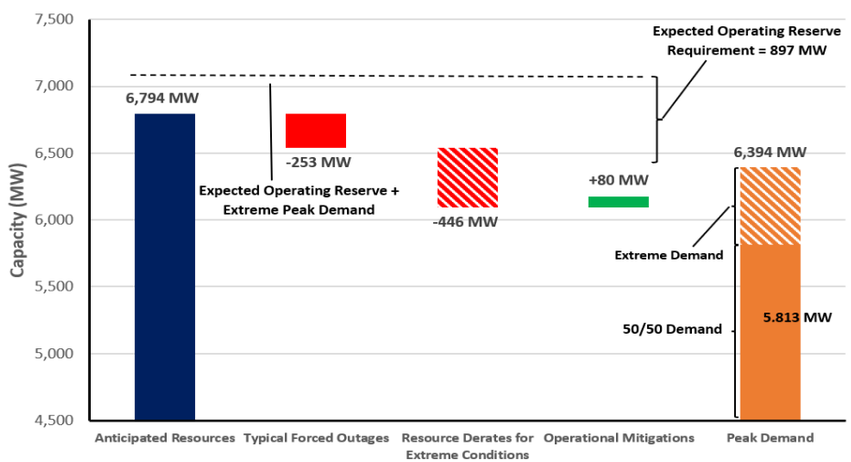
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Scenario peak load with adjustment calculated by adding a 10% margin of error to the peak internal demand forecast taken from the *Long-Term Reliability Assessment* (LTRA) for the 2025–2026 Winter period (aligns with the all-time winter peak, which occurred on February 4, 2024)

Typical Forced Outages: Based on historical operating experience

Resource Derates for Extreme Conditions: Based on ambient temperature thermal derates, wind derated to zero, as well as natural gas capacity derated by 50% due to supply issues

Operational Mitigations: Based on emergency operations and planning procedures in place including fuel switching



NPCC-New England

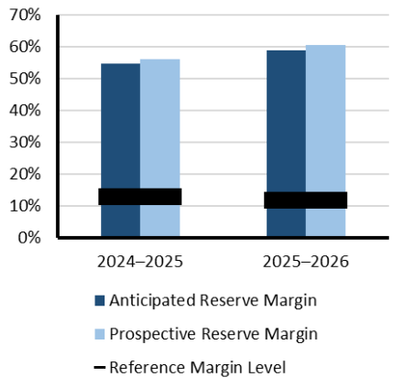
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New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

- ISO-NE expects to meet its regional resource adequacy requirements this 2025–2026 Winter operating period without calling upon operating procedures to maintain a balance between electricity supply and demand.
- A standing concern is whether there will be sufficient energy available to satisfy electricity demand during an extended cold spell given the existing resource mix, fuel delivery infrastructure, and expected fuel arrangements without considerable effort to replenish stored fuels (i.e., fuel oil and liquefied natural gas (LNG)).
- ISO-NE expects to have sufficient capacity resources to meet the 2025–2026 50/50 and 90/10 winter peak demand forecast of 19,616 MW and 21,125 MW, respectively, for the weeks beginning January 10, January 17, and January 24.
- ISO-NE has recently developed the Regional Energy Shortfall Threshold (REST) as an effort to quantify the tolerable risk of energy shortfall during extreme events. Within the 0.25% highest-risk scenarios, the REST thresholds are 3.0% normalized EUE over 72-hour periods and 18.0 hours over 21-day periods.
    - ISO-NE does not anticipate exceeding the REST criteria for Winter 2025–2026.

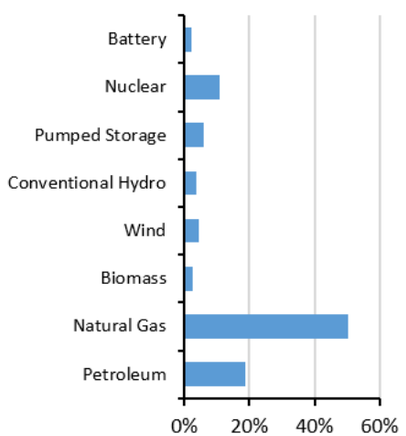
On-Peak Reserve Margin



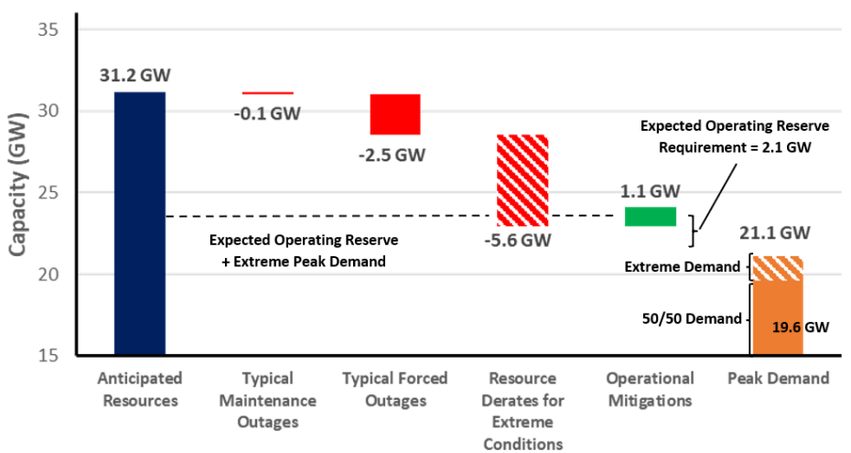
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed demand scenarios. Above-normal winter peak load combined with high generator outages could result in the need for operating mitigations (i.e., demand response and transfers). Prolonged extreme cold weather events that result in depletion of stored fuels can lead to resource shortfalls.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast capturing the region's coldest day in the last 30 years using current and future load models

Typical Maintenance Outages: Based on historical weekly averages

Typical Forced Outages: Based on seasonal capacity of each resource as determined by ISO-NE

Resource Derates for Extreme Conditions: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages and additional reductions for generation at risk due to natural gas supply and cold weather-related outages

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 WRA, the established RML 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 2025–2026 IRM at 24.4%.

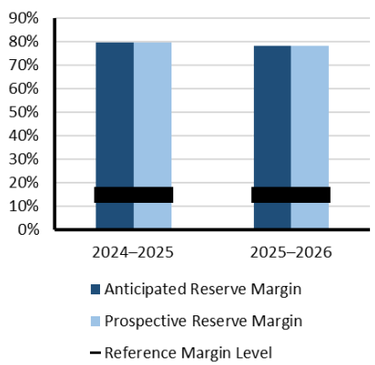
Highlights

- New York is presently a summer-peaking area, and no emerging reliability issues are anticipated during the 2025–26 Winter assessment period.
- Expected resources meet operating reserve requirements under the assessed demand and resource scenarios. A scenario involving an extended cold snap that causes above-normal demand and diminished natural gas supplies would result in low but sufficient reserves.
- The preliminary results of the NPPCC winter probabilistic assessment indicate that operating procedures are not needed to maintain a balance between electricity supply and demand. No cumulative LOLE, LOL,H or EUE risks were indicated over the December–February winter period for all the scenarios modeled.

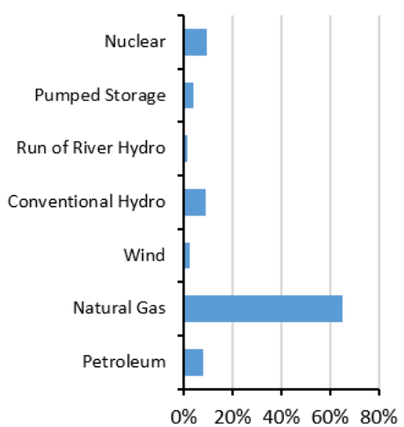
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed demand and resource scenarios.

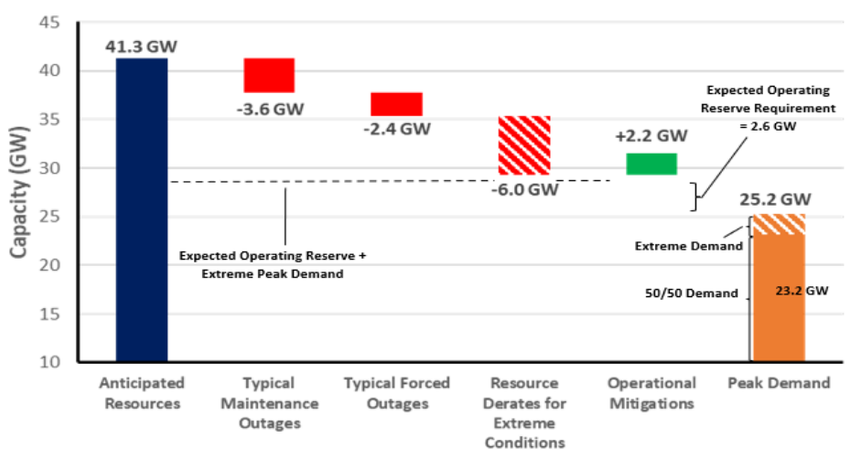
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Based on planned scheduled maintenance

Typical Forced Outages: Based on 5–year averages from GADS data.

Resource Derates for Extreme Conditions: Potential natural gas generation at risk if non-firm supply is unavailable in a period of extended cold weather. Based on a 2025 analysis, approximately 6,307 MW of gas generation with non-firm fuel supplies could be unavailable.

Operational Mitigations: Based on NYISO operating procedures



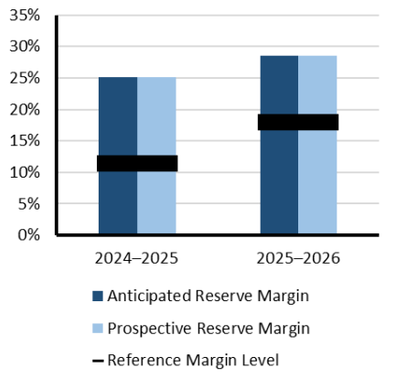
NPCC-Ontario

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 almost 16 million people. The Independent Electricity System Operator (IESO) is the balancing authority 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

- As Ontario is a summer-peaking province, there is typically a lower risk of reliability issues during the winter than the summer. However, Ontario regularly experiences extreme cold weather in the winter.
- NPCC-Ontario is well prepared for Winter 2025–2026, and IESO expects that the electric system will remain reliable with reserve margins well above required levels.
- Operators and forecasters in Ontario work closely with neighboring jurisdictions to manage extreme weather events.
- Natural-gas-fired generators in Ontario are supplied by pipelines with access to the Enbridge Gas Dawn Hub and its associated storage facilities, which significantly reduces natural gas deliverability and reliability concerns by connecting those systems to several major gas transportation corridors, enabling access to multiple supply basins.

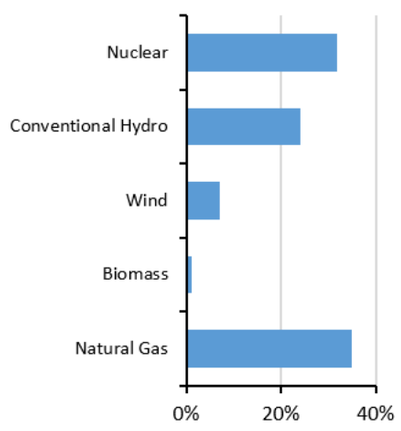
On-Peak Reserve Margin



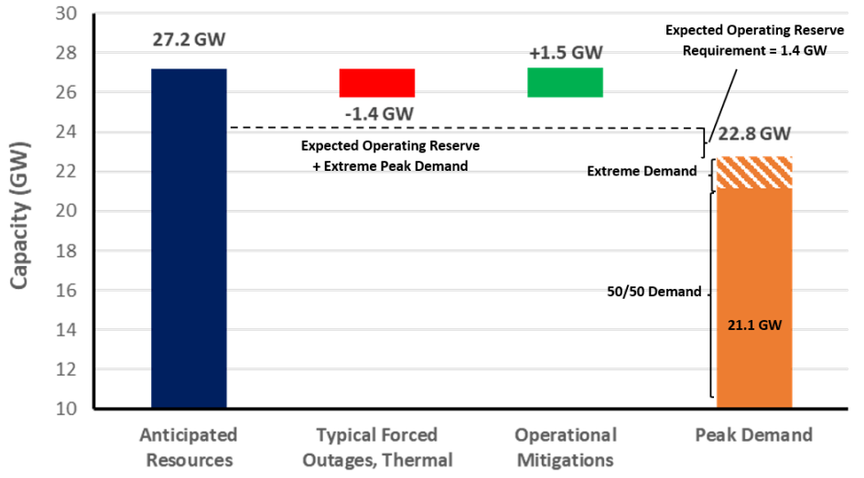
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter 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 from 31 years of winter demand history

Typical Forced Outages, Thermal: Based on analysis of a rolling five-year history of actual forced outage data.

Operational Mitigations: Imports anticipated from **neighbors** during emergencies



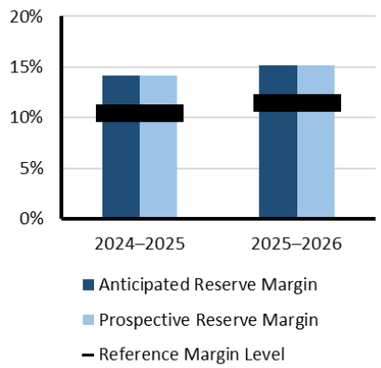
NPCC-Québec

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 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 predominately 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

- NPCC-Québec projects adequate capacity margins above its reference reserve requirements and that system resource adequacy will be maintained for the province for the 2025–26 Winter assessment period.
- No hydropower performance issues are expected during extreme cold because of design criteria for cold weather.
- No fuel supply or transportation issues are anticipated for the upcoming winter season.
- While a slight decrease in net firm transfers has occurred since last winter (-89 MW), significant increases in demand-side management programs (+450 MW year-over-year) have been realized over the same period and are expected to compensate for this winter's modest expected load growth.

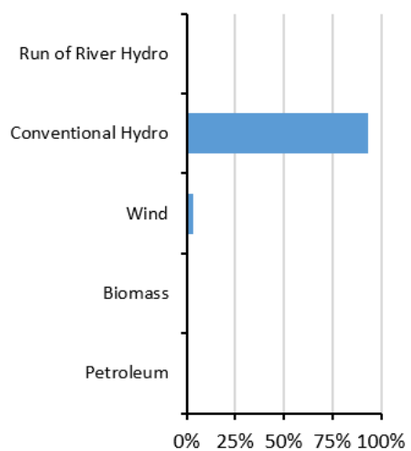
On-Peak Reserve Margin



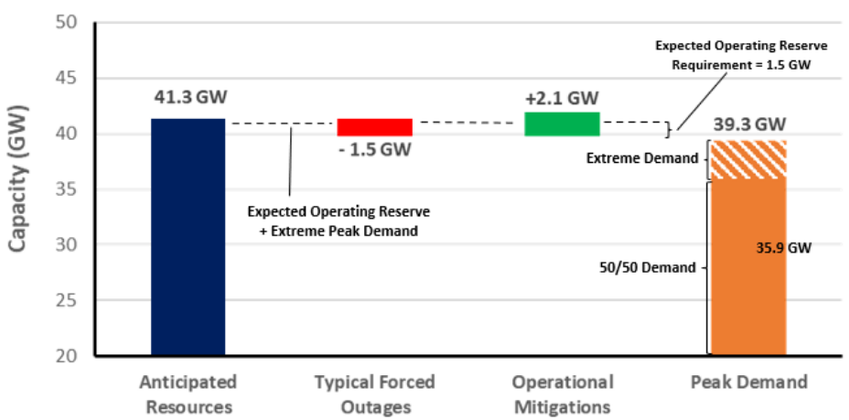
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at hour ending 8:00 a.m.

Demand Scenarios: Demand forecasts include demand-side resources. The demand side resources are the same for the 50/50 and extreme demand scenarios. The extreme load forecast is determined at two standard deviations higher than the mean, which has a 6.06% probability of occurrence.

Extreme Derates: Maintenance outages and other deratings are already included in existing-certain capacity calculation. Wind capacity is 64% derated

Typical Forced Outages: Unplanned outages are 1,500 MW.

Operational Mitigations: Operational mitigations include imports from neighboring areas and reduction of reserves



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 with an approximate population of 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.

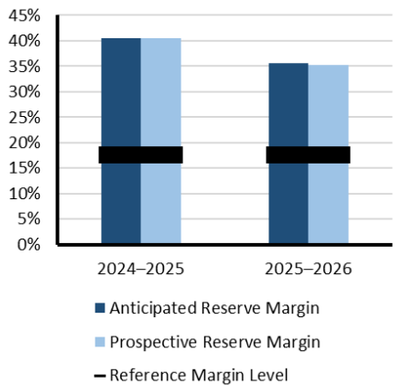
Highlights

- Due to the low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with highest loss-of-load risk remains the hour with highest forecasted demand.
- PJM is expecting little capacity adequacy risk during Winter 2025–2026 and expects around 35% installed reserves, which is above the target IRM of 17.7% necessary to meet the 1-day-in-10-years LOLE criterion.
- Last winter, PJM hit a new all-time winter peak, but generator preparations anticipating congestion and tight capacity projections led to sufficient reserves throughout the demand event and PJM's transmission system performed well.
- The decrease in reserves from Winter 2024–2025 is due to load increases and retirement of generation without like (non-solar dispatchable) replacement generation.

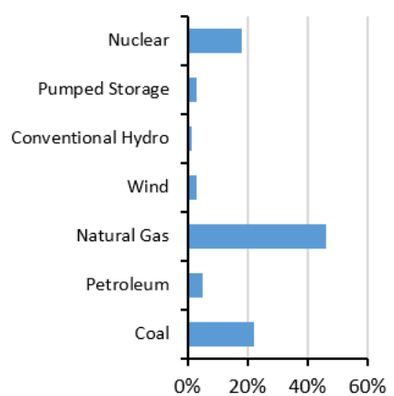
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

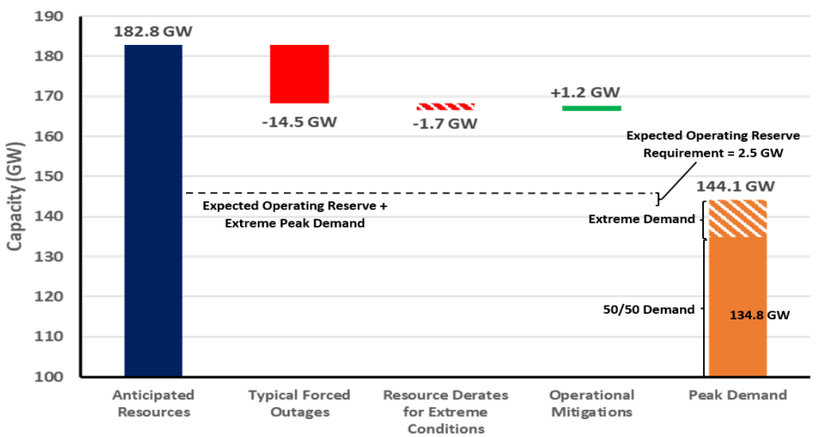
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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

Typical Forced Outages: Based on historical data and trending

Resource Derates for Extreme Conditions: Reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: accounts for an estimated value based on operational / emergency procedures



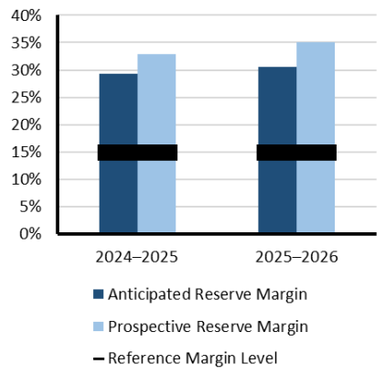
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 planning entities, and 6 RCs.

Highlights

- SERC-Central is transitioning from a summer-peaking area to a dual-peaking system.
- For the 2025–2026 Winter, SERC-Central projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Most entities across SERC-Central report that fuel security is strong since it is supported by firm natural gas contracts, storage resources, and reliable pipeline capacity. Coal inventories are projected to remain within operational ranges necessary to meet winter demand.
- Following lessons from Winter Storm Elliott, one SERC-Central entity raised its winter Planning Reserve Margin target to 26% and updated preparedness programs with improved heat trace capabilities.

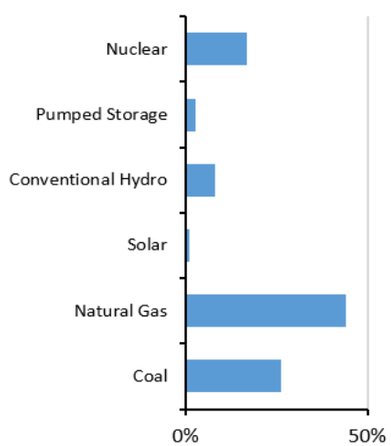
On-Peak Reserve Margin



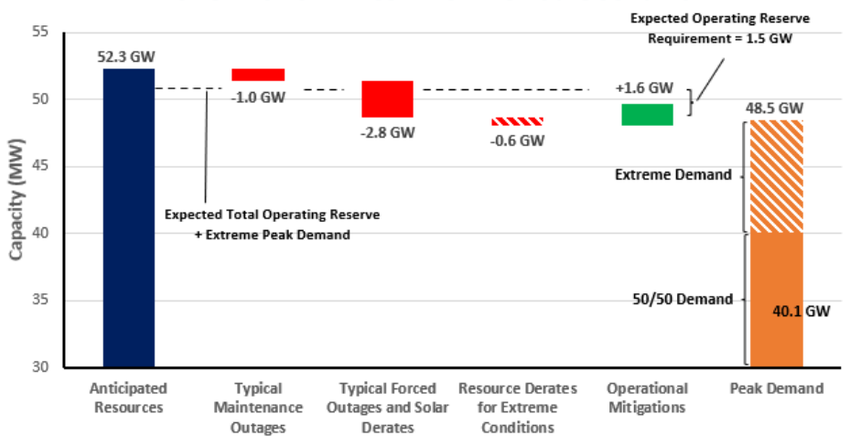
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand. A severe cold weather event that extends to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter 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 using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for expected outages during December through February

Typical Forced Outages and Solar Derate: Includes any weighted average forced-outage rates on-peak that are not factored into the anticipated resources calculation . Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions

Operational Mitigations: A total of over 1.6 GW based on operational/emergency procedures



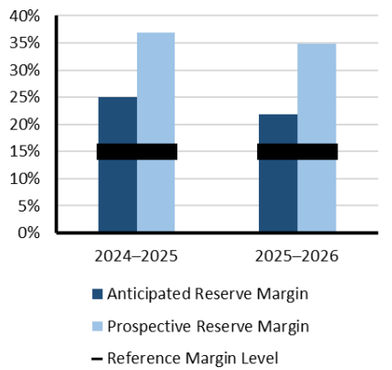
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six Regional Entities across North America that are responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- SERC-East is transitioning from a summer-peaking area to potentially peaking during both summer and winter. This shift is attributed to the continued addition of solar PV generation, which reduces summer peak demand, and a trend toward electrification of heating, which drives up winter peak demand.
- For the 2025–2026 Winter, the SERC-East region projects a sufficient level of resources to serve the expected load under median weather and typical system operating conditions, based on the 2024 NERC ProbA base-case results.
- Fuel supplies and transportation remain stable, and entities anticipate maintaining adequate coal and oil inventories with no reported changes to fuel procurement or operator plans for the upcoming winter.
- Probabilistic Base Case Results (Median Weather): EUE is 61.95 MWh and LOLH is 0.06 hours/year. EUE values are likely due to higher winter peaks and/or lower supply of capacity that can meet early winter morning demand.
- Mitigation measures for extreme conditions include voltage reduction (25–50 MW) and load-shedding programs that cover up to 30% of system load.

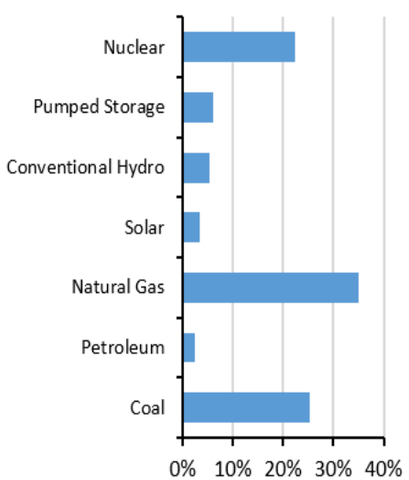
On-Peak Reserve Margin



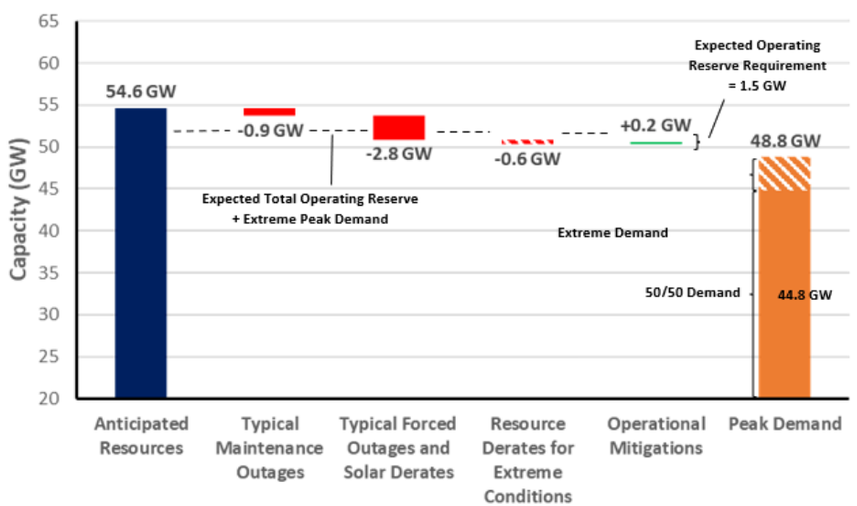
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal demand scenarios. A severe cold weather event extending to the south could lead to energy emergencies as operators face sharp increases in generator forced outages and electricity demand. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter 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

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages (excluding 2022–2025)

Operational Mitigations: A total of 0.2 GW based on operational/emergency procedures



SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity area covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

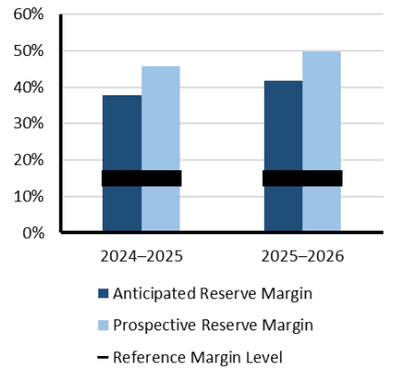
Highlights

- SERC-Florida Peninsula is a summer-peaking assessment area.
- Florida Peninsula entities have not identified any emerging reliability issues for the upcoming 2025–26 Winter season with an ARM projected at 39%, well above the RML, while the 2024 NERC ProbA base-case results project a sufficient level of resources to serve the expected load under median weather and typical system operating conditions (EUE is 1.09 MWh and LOLH is 0.00 hours/year).
- Many entities report strong fuel security, supported by firm natural gas contracts, storage resources, reliable pipeline capacity, and actively managed coal and oil inventories, which are projected to remain within operational ranges to meet winter demand.
- Florida Peninsula entities do not assume non-firm external assistance from neighboring areas during extreme conditions.

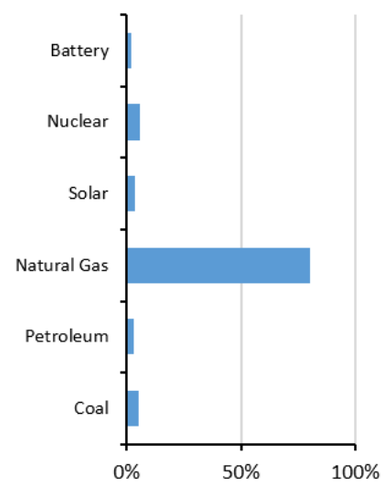
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

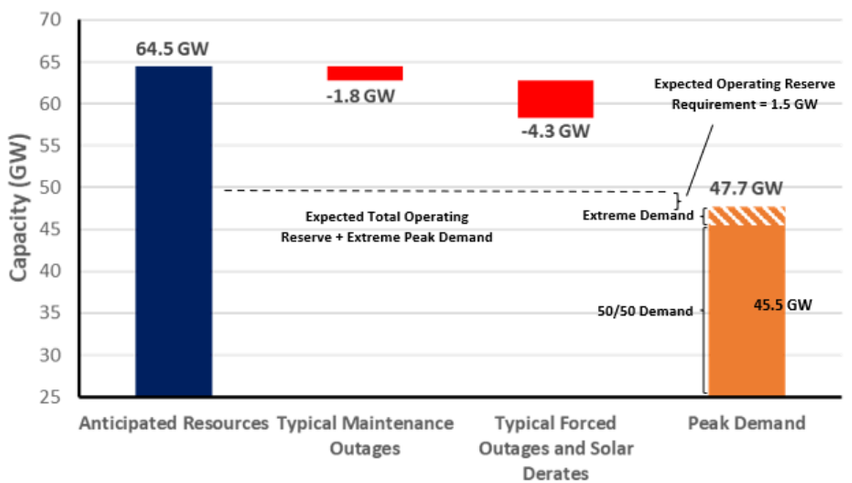
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Entity-provided values for low likelihood extreme conditions



SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six Regional Entities across North America that is responsible for the work under FERC-approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central United States. The SERC Regional Entity covers approximately 630,000 square miles with a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

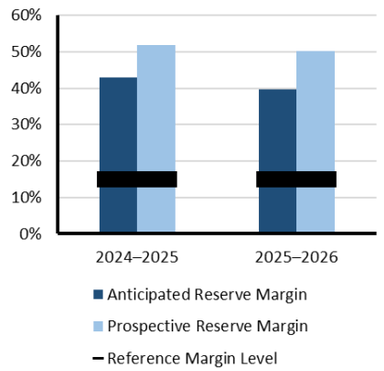
Highlights

- SERC-Southeast is trending towards becoming slightly winter-peaking.
- For the 2025–2026 Winter, SERC-Southeast entities report no emerging reliability concerns and expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories to serve the expected load under typical system operating conditions. The 2024 NERC ProbA base-case results in EUE and LOLH are both 0.00.
- While most SERC-Southeast BAs expect to have adequate resources, supported by firm natural gas transportation contracts, diverse fuel portfolios, and sufficient on-site coal inventories, one BA highlights potential risks related to natural gas transportation capacity, citing high pipeline utilization, competition for delivered gas, and ratable flow requirements. Mitigation strategies include securing third-party gas supply, adding dual-fuel capability, and implementing coal inventory management.
- Entities have made refinements such as replacing specific 230 kV circuit breakers and increasing monitoring frequencies for critical plant systems after January 2025 winter events.

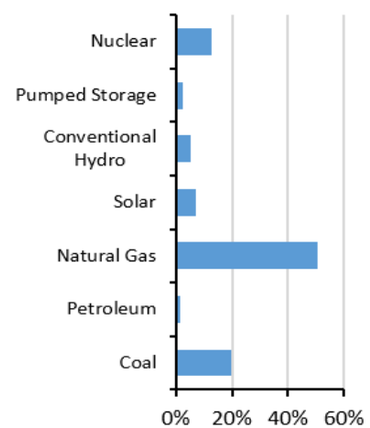
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

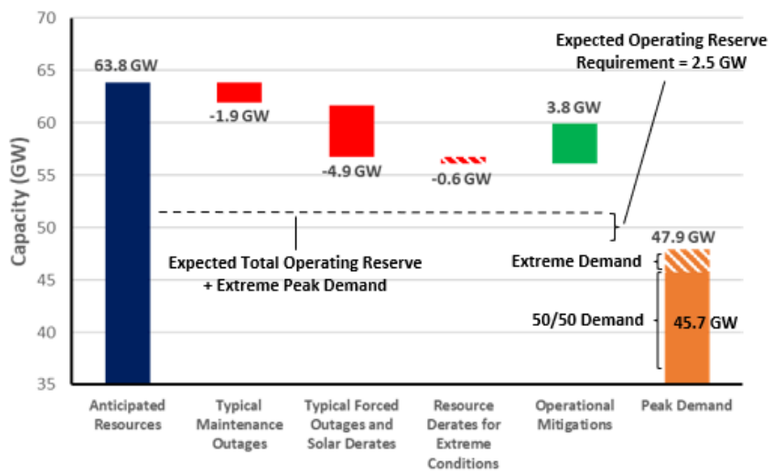
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter 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 using 30 years of historical data

Typical Maintenance Outages: Data collected through a survey of members for outages during December through February

Typical Forced Outages and Solar Derate: Weighted average forced-outage rates on-peak are factored into the anticipated resources calculation. Also, solar resources are derated to account for peak demand occurrence during darkness.

Resource Derates for Extreme Conditions: Maximum historical generation outages

Operational Mitigations: A total of 3.8 GW based on operational/emergency procedures



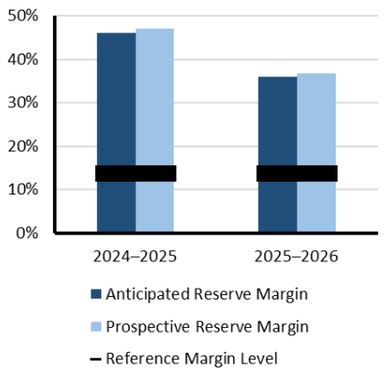
Texas RE-ERCOT

ERCOT is the 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 covers approximately 200,000 square miles, connects over 54,100 miles of transmission lines, has over 1,250 generation units, and serves more than 27 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 power grid.

Highlights

- Given expected system conditions, an ARM of 36% and RML of 13.75%, ERCOT expects to have sufficient operating reserves for the peak hour ending 8:00 a.m.
- ERCOT does not expect any significant fuel supply issues for the winter.
- ERCOT has conducted 2,028 generation resource and transmission service provider (TSP) winter weatherization inspections since Winter 2021–2022.
- Winter peak demands typically occur before sunrise and after sunset when solar generation is not available. Significant battery storage mitigates these risks.
- ERCOT's probabilistic risk assessment indicates a 2% probability of having to declare EEAs during the January forecasted winter peak day (which coincides with the highest reserve shortage risk) and a controlled load shed probability of 1.8%. ERCOT defines low-risk hours as when the probability of an EEA is less than 10%.
- Increased load growth in west Texas combined with "no solar" and low wind conditions can cause transmission lines into this area to become heavily loaded. ERCOT has introduced improved dynamic line ratings that allow for greater transfers at colder temperatures and periods of low irradiance.

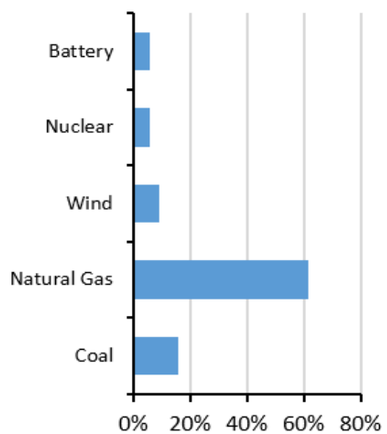
On-Peak Reserve Margin



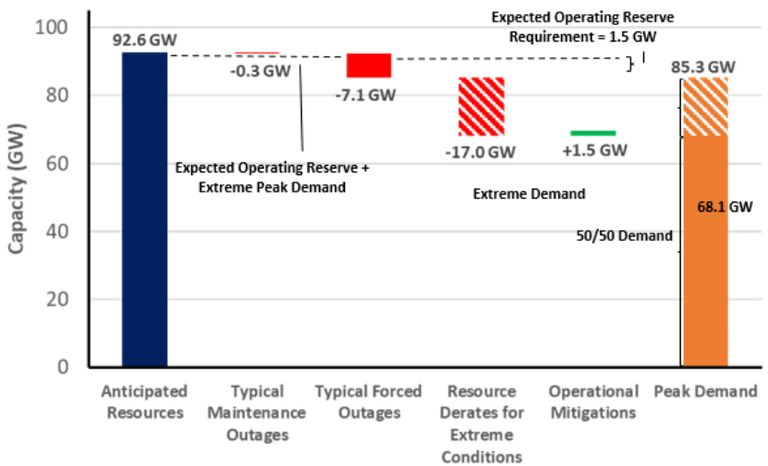
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal winter peak load and outage conditions could result in the need for operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding is unlikely but may be needed under wide-area cold weather events.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Presumes weather conditions comparable to Winter Storm Uri. The adjustment is calculated as the difference between the 100th percentile and 50th percentile values from ERCOT's Probabilistic Reserve Risk Model (PRRM) simulated load outcome distribution for hour ending 8:00 a.m.

Typical Maintenance Outages: Based on historical winter data and consideration of ERCOT's allowed maximum system daily planned outage capacity

Typical Forced Outages: Based on a probability distribution created using historical ERCOT Outage Scheduler data for the last three Januarys.

Resource Derates for Extreme Conditions: Weather-related thermal and wind outages based on Winter Storm Uri levels, adjusted for reductions due to weatherization standards. Also includes high non-weather-related outages.

Operational Mitigations: Additional potential capacity from switchable generation and imports



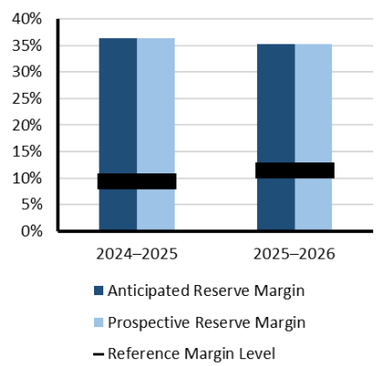
WECC-Alberta

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

- At an extreme winter peak of 12,982 MW, with extreme forced outages at 530 MW and derates for extreme conditions bringing wind energy availability down by 1,800 MW and hydroelectricity by 88 MW, the required reserves are 759 MW and are sufficiently met, even with low availability.
- Demand is expected to increase 1.1% from last winter with the existing-certain installed capacity having increased 23%.
- Solar availability is down because 1,000 MW of PV moved from originally expecting to come on-line in 2024 as Tier 1 resources to Tier 2s mostly anticipated to come on-line in 2025, but with less certainty.

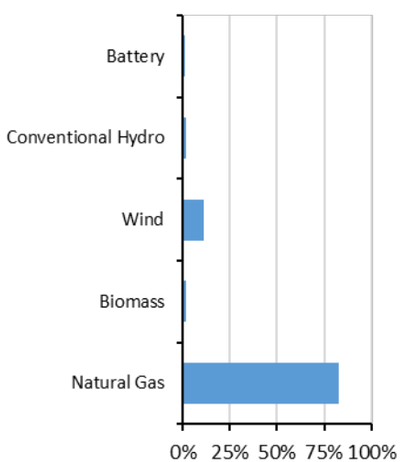
On-Peak Reserve Margin



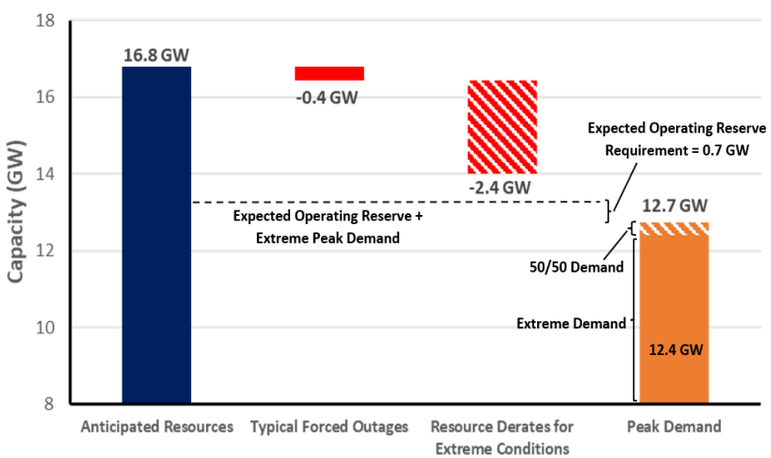
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS data

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



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 BA 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. *Note: The 2025-26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA*.

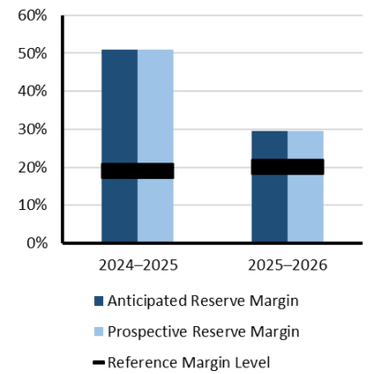
Highlights

- At an extreme winter peak of 11.1 GW under an extreme combination of derates and outages, the region could be short 1.0 GW before imports and is expected to need to rely on transfers.
- Net internal demand is expected to increase 1% since last year, with total internal demand up 1.8% being offset by a doubling of controllable and dispatchable demand response.
- Tier 1 resources have declined and do not appear to be offset by increases in existing-certain generation resource capacity. Nameplate wind has increased by almost 18% and solar by almost 30%. Hydro is also up over 7% in total installed capacity.
- Reliance on imports is expected to be required to maintain resource adequacy during extreme peak demand and extreme derate conditions.

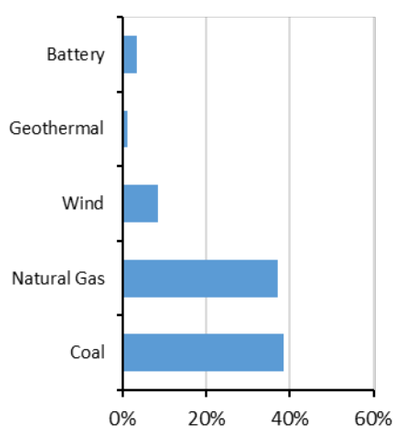
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

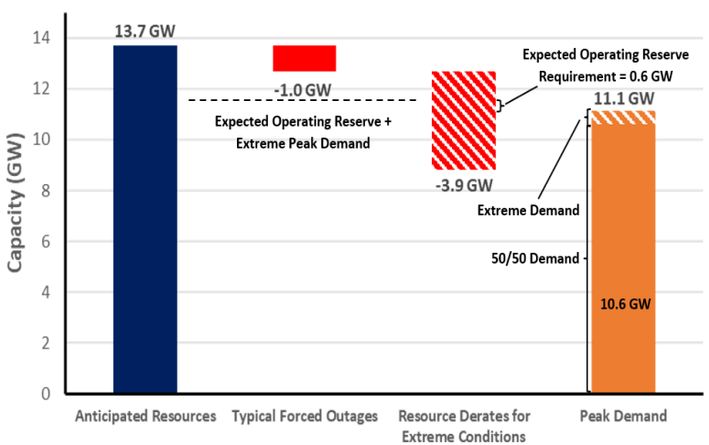
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Extreme Derates: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



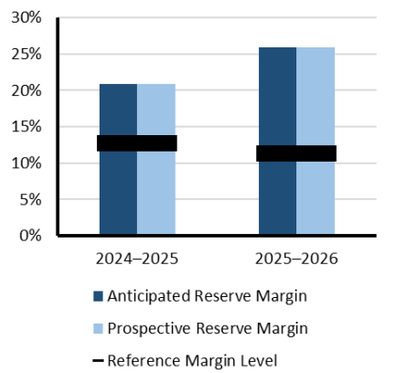
WECC-British Columbia

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 30 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 winter.

Highlights

- Peak demand is expected to remain about the same as last winter.
- There are about 200 MW more (47%) planned Tier 1 resources for this winter than last.
- Solar nameplate capacity has increased from 2 MW to 17 MW since last winter and hydroelectric nameplate capacity is up more than 5%, or 1,366 MW.

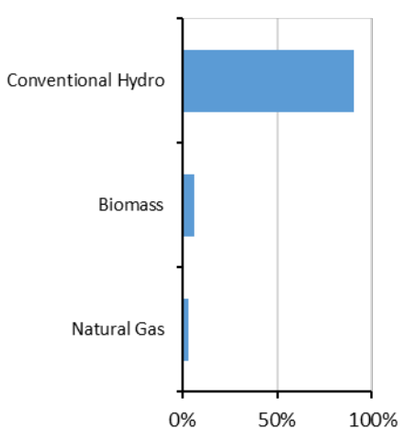
On-Peak Reserve Margin



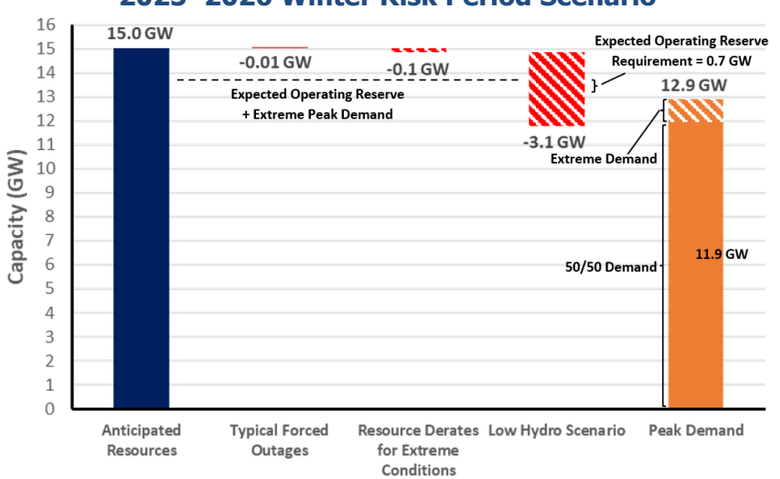
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme demand scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

Low Hydro Scenario: Estimated derate for lower hydro output



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. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

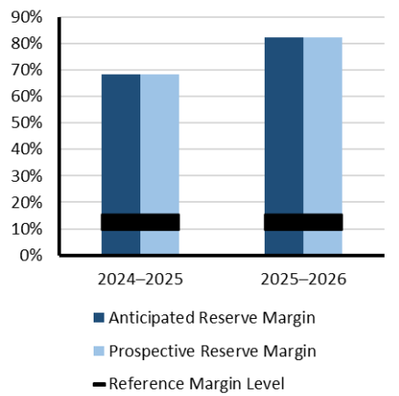
Highlights

- Operating reserve margins are met before imports in all winter resource availability scenarios.
- On-peak demand is expected to remain about the same as last winter. Demand-side management is down about 10%.
- Existing-certain capacity is up almost 5%, while planned Tier 1 resources are up more than 2 GW. The total wind nameplate capacity is up almost 27% and solar almost 13%. Hydro is down 4%.
- No reliance on imports is expected to be required to maintain resource adequacy for Winter 2025–2026.

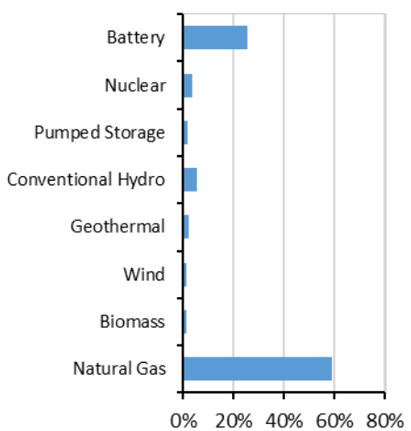
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

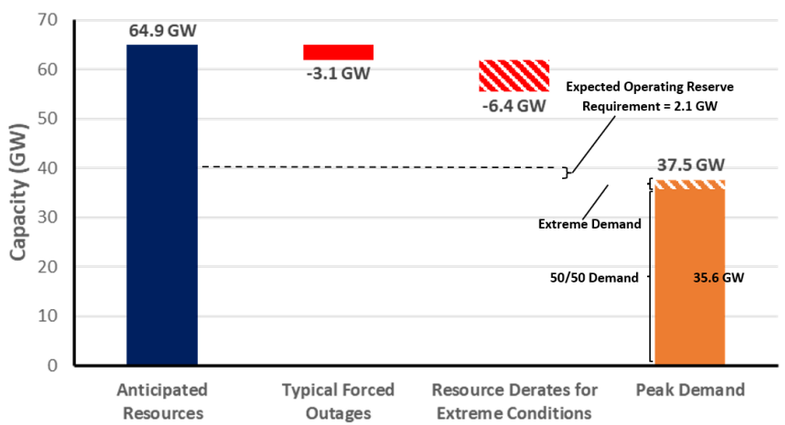
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



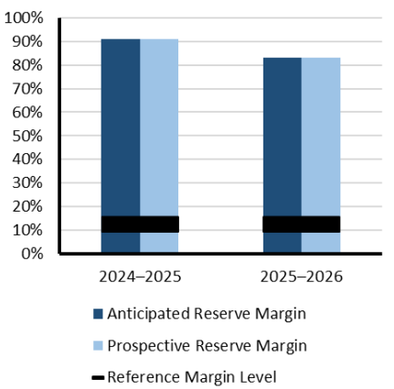
WECC-Mexico

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 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. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

Highlights

- As a summer-peaking region, operating reserve margins are met before imports in all scenarios.
- Planned Tier 1 resources are down 100% to zero as expected resources have either been brought on-line to move into existing or, in the case of some natural gas, have been delayed until 2026 and moved into Tier 2.
- The existing-certain on peak reserve margin is down by 5.2%, and the anticipated and prospective reserve margins are down by 7.8%; however, since Mexico is heavily summer-peaking, the 83% reserve margin still exceeds the RML of 12.5%, which remains unchanged.

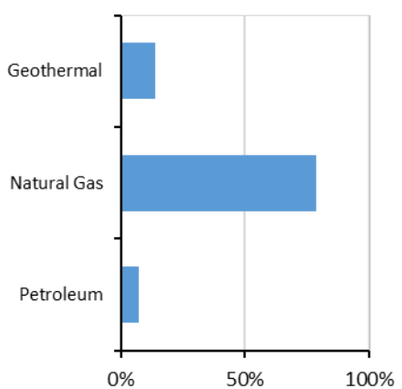
On-Peak Reserve Margin



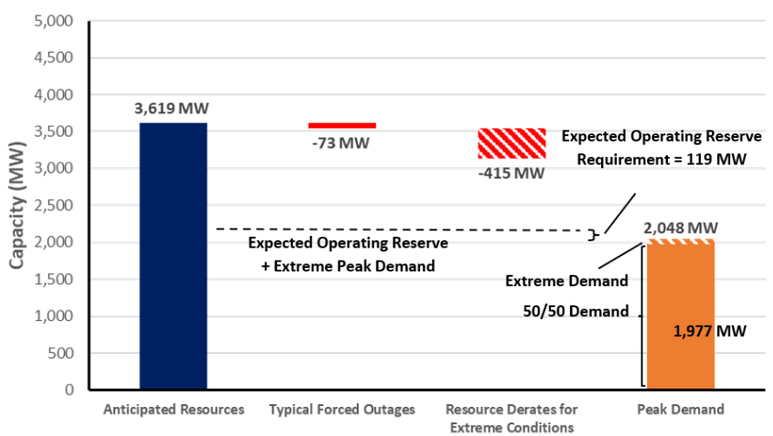
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



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. *Note: The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

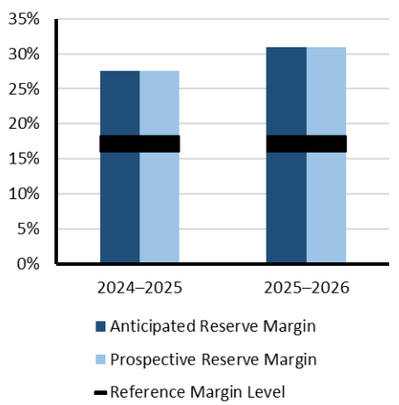
Highlights

- The Northwest has historically been a mixed season-peaking region.
- Operating reserve margins are expected to be met after imports in all winter scenarios.
- Total and net internal demand are up 9.3% with the primary drivers being data centers, residential electrification, transportation electrification, and semiconductor manufacturing.
- Large coal unit retirements and conventional hydro unit retirements are attributable to the reduction in existing certain capacity of 10.5%; however, planned Tier 1 resources have soared over 580%, from 463 MW to over 3 GW.
- Nameplate wind capacity is up over 3 GW (26%) and solar nameplate capacity is up nearly 2,690 MW (134%), which has also increased the solar availability on the peak hour.
- An increase in firm imports is seen in the model, 6.1 GW, absorbing the reduction in existing certain capacity of 4 GW.

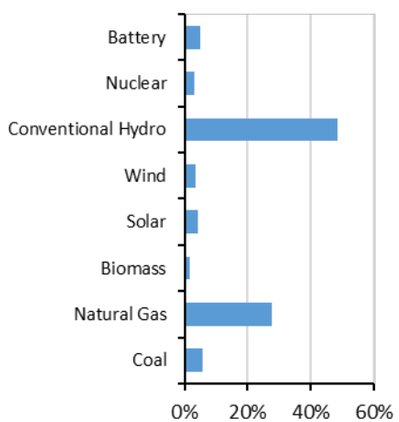
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak demand scenarios. Above-normal peak demand combined with high generator outages in extreme conditions results in the need for external assistance to maintain reserves.

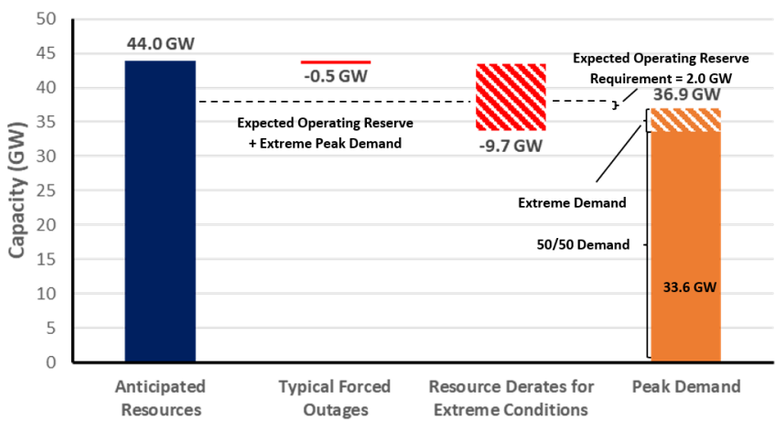
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period. This value includes 6.8 GW of hydro derates.



WECC-Rocky Mountain

WECC-Rocky Mountain is a summer-peaking assessment area in the Western Interconnection that includes Colorado, most of Wyoming, and parts of Nebraska and South Dakota. The population of the area is approximately 6.7 million. It covers the balancing areas of the Public Service Company of Colorado and the Western Area Power Administration's Rocky Mountain Region. It has 18,797 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. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

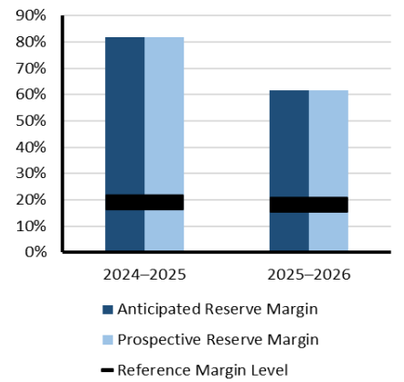
Highlights

- In Rocky Mountain, operating reserve margins are expected to be met before imports in all winter scenarios.
- Total and net internal demand are up almost 1%. The primary drivers are data centers and commercial and industrial customer growth.
- Planned Tier 1 resources are up over 84%, from almost 200 MW to over 365 MW. Solar nameplate capacity is up 27%; however, on-peak solar energy availability is down 100% due to the shift to after sunset. Expected hydro on peak energy availability is also down by around a quarter on the peak hour. Existing-Certain, Anticipated, and Prospective Reserve Margins are all down by over 20% on the peak hour; however, the region still maintains resource adequacy with margins hovering around 60% compared to the RML of 18%.
- No reliance on imports is expected to be required to maintain resource adequacy under combined extreme peak and extreme derated conditions.

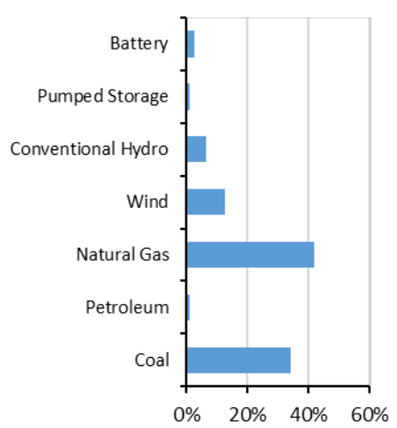
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

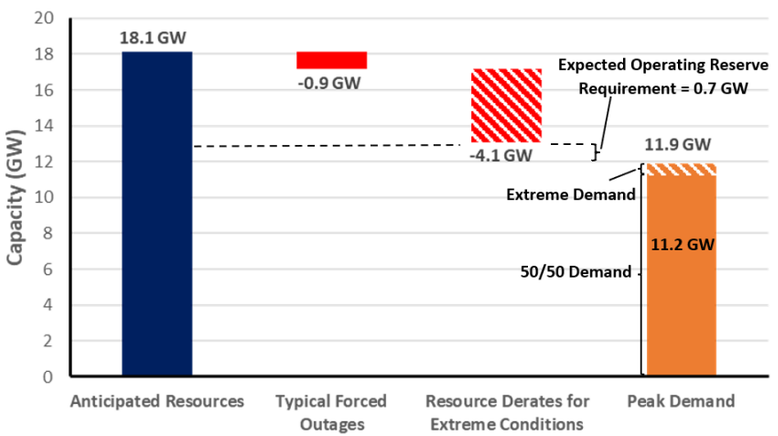
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period



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. *Note The 2025–26 WRA includes a new assessment area map for the U.S. Western Interconnection. The new assessment area boundaries provide more geographic detail of reliability risk information. WECC-Basin is a new assessment area in 2025 that was part of WECC-NW in the 2024–25 WRA.*

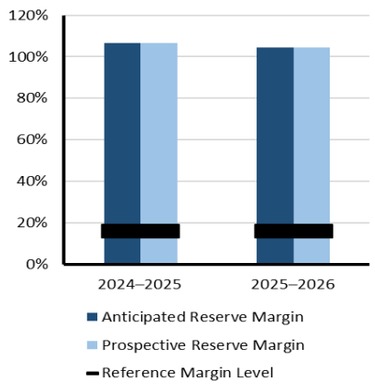
Highlights

- The Southwest is anticipated to be resource adequate under all winter expected and extreme energy availability and demand scenarios before imports.
- Total internal demand is expected to be up 1.5% and net internal demand up 2.3% since last winter. The primary drivers for load growth are data centers and industrial and residential electrification. Controllable and dispatchable demand response is down nearly half, by 163 MW.
- Planned Tier 1 resources are down over 19% as some have moved into existing certain, which is up almost 3%, over 1 GW, and other projects have experienced delays.
- Wind nameplate is up 12%, 470 MW, correlating to on-peak energy availability from wind increasing almost 11%, by 114 MW, while solar nameplate is up 27% or over 2.5 GW.

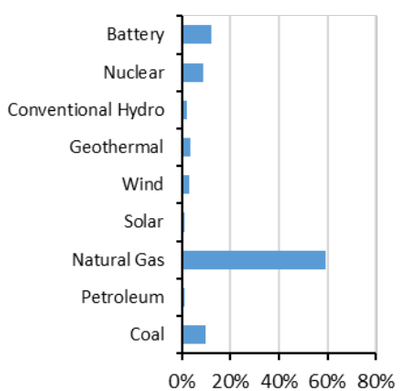
Risk Scenario Summary

Expected resources meet operating reserve requirements under assessed scenarios.

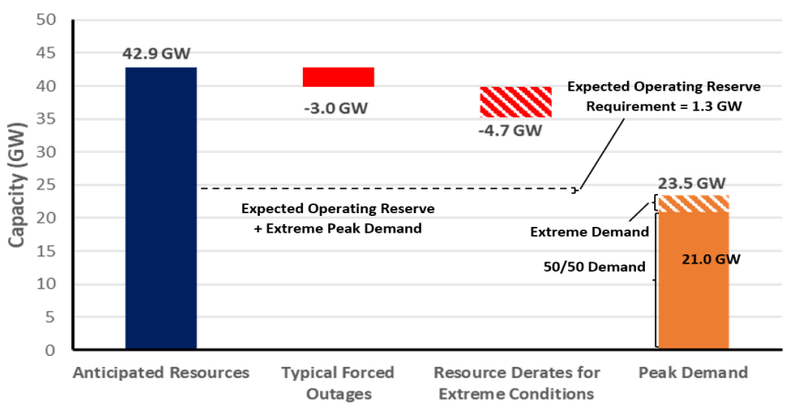
On-Peak Reserve Margin



On-Peak Resource Mix



2025–2026 Winter Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy is on the peak demand hour

Demand Scenarios: Net internal demand is the expected (50th percentile) peak and the 90th percentile of peak demand is the extreme forecast

Typical Forced Outages: Calculated using historical GADS

Resource Derates for Extreme Conditions: Thermal, wind, and solar are based on the hourly energy availability curves' probability distributions' 10th percentiles for the risk period

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[11] or total internal demand for the summer and winter of each year.[12]
• Total internal demand projections are based on normal weather (50/50 distribution)[13] and are provided on a coincident[14] 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.
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 variable energy resources (VER) (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.

[11] https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf used in NERC Reliability Standards

[12] The summer season represents June–September and the winter season represents December–February.

[13] 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.

[14] 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.

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 RML 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 an RML 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 forecasted. In many assessment areas, an RML is established by a state, provincial authority, ISO/Regional Transmission Organization (RTO), or other regulatory body. In some cases, the RML is a requirement. RMLs may be different for the summer and winter seasons. If an RML 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 ARM, 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.[15] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. NPCC-Maritimes marginally does not meet its RML for the upcoming winter. Other than NPCC-Maritimes, all assessment areas have sufficient ARMs to meet or exceed their RML for the 2025 winter as shown in **Figure 4**.

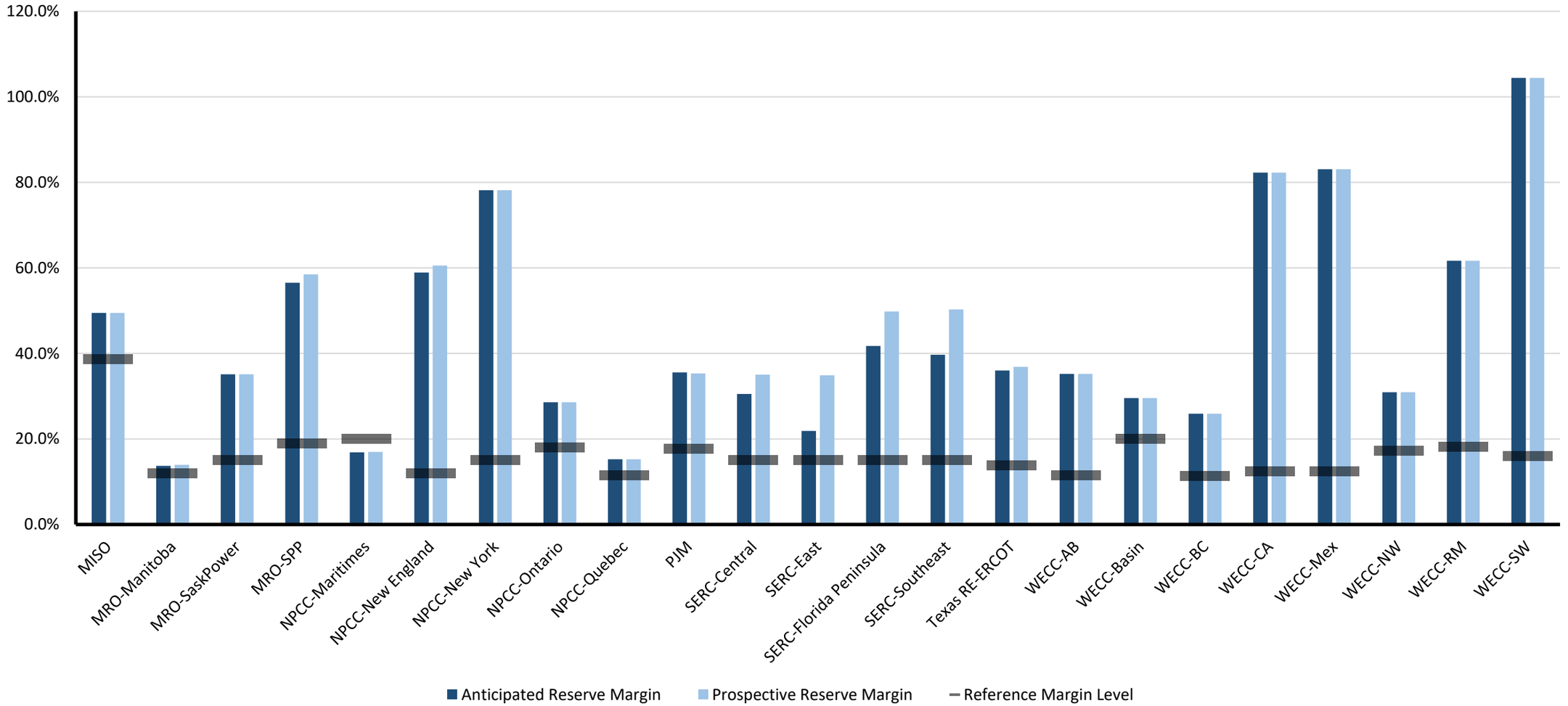


Figure 4: Winter 2025–2026 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[15] 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 RMLs.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast ARMs from the 2024–2025 Winter to the 2025–2026 Winter. All areas except NPCC-Maritimes remain above their RMLs for 2025–2026 Winter. The Canadian winter-peaking systems, which include MRO-Manitoba, MRO-SaskPower, NPCC-Maritimes, NPCC-Québec, WECC-Alberta, and WECC-British Columbia, may have reserve margins that are near RMLs but are unlikely to experience high outage rates from their winterized generators. Additional details are provided in the Data Concepts and Assumptions section.

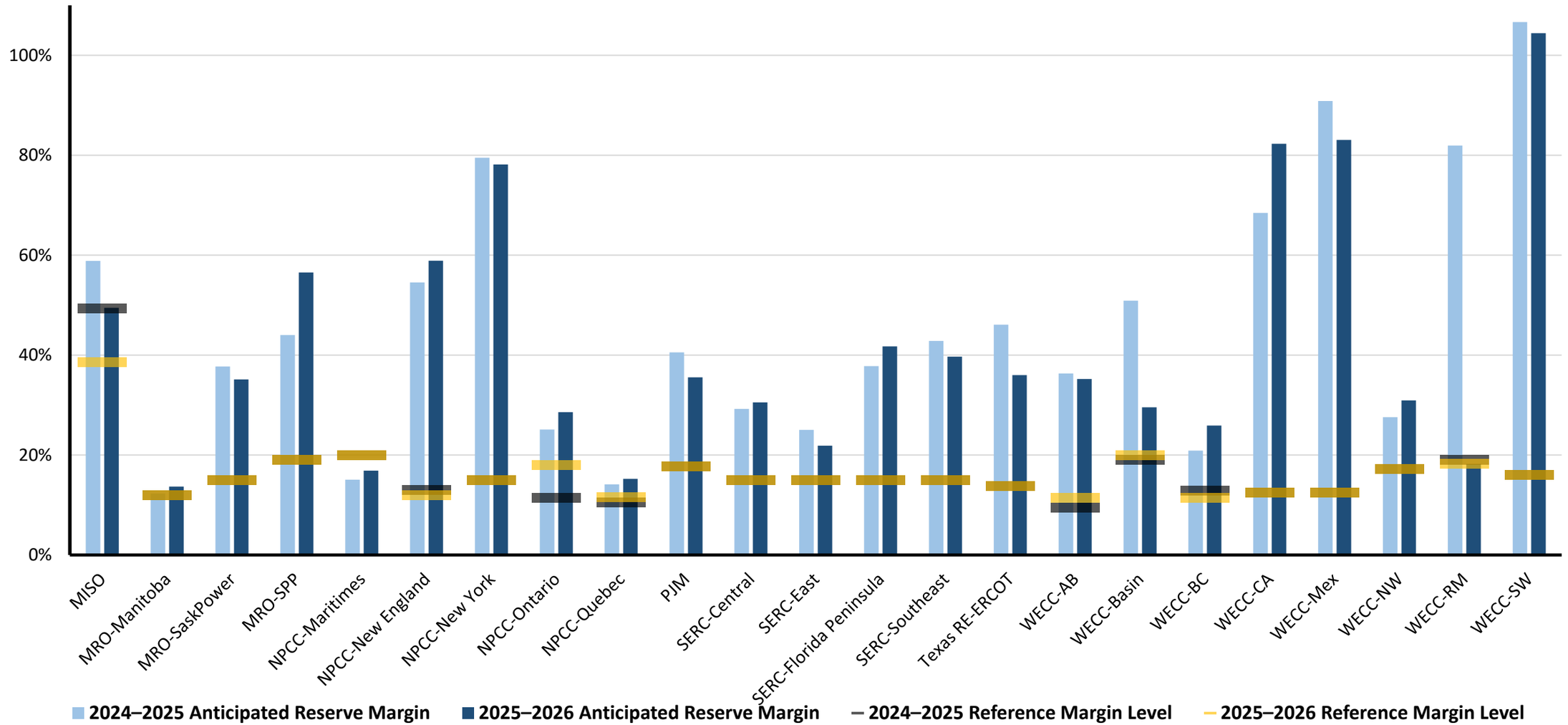


Figure 5: Winter 2024–2025 and Winter 2025–2026 Anticipated Reserve Margins Year-to-Year Change

Demand and Resource Tables

Peak demand and supply capacity data (i.e., resource adequacy data) for each assessment area are as follows in each table.

MISO			
Demand, Resource, and Reserve Margins	**2024–2025 WRA[16]**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	102,353	105,249	2.8%
Demand Response: Available	6,219	8,250	32.7%
Net Internal Demand	96,134	96,999	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	150,407	142,880	-5.0%
Tier 1 Planned Capacity	122	0	0.0%
Net Firm Capacity Transfers	2,310	2,113	-8.5%
Anticipated Resources	152,717	144,993	-5.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	152,839	144,993	-5.1%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	58.9%	49.5%	-9.4
Prospective Reserve Margin	59.0%	49.5%	-9.5
Reference Margin Level	49.4%	38.6%	-10.8

MRO-SPP			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,788	47,168	3.0%
Demand Response: Available	1,128	1,091	-3.3%
Net Internal Demand	45,926	46,077	0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	67,252	71,074	5.7%
Tier 1 Planned Capacity	0	1087	0.0%
Net Firm Capacity Transfers	-1,116	-32	-97.1%
Anticipated Resources	66,136	72,129	9.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	66,090	73,029	10.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	44.0%	56.5%	12.5
Prospective Reserve Margin	43.9%	58.5%	14.6
Reference Margin Level	19.0%	19.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	3,852	3,944	2.4%
Demand Response: Available	50	50	0.0%
Net Internal Demand	3,802	3,894	2.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	4,946	4,972	0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	5,236	5,262	0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	5,236	5,262	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.7%	35.1%	-2.6
Prospective Reserve Margin	37.7%	35.1%	-2.6
Reference Margin Level	15.0%	15.0%	0.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	4,814	4,903	1.8%
Demand Response: Available	0	0	0.0%
Net Internal Demand	4,814	4,903	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	5,924	5,688	-4.0%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	-527	-113	-78.5%
Anticipated Resources	5,407	5,575	3.1%
Existing-Other Capacity	18	13	-26.8%
Prospective Resources	5,425	5,588	3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	12.3%	13.7%	1.4
Prospective Reserve Margin	12.7%	14.0%	1.3
Reference Margin Level	12.0%	12.0%	0.0

[16] MISO-provided updated data post 2024-25 WRA publication.

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	6,167	6,061	-1.7%
Demand Response: Available	259	248	-4.4%
Net Internal Demand	5,907	5,813	-1.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	6,647	6,704	0.9%
Tier 1 Planned Capacity	6	88	0.0%
Net Firm Capacity Transfers	145	1	-99.0%
Anticipated Resources	6,798	6,794	-0.1%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	6,798	6,800	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	15.1%	16.9%	1.8
Prospective Reserve Margin	15.1%	17.0%	1.9
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,651	20,056	-2.9%
Demand Response: Available	343	440	28.2%
Net Internal Demand	20,308	19,616	-3.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	30,030	29,935	-0.3%
Tier 1 Planned Capacity	194	0	-100.0%
Net Firm Capacity Transfers	1,161	1,235	6.4%
Anticipated Resources	31,385	31,170	-0.7%
Existing-Other Capacity	306	322	5.2%
Prospective Resources	31,691	31,492	-0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	54.5%	58.9%	4.4
Prospective Reserve Margin	56.1%	60.5%	4.5
Reference Margin Level	13.0%	12.0%	-1.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	23,800	24,200	1.7%
Demand Response: Available	802	1,027	28.1%
Net Internal Demand	22,998	23,173	0.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	40,522	40,080	-1.1%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	759	1,203	58.5%
Anticipated Resources	41,281	41,283	0.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	41,281	41,283	0.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	79.5%	78.2%	-1.3
Prospective Reserve Margin	79.5%	78.2%	-1.3
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	21,898	22,013	0.7%
Demand Response: Available	915	868	-5.2%
Net Internal Demand	20,982	21,146	0.9%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	26,652	27,319	2.5%
Tier 1 Planned Capacity	0	294	#DIV/0!
Net Firm Capacity Transfers	-450	-420	-6.7%
Anticipated Resources	26,202	27,193	3.8%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	26,202	27,193	3.8%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.1%	28.6%	3.5
Prospective Reserve Margin	25.1%	28.6%	3.5
Reference Margin Level	11.5%	18.0%	6.5

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	40,512	40,799	0.8%
Demand Response: Available	4,451	4,902	10.9%
Net Internal Demand	36,061	35,897	-0.4%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	41,560	41,698	0.3%
Tier 1 Planned Capacity	73	61	0.0%
Net Firm Capacity Transfers	-479	-390	-18.6%
Anticipated Resources	41,154	41,368	0.5%
Existing-Other Capacity	-479	0	0.0%
Prospective Resources	41,154	41,368	0.5%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	14.1%	15.2%	1.1
Prospective Reserve Margin	14.1%	15.2%	1.1
Reference Margin Level	10.5%	11.5%	1.0

PJM			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	136,328	140,827	3.3%
Demand Response: Available	5,616	5,998	6.8%
Net Internal Demand	130,712	134,829	3.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	179,216	178,335	-0.5%
Tier 1 Planned Capacity	0	0	0.0%
Net Firm Capacity Transfers	4,502	4,448	-1.2%
Anticipated Resources	183,718	182,783	-0.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	183,718	182,452	-0.7%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.6%	35.6%	-5.0
Prospective Reserve Margin	40.6%	35.3%	-5.2
Reference Margin Level	17.7%	17.7%	-12.3

SERC-Central			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	42,895	42,875	0.0%
Demand Response: Available	1,497	2,809	87.6%
Net Internal Demand	41,397	40,067	-3.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	51,578	50,454	-2.2%
Tier 1 Planned Capacity	0	0	0%
Net Firm Capacity Transfers	1,922	1,847	-3.9%
Anticipated Resources	53,500	52,301	-2.2%
Existing-Other Capacity	1,498	1,810	20.8%
Prospective Resources	54,998	54,111	-1.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	29.2%	30.5%	1.3
Prospective Reserve Margin	32.9%	35.1%	2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,005	45,703	1.6%
Demand Response: Available	982	888	-9.6%
Net Internal Demand	44,023	44,815	1.8%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	54,379	54,460	0.1%
Tier 1 Planned Capacity	72	11	-84.3%
Net Firm Capacity Transfers	593	150	-74.7%
Anticipated Resources	55,045	54,622	-0.8%
Existing-Other Capacity	5,209	5,832	12.0%
Prospective Resources	60,254	60,453	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	25.0%	21.9%	-3.2
Prospective Reserve Margin	36.9%	34.9%	-2.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	48,494	48,628	0.3%
Demand Response: Available	2,780	3,127	12.5%
Net Internal Demand	45,714	45,501	-0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,579	63,502	1.5%
Tier 1 Planned Capacity	15	692	4510.0%
Net Firm Capacity Transfers	400	300	-25.0%
Anticipated Resources	62,994	64,494	2.4%
Existing-Other Capacity	3,673	3,671	0.0%
Prospective Resources	66,667	68,165	2.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	37.8%	41.7%	3.9
Prospective Reserve Margin	45.8%	49.8%	4.0
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	45,308	47,056	3.9%
Demand Response: Available	1,638	1,365	-16.7%
Net Internal Demand	43,670	45,691	4.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	62,805	63,339	0.9%
Tier 1 Planned Capacity	765	0	-100.0%
Net Firm Capacity Transfers	-1,192	489	-141.0%
Anticipated Resources	62,378	63,828	2.3%
Existing-Other Capacity	3,920	4,847	23.7%
Prospective Resources	66,298	68,675	3.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	42.8%	39.7%	-3.1
Prospective Reserve Margin	51.8%	50.3%	-1.5
Reference Margin Level	15.0%	15.0%	0.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	73,193	77,387	5.7%
Demand Response: Available	5,447	9,330	71.3%
Net Internal Demand	67,746	68,057	0.5%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	98,712	89,977	-8.8%
Tier 1 Planned Capacity	239	1351	464.9%
Net Firm Capacity Transfers	20	1,235	6075.0%
Anticipated Resources	98,971	92,562	-6.5%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	99,691	93,137	-6.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	46.1%	36.0%	-10.1
Prospective Reserve Margin	47.2%	36.9%	-10.3
Reference Margin Level	13.75%	13.8%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	12,280	12,411	1.1%
Demand Response: Available	0	0	0.0%
Net Internal Demand	12,280	12,411	1.1%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,535	16,658	23.1%
Tier 1 Planned Capacity	3206	124	-96.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	16,740	16,782	0.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	16,740	16,782	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	36.3%	35.2%	-1.1
Prospective Reserve Margin	36.3%	35.2%	-1.1
Reference Margin Level	9.5%	11.5%	2.0

WECC-Basin			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,568	10,758	1.8%
Demand Response: Available	85	170	100.0%
Net Internal Demand	10,483	10,588	1.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,213	13,183	-0.2%
Tier 1 Planned Capacity	2,605	533	-79.5%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	15,817	13,717	-13.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	15,817	13,717	-13.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	50.9%	29.6%	-21.3
Prospective Reserve Margin	50.9%	29.6%	-21.3
Reference Margin Level	19.0%	20.0%	1.0

WECC-CA			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	36,441	36,281	-0.4%
Demand Response: Available	743	666	-10.4%
Net Internal Demand	35,698	35,615	-0.2%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	55,380	57,923	4.6%
Tier 1 Planned Capacity	4,757	6,997	47.1%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	60,138	64,920	8.0%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	60,138	65,920	8.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	68.5%	82.3%	13.8
Prospective Reserve Margin	68.5%	82.3%	13.8
Reference Margin Level	12.5%	12.5%	0.0

WECC-BC			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	11,966	11,936	-0.3%
Demand Response: Available	0	0	0.0%
Net Internal Demand	11,966	11,936	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	13,870	14,389	3.7%
Tier 1 Planned Capacity	433	637	47.0%
Net Firm Capacity Transfers	164	0	-100.0%
Anticipated Resources	14,467	15,026	3.9%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	14,467	15,026	3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.9%	25.9%	5.0
Prospective Reserve Margin	20.9%	25.9%	5.0
Reference Margin Level	12.8%	11.4%	-1.5

WECC-Mexico			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–2025 vs. 2025–2026**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	1,983	1,977	-0.3%
Demand Response: Available	0	0	0%
Net Internal Demand	1,983	1,977	-0.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	3,733	3,619	-3.0%
Tier 1 Planned Capacity	52	0	-100.0%
Net Firm Capacity Transfers	0	0	0%!
Anticipated Resources	3,784	3,619	-4.4%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	3,784	3,619	-4.4%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	90.8%	83.1%	-7.8
Prospective Reserve Margin	90.8%	83.1%	-7.8
Reference Margin Level	12.5%	12.5%	0

WECC-Northwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	30,748	33,604	9.3%
Demand Response: Available	30	30	0.0%
Net Internal Demand	30,718	33,574	9.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,729	34,671	-10.5%
Tier 1 Planned Capacity	463	3,152	581.5%
Net Firm Capacity Transfers	0	6,136	100%!
Anticipated Resources	39,192	43,959	12.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	39,192	43,959	12.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	27.6%	30.9%	3.3
Prospective Reserve Margin	27.6%	30.9%	3.3
Reference Margin Level	17.2%	17.2%	0.0

WECC-Rocky Mountain			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	10,481	11,501	9.7%
Demand Response: Available	282	285	1.1%
Net Internal Demand	10,199	11,216	10.0%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	18,356	17,768	-3.2%
Tier 1 Planned Capacity	199	366	84.3%
Net Firm Capacity Transfers	0	0	0%
Anticipated Resources	18,555	18,134	-2.3%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	18,555	18,134	-2.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	81.9%	61.7%	-20.3
Prospective Reserve Margin	81.9%	61.7%	-20.3
Reference Margin Level	19.0%	18.2%	-0.8

WECC-Southwest			
Demand, Resource, and Reserve Margins	**2024–2025 WRA**	**2025–2026 WRA**	**2024–25 vs. 2025–26**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	20,844	21,147	1.5%
Demand Response: Available	340	177	-47.9%
Net Internal Demand	20,504	20,970	2.3%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	38,991	40,135	2.9%
Tier 1 Planned Capacity	3,381	2,733	-19.2%
Net Firm Capacity Transfers	0	0	0.0%
Anticipated Resources	42,372	42,868	1.2%
Existing-Other Capacity	0	0	0.0%
Prospective Resources	42,372	42,868	1.2%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	106.6%	104.4%	-2.2
Prospective Reserve Margin	106.6%	104.4%	-2.2
Reference Margin Level	16.0%	16.0%	0.0

Variable Energy Resource Contributions

Because the electrical output of VERs (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity and may vary widely year to year based on the identified risk hour. In many areas, winter demand peaks in the early morning hours or early evening resulting in little or no electrical resource output from solar PV resources and wide variability in wind availability. The following table shows the capacity contribution of existing wind and solar PV resources at the identified risk hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS.

BPS Variable Energy Resources On-Peak Capacity Contributions by Assessment Area

	Wind			Solar			Run of River Hydro		
Assessment Area/Interconnection (* - includes all hydro)	Nameplate Wind (MW)	Expected Wind (MW)	Expected Share of Nameplate (%)	Nameplate Solar PV (MW)	Expected Solar (MW)	Expected Share of Nameplate (%)	Nameplate Hydro (MW)	Expected Hydro (MW)	Expected Share of Nameplate (%)
MISO	30,247	8,772	29%	13,726	686	5%	2,351	1,404	60%
MRO-Manitoba Hydro	259	52	20%	0	0	0%	202	0	0%
MRO-SaskPower	816	433	53%	30	0	13%	884	703	80%
MRO-SPP	35,714	7,198	20%	1,197	457	38%	114	72	63%
NPCC-Maritimes	1,635	241	15%	155	10	6%	1,357	1,283	95%
NPCC-New England	2,675	455	17%	3,620	0	0%	3,742	1,453	39%
NPCC-New York	2,586	737	29%	627	0	0%	974	596	61%
NPCC-Ontario	4,943	1,971	40%	478	0	0%	0	0	0%
NPCC-Québec	4,024	1,426	35%	10	0	0%	445	445	100%
PJM*	13,318	5,463	41%	15,732	1	0%	8,134	7,900	97%
SERC-Central	1,324	370	28%	1,576	455	29%	4,991	4,027	81%
SERC-East	0	0	0%	7,068	1,792	25%	3,010	2,951	98%
SERC-Florida Peninsula	0	0	0%	12,058	2,151	18%	0	0	0%
SERC-Southeast	0	0	0%	8,670	4,461	51%	3,258	3,258	100%
Texas RE-ERCOT	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC-AB*	5,712	1,919	34%	2,206	0	0%	894	285	32%
WECC-Basin*	5,932	1,148	19%	3,853	62	2%	2,667	1,473	55%
WECC-BC*	747	85	11%	17	0	0%	17,752	13,560	76%
WECC-CA*	9,382	682	7%	28,328	0	0%	15,740	4,572	29%
WECC-Mex	40	4	11%	350	0	0%	0	0	0%
WECC-NW*	14,744	1,319	9%	4,695	1,556	33%	32,915	18,502	56%
WECC-RM*	5,681	2,265	40%	3,521	0	0%	3,251	1,327	41%
WECC-SW*	4,303	1,182	27%	12,139	391	3%	3,117	948	30%
EASTERN INTERCONNECTION	93,517	25,692	27%	64,937	10,013	15%	29,017	23,647	81%
QUÉBEC INTERCONNECTION	4,024	1,426	35%	10	0	0%	445	445	100%
TEXAS INTERCONNECTION	40,629	7,833	19%	35,609	660	2%	579	566	98%
WECC INTERCONNECTION	46,541	8,605	19%	55,108	2,008	4%	76336	40667	53%
INTERCONNECTION TOTAL:	**184,711**	**43,556**	**23%**	**155,664**	**12,685**	**8%**	106,377	65,325	61%

Review of Winter 2024–2025 Capacity and Energy Performance

The meteorological winter across the contiguous United States had an average temperature of 34.1 degrees F—1.9 degrees above average—ranking in the warmest third of NOAA's historical record. Total winter precipitation in the US was 5.87 inches, 0.92 of an inch below average, ranking in the driest third of the December–February climate record.[17] Most of Canada experienced temperatures at least 2°C above the baseline average with the Maritime provinces, southern Ontario, and the Canadian west coast recording temperature departures nearer the baseline average while a small region in southern Saskatchewan recorded temperatures just slightly below the baseline average.[18]

In February 2025, FERC and NERC and its Regional Entities launched a joint review of the BPS' performance during the January 2025 arctic events, which comprised Winter Storms Blair, Cora, Demi, and Enzo.[19] The week of January 19–25, 2025 was the third coldest winter week (spanning Sunday through Saturday) across the United States since 2000. Between January 21 and 22, 2025, natural gas demand peaked at 150 Bcf/day, electric demand peaked at 683 GW, and unplanned outages peaked at 71,022 MW. Nevertheless, during the January 2025 arctic events, manual load shed was not required. The January 2025 arctic events had lower observed hourly wind chill temperatures in pockets of the Northeast, the Louisiana Gulf, California, and the Southwest compared to Winter Storms Uri, Elliott, Gerri, and Heather. During the January 2025 arctic events, the most extreme storm relative to typical weather was Winter Storm Enzo—a Gulf and Southern storm. On January 20, 2025, a burst of snow, sleet, and freezing rain developed across Texas and Louisiana late in the day. A mixture of sleet and freezing rain fell from Austin to San Antonio and to the southernmost point of Texas. By the early morning hours of January 21, 2025, for the first time in history, a blizzard warning was issued for southwest Louisiana and the southeastern-most point of Texas. Snow fell in Gulf cities in Texas, southern Mississippi, southern Alabama, and western Florida. On January 21, 2025, Baton Rouge recorded 7.6 inches of snowfall, making it the city's snowiest day since recordkeeping began in 1892, while New Orleans saw its snowiest day on record, with a total of 8.0 inches. Temperatures plunged to single digits in Louisiana. Temperatures in some parts of the state fell to levels not seen in more than 125 years.

The review team engaged with 10 electric entities across the Eastern and Texas Interconnections to gather the information necessary to provide a high-level overview of the BPS' performance during the cold weather events. Based on the data and interviews that the team reviewed, electric generators appear to have performed better during the January 2025 arctic events because of additional generator commitments, improved preparedness, increased situational awareness, and the implementation of lessons learned from previous extreme cold weather events and prior report recommendations. The natural gas system also performed better overall, serving record levels of natural gas demand and experiencing only minor production declines and short-duration force majeure events.

On October 1, 2025, NERC submitted to the Federal Energy Regulatory Commission its first *Cold Weather Data Annual Report*. This report includes a review of forced outage data from GADS for the winter 2024–2025 period indicating performance consistent with historical performance as reported in NERC's annual *State of Reliability* report. This is within the normal range of capacity that occurs across the fleet. During the Winter 2024–2025 period, the highest amount of capacity in a forced outage state for all reasons occurred on January 20, 2025, with 68,519 MW across all regions. The outages occurring over January 20, 2025, were analyzed as part of the joint FERC, NERC, and Regional Entity *2025 System Performance Review*. The joint FERC, NERC, and Regional Entity *2025 System Performance Review* found a reduction in peak coincident unplanned generator outages for the four 2025 winter storms reviewed compared to past winter storms; however, this review also noted that it was not an exact comparison due to prior winter storms having different characteristics.

Eastern Interconnection–Canada and Québec Interconnection

No EEAs were needed during the previous winter season. One entity plans to make a slight increase to the demand-response program based on last winter's operations.

[17] Despite Arctic air outbreaks, U.S. had warm, dry winter on average | National Oceanic and Atmospheric Administration
[18] Climate Trends and Variations Bulletin – Winter 2024/2025 - Canada.ca
[19] https://www.ferc.gov/media/report-january-2025-arctic-events-system-performance-review-ferc-nerc-and-its-regional

Eastern Interconnection–United States

Several entities indicated that generators performed better during the January 2025 arctic events than in previous winter storms. For example, TVA stated that generator performance within its footprint was stable, with minimal natural gas delivery issues. Southeastern RC detailed that no major fuel-related outages occurred. FRCC noted that generator performance was strong during this period. The significant characteristics of Winter Storm Enzo in the Southern and Gulf states were freezing precipitation and snow accumulation, especially in regions where those conditions rarely occur. In FRCC, only the northern portion of Florida experienced severe arctic weather including freezing precipitation and snowfall (record-setting, in some cities) that were abnormal for the region even though certain northern cities have faced cold temperatures in the past. In Florida, entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events. ISO-NE, NYISO, and PJM all generally described the January 2025 arctic events as having cold temperatures but overall weather conditions that were similar to a winter without a major storm.

MISO emerged from Winter 2024–2025 without turning to emergency procedures despite the wide-ranging winter storms from January 6 to 9 and again from January 20 to 22. Generators continue to prioritize scheduling planned or maintenance outages to the shoulder seasons of fall and spring to maximize unit availability for the winter season. Also, extreme cold weather outage adders were added to the LOLE model to make sure that winter storm risks are included in planning. In PJM, demand reached a new all-time winter peak on January 22, 2025, of 143,714 MW with sufficient reserves. PJM did call an EEA1 on January 22, 2025, however reserves remained adequate. PJM had less than 3% load forecast error over the peak days of the January cold weather events. Reliability cases were conducted, and units with extended start times were evaluated and started early to ensure units were on-line before extreme cold weather settled in. PJM had a 9.24% forced outage rate on the peak day, a relatively low forced outage rate for the weather experienced. There were also very few gas production problems; however, market issues prevented proper scheduling because of the four-day holiday weekend.

In SERC-Central, entities reported only limited impacts from Winter 2024–2025 coldest weather and made minor adjustments. One entity declared conservative operations ahead of peak conditions but experienced no emergencies. One entity raised its winter Planning Reserve Margin target to 26% following lessons learned from Winter Storm Elliott. Corrective actions were implemented due to isolated equipment issues, including improved heat trace capabilities and adding heat trace equipment to the cold weather critical component list. During the previous winter season, some SERC-Florida Peninsula entities experienced energy emergencies caused by extended generation outages from hurricanes Milton and Helene, compounded by unusually high loads from cold weather. Despite these challenges, entities were able to serve native load and firm delivery obligations, though non-firm sales were curtailed during certain events.

Texas Interconnection–ERCOT

There were no energy emergencies for the Texas RE-ERCOT region last winter and no conditions that prompted changes in operating procedures. Winter Storm Kingston, which occurred in February 2025, was the only storm where ERCOT utilized firm fuel supply service resources (FFSS), a firm-fuel product that provides additional grid reliability and resiliency during extreme cold weather and compensates generation resources that meet a higher resiliency standard. A maximum FFSS deployment of 470 MW occurred on February 19 between the hours 13:10 and 17:02. Two other storms, Enzo and Cora, impacted ERCOT in January 2025, but these storms did not cause any system reliability issues.

Western Interconnection

Between January 11 and 17, 2024, a prolonged Arctic outbreak impacted British Columbia, Alberta, and the U.S. Pacific Northwest, driving record electricity demand and widespread reliability challenges. Four U.S. Northwest BAs and one Canadian BA declared energy emergencies, underscoring two core vulnerabilities: Inadequate capacity during evening peak hours (4 to 8 p.m.) and Insufficient fuel supply (limited hydro availability) across multiple days.

Although temperatures were comparable to the December 2022 cold snap, WECC-Northwest peak demand rose two percentage points to 6% over then, with BC Hydro and AESO both setting new all-time records. The U.S. Northwest relied heavily on imports—averaging 4,745 MW during peaks and 5,241 MW across all hours, mostly from the Southwest and Rockies. California remained a net importer, providing little relief. Market prices in the Northwest reached or neared caps across most hours, indicating persistent scarcity rather than short-term peaks. Overall, the January 2024 event illustrated capacity alone does not ensure resilience. Sustained energy availability with interregional flexibility (both physical and market-based) will be key to maintaining reliability through the 2025–2026 and future winter seasons.

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
MISO	Jan. 21	18:00	108,888*	96,134 100,395	101,655	-977	18,468	16,761	0	519	17,010
MRO-Manitoba Hydro	Jan. 20	08:00	5,132	4,814 5,060	5,292	-277	142	52	N/A	0	146
MRO-SaskPower	Dec. 18	18:00	3,785	3,802 3,897	3,641	-231	664	368	0	3	0
MRO-SPP	Feb. 20	08:00	47,981	45,926 47,054	40,898	-1,424	4,886	4,783	255	36	9,272
NPCC-Maritimes	Jan. 22	07:00	5,810	5,907 6,498	4,266	-1,174	368	261	3	5	*
NPCC-New England	Jan. 21	18:00	19,607	20,308 21,814	17,686	-1,896	285	329	4	23	624
NPCC-New York	Jan. 22	19:00	23,521	22,998 24,023	18,932	-4,589	654	728	0	0	4,835

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
NPCC-Ontario	Jan. 22	18:00	21,940	20,951 22,179	24,250	2,990	3,693	1,914	0	0	*
NPCC-Québec	Jan. 22	08:00	37,178	36,061 39,545	39,514	-766	1,463	1,449	0	0	*
PJM	Jan. 22	09:00	144,420	130,712 144,939	152,142	7,731	3,704	3,620	3,076	1	8,663
SERC-C	Jan. 22	08:00	47,815	41,397 47,062	40,898	-6,921	563	176	214	455	1,538
SERC-E	Jan. 23	08:00	47,130	44,023 47,662	41,810	-5,323	0	0	145	2,526	1,830
SERC-FP	Jan. 25	08:00	43,974	45,714 54,239	41,702	-557	0	0	362	1,684	2,824
SERC-SE	Jan. 22	08:00	46,490	43,670 45,116	48,227	1,741	0	0	592	3,861	2,210

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
TRE-ERCOT	Feb. 20	08:00	80,560	73,193[5] 90,405[5]	79,960	-191	9,397	15,697	1,586	15	5,742
WECC-AB	Dec. 18	17:00	12,241	12,280 12,635	12,711	-470	3,175	1,867	4	0	*
WECC-BC	Feb 3	18:00	11,359	11,996 12,749	11,415	44	70	279	0	0	839
WECC-CA/MX	Dec. 12	15:00	35,555	35,359 36,823	31,925	-4,669	4,021	569	11,547	0	1,627
WECC-NW	Feb. 12	08:00	54,278	58,001 62,230	48,437	-920	2,607	7,876	1,494	2,198	3,281
WECC-SW	Feb. 13	16:00	22,969	16,177 17,777	25,087	2,117	2,741	1,065	1,599	182	1,496
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

2024–2025 Winter Demand and Generation Summary at Peak Demand											
Assessment Area	**Peak Demand Date**	**Peak Demand Hour**	**Demand[1] (MW)**	**WRA Peak Demand Scenarios[2] (MW)**	**Generation[1] (MWh)**	**Transfers[1] (MW)**	**Wind – Actual[1] (MWh)**	**Wind – Expected[3] (MW)**	**Solar – Actual[1] (MWh)**	**Solar – Expected[3] (MW)**	**Forced Outages Summary[4] (MW)**
Table Notes: [1] Actual demand, wind, and solar values for the hour of peak demand in U.S. areas were obtained from EIA From 930 data. For areas in Canada, this data was provided to NERC by system operators and utilities. [2] See NERC *2024–2025* WRA demand scenarios for each assessment area. Values are the normal winter peak demand forecast and an extreme peak demand forecast that represents a 90/10, or once-per-decade, peak demand. Some areas use other basis for extreme peak demand. [3] Expected values of wind and solar resources from the *2024–2025 WRA*. [4] Values from NERC Generator Availability Data System for the 2024–2025 winter hour of peak demand in each assessment area. Highlighted areas had actual forced outages that were more than twice the value for typical forced outage rates used in the 2024–2025 winter risk period scenarios in the *2024–2025 WRA*. [5] Texas RE-ERCOT peak demand scenarios are obtained by adding expected demand response (5.4 GW for winter 2024-2025) to the demand scenarios found on p. 29 of the 2024-2025 WRA. *Canadian assessment areas report to the NERC Generator Availability Data System on a voluntary basis, which can contribute to the absence of some values in certain assessment areas.										

Errata

December 2025

- Corrections made to the VER Table (page 50): Hydro values for WECC NW, Western Interconnection Total, and Total

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-60:
Department Press Release on Centralia Order

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

U.S. DEPARTMENT of ENERGY

Energy Secretary Ensures Washington Coal Plant Remains Open to Ensure Affordable, Reliable and Secure Power Heading into Winter

U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months.

Energy.gov

December 17, 2025

2 min

Emergency order addresses critical grid reliability issues, lowering risk of blackouts and ensuring affordable electricity access

WASHINGTON—U.S. Secretary of Energy Chris Wright today issued an emergency order to ensure Americans in the Northwestern region of the United States have access to affordable, reliable and secure electricity heading into the cold winter months. The order directs TransAlta to keep Unit 2 of the Centralia Generating Station in Centralia, Washington available to operate. Unit 2 of the coal plant was scheduled to shut down at the end of 2025. The reliable supply of power from the Centralia coal plant is essential for grid stability in the Northwest. The order prioritizes minimizing the risk and costs of blackouts.

"The last administration's energy subtraction policies had the United States on track to experience significantly more blackouts in the coming years — thankfully, President Trump won't let that happen," said **Energy Secretary Wright**. "The Trump administration will continue taking action to keep America's coal plants running so we can stop the price spikes and ensure we don't lose critical generation sources. Americans deserve access to affordable, reliable, and secure energy to heat their homes all the time, regardless of whether the wind is blowing or the sun is shining."

According to DOE's Resource Adequacy Report, blackouts were on track to potentially increase 100 times by 2030 if the U.S. continued to take reliable power offline as it did during the Biden administration.

The North American Electric Reliability Corporation (NERC) determined in its 2025-2026 Winter Reliability

Assessment that the WECC Northwest region is at elevated risk during periods of extreme weather, such as prolonged, far-reaching cold snaps.

This order is in effect beginning on December 16, 2025, and continuing until March 16, 2026.

Background:

The NERC Winter Reliability Assessment warns that "extreme winter conditions extending over a wide area could result in electricity supply shortfalls." With winter electricity demand continuing to rise, peak demand in the U.S. increased by 2.5% since last winter.

###

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-61:
Department Export Authorizations Library

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Grid Deployment Office Export Authorization Library

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Docket No.	Company Name	Country	Date Issued	Status	Date Expires
EA-365-C	Research Power Corporation	Canada	10/21/2025	Active	10/21/2030
EA-408-B	Nalcor Energy Marketing Corporation (NEMC)	Canada	10/17/2025	Active	10/17/2030
EA-479-A	Macquarie Energy LLC	Canada	7/11/2025	Active	7/11/2030
EA-284-G	Calpine Energy	Mexico	6/10/2025	Active	6/10/2030
EA-520	XTS LLC	Mexico	6/10/2025	Active	6/10/2030
EA-171-F	Powerex Corp.	Canada	6/10/2025	Active	6/10/2030
EA-519	Oiko Energy Inc.	Canada	6/10/2025	Active	5/27/2030
EA-517	Altop Energy Investments LP	Mexico	5/23/2025	Active	5/23/2030
EA-518	Altop Energy Investments LP	Canada	5/21/2025	Active	5/21/2030
EA-516	Energia Sierra Juarez U.S., LLC	Mexico	5/16/2025	Active	
EA-391-B	Emera Energy Services Subsidiary No. 6 LLC	Canada	10/15/2024	Active	2/21/2029
EA-392-B	Emera Energy Services Subsidiary No. 7 LLC	Canada	10/15/2024	Active	2/21/2029
EA-393-B	Emera Energy Services Subsidiary No. 8 LLC	Canada	10/15/2024	Active	2/21/2029
EA-504	AlbertaEx, L.P.	Canada	10/9/2024	Active	10/9/2029
EA-475-A	Idaho Power Company	Canada	9/26/2024	Active	9/26/2029
EA-473-A	Northland Power and Energy Marketing, Inc.	Canada	9/24/2024	Active	9/24/2029
EA-264-E	ENMAX Energy Market Inc.	Canada	9/24/2024	Active	9/24/2029
EA-512	ATNV Energy, LP	Mexico	9/20/2024	Active	9/20/2029
EA-515	AMA QSE, LLC	Mexico	9/20/2024	Active	9/20/2029
EA-249-E	Constellation Energy Generation, LLC	Canada	9/20/2024	Active	9/20/2029
EA-97-F	Portland General Electric Company	Canada	9/20/2024	Active	6/25/2034
EA-514	Altop Energy Trading Texas LLC	Mexico	9/6/2024	Active	9/6/2029
EA-456-A	Manifold Energy Inc	Canada	9/6/2024	Expired	9/6/2024
EA-513	Altop Energy	Canada	9/6/2024	Active	9/6/2029

Docket No.	Company Name	Country	Date Issued	Status	Date Expires
EA-427 (E-6751)	Versant Power	Canada	8/26/2024	Active	8/26/2029
EA-510	MFT Energy US Power LLC	Mexico	8/13/2024	Active	8/15/2029
EA-470-A	EDECSAMEX, S.A. de C.V.	Mexico	8/13/2024	Active	8/15/2029
EA-511	ATNV Energy, LP	Canada	8/13/2024	Active	8/15/2029
EA-312-D	Emera Energy U.S. Subsidiary No. 2, Inc.	Canada	7/31/2024	Expired	5/5/2025
EA-466-A	Dynasty Power, Inc.	Mexico	7/31/2024	Active	8/2/2029
EA-466-A	Dynasty Power, Inc.	Mexico	7/31/2024	Active	8/2/2029
EA-385-B	Dynasty Power, Inc.	Canada	7/31/2024	Active	7/31/2029
EA-385-B	Dynasty Power, Inc.	Canada	7/31/2024	Active	8/2/2029
EA-312-C	Emera Energy U.S. Subsidiary No. 2, Inc.	Canada	7/31/2024	Active	7/31/2029
EA-312-C	Emera Energy U.S. Subsidiary No. 2, Inc.	Canada	7/31/2024	Active	8/2/2029
EA-469-A	Puget Sound Energy	Canada	7/31/2024	Active	8/2/2029
EA-469-A	Puget Sound Energy	Canada	7/31/2024	Active	8/2/2029
EA-471-A	Luminant Energy Company LLC	Mexico	6/5/2024	Active	6/5/2029
EA-467-A	Citigroup Commodities Canada ULC	Canada	5/9/2024	Active	5/9/2029
EA-348-D	NextEra Energy Marketing, LLC	Canada	3/21/2024	Active	7/10/2029
EA-260-G	CP Energy Marketing (US) Inc.	Canada	3/11/2024	Active	5/29/2029
EA-145-G	Powerex Corp	Mexico	2/27/2024	Active	4/16/2029
EA-508	ENGIE Energy Marketing NA, Inc.	Mexico	2/26/2024	Active	6/24/2029
EA-464-A	Boston Energy Trading and Marketing LLC	Mexico	2/21/2024	Active	2/21/2029
EA-458-A	Sempra Gas and Power Marketing, LLC	Mexico	2/16/2024	Active	2/16/2029
EA-472-A	Luminant Energy Company LLC	Canada	2/13/2024	Active	6/5/2029
EA-509	Merelec USA	Mexico	1/29/2024	Active	7/10/2029
EA-465-A	Brookfield Renewable Trading and Marketing LP	Canada	1/11/2024	Active	3/25/2029
EA-506	Second Foundation US Trading LLC	Canada	1/8/2024	Active	4/16/2029
EA-507	Second Foundation US Trading LLC	Mexico	1/8/2024	Active	4/16/2029
EA-497-A	NRG Business Marketing LLC	Mexico	12/29/2023	Active	4/10/2028
EA-498-A	NRG Business Marketing LLC	Canada	12/29/2023	Active	9/21/2028
EA-505	Altop Energy	Mexico	12/28/2023	Active	4/16/2029
EA-287-E	Emera Energy U.S. Subsidiary No. 1, Inc.	Canada	12/20/2023	Expired	5/21/2025
EA-503	CWP Energy, Inc.	Mexico	12/19/2023	Active	12/19/2028
EA-287-D	Emera Energy U.S. Subsidiary No. 1	Canada	12/19/2023	Active	12/19/2028
EA-388-B	TEC Energy Inc.	Canada	12/18/2023	Active	12/18/2028
EA-462-A	Guzman Energy LLC	Mexico	12/18/2023	Active	12/18/2028
EA-455-A	NS Power Energy Marketing Incorporated	Canada	11/18/2023	Active	11/8/2028
EA-345-C	New Brunswick Energy Marketing Corporation	Canada	11/16/2023	Active	11/16/2028

Docket No.	Company Name	Country	Date Issued	Status	Date Expires
EA-459-B	Mercuria Energy America, LLC	Mexico	11/16/2023	Active	11/16/2028
EA-461-A	Saavi Energy Solutions, LLC	Mexico	11/16/2023	Active	11/16/2028
EA-468-A	TransCanada Energy Sales Ltd.	Canada	11/14/2023	Active	2/16/2029
EA-463-A	Boston Energy Trading and Marketing LLC	Canada	11/14/2023	Active	2/16/2029
EA-342-C	Royal Bank of Canada	Canada	11/8/2023	Active	11/8/2028
EA-500	MFT Energy US Power LLC	Canada	11/8/2023	Active	11/8/2028
EA-502	In Commodities	Canada	11/8/2023	Active	11/8/2028
EA-257-F	Emera Energy Services, Inc.	Canada	10/25/2023	Active	2/21/2029
EA-257-F	Emera Energy Services, Inc.	Canada	10/25/2023	Active	12/30/2029
EA-257-F	Emera Energy Services, Inc.	Canada	10/25/2023	Active	2/21/2029
EA-257-F	Emera Energy Services, Inc.	Canada	10/25/2023	Active	12/30/2029
EA-108-A	Arizona Public Service Company	Mexico	10/6/2023	Active	
EA-497	Direct Energy Business Marketing, LLC	Mexico	9/21/2023	Active	9/21/2028
EA-499	Elektron Power LLC	Mexico	9/21/2023	Active	9/21/2028
EA-498	Direct Energy Business Marketing, LLC	Canada	9/21/2023	Active	9/21/2028
EA-196-F	Minnesota Power	Canada	9/21/2023	Active	9/21/2028
EA-321-C	Emera Energy Services Subsidiary No. 1 LLC	Canada	8/24/2023	Active	8/24/2028
EA-322-C	Emera Energy Services Subsidiary No. 2 LLC	Canada	8/24/2023	Active	8/14/2028
EA-323-C	Emera Energy Services Subsidiary No. 3 LLC	Canada	8/24/2023	Active	8/24/2028
EA-324-C	Emera Energy Services Subsidiary No. 4 LLC	Canada	8/24/2023	Active	8/24/2028
EA-325-C	Emera Energy Services Subsidiary No. 5 LLC	Canada	8/24/2023	Active	8/24/2028
EA-453-A	Matador Power Marketing, Inc.	Canada	7/6/2023	Active	7/6/2028
EA-452-A	Matador Power Marketing, Inc.	Mexico	7/6/2023	Active	7/6/2028
EA-444-A	Emera Energy Services Subsidiary No. 9 LLC	Canada	6/26/2023	Active	6/26/2028
EA-445-A	Emera Energy Services Subsidiary No. 10 LLC	Canada	6/26/2023	Active	6/26/2028
EA-446-A	Emera Energy Services Subsidiary No. 11 LLC	Canada	6/26/2023	Active	6/26/2028
EA-447-A	Emera Energy Services Subsidiary No. 12 LLC	Canada	6/26/2023	Active	6/26/2028
EA-448-A	Emera Energy Services Subsidiary No. 13 LLC	Canada	6/26/2023	Active	6/26/2028
EA-449-A	Emera Energy LNG, LLC	Canada	6/26/2023	Active	6/26/2028
EA-450-A	Emera Energy Services Subsidiary No. 15 LLC	Canada	6/26/2023	Active	6/26/2028
EA-349-C	Bruce Power Inc.	Canada	6/21/2023	Expired	6/21/2023
EA-501	EDC Power, LLC	Mexico	6/12/2023	Active	6/12/2028
EA-380-A	Freepoint Commodities LLC	Canada	6/12/2023	Active	6/12/2028
EA-336-C	ConocoPhillips Company	Mexico	6/12/2023	Active	6/12/2028
EA-318-D	AEP Energy Partners	Mexico	5/2/2023	Active	5/2/2028
EA-339-C	Shell Energy North America	Canada	5/2/2023	Active	5/23/2028
EA-296-D	Rainbow Energy Marketing Corporation	Canada	5/2/2023	Active	5/2/2028

Docket No.	Company Name	Country	Date Issued	Status	Date Expires
EA-338-C	Shell Energy North America	Mexico	5/2/2023	Active	5/2/2028
EA-496	Command Power Corp.	Canada	5/2/2023	Active	5/2/2028
EA-436-A	MAG Energy Solutions, Inc	Mexico	8/11/2022	Active	9/28/2027

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-62:
Department Export Authorization EA-365-C (Oct. 21, 2025)

United States
Department of Energy

Grid Deployment Office

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
GDO Docket No. EA-365-C

Order Authorizing Electricity Exports to Canada

Order No. EA-365-C

October 21, 2025

Research Power Corporation
(formerly known as Centre Lane Trading Ltd.)
Order No. EA-365-C
Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE's Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id*.

A. Application for Export Authorization

Research Power Corporation (the Applicant) is a power marketer seeking renewal of its authorization to export electric energy to Canada, which was originally granted in Order No. EA-365-A on June 29, 2015, and subsequently renewed (EA-365-B) on April 29, 2020. On December 26, 2024, Centre Lane filed an application with DOE (Application or App.) requesting renewal of its export authority for a five-year term. App. at 1. On July 7, 2025, the Applicant notified DOE of its corporate name change from Centre Lane Trading Ltd. to Research Power Corporation.

According to the Application, Research Power Corporation (formerly known as Centre Lane Trading Ltd.) "is a Canadian Corporation with its principal place of business in Toronto, Ontario" that is "organized under the *Business Corporations Act* of the Province of Ontario, Canada." *Id*. The Applicant states that it "does not own, operate or control any generation or transmission facilities in any region, nor is it affiliated with any entity that owns, operates or controls generation or transmission facilities, and is not affiliated with any franchised public utility." *Id* at 1-2. The applicant further represents that it is a "[Federal Energy Regulatory Commission]-authorized power marketer engaging in the purchase and sale of physical and/or

virtual energy in the Day-ahead and Real-time Markets of various Independent System Operators and Regional Transmission Organizations." App at 2.

Research Power Corporation represents that it "has no electric power supply system on which the proposed exports could have a reliability, fuel use system or stability impact." App. at 3. The Applicant states that it "has no obligation to serve native load usually associated with a franchised service area, and, thus, the exports proposed by [Research Power Corporation] will not impair its ability to meet current and prospective power supply obligations." *Id.* The Applicant further affirms that it "will purchase power to be exported from a variety of sources such as power marketers, independent power producers, or U.S. electric utilities and federal power marketing entities as those terms are defined in Sections 3(22) and 3(19) of the FPA" and that "such power is surplus to the system of the generator and, therefore, the electric power that [Research Power Corporation] will export on either a firm or interruptible basis will not impair the sufficiency of the electric power supply within the U.S." *Id*.

The applicant states that it "will make all necessary commercial arrangements and will obtain any and all other regulatory approvals required in order to schedule and deliver power exports." *Id*. The Applicant further states that it will "schedule its transactions with the appropriate balancing authority areas in compliance with the reliability criteria standards and guidelines established by the North American Electric Reliability Corporation[.]" *Id*. Research Power Corporation also attests to not exceed the export limits for the facilities, or otherwise cause a violation of the terms and conditions set forth in the export authorizations for each. App at 4.

B. Procedural History

On December 26, 2024, Centre Lane filed a renewal application with DOE for export authority for a five-year term. *Id* at 1. On June 16, 2025, DOE published notice of Centre Lane's Application in the Federal Register (90 Fed. Reg. 25252) and asked for any interested parties to submit comments on the Application by July 16, 2025. On July 7, 2025, DOE received notice of Centre Lane's corporate name change to Research Power Corporation.

C. Public Comments

No public comments were received.

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including

serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed,* Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, Order No. EA-314-C, at 4.

A. Research Power Corporation Will Not Impair the Sufficiency of the Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[1] and to ensure that these markets are functioning properly.[2] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in

[1] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

[2] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[3] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[4] Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified the North American Electric Reliability Corporation (NERC) in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[5] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[6] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[7] Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[8] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating

[3] A related reliability analysis follows in the next section of this Order.

[4] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

[5] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, ReliabilityFirst Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

[6] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[7] *Id.* ¶ B.R1.

[8] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[9]

DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Research Power Corporation's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as Research Power Corporation, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility[10] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Research Power Corporation's exports would jeopardize domestic sufficiency of supply. Therefore, an export by Research Power Corporation would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

---

[9] *Id.* ¶ B.R1.

[10] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 US 1, 5 (2002).

B. Research Power Corporation's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area."[11]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions"), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the

[11] EOP-011-1 (Emergency Operations), at ¶ B.R2.

Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements"), and R3 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1").

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Research Power Corporation's export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States' electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE's reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[12] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,[13] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its application, Research Power Corporation committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC's reliability enforcement.

III. FINDINGS AND DECISION

A. Research Power Corporation Meets the Statutory Requirements to Export Electric Energy to Canada

[12] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

[13] *See, e.g.*, *AEP Tex. Cent. Co*., Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Research Power Corporation, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Research Power Corporation Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Research Power Corporation's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's NEPA Implementing Procedures (June 2025) set forth this categorical exclusion, codified as "B4.2," as follows:

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B, § B4.2.

DOE has determined that actions in this category do not normally have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.102(a).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal." 10 C.F.R. § 1021.102(b)(2). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal; uncertain effects or effects involving unique or unknown risks; and unresolved conflicts concerning alternative uses of available resources." *Id*. DOE finds that granting Research Power Corporation's request for export authorization does not present such extraordinary circumstances. Research Power Corporation seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application.

C. Conclusion

DOE grants Research Power Corporation's request for export authorization. Research Power Corporation is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order. The authorization shall be effective for a five (5) year term consistent with DOE's standard term for new electricity export authorizations.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at *electricity.exports@hq.doe.gov*. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Research Power Corporation to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Research Power Corporation compliance with these terms and conditions, including the requirement in paragraph G of this Order that Research Power Corporation create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Research Power Corporation to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Research Power Corporation is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by Research Power Corporation pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[14, 15]

Owner	**Location**	**Voltage**	**Permit No.**[16]
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481[17]

[14] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[15] The Applicant submitted a list identifying currently authorized transmission facilities (Attachment 1 of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant's submission to reflect those changes.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

[17] Currently under construction and not yet operational as of September 2025.

Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission Company	Detroit, MI	230 kV	PP-230
	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
Lake Erie Connector Transmission, LLC	Erie County, PA	320 kV	PP-412[18]
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438[19]
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299[20]
TDI New England	Alburgh, VT	±320 kV DC	PP-400[21]

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.
[19] These transmission facilities have been authorized but not yet constructed or placed into operation.
[20] These transmission facilities have been authorized but not yet constructed or placed into operation.
[21] These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Easton, ME	7.2 kV	PP-499
	Baileyville, ME	345kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(a) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Research Power Corporation may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(b) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Research Power Corporation may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(c) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.

(d) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

(e) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412-1 (issued to Lake Erie Connector Transmission, LLC) to exceed an instantaneous transmission rate of 1,000 MW.

(f) Exports by Research Power Corporation made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities

authorized by Presidential Permits PP-43 (issued to Maine Electric Power Company) and PP-500 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(g) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 134 MW.

(h) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Research Power Corporation may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Research Power Corporation cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(i) Exports made by Research Power Corporation pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.

(j) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc. (Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.

(k) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Research Power Corporation may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(l) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.

(m) Exports by Research Power Corporation made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650

MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Research Power Corporation may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(n) Exports by Research Power Corporation made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(o) Exports by Research Power Corporation made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

Exports Through	NEPOOL Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(p) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(q) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.

(r) Exports by Research Power Corporation made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299

(issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(s) Exports by Research Power Corporation made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(t) Exports by Research Power Corporation made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Research Power Corporation.

(C) Research Power Corporation shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) Research Power Corporation shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Research Power Corporation shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

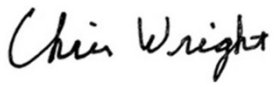
(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) Research Power Corporation has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of October 21, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred and twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Research Power Corporation's authority to export electricity.

Issued in Washington, D.C., on October 21, 2025.



Chris Wright
Secretary of Energy
U.S. Department of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-63:
Gridforce 2019 Audit Report

NCR ID:	**NCR11393**		
Registered Entity Name:	**Gridforce Energy Management, LLC**		
Registered Entity Acronym:	**GRID**		
Reliability Standards Scope:	**Operations & Planning (FERC Order 693) Standards**		
Compliance Monitoring Process:	**Compliance Audit**		
Distribution:	**Public Version. Confidential Information Has Been Removed, Including Privileged and Critical Energy Infrastructure Information.**		
Regional Entity:	**Western Electricity Coordinating Council (WECC)**		
Date of Opening Presentation:	**September 24, 2019**	Date of Closing Presentation:	**September 26, 2019**
Date of Report:	**December 20, 2019**	IP Year:	**2019**
Potential Noncompliance:	**None (zero)**		
Jurisdiction:	**United States**		

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Executive Summary

WECC conducted an Operations & Planning (FERC Order 693) Standards Compliance Audit of Gridforce Energy Management, LLC (GRID), NCR ID NCR11393 from September 24, 2019 to September 26, 2019.

At the time of the Compliance Audit, GRID was registered for the function of Balancing Authority (BA).

The Reliability Coordinator (RC) for GRID is Peak Reliability (PEAK). The Transmission Operators (TOP), Planning Authorities (PA), Transmission Planners (TP), and Resource Planners (RP) for GRID are Bonneville Power Administration (BPA), Public Service Company of New Mexico (PNM), and Salt River Project Agricultural Improvement and Power District (SRP).

The Compliance Audit team (team) evaluated GRID for compliance with Seven (7) Operations and Planning requirements for the 2019 Electric Reliability Organization (ERO) Enterprise Compliance Monitoring and Enforcement Program (CMEP). The team assessed compliance with the NERC Reliability Standards for the period of June 29, 2016 to June 17, 2019.

GRID submitted evidence for the team's evaluation of compliance with requirements. The team reviewed and evaluated all evidence provided to assess compliance with Reliability Standards applicable to GRID at this time.

Based on the evidence provided, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

There were no open Mitigation Plans; therefore, none were reviewed by the team.

The WECC Compliance Audit team lead certifies that the team adhered to all applicable requirements of the NERC Rules of Procedure (ROP) and Compliance Monitoring and Enforcement Program (CMEP).[1]

Compliance Audit Process

The Compliance Audit process steps are detailed in the NERC ROP. The CMEP generally conforms to the United States Government Auditing Standards and other generally accepted audit practices.

[1]This statement replaces the Regional Entity Self-Certification process.

Objectives

All registered entities are subject to compliance assessments with all Reliability Standards applicable to the functions for which the registered entity is registered[2] in the Region(s) performing the assessment. The Compliance Audit objectives are designed to:

- Provide reasonable assurance of compliance to the identified applicable Reliability Standards;
- Review compliance with applicable NERC Reliability Standards identified for 2019 ERO Enterprise CMEP;
- Review evidence of self-reported violations and previous self-certifications;

Scope

The scope of this Compliance Audit considered the NERC Reliability Standards from 2019 ERO Enterprise CMEP Implementation Plan and Inherent Risk Assessment (IRA) of GRID completed by WECC. In addition, the scope of the Compliance Audit included a review of Mitigation Plans or Remedial Action Directives that were open during the Compliance Audit.

The Reliability Standards and Requirements in-scope for this Compliance Audit are illustrated in **Table 2** Compliance Audit Scope.:

Table 2: Compliance Audit Scope	
Standards	**Requirement(s)**
COM-001-3	R9
COM-002-4	R4
COM-002-4	R6
EOP-008-2	R1
EOP-008-2	R6
EOP-011-1	R2
TOP-010-1(i)	R4

The team did not expand the scope of the Compliance Audit beyond what was stated in the notification package.

Controls

The team reviewed GRID's related internal controls associated with some of the NERC Reliability Standards in scope.

Confidentiality and Conflict of Interest

[2]NERC ROP, Appendix 4C, Section 3.1, Compliance Audits.

Confidentiality and conflict of interest of the team are governed under the Regional Delegation Agreements with NERC, and Section 1500 of the NERC ROP[3] . GRID was informed of Western Electricity Coordinating Council (WECC)'s obligations and responsibilities under the agreement and procedures. The work history for each team member was provided to GRID, which was given an opportunity to object to a team member's participation on the basis of a possible conflict of interest or the existence of other circumstances that could interfere with a team member's impartial performance of duties. GRID had not submitted any objections by the stated objection due date based on the ROP and accepted the team member participants without objection. There were no denials or access limitations placed upon this team by GRID.

Methodology

The ERO Compliance Monitoring and Enforcement Manual (Manual)[4] documents the ERO Enterprise's current approaches used to assess a registered entity's compliance with the NERC Reliability Standards. The ERO Enterprise uses, "to the extent possible, the Generally Accepted Auditing Standards (GAAS), the Generally Accepted Government Auditing Standards (GAGAS), and standards sanctioned by the Institute of Internal Auditors, as guidance for performing activities under the Compliance Monitoring and Enforcement Program (CMEP)."[5] While the ERO Enterprise does not necessarily perform compliance monitoring activities that must be in accordance with these standards recognized in the United States, the ERO Enterprise uses these standards as framework to conduct compliance monitoring activities under the CMEP, and recognizes that these standards provide information used in oversight, accountability, transparency, and improvements in ERO Enterprise operations.

The Western Electricity Coordinating Council (WECC) provided GRID with a Compliance Audit notification package to commence the Compliance Audit. GRID provided evidence at the time requested, or as agreed upon, by Western Electricity Coordinating Council (WECC). The team reviewed the evidence submitted by GRID and assessed compliance with the requirements of the applicable Reliability Standards. Additional evidence could be submitted until the agreed-upon deadline prior to the exit briefing. After that date, only data or information that was relevant to the content of the report or its finding could be submitted with the agreement of the team lead.

The team reviewed documentation provided by GRID and requested additional evidence and sought clarification from subject matter experts during the Compliance Audit. The evidence submitted in the form of policies, procedures, emails, logs, studies, data sheets, etc. were validated, substantiated, and

[3] See NERC ROP

[4] http://www.nerc.com/pa/comp/Pages/ERO-Enterprise-Compliance-Auditor-Manual.aspx

[5] NERC ROP, Section 1207 and 126 FERC 61,038, Paragraph 3

cross-checked for accuracy as appropriate. Where sampling is applicable to a requirement, the sample set was determined by a statistical methodology, along with professional judgment as mentioned in the Manual.

The findings were based on the facts and documentation reviewed, the team's knowledge of the Bulk Electric System (BES), the NERC Reliability Standards, and professional judgment. All findings were developed based upon the consensus of the team.

Company Profile

Gridforce Energy Management, LLC is a holding company providing Balancing Authority Services under multiple NERC-registered Balancing Authorities inclusive of the NERC-registered entity GRID. GRID as a generation-only Balancing Authority (BA) balances approximately 3,155 MW of generation. GRID balances generation amounts indicated per the following NERC Registered Entity generation entities and generation resource amounts located within the Western Interconnection:

- Calpine Hermiston (NCR00060) (615 MW)
- Perennial Hermiston (NCR5181) (240 MW)
- Centralia Generation Plant (NCR05533) (1,400 MW)
- Mesquite Power (NCR05235) (600 MW)
- Broadview Wind Project (NCR11714) (300 MW)

Compliance Audit Findings

Based on the results of this Compliance Audit, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

Compliance Culture

GRID's compliance culture was not formally reviewed by the team as part of the compliance audit. Assessment of GRID's internal compliance program will be reviewed by WECC Enforcement on an as-needed basis.

WECC Contact Information

Any questions regarding this Compliance Audit report can be directed to:

WECC

155 North 400 West, Suite 200
Salt Lake City, UT 84103

On behalf of WECC, this report was prepared and reviewed by:

Compliance Audit Team Lead	Date
Senior Compliance Auditor, Operations and Planning	November 4, 2019
Management Rep	**Date**
Compliance Monitoring Manager, Operations and Planning	November 4, 2019

Appendix 1: Compliance Audit Participants

Appendix Table 1: Compliance Audit Team and Appendix Table 2: GRID Participants list all personnel from the team and GRID who were directly involved during the meetings and interviews.

Appendix Table 1: Compliance Audit Team		
Role	**Title**	**Entity**
Audit Team Lead	Senior Compliance Auditor	WECC
Team Member	WECC Consultant	WECC
Team Member	Senior Compliance Auditor	WECC
Team Member	Compliance Auditor	WECC
Team Member	Compliance Program Coordinator	WECC

Appendix Table 2: GRID Participants	
Title	**Entity**
President	Gridforce
Director	Gridforce
Vice President	Gridforce
Security Engineer	Gridforce
System Operator	Gridforce
EMS Engineer 3	Gridforce

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-64:
Gridforce 2022 Audit Report

NCR ID:	**NCR11393**		
Registered Entity Name:	**Gridforce Energy Management, LLC**		
Registered Entity Acronym:	**Gridforce**		
Reliability Standards Scope:	**Operations & Planning (FERC Order 693) Standards**		
Compliance Monitoring Process:	**Compliance Audit**		
Distribution:	**Public Version. Confidential Information Has Been Removed, Including Privileged and Critical Energy Infrastructure Information.**		
Regional Entity:	**Western Electricity Coordinating Council (WECC)**		
Date of Opening Presentation:	**July 25, 2022**	Date of Closing Presentation:	**August 5, 2022**
Date of Report:	**November 30, 2022**	IP Year:	**2022**
Potential Noncompliance:	**None (zero)**		
Jurisdiction:	**United States**		

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Executive Summary

WECC conducted an Operations & Planning (FERC Order 693) Standards Compliance Audit of Gridforce Energy Management, LLC (Gridforce), NCR ID NCR11393 from July 25, 2022 to August 5, 2022.

At the time of the Compliance Audit, Gridforce was registered for the function of Balancing Authority (BA).

The Reliability Coordinator (RC) for Gridforce is Southwest Power Pool, Inc.; the Transmission Operator (TOP) is Bonneville Power Administration.

The Compliance Audit team (team) evaluated Gridforce for compliance with eight (8) Operations and Planning requirements for the 2022 Electric Reliability Organization (ERO) Enterprise Compliance Monitoring and Enforcement Program (CMEP). The team assessed compliance with the NERC Reliability Standards for the period of June 18, 2019, to March 25, 2022.

Gridforce submitted evidence for the team's evaluation of compliance with requirements. The team reviewed and evaluated all evidence provided to assess compliance with Reliability Standards applicable to Gridforce at this time.

Based on the evidence provided, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

The Audit team did not identify any areas of concern[1] or recommendations.

There were open Mitigation Plans; therefore, portions were reviewed by the team.

The WECC Compliance Audit team lead certifies that the team adhered to all applicable requirements of the NERC Rules of Procedure (ROP) and Compliance Monitoring and Enforcement Program (CMEP).[2]

Compliance Audit Process

The Compliance Audit process steps are detailed in the NERC ROP. The CMEP generally conforms to the United States Government Auditing Standards and other generally accepted audit practices.

[1]Per FERC Guidance Order on Compliance Audits Conducted by the Electric Reliability Organization and Regional Entities, dated January 15, 2009.

[2]This statement replaces the Regional Entity Self-Certification process.

Objectives

All registered entities are subject to compliance assessments with all Reliability Standards applicable to the functions for which the registered entity is registered[3] in the Region(s) performing the assessment. The Compliance Audit objectives are designed to:

- Provide reasonable assurance of compliance to the identified applicable Reliability Standards;
- Review compliance with applicable NERC Reliability Standards identified for 2022 ERO Enterprise CMEP;
- Review evidence of self-reported violations and previous self-certifications;
- Review Gridforce's internal compliance program and controls;
- Review the status of open Mitigation Plans.

Scope

The scope of this Compliance Audit considered the NERC Reliability Standards from the 2022 ERO Enterprise CMEP Implementation Plan, Inherent Risk Assessment (IRA) of Gridforce completed by WECC. In addition, the scope of the Compliance Audit included a review of Mitigation Plans or Remedial Action Directives that were open during the Compliance Audit.

The Reliability Standards and Requirements in-scope for this Compliance Audit are illustrated in **Table 2** Compliance Audit Scope.:

Table 2: Compliance Audit Scope		
Registered Function	**Standards**	**Requirement(s)**
BA	EOP-008-2	R2.
BA	EOP-008-2	R5.
BA	EOP-008-2	R6.
BA	EOP-008-2	R7.
BA	EOP-011-1	R2.
BA	INT-006-5	R1.
BA	TOP-001-5	R23.
BA	TOP-001-5	R24.

The team did not expand or reduce the scope of the Compliance Audit beyond what was stated in the notification package.

[3]NERC ROP, Appendix 4C, Section 3.1, Compliance Audits.

Internal Compliance Program

Within the scope of the Compliance Audit, Gridforce's compliance program was not reviewed.

Controls

The team reviewed Gridforce's related internal controls associated with NERC Reliability Standards in scope.

Confidentiality and Conflict of Interest

Confidentiality and conflict of interest of the team are governed under the Regional Delegation Agreements with NERC, and Section 1500 of the NERC ROP.[4] Gridforce was informed of WECC's obligations and responsibilities under the agreement and procedures. The work history for each team member was provided to Gridforce, which was given an opportunity to object to a team member's participation on the basis of a possible conflict of interest or the existence of other circumstances that could interfere with a team member's impartial performance of duties. Gridforce had not submitted any objections by the stated objection due date based on the ROP and accepted the team member participants without objection. There were no denials or access limitations placed upon this team by Gridforce.

Methodology

The ERO Compliance Monitoring and Enforcement Manual (Manual)[5] documents the ERO Enterprise's current approaches used to assess a registered entity's compliance with the NERC Reliability Standards. The ERO Enterprise uses, "to the extent possible, the Generally Accepted Auditing Standards (GAAS), the Generally Accepted Government Auditing Standards (GAGAS), and standards sanctioned by the Institute of Internal Auditors, as guidance for performing activities under the Compliance Monitoring and Enforcement Program (CMEP)."[6] While the ERO Enterprise does not necessarily perform compliance monitoring activities that must be in accordance with these standards recognized in the United States, the ERO Enterprise uses these standards as framework to conduct compliance monitoring activities under the CMEP, and recognizes that these standards provide information used in oversight, accountability, transparency, and improvements in ERO Enterprise operations.

WECC provided Gridforce with a Compliance Audit notification package to commence the Compliance Audit. Gridforce provided evidence at the time requested, or as agreed upon, by WECC.

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[4] See NERC ROP

[5] https://www.nerc.com/pa/comp/CAOneStopShop/ERO_Enterprise_Compliance%20Monitoring%20and%20Enforcement%20Manual_v5.0.pdf

[6] NERC ROP, Section 1207 and 126 FERC 61,038, Paragraph 3

The team reviewed the evidence submitted by Gridforce and assessed compliance with the requirements of the applicable Reliability Standards. Additional evidence could be submitted until the agreed-upon deadline prior to the exit briefing. After that date, only data or information that was relevant to the content of the report or its finding could be submitted with the agreement of the team lead.

The team reviewed documentation provided by Gridforce and requested additional evidence and sought clarification from subject matter experts during the Compliance Audit. The evidence submitted in the form of policies, procedures, emails, logs, studies, data sheets, etc. were validated, substantiated, and cross-checked for accuracy as appropriate. Where sampling is applicable to a requirement, the sample set was determined by a statistical methodology, along with professional judgment as mentioned in the Manual.

The findings were based on the facts and documentation reviewed, the team's knowledge of the Bulk Electric System (BES), the NERC Reliability Standards, and professional judgment. All findings were developed based upon the consensus of the team.

Company Profile

Gridforce Energy Management, LLC, (GEM) founded in 2001, based in Houston, Texas and was acquired by NAES Corporation (NAES) in July 2017.

The NAES Corporation was founded in 1980, is based in Issaquah, Washington, is a wholly-owned subsidiary of ITOCHU Corporation. NAES is an independent services company dedicated to optimizing the performance of energy facilities across the power generation landscape.

The NAES team consists of ~4,000 colleagues, possessing a national footprint, with experience in operations, maintenance, construction, engineering and technical support, in order to support client needs by constructing, operating and maintaining traditional and renewable resources.

NAES is currently responsible and/or supporting more than 1,360 facilities producing, ~100 GW of generation nationwide.

Compliance Audit Findings

Based on the results of this Compliance Audit, no findings were noted for the Reliability Standards and applicable Requirements in scope for this engagement.

Compliance Culture

Gridforce's compliance culture was not formally reviewed by the team as part of the compliance audit. Assessment of Gridforce's internal compliance program will be reviewed by WECC Enforcement on an as-needed basis.

WECC Contact Information

Any questions regarding this Compliance Audit report can be directed to:

WECC
155 North 400 West, Suite 200
Salt Lake City, UT 84103

On behalf of WECC, this report was prepared and reviewed by:

Compliance Audit Team Lead	Date
Compliance Auditor, Operations & Planning	September 2, 2022
Management Rep	**Date**
Manager, Entity Monitoring, Operations & Planning	September 2, 2022

Appendix 1: Compliance Audit Participants

Appendix Table 1: Compliance Audit Team and Appendix Table 2: Gridforce Participants list all personnel from the team and Gridforce who were directly involved during the meetings and interviews.

Appendix Table 1: Compliance Audit Team		
Role	Title	Entity
Compliance Audit Team Lead	Compliance Auditor, Operations and Planning	WECC
Team Member	Senior Compliance Auditor, Operations and Planning	WECC
Team Member	Senior Compliance Auditor, Operations and Planning	WECC
Team Member	Compliance Auditor, Operations and Planning	WECC
Team Member	Compliance Auditor, Operations and Planning	WECC
Team Member	Compliance Auditor, Operations and Planning	WECC
Team Member	Compliance Program Coordinator	WECC
Observer	Director of Entity Monitoring	WECC
Observer	Director, Entity Risk Assessment & Registration	WECC
Observer	Manager, Entity Monitoring, Operations & Planning	WECC
Observer	Internal Controls and Compliance Analyst	WECC

Appendix Table 2: Gridforce Participants	
Title	Entity
Director of Reliability Compliance	Gridforce
Director of CIP Compliance	Gridforce
Operations Engineer at BUCC	Gridforce
President	Gridforce
Director of Operations	Gridforce
System Operator at PCC	Gridforce
System Operator at the BUCC	Gridforce
Director of Applications and Infrastructure	Gridforce

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

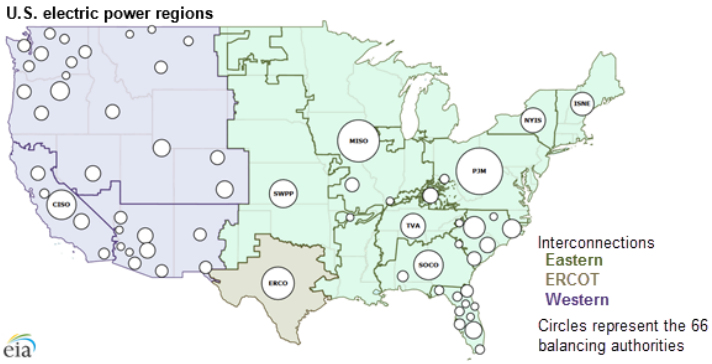
Exhibit 2-65:
EIA Explainer on Balancing Authorities

U.S. Energy Information Administration

Today in Energy

July 20, 2016

U.S. electric system is made up of interconnections and balancing authorities



Source: U.S. Energy Information Administration
Note: The locations of the electric systems are illustrative and are not geographically accurate. The sizes of the circles are roughly indicative of electric system size.

Electricity generated at power plants moves through a complex network of electricity substations, power lines, and distribution transformers before it reaches customers. In the United States, the power system consists of more than 7,300 power plants, nearly 160,000 miles of high-voltage power lines, and millions of low-voltage power lines and distribution transformers, which connect 145 million customers.

Local electricity grids are interconnected to form larger networks for reliability and commercial purposes. At the highest level, the United States power system in the Lower 48 states is made up of three main interconnections, which operate largely independently from each other with limited transfers of power between them.

- The Eastern Interconnection encompasses the area east of the Rocky Mountains and a portion of northern Texas. The Eastern Interconnection consists of 36 balancing authorities: 31 in the United States and 5 in Canada.
- The Western Interconnection encompasses the area from the Rockies west and consists of 37 balancing authorities: 34 in the United States, 2 in Canada, and 1 in Mexico.
- The Electric Reliability Council of Texas (ERCOT) covers most, but not all, of Texas and consists of a single balancing authority.

The network structure of the interconnections helps maintain the reliability of the power system by providing multiple routes for power to flow and by allowing generators to supply electricity to many load centers. This redundancy helps prevent transmission line or power plant failures from causing interruptions in service.

These interconnections describe the physical system of the grid. The actual operation of the electric system is managed by entities called balancing authorities. Most, but not all, balancing authorities are electric utilities that have taken on the balancing responsibilities for a specific portion of the power system. All of the regional transmission organizations in the United States also function as balancing authorities. ERCOT is unique in that the balancing authority, interconnection, and the regional transmission organization are all the same entity and physical system.

A balancing authority ensures, in real time, that power system demand and supply are finely balanced. This balance is needed to maintain the safe and reliable operation of the power system. If demand and supply fall out of balance, local or even wide-area blackouts can result.

Balancing authorities maintain appropriate operating conditions for the electric system by ensuring that a sufficient supply of electricity is available to serve expected demand, which includes managing transfers of electricity with other balancing authorities. Balancing authorities are responsible for maintaining operating conditions under mandatory reliability standards issued by the North American Electric Reliability Corporation and approved by the U.S. Federal Energy Regulatory Commission and, in Canada, by Canadian regulators. These operators monitor the grid to identify potential problems before a situation becomes critical.

Principal contributor: Sara Hoff

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

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Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-66:
Bonneville's Typical Balancing Authority Milestones

LOCAL NEWS

Oregon lawmakers advance one-year moratorium on tax breaks for data centers

On Monday, an economic incentives bill advanced out of committee with an amendment that would pause tax breaks for new data centers.



Author: **Alma McCarty (KGW)**
Published: **11:32 PM PST March 2, 2026**
Updated: **5:18 AM PST March 3, 2026**

SALEM, Oregon — In the final week of Oregon's legislative short session, lawmakers in Salem discussed regulating data centers — specifically, placing a one-year moratorium on certain tax breaks.

Governor Tina Kotek has been looking to expand the state's enterprise zone program, which is intended to grow Oregon companies and attract new ones. Businesses that locate or expand within designated zones can qualify for property tax exemptions on new investments if they meet eligibility requirements.

However, some advocates argue that extending incentives to data centers may not be sustainable long term.

“Data centers have been around for a while,” said Kelly Campbell, policy director for Columbia Riverkeeper. “Data centers are getting bigger and bigger. Some of these new AI hyperscale data centers are exponentially bigger than those tiny ones. They’re really just using a lot of energy, a lot of water.”

Last week, Columbia Riverkeeper released a report examining data centers operating or planned along the Columbia River in Oregon and Washington.

“I think the question becomes, do we want to stick to our climate goals of getting to 100% renewable? Or do we want to have these big, mega data centers owned by big tech companies — some of the wealthiest corporations in the world — getting to use whatever energy they want? We would say, no, that’s not OK,” Campbell said.

On Monday, lawmakers amended an economic incentives bill to block new data centers from qualifying for certain tax breaks for one year.

“I think this moratorium is a pretty short pause to give the advisory council time and space to do their work,” said Rep. Nancy Nathanson, D-Eugene, during a subcommittee meeting Monday morning.

The Data Center Advisory Committee, convened by Kotek, held its first meeting Friday. The group’s goal is to develop policy recommendations addressing the rapid growth of data centers.

"There are some businesses that will need them, but freestanding data centers, the way we've been growing in the state, is not sustainable," the Governor told reporters during a press conference last week.

On Monday, her office sent KGW a statement regarding the moratorium:

"The moratorium will address immediate concerns and also allow for the Governor’s Data Center Advisory Committee to develop recommendations to strategically pursue economic development opportunities while ensuring utility costs, infrastructure investments, and environmental impacts remain sustainable and equitable for all residents."

Supporters of data center growth, particularly in rural communities, also spoke during work sessions.

“This moratorium will have a disparate impact on communities east of the Cascades — communities like Prineville, Hermiston and Redmond that have leveraged enterprise zones and data centers to bring hundreds of living-wage jobs to their communities,” said Alexandra Ring, a lobbyist for the League of Oregon Cities.

“While data centers may be seen as a nuisance or inconvenient in Washington County, they are not in Crook County. They are not in Morrow County, in Umatilla County,” said Sen. Mark McLane, who represents several Eastern Oregon counties, including Baker, Crook, Grant and Harney.

Even if the House and Senate ultimately approve the moratorium, it would apply only to new data centers — not those that already receive tax breaks or projects currently underway.

Related Articles

- 'I don't see this as getting better': Data centers fuel concern over water, energy use, air pollution
- Oregon governor convenes group to weigh the rapid growth of data centers
- Oregon bill could open 1,700 acres near Hillsboro for industrial use. Will it include data centers?

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Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-67:
Email Correspondence with E3

From: Brad Cebulko
To: Arne Olson; Fred Heutte
Cc: Laura Burford; Michael Lenoff; Erik Olson; Edward Burgess
Subject: Re: E3 NW RA study and Centralia
Date: Friday, January 9, 2026 6:57:25 PM

External Sender

Thank you, Arne.

_____
Brad Cebulko
m: 317.519.3165

From: Arne Olson <arne@ethree.com>
Sent: Friday, January 9, 2026 3:43 PM
To: Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: Re: E3 NW RA study and Centralia

Yes everything that I didn't comment on is correct

Sent from my Verizon, Samsung Galaxy smartphone
Get Outlook for Android

From: Brad Cebulko <bcebulko@currentenergy.group>
Sent: Friday, January 9, 2026 3:35:46 PM
To: Arne Olson <arne@ethree.com>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: Re: E3 NW RA study and Centralia

Arne,

I really appreciate the response as well as the data. Thank you. I have one final point of clarification. I understand your response as confirming the accuracy of our summary, subject to the qualifications and information you provided. Please let me know if that understanding is incorrect.

Have a great weekend.

_____
Brad Cebulko
m: 317.519.3165

From: Arne Olson <arne@ethree.com>

Sent: Thursday, January 8, 2026 7:26 PM
To: Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: RE: E3 NW RA study and Centralia

Hi Brad,

Thanks for this summary. I have placed some answers below in red. Also please see the attached spreadsheet with the data that was requested.

Please let me know if I can answer any other questions for you.

Best,

Arne

From: Brad Cebulko <bcebulko@currentenergy.group>
Sent: Friday, January 2, 2026 12:22 PM
To: Arne Olson <arne@ethree.com>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>; Edward Burgess <eburgess@currentenergy.group>
Subject: Re: E3 NW RA study and Centralia

Arne,

Thank you again for speaking with us on Wednesday, December 31. We appreciate you taking the time to discuss your September 2025 presentation on resource adequacy to the Washington Utilities and Transportation Commission and the Washington Department of Commerce. We also appreciate your efforts to locate and share information on Canadian entitlements, the list of in-development resources, and achieved LOLE values. Thank you for your assistance. My understanding is that your anticipated timing works, as the deadline for making use of the materials would be early the following week.

To confirm the accuracy of our notes from the Wednesday call, my colleagues and I have summarized our understanding below. Would you please let us know if the notes below are accurate and if any modifications to the below are appropriate? If possible, we'd be happy to receive this response in advance of the other materials, but also understand your schedule may get in the way.

- The “Greater Northwest” region evaluated in the presentation includes all of the traditional NW Power Act Northwest (Washington, Oregon, Idaho and western Montana) plus all of NorthWestern Energy and PAC-East.
- Slide 10 of the presentation is based on the following inputs:

- Each year shown in the table is a water year beginning October 1. So, for instance, “2026” refers to the year from October 1, 2025 through September 30, 2026.

- The “peak load” used to calculate “Total Resource Need” was developed by E3’s own load forecast. To forecast data center demand, including whether data centers will reduce load at times of peak demand, E3 used figures from utilities’ integrated resource plans.

- The “planning reserve margin” used to calculate “Total Resource Need” was calculated to achieve a loss of load expectation of one event-day per decade (i.e., the 1-in-10 LOLE standard). E3 used its own loss-of-load expectation model to calculate the planning reserve margin.

- The “Existing Portfolio w/ Retirements” assigns value to individual resources based on E3’s own set of capacity accreditation values that were developed using E3’s calculations of resource types’ marginal effective load carrying capacity.

- E3’s August whitepaper explains E3’s accreditation approach.

- Centralia is modeled as retired for all study years. In other words, the study attributes 0 MW to Centralia and does not model the proposed coal-to-gas conversion of Centralia scheduled to be completed in 2028.

- The “firm imports” of 3,750 MW each year is calculated by looking to the 2,500 MW figure that the Northwest Power and Conservation Council uses for a smaller region than the region E3 studies for the presentation. E3 added to the 2,500 MW figure to account for the larger region. E3 was intentionally conservative in setting the 3,750 MW figure. The 3,750 MW figure is not intended to represent the maximum import capability of the region E3 studied.

- The quantum of “in-development” Firm, Wind, Solar, and Battery resources are sourced from WECC’s Anchor Data Set, after accreditation using E3’s calculations of resource types’ effective load carrying capacity. The quantum of “in-development” resources does not include planned resources in utilities’ integrated resource plans shown on slide 21. To confirm whether the “in-development” resources are in service, one can investigate the status of resources shown in the WECC Anchor Data Set, including by reference to press releases.

- With regard to the “Reliability Positions” shown on slide 10:
  - The “Surplus” or “Shortfall” does not include the “in-development” resources. So, for instance, including the “in-development” resources for 2026 improves the calculated Reliability Position from a shortfall of 1,321 MW to a shortfall of 380 MW.

- Any electric system will have some level of resource adequacy risk. The "Surplus" or "Shortfall" shows whether the region has more or fewer resources needed to achieve, in E3's model, the target risk threshold of a loss of load expectation of one event-day in ten years. A shortfall indicates that the region has higher risk of loss of load than the one event-day in ten years standard. A surplus indicates that the region has lower risk of loss of load than the one event-day in ten years standard.
- The "Surplus" or "Shortfall" does not show whether the region has insufficient resources to meet forecasted peak load.

THE 'SURPLUS' OR 'SHORTFALL' SHOWS WHETHER THE REGION HAS SUFFICIENT RESOURES TO MEET FORECASTED PEAK LOAD PLUS THE PLANNING RESERVE MARGIN NEEDED TO ACHIEVE THE 0.1 LOLE RESOURCE ADEQUACY STANDARD.

- For 2026, the risk in the studied region is slightly elevated above the target risk.
- The planned resources in utilities' integrated resource plans shown on slide 21 are enough to meet the shortfalls shown on slide 10 for all years studied.
- Data center flexibility, such as reductions in demand during times of peak demand, can help address the calculated shortfalls.

- Slide 12 indicates that there is essentially no LOLE risk in the year 2025 unless there is a "bad" water year. Will you please clarify whether Slide 12 represents water year 2025 (October 1, 2024 – September 30, 2025)?

CORRECT

- The study finds that the greatest risk to the system is during low hydro years and the evidence, as of December 31, 2025, does not indicate we are in a low hydro year.

- With regard to the presentation's fit to current conditions:
  - The presentation is based on a probabilistic model incorporating 30 years of past weather and hydrological conditions. The model does not reflect actual weather and hydrological conditions presently existing for this winter, such as La Niña. Similarly, the model does not reflect weather and hydrological forecasts for this winter.

THE MODEL CONSIDERS 30 HYDRO YEARS (1989-2018) AND 44 TEMPERATURE YEARS (1979-2022). THE HYDRO YEARS AND LOAD YEARS ARE PAIRED RANDOMLY USING MONTE CARLO DRAWS.

- To gauge the extent to which the model represents current conditions, the key factors are: (1) weather forecasts; (2) hydrological conditions; (3) load conditions; and (4) resource additions and retirements. Thus, for instance, if prevailing and forecasted hydrological conditions are stronger than the average conditions observed in the 30-year dataset used for the model, and holding constant other factors, the "Reliability Position" shown on

slide 10 likely underestimates the actual reliability position in the region. The same goes for a winter weather forecast that is milder than the average weather observed over the thirty-year dataset used for the model.

- Flexibility of data center demand, such as reductions in demand during times of peak load, is one way to help address the shortfalls shown on slide 10.

CORRECT, HOWEVER, DATA CENTER "LOAD FLEXIBILITY" IS OFTEN ACHIEVED WITH ONSITE GENERATION. THIS WOULD MOVE THE PROBLEM FROM ONE SIDE OF THE METER TO THE OTHER, BUT WOULDN'T ELIMINATE THE NEED TO BUILD THE RESOURCES SUBJECT TO THE SUPPLY CHAIN AND OTHER CHALLENGES. TRUE FLEXIBILITY OF COMPUTE LOAD WOULD BE A SIGNIFICANT NEW RESOURCE BUT WE HAVE NOT YET SEEN EVIDENCE OF THIS AT SCALE.

- The Department of Energy's December 16, 2025 Order No. 202-25-11 to Transalta is counterproductive and risks harming reliability in the studied region to the extent the order delays the conversion of Centralia Unit 2 to gas. The order need not be renewed in March 2026 to address the Reliability Positions shown on slide 10 of the presentation.

Please let me know if you have any clarifying questions. Thank you again, and Happy New Year.

Brad Cebulko
m: 317.519.3165

From: Arne Olson <arne@ethree.com>
Sent: Wednesday, December 31, 2025 6:32 PM
To: Brad Cebulko <bcebulko@currentenergy.group>; Fred Heutte <fred@nwenergy.org>
Cc: Laura Burford <LBurford@currentenergy.group>; Michael Lenoff <mlenoff@earthjustice.org>; Erik Olson <eolson@currentenergy.group>
Subject: RE: E3 NW RA study and Centralia

Hi all, thanks for the good questions this morning. Just following up to let you know that, given the holidays and some upcoming deadlines, we will aim to get you the information you requested by late next week. The information we are digging up is:

- Details on how we are modeling the Canadian Entitlement
- List of the "in-development" resources through 2030
- Achieved LOLE values for each year through 2030

Let me know if there is any additional information you might need, and also if there is any impending deadline that we should be aware of.

Also, here is a link to E3's newest resource adequacy white paper.

https://www.ethree.com/new-framework-resource-adequacy/

As I mentioned during our call, it's intended to be a detailed guidebook for how to evaluate resource adequacy needs across markets and vertically integrated systems. Happy to answer any questions you might have about the white paper, or if any other questions come up about our current NW study.

Happy New Year!

Arne

-----Original Appointment-----
From: Arne Olson
Sent: Monday, December 29, 2025 2:08 PM
To: Arne Olson; Brad Cebulko; Fred Heutte
Cc: Laura Burford; Michael Lenoff; Erik Olson
Subject: E3 NW RA study and Centralia
When: Wednesday, December 31, 2025 8:00 AM-8:25 AM (UTC-08:00) Pacific Time (US & Canada).
Where: Microsoft Teams Meeting

Microsoft Teams Need help?

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Meeting ID: 256 665 160 678 92
Passcode: Ei7NT9X3

For organizers: Meeting options

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Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-67a:
E3's Attachment to Email Correspondence with E3

Columbia River Treaty Regime

Sources

https://www.state.gov/bureau-of-western-hemisphere-affairs/details-about-the-key-elements-agreed-between-the-united-states-and-canada-regarding-modernization-of-the-columbia-river-treaty-regime

(Table 1.) https://www.congress.gov/crs-product/R43287

Year	Capacity (MW)[1]	Generation (MW)[2]
2024 (Baseline)	1,141	454
2025-2029	660	305
2030	590	278
2031	573	225
2032	565	225
2033	558	225
2034-2044	550	225

How it is modeled

The capacity component of the treaty (1) was interpreted as the capacity BC is able to access and demand at any point in time. After consulting with BPA, we also interpret that BC could demand this amount for a sustained long period of time, such as for two weeks or more, without violating the generation amounts of the treaty (2) which is itself interpreted as the annual average energy for the treaty. This means the treaty's capacity could be requested for longer than the reliability risk periods and present a firm requirement. **Therefore, the capacity component of the treaty was modeled as a firm obligation which increases the region's total reliability need by the same amount in MWs.**

Year	Firm Obligation, MW
2025	660
2026	660
2027	660
2028	660
2029	660
2030	590

In-Development Resources

Sources
https://www.wecc.org/program-areas/reliability-planning-performance-analysis/reliability-modeling/anchor-data-set-ads
https://www.pacificorp.com/energy/integrated-resource-plan.html

Plant-level list in-development resources within the Greater Northwest Study Region with commission dates between 2025-2030. In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and can be verified online. In-development resources include coal-to-gas plant conversions in Pacificorp's 2025 IRP. Plants with commission dates before January 1 are considered available in the study year. Each resource is assgined to a Transmission Zone based on physical location within the Greater Northwest for zonal modeling.

Annual Capacity Additions (Nameplate MW)							
	2025	2026	2027	2028	2029	2030	Total
Hydro	99	251	78	2	91	-	522
Nuclear	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-
Gas	1,339	357	-	-	205	360	2,261
Other	-	-	-	-	-	-	-
Wind	1,026	1,126	460	-	-	-	2,611
Solar	344	1,396	125	-	-	-	1,866
BTM Solar	-	-	-	-	-	-	-
Battery Storage	460	545	-	-	-	-	1,005
Demand Response	-	-	-	-	-	-	-
Total	3,267	3,676	663	2	296	360	8,264

Source	GeneratorKey	Name	State	County	Tranmission Zone	Rated Capacity (Nameplate MW)	Resource Type	Balancing Authority	Commission Date	First Available Year
ADS 2034	2177	Meyers Falls 1 HY	WA	NA	PNW_NE	1	Hydro	AVA	12/31/2024	2025
ADS 2034	2197	Upper Falls Post St 1 HY	WA	NA	PNW_NE	10	Hydro	AVA	1/4/2026	2027
ADS 2034	2393	Cedar Falls 2 HY	WA	NA	PNW_NW	15	Hydro	PSEI	1/1/2026	2027
ADS 2034	2394	Cedar Falls 1 HY	WA	NA	PNW_NW	15	Hydro	PSEI	1/1/2026	2027
ADS 2034	3472	Thompson Falls 2 HY	MT	NA	Inland_NW	5	Hydro	NWMT	6/1/2025	2026
ADS 2034	3479	Thompson Falls 6 HY	MT	NA	Inland_NW	5	Hydro	NWMT	12/1/2024	2025
ADS 2034	3480	Thompson Falls 5 HY	MT	NA	Inland_NW	5	Hydro	NWMT	12/1/2024	2025
ADS 2034	3481	Thompson Falls 4 HY	MT	NA	Inland_NW	5	Hydro	NWMT	3/31/2025	2026
ADS 2034	3486	Holter 4 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	6/15/2025	2026
ADS 2034	3487	Holter 3 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	7/1/2025	2026
ADS 2034	3488	Holter 2 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	8/25/2025	2026
ADS 2034	3489	Ryan 6 HY	MT	NA	Inland_NW	8	Hydro	NWMT	1/1/2025	2026
ADS 2034	3490	Ryan 5 HY	MT	NA	Inland_NW	8	Hydro	NWMT	3/9/2025	2026
ADS 2034	3515	Ryan 3 HY	MT	NA	Inland_NW	8	Hydro	NWMT	12/1/2024	2025
ADS 2034	3517	Ryan 1 HY	MT	NA	Inland_NW	8	Hydro	NWMT	12/1/2024	2025
ADS 2034	3531	Holter 1 HY	MT	Lewis&Clark	Inland_NW	10	Hydro	NWMT	12/1/2025	2026
ADS 2034	3537	Thompson Falls 3 HY	MT	NA	Inland_NW	5	Hydro	NWMT	4/1/2025	2026
ADS 2034	3539	Thompson Falls 1 HY	MT	NA	Inland_NW	5	Hydro	NWMT	6/1/2025	2026
ADS 2034	4925	Boundary 1 HY	WA	NA	PNW_NW	158	Hydro	SCL	8/1/2025	2026
ADS 2034	4966	Long_Lake_1	WA	Lincoln	PNW_NE	9	Hydro	AVA	12/31/2024	2025
ADS 2034	7473	Lagrande 2 HY	WA	NA	PNW_NW	6	Hydro	TPWR	1/1/2024	2025
ADS 2034	7474	Lagrande 3 HY	WA	NA	PNW_NW	6	Hydro	TPWR	1/1/2024	2025
ADS 2034	7475	Lagrande 4 HY	WA	NA	PNW_NW	6	Hydro	TPWR	1/1/2024	2025
ADS 2034	7606	Long_Lake_2	WA	Lincoln	PNW_NE	9	Hydro	AVA	12/31/2024	2025
ADS 2034	7607	Long Lake 3 HY	WA	NA	PNW_NE	18	Hydro	AVA	12/1/2025	2026
ADS 2034	7608	Long Lake 4 HY	WA	NA	PNW_NE	18	Hydro	AVA	1/1/2028	2029
ADS 2034	8613	Ryan 2 HY	MT	Cascade	Inland_NW	9	Hydro	NWMT	12/13/2024	2025
ADS 2034	8614	Ryan 4 HY	MT	Cascade	Inland_NW	9	Hydro	NWMT	12/31/2024	2025
ADS 2034	9698	Gorge 1 HY	WA	NA	PNW_NW	37	Hydro	SCL	1/1/2028	2029
ADS 2034	9699	Gorge 2 HY	WA	NA	PNW_NW	37	Hydro	SCL	1/1/2028	2029
ADS 2034	18045	Boswell Springs Wind WT	WY	Sweetwater	Central_West	320	Wind	PACE	4/1/2024	2025
ADS 2034	18048	Cedar Creek Wind WT	ID	Power	Central_West	152	Wind	PACE	4/1/2024	2025
ADS 2034	18179	Hauser Agg HY	MT	Lewis&Clark	Inland_NW	17	Hydro	NWMT	12/31/2024	2025
ADS 2034	18210	Uinta Agg HY	UT	Uintah	Central_West	1	Hydro	PACE	12/1/2025	2026
ADS 2034	18218	Utility Solar+Storage - PV - S-O	OR	NA	PNW_SW	1	Battery Storage	PACW	1/1/2024	2025
ADS 2034	18224	Big Fork 1 HY	MT	Flathead	PNW_NE	2	Hydro	BPAT	1/1/2027	2028
ADS 2034	18345	Glen Canyon Solar A PV-T	UT	Kane	Central_West	95	Solar	PACE	1/1/2024	2025
ADS 2034	19147	Tower Rd Solar PV-T	OR	Morrow	PNW_NE	120	Solar	BPAT	12/1/2024	2026
ADS 2034	19260	Farmers Irrigation District Coppe	OR	Hood River	PNW_SW	2	Hydro	PACW	1/1/2026	2027
ADS 2034	20916	Oregon Trail Solar PV-T	OR	Gilliam	PNW_NE	41	Solar	BPAT	12/31/2025	2026
ADS 2034	20917	Green River Energy Center PV-	UT	Emery	Central_West	400	Solar	PACE	6/15/2025	2026
ADS 2034	20962	Cedar Springs Wind IV WT	WY	NA	Central_West	350	Wind	PACE	12/31/2024	2025

ADS 2034	20963	Anticline Wind WT	WY	NA	Central_West	101	Wind	PACE	12/31/2024	2025
ADS 2034	20964	Two Rivers Wind LLCWT	WY	Carbon	Central_West	280	Wind	PACE	3/31/2025	2026
ADS 2034	21121	Franklin BESS paired with Solar	ID	Twin Falls	Central_West	60	Battery Storage	IPCO	6/1/2024	2025
ADS 2034	21163	Oregon Trail BESS BA	OR	Gilliam	PNW_NE	41	Battery Storage	BPAT	12/31/2025	2026
ADS 2034	21164	Tower Rd BESS BA	OR	Morrow	PNW_NE	60	Battery Storage	BPAT	12/31/2025	2026
ADS 2034	21215	Jim Bridger 1 ST	WY	Sweetwater	Central_West	578	Gas	PACE	4/1/2024	2025
ADS 2034	21216	Jim Bridger 2 ST	WY	Sweetwater	Central_West	586	Gas	PACE	4/1/2024	2025
ADS 2034	21401	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21402	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21403	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21404	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21405	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21406	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21407	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21408	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21409	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21410	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21411	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21412	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21413	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21414	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21415	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21416	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21417	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21418	Yellowstone County Generating	MT	Yellowstone	Inland_NW	10	Gas	NWMT	5/15/2024	2025
ADS 2034	21423	DaveJohnston 1 1 ST	WY	Converse	Central_West	99	Gas	PACE	1/1/2029	2029
ADS 2034	21432	Naughton 1 (natural gas convers	WY	Lincoln	Central_West	156	Gas	PACE	1/1/2026	2026
ADS 2034	21433	Naughton 2 (natural gas convers	WY	Lincoln	Central_West	201	Gas	PACE	1/1/2026	2026
ADS 2034	21678	Additional Hemingway Standalo	ID	Owyhee	Central_West	36	Battery Storage	IPCO	6/1/2024	2025
ADS 2034	21679	Elmore Distributed BESS BA	ID	Elmore	Central_West	3	Battery Storage	IPCO	6/1/2024	2025
ADS 2034	21680	Happy Valley BESS I 1 BA	ID	Canyon	Central_West	39	Battery Storage	IPCO	6/1/2025	2026
ADS 2034	21681	Happy Valley BESS II 1 BA	ID	Canyon	Central_West	39	Battery Storage	IPCO	6/1/2025	2026
ADS 2034	21682	Kuna BESS 1 BA	ID	Ada	Central_West	150	Battery Storage	IPCO	6/1/2025	2026
ADS 2034	21683	Melba Distributed BESS BA	ID	Canyon	Central_West	2	Battery Storage	IPCO	6/1/2024	2025
ADS 2034	21735	Parowan Solar BA	UT	Iron	Central_West	58	Battery Storage	PACE	12/1/2024	2025
ADS 2034	21749	Pump Storage - West 1 PS	OR	Douglas	PNW_SW	35	Hydro	PACW	1/1/2026	2027
ADS 2034	21752	Coffee Creek 1 BA	OR	Washington	PNW_NE	17	Battery Storage	BPAT	6/1/2025	2026
ADS 2034	21753	Constable BESS 1 BA	OR	Washington	PNW_SW	100	Battery Storage	BPAT	12/31/2024	2025
ADS 2034	21754	Seaside BESS 1 BA	OR	Multnomah	PNW_SW	200	Battery Storage	BPAT	6/1/2025	2026
ADS 2034	21755	Troutdale BESS 1 BA	OR	Multnomah	PNW_NE	200	Battery Storage	BPAT	12/31/2024	2025
ADS 2034	22116	Pleasant Valley Solar II 1 PV-T	ID	Ada	Central_West	125	Solar	IPCO	12/1/2026	2027
ADS 2034	22212	Arco Wind WT	ID	Bonneville	Central_West	360	Wind	PACE	12/1/2026	2027
ADS 2034	22215	Faraday Solar B LLC PV-T	UT	Utah	Central_West	525	Solar	PACE	9/30/2025	2026
ADS 2034	22217	Hornshadow Solar II LLC PV-T	UT	Emery	Central_West	200	Solar	PACE	6/30/2025	2026
ADS 2034	22218	Hornshadow Solar LLC PV-T	UT	Emery	Central_West	100	Solar	PACE	6/30/2025	2026
ADS 2034	22220	Parowan Solar PV-T	UT	Iron	Central_West	58	Solar	PACE	12/1/2024	2025
ADS 2034	22231	Rock Creek I Wind 32 WT	WY	Carbon	Central_West	195	Wind	PACE	6/1/2025	2026
ADS 2034	22232	Rock Creek II Wind 66 WT	WY	Albany	Central_West	403	Wind	PACE	9/1/2025	2026
ADS 2034	22256	Buckaroo Solar 1 PV-T	OR	Pendleton	PNW_SW	2	Solar	PACW	9/30/2025	2026
ADS 2034	22257	Buckaroo Solar 2 PV-T	OR	Pendleton	PNW_SW	3	Solar	PACW	9/30/2025	2026
ADS 2034	22262	Antelope Creek Solar LLC PV-T	OR	Jackson	PNW_SW	2	Solar	PACW	4/19/2024	2025
ADS 2034	22264	Black Rock Solar PV-T	WA	Yakima	PNW_NE	100	Solar	BPAT	1/1/2024	2025
ADS 2034	22267	Green Solar LLC PV-T	OR	Culver	PNW_SW	3	Solar	TH_Malin	3/15/2024	2025
ADS 2034	22268	High Top Solar PV-T	WA	Yakima	PNW_NE	80	Solar	BPAT	4/1/2024	2025
ADS 2034	22270	Orchard Knob Solar PV-T	OR	Polk	PNW_NE	2	Solar	BPAT	2/23/2024	2025
ADS 2034	22274	Pilot Rock Solar I PV-T	OR	Umatilla	PNW_SW	2	Solar	PACW	9/30/2025	2026
ADS 2034	22275	Pilot Rock Solar II PV-T	OR	Umatilla	PNW_SW	3	Solar	PACW	9/30/2025	2026
ADS 2034	22276	Pine Grove Solar LLC PV-T	OR	Klamath	PNW_SW	1	Solar	TH_Malin	2/16/2024	2025
ADS 2034	22281	Sunset Ridge Solar LLC PV	OR	Klamath	PNW_SW	2	Solar	TH_Malin	7/25/2024	2025
ADS 2034	22292	Clearwater II 37 WT	MT	Custer	Central_West	103	Wind	PACE	1/2/2024	2025
ADS 2034	22323	BHCE 100 MW Wind WT	CO	TBD	PNW_NE	100	Wind	BPAT	1/1/2026	2027
ADS 2034	22340	Beaver Creek 1 WT	MT	Gallatin	Inland_NW	248	Wind	NWMT	3/1/2025	2026
ADS 2034	22487	Sprague Hydro (North Fork) 1 H	OR	Klamath	PNW_SW	1	Hydro	PACW	1/1/2024	2025
ADS 2034	22546	Wallowa Falls 1 HY	OR	NA	PNW_SW	1	Hydro	PACW	1/1/2026	2027
ADS 2034	22567	DaveJohnston 2 2 ST	WY	Converse	Central_West	106	Gas	PACE	1/1/2029	2029
Pacificorp 2025 IRP	Pacificorp 2025 IRP	E3 Dave Johnston 4 Coal-to-Ga	WY	Converse	Central_West	360	Gas	PACE	12/31/2029	2030

Greater Northwest System Metrics

	Unit	2025	2026	2027	2028	2029	2030
Total Resource Need*	*MW*	49,245	50,737	52,499	54,184	55,879	57,195
Existing Portfolio w/ Retirements**	*MW*	46,716	45,666	45,395	45,388	45,098	44,757
Firm Imports	*MW*	3,750	3,750	3,750	3,750	3,750	3,750
Reliability Position ***before Resource Additions*** Surplus (+) / Shortfall (-)	*MW*	1,221	-1,321	-3,354	-5,046	-7,031	-8,689
"In-Development"*** Firm Resources	*MW*	0	296	407	580	770	1,114
"In-Development" Wind, Solar and Battery projects	*MW*	0	645	1,015	1,316	1,508	1,934

** Total Resource Need includes peak load + planning reserve margin as well as obligation to serve the Columbia River Treaty Regime*

***Does not include new gas capacity from converted coal units, only the coal retirements. New gas capacity from conversion categorized as "In-Development" below. Still includes retirement of Centralia 2, at 687 MW of effective firm capacity.*

*** In-development resources are WECC ADS 2034 facilities with confirmed project location, project name, and can be verified online. Includes new gas capacity from the conversion of coal units. Does not inclue repowering of Centralia 2 as a gas unit.*

System Metrics including "In-Development" Resources	Unit	2025	2026	2027	2028	2029	2030
Reliability Position ***with "In-Development" Resources*** Surplus (+) / Shortfall (-)	*MW*	1,221	-380	-1,932	-3,150	-4,753	-5,641
Loss-of-Load Expectation	*MWh/year*	63	1,212	6,987	20,398	58,132	98,067
	Hours/year	0.14	1.65	5.58	14.70	36.43	56.57
	Days/year	0.01	0.15	0.68	1.77	4.14	6.01
	% chance/year	0.3%	5.2%	21.0%	40.5%	59.4%	67.5%

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-67b:
E3's Attachment to Email Correspondence with E3 (as transmitted in Excel form)
[Provided in Native Excel Format]

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-68:
Wash. Utils. Comm'n Rejection of Colstrip Investments in Avista Rates

Service Date: December 19, 2025

BEFORE THE WASHINGTON
UTLITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. AVISTA CORPORATION, D/B/A AVISTA UTILITIES Respondent.	DOCKET UE-240891 FINAL ORDER 08 REJECTING TARIFF SHEETS; AUTHORIZING AND REQUIRING COMPLIANCE FILING

Synopsis: *The Washington Utilities and Transportation Commission rejects the tariff sheets filed by Avista Corporation d/b/a Avista Utilities (Avista or Company) on October 31, 2024, and revised on December 20, 2024, and allowed its requested rate increase to provisionally go into effect subject to refund. The Commission has considered the full record and requires Avista to file tariff sheets that will result in a decrease in revenue of approximately $5.86 million or 1.0 percent in accordance with the decisions in this Order summarized below. The Commission concludes that Colstrip Units 3 and 4 will be "retired" within the meaning of CETA when Avista transfers its ownership in those units to NorthWestern Energy Corporation (NorthWestern) on January 1, 2026. The Commission further determines that the Abandonment and Acquisition Agreement (A&A Agreement) is not subject to Commission approval because Colstrip is not useful or necessary for Avista's service in Washington at the time of transfer.*

However, the Commission establishes a condition to facilitate review of future property transfers to comply with CETA. Additionally, the Commission finds that Avista acted contrary to its commitment not to support life-extending investments at Colstrip in the 2019 General Rate Case (GRC) Settlement approved in Dockets UE-190334, et al., but declines to impose penalties in this docket for violation of that Settlement. The Commission also finds it appropriate for Avista to include its request to recover 2025 plant additions consistent with Final Order 10/04 and the Settlement Agreement in Avista's 2022 GRC in Dockets UE-220053, et al.

The Commission determines that Avista's Colstrip investments are not used and useful after December 31, 2025, and that such investments should be prorated, except for 13 investments in support of human health and safety. The Commission further requires

Avista to establish the in-service dates of two other investments, the U4 Generator Exciter and the Northern Cheyenne AAQ System, to establish a prorated level of recovery, if any. The Commission determines that Avista has demonstrated the prorated portion of its Colstrip investments are prudent but has not demonstrated prudence of its investment in the two TOFA SmartBurn components and the Baghouse Project, which will not be in service and used and useful to Avista's Washington customers in 2025.

The Commission further requires Avista to refund the return on inventory balances, which were inadvertently included in base rates for 2026, remove these inventory balances from working capital in Avista's next general rate case filing, and to refund any over-collected amounts in the manner described in this Order. The Commission further requires Avista to file an accounting to true-up 2025 Colstrip investments along with the refund, in a compliance filing submitted by March 31, 2026, consistent with the decisions in this Order.

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PROCEDURAL HISTORY

1 On October 31, 2024, Avista Corporation d/b/a Avista Utilities (Avista or Company) filed with the Washington Utilities and Transportation Commission (Commission) proposed revisions to its rates under electric service tariff, Tariff WN U-28, Schedule 99

Colstrip Tracker to recover Avista's portion of investments in the Colstrip Steam Electric Station (Colstrip). Colstrip is a four-unit coal fired electric generation facility operated by Talen MT (Talen),[1] located in Colstrip, Montana.[2] Avista states that it submitted this filing in accordance with Final Order 10/04 in consolidated Dockets UE-220053, UG-220054 and UE-210854, and seeks to recover capital investments incurred from December 31, 2023, through December 31, 2025, in this tariff schedule over the 2025 calendar year.[3] Specifically, Avista's proposed rates reflect an increase of $18.2 million, or 2.7 percent, from $23.9 million in 2024 to $42.6 million, and the Company seeks to recover that balance from customers effective January 1, 2025, over the 2025 calendar year.[4]

2 On December 19, 2024, this matter came before the Commission at the regularly scheduled Open Meeting. Commission staff (Staff) raised concerns about several capital investments reflected in the filing that are potentially unrecoverable by law or imprudent for Washington ratepayers. The Commission voted to suspend the filing for hearing.[5] On December 20, 2024, Avista filed revised tariff sheets, and the Commission issued Corrected Order 01, Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication in this docket (Corrected Order 01), requiring Avista to file revised tariff pages no later than December 23, 2024, and indicating that the increased rates would go into effect on January 1, 2025, subject to refund.[6]

3 On March 6, 2025, the Commission held a prehearing conference before Administrative Law Judge Amy Bonfrisco (ALJ Bonfrisco) and on that same date entered Order 02, granting Avista's request for a Protective Order.

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[1] Kinney, Exh. SJK-1T at 6:11-12.

[2] Kinney, Exh. SJK-1T at 4:16.

[3] *Washington Utilities and Transportation Commission (WUTC) v. Avista Corporation d/b/a Avista Utilities (Avista),* Dockets UE-220053, UG-220054, UE-210854 (*Consolidated*) Tariff Schedule 99 Colstrip 2025 Compliance Filing (October 31, 2024).

[4] Kinney, Exh. SJK-1T at 2:8-16. *See also* Kinney, Exh. SKJ-9C (confidential native workpapers) and SJK-10 (for non-confidential workpapers). The difference between the 2024 Tariff 99 balance for revenue requirement (AMA basis) versus the 2025 Tariff 99 balance (AMA basis) is an increase of $18.7 million. However, when the total revenue requirement runs through the rate design workpapers based on load and allocation factors, the required change in revenue is $18.2 million as provided in witness Kinney's testimony referenced above.

[5] *WUTC v. Avista*, Docket UE-240891, Order 01, Complaint and Order Suspending Tariff Revisions; Allowing Rates Subject to Later Review and Refund (December 19, 2024).

[6] Docket UE-240891, Corrected Order 1 at 2 ¶ 5 and 4 ¶ 20 (December 20, 2024) (hereafter Corrected Order 01).

4 On March 21, 2025, the Commission entered Order 03 Prehearing Conference Order and Notice of Hybrid Evidentiary Hearing adopting the parties' agreed procedural schedule, setting the evidentiary hearing for October 3, 2025,[7] and granting the unopposed petitions for intervention submitted by NW Energy Coalition (NWEC) and Alliance of Western Energy Consumers (AWEC). Order 03 also granted NWEC's and AWEC's requests for case certification, directed each to file their proposed budgets for participatory funding within thirty days,[8] and addressed the filing of testimony and exhibits to be considered in the adjudication of issues raised in this docket for all parties.[9]

5 On March 24, 2025, an Errata Correcting paragraph 18 of the Prehearing Conference Order 03 was issued to include the requirement for the parties to submit five paper copies to the Commission within three business days of electronically filing testimony, exhibits and post-hearing briefs."[10]

6 By April 07, 2025, NWEC and AWEC both timely filed their proposed budgets and requests for fund grants, and on May 12, 2025, NWEC filed a Motion to Revise its Proposed Budget pursuant to Washington Administrative Code (WAC) 480-07-375.

7 On May 27, 2025, the Commission entered Order 04 approving NWEC's revised proposed budget together with the initial proposed budget AWEC submitted.[11]

8 On June 9, 2025, pursuant to the procedural schedule, Avista filed its direct testimony, and exhibits in support of its Tariff WN U-28, Schedule 99 Colstrip Tracker filing in this docket.

9 On June 30, 2025, the Public Counsel Unit of the Attorney General's Office (Public Counsel) filed a motion for relief from Order 03 (Motion) requesting suspension of the

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[7] Docket UE-240891, Prehearing Conference Order; Notice of Hybrid Evidentiary Hearing at 2 ¶ 7, 3 ¶¶ 14-16, and 5 ¶ 20; *See also* Appendix A (March 21, 2025).

[8] Pursuant to RCW 80.28.430, utilities must enter into funding agreements with organizations that represent broad customer interests. The Commission is directed to determine the amount of financial assistance, if any, that may be provided to any organization; the way the financial assistance is distributed; the way the financial assistance is recovered in a utility's rates; and other matters necessary to administer the agreement. See *In re Examination of Participatory Funding Provisions for Regulatory Proceedings,* Docket U-210595, Policy Statement on Participatory Funding for Regulatory Proceedings (November 19, 2021).

[9] *Id*.

[10] Docket UE-240891, Notice of Errata to Order 03 (March 24, 2025).

[11] Docket UE-240891, Order 04, Granting NWEC's Motion to Revised Proposed Budget and Order Approving Proposed Budgets and Fund Grants at 10 ¶¶ 34-35 (May 27, 2025).

Commission's requirement for parties to submit five paper copies of testimony, exhibits, post-hearing briefs, and on July 15, 2024, the Commission entered Order 05, denying the Motion.[12]

10 On July 24, 2025, Staff, Public Counsel, AWEC, and NWEC filed response testimony.

11 On August 15, 2025, the Commission entered a Notice assigning Administrative Law Judge Ann Paisner (ALJ Paisner) to serve as a co-presiding officer with ALJ Bonfrisco and the Commissioners in this matter.

12 On September 12, 2025, NWEC filed a Motion to Strike a Portion of the Rebuttal Testimony of Avista witness Scott J. Kinney (Kinney) in which Kinney incorporated by reference extra-record testimony submitted by Puget Sound Energy witness Ronald J. Roberts (Roberts) in Docket UE-240729 by fully concurring with that testimony and attempting to incorporate those arguments in this docket.[13]

13 On September 16, 2025, Avista filed a response stating that it did not object to NWEC's motion, and did not intend to introduce Roberts' testimony,[14] and after no parties filed any further responses, the Commission entered Order 06, granting NWEC's motion to strike.[15]

14 On September 22, 2025, Avista filed a Motion for Leave to File Revised Exhibit SKJ-13Cr, to substitute the final executed version of the Letter Agreement Re: Enhancement Work Under the Abandonment and Acquisition Agreement Between Avista and NorthWestern Energy (NWE) Regarding Cost Allocation (A&A Agreement), for the previously filed unsigned draft version.[16]

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[12] Docket UE-240891, Order 05, Dening Public Counsel's Motion for Relief From Order 03 Prehearing Conference Order at 3-4 ¶¶ 12-14 (July 15, 2025).

[13] Docket UE-240891, NW Energy Coalition's Motion to Strike a Portion of the Rebuttal Testimony of Avista Corporation Witness Scott J. Kinney at 2-3 ¶ 3 citing Kinney, Ex. SJK-11CT at 3:7-10 (September 12, 2025).

[14] Docket UE-240891, Answer of Avista Corporation to NWEC's Motion to Strike a Portion of the Rebuttal Testimony of Avista Corporation Witness Scott J. Kinney at 2-3 ¶¶ 2- 3 (September 16, 2025).

[15] Docket UE-240891, Order 06, Granting NWEC's Motion to Strike a Portion of the Rebuttal Testimony of Avista Corporation Witness Scott J. Kinney at 3 ¶¶ (September 30, 2025).

[16] Docket UE-240891, Letter Agreement Between Avista and NWE Regarding Cost Allocation, Kinney, Exh. 13Cr (October 1, 2025).

15 On September 24, 2025, the Commission convened a Public Comment Hearing, and over the course of the proceeding received a total of 60 comments from Washington customers opposing Avista's filing. Of the 60 comments received, none support the filing, 59 were opposed, 1 was undecided, and 2 of the 59 were duplicates.[17] Most of the customers opposing the filing raised concerns about the ability to continue paying for rate increases in utility bills, particularly when it would run contrary to the purpose of CETA, lead to subsidizing coal electricity for use by other states, and avert investments from being made in cleaner, less expensive energy sources.[18]

16 On September 26, 2025, the Commission issued Notice of Bench Request No. 01,[19] and Staff timely responded.[20] On this same date, Avista filed proposed time estimates and a consolidated exhibit list on behalf of all parties, and Public Counsel and NWEC filed proposed cross exhibits for the evidentiary hearing.

17 On October 1, 2025, the Commission issued Order 07, granting Avista's Motion for Leave to file revised Exh. SKJ-13Cr, and Avista filed a revised copy of page 3 to Exhibit SJK-11CTr in accordance with Order 06. Avista also filed a Motion to Submit Late-Filed Exhibit SJK-30C,[21] which consisted of the letter agreement between Avista and NWE relating to the precise time of closing under the A&A Agreement.

18 On October 3, 2025, the Commission held an evidentiary hearing in this matter before the Commissioners, with ALJs Bonfrisco and Paisner presiding.

19 On October 7, 2025, the Commission issued Notice of Bench Requests No. 2 and 3 to Avista and NWEC, and on October 10, 2025, requested supplemental briefing from all the parties relating to whether Revised Code of Washington (RCW) 19.405.030(3)

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[17] Docket UE-240891, Offer of Public Comment, Exh. BR-4 at 2-3 ¶¶ 6-7, and UTC Matrix Attachment A (October 10, 2025).

[18] Offer of Public Comment, Exh. BR-4, and UTC Matrix Attachment A at 4-7.

[19] Bench Request No. 1 requested that Staff file as exhibits in this docket, UE-240891, Supplemental Joint Testimony of Exh. JT-3T and JT-4, originally filed in Avista's 2022 general rate case in Dockets UE-220053, UG-220054, and UE-210854. The Commission also requested that Staff provide the specific citation to Final Order 10/04 and Appendix A, which it recommended be the subject of amendment as described in Staff Witness McGuire's Testimony, Exh. CRM -1CT at 31:5 and 37:3.

[20] Docket UE-240891, Staff Response to Bench Request No. 1 and Attachments A and B (September 29, 2025).

[21] Docket UE-240891, Letter Agreement Between Avista and NWE Regarding Closing Timing Under the Abandonment and Acquisition Agreement, Kinney, Exh. SJK-30C (October 1, 2025).

pertains to an "undepreciated investment in fossil fuel resource," to which all parties timely responded.

20 On October 24, 2025, all the parties responded timely and submitted their post-hearing and supplemental briefing.

21 On November 24, 2025, the Commission issued Notice of Bench Request No. 4 requesting that Avista provide the revenue model and supporting workpapers in their native format along with detailed information relating to gross plant, accrued depreciation, and ADFIT and on December 2, 2025, Avista timely responded.

22 **PARTY REPRESENTATIVES.** David Meyer, Chief Counsel, represents Avista. Jeff Roberson, Nash Callaghan and Josephine Strauss, Assistant Attorneys General, represent Staff.[22] Alexandra Kory, Tad Robinson O'Neill, and Robert Sykes, Assistant Attorneys General, represent Public Counsel. Sommer Moser, Michelle Madsen and Tyler Pepple of Pepple Moser, P.C., represent AWEC. Yochanan Zakai and Orran Balagopalan of Shute, Mihaly & Weinberger LLP., represent NWEC.

BACKGROUND

23 **Clean Energy Transformation Act (CETA).** In 2019, the Washington State Legislature passed the Clean Energy Transformation Act (CETA),[23] codified in RCW Chapter 19.405. In the face of immediate and significant threats posed by climate change, CETA requires that each Washington electric utility "eliminate coal-fired resources from its allocation of electricity" no later than December 31, 2025,[24] that all retail sales of electricity are "one hundred percent carbon-neutral by January 1, 2030,"[25] and that by January 1, 2045 "one hundred percent of all sales of electricity to Washington retail customers" are supplied by either non-emitting or renewable electricity generation

[22] In formal proceedings such as this, the Commission's regulatory staff participates like any other party, while the Commissioners make the decision. To assure fairness, the Commissioners, the presiding administrative law judge, and the Commissioners' policy and accounting advisors do not discuss the merits of this proceeding with the regulatory staff, or any other party, without giving notice and opportunity for all parties to participate. *See* RCW 34.05.455.

[23] Laws of 2019, Ch. 288, §§ 1–13 and 26. Codified at RCW 19.405.

[24] RCW 19.405.030(1). *See also* RCW 19.405.020(1) which defines "*Allocation of electricity*" for the purposes of setting electricity rates as "the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state."

[25] RCW 19.405.010 (2) and RCW 19.405.040(1).

resources.[26] CETA promotes a transition to a clean energy economy,[27] provides incentives for clean alternative energy sources,[28] and expands the meaning of "public interest" under Title 80 RCW.[29]

24 **Settlement Agreement in Avista's 2022 General Rate Case (GRC).** On December 12, 2022, the Commission approved the Colstrip Tracker and Tariff Schedule 99 in its resolution of Avista's 2022 GRC in Final Order 10/04, approving with conditions a Full Multiparty Settlement (Settlement or 2022 GRC Settlement) with an annual true-up mechanism.[30] Among other terms, the Tariff Schedule 99 Colstrip Tracker had a rate effective date of December 21, 2022, that would be reset each January 1st via a filing made each October 31st until all prudently incurred costs were recovered,[31] including "operating and maintenance ("O&M") and other expenses, depreciation expense, decommissioning and remediation ("D&R") costs, and return on rate base."[32] However, "non-O&M items" would be recovered "on a one-year lag, using actuals through August 31st and estimates through December 31st of the filing year,[33] but transmission investments and costs included in Avista's Energy Recovery Mechanism (ERM) were excluded.[34]

25 **Settlement Agreement in Avista's 2019 GRC.** On March 25, 2020, the Commission entered Final Order 09 in Avista's 2019 GRC, approving without condition, a Partial

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[26] RCW 19.405.010(2) and RCW 19.405.050(1).

[27] RCW 19.405.010(1).

[28] RCW 19.405.010(4).

[29] RCW 19.405.010(6). In enacting CETA, the Legislature found that the public interest includes: (a) the "equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacts communities;" (b) "long-term and short-term public health, economic, and environmental benefits;" and (c) "the reduction of costs and risks and energy security and resiliency."

[30] *WUTC v. Avista*, Dockets UE-220053, UG-220054, & UE-210854 (*Consolidated*), Final Order 10/04, Rejecting Tariff Sheets; Granting Petition; Approving and Adopting Full Multiparty Settlement Stipulations Subject to Conditions; Authorizing and Requiring Compliance Filing at 21-22 ¶¶ 63-64 (December 12, 2022). Hereinafter referred to as "Avista 2022 GRC."

[31] Dockets UE-220053 et. al., Avista 2022 GRC, Final Order 10/04 at 23 ¶ 65 and Supplemental Joint Testimony, Exh. JT-3T at 6:12-14 and 10:20-21.

[32] Dockets UE-220053 et. al., Supplemental Joint Testimony, Exh. JT-3T at 3:1-5 and Avista, Tariff WN U-28, Schedule 99, Second Substitute Revision Sheet 99 (filed December 20, 2024).

[33] Dockets UE-220053 et. al., Supplemental Joint Testimony, Exh. JT-3T at 6:12-14 and 10:20-21.

[34] Dockets UE-220053 et. al., Supplemental Joint Testimony, Exh. JT-3T at 3:1-5 and Avista, Tariff WN U-28, Schedule 99, Second Substitute Revision Sheet 99 (filed December 20, 2024).

Multiparty Settlement, in which Avista agreed "that it will not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life beyond December 31, 2025."[35] However, since Avista now seeks to recover certain long-lived investments, NWEC, Staff, and Public Counsel raise several concerns about the requested recovery being prohibited under the parties' 2019 Partial Multiparty Settlement, which is addressed in detail in detail in Section IV below.

26 **Colstrip Ownership and Operations Agreement (O&O Agreement), and Development of the Abandonment and Acquisition Agreement (A&A Agreement).** Avista seeks recovery of its portion of investments in Colstrip Units 3 and 4.[36] Colstrip Units 1 and 2 were closed in January 2020, and Colstrip Units 3 and 4 remain in operation.[37] At present, Avista owns 15 percent of Colstrip Units 3 and 4, with the other 85 percent divided among other entities as follows:[38]

	Colstrip Unit 3	**Colstrip Unit 4**
Avista Corporation	15%	15%
NorthWestern Energy	--	30%
PacifiCorp	10%	10%
Puget Sound Energy	25%	25%
Portland General Electric Company	20%	20%
Talen MT	30%	--

27 "Avista's obligations regarding its ownership in Colstrip are governed by the Ownership and Operations Agreement dated May 6, 1981" (O&O Agreement).[39] Under the O&O Agreement, Avista must "fund costs to operate and maintain Colstrip Units 3 and 4 so long as Avista has an ownership interest in the plant."[40] This includes requiring each owner to provide the plant with the amount of coal needed to generate each owner's share of the plant's minimum operating capacity.[41] Each year, the owners of the Colstrip units

[35] *WUTC v. Avista Corp.*, Dockets UE-190334, UG-190335 and UE-190222 (*Consolidated*) Final Order 09, Approving and Adopting Partial Multiparty Settlement Stipulation Appendix A at 12-13 ⁋ 14(j) (March 25, 2020).

[36] Kinney, SJK-1T at 4:16.

[37] Kinney, Exh. SJK-1T at 4:15-17.

[38] Kinney, Exh. SJK-1T at 4:20-21 and 5:1-2.

[39] Kinney, Exh. SJK-1T at 5:4-5 citing to Kinney, Exh. SJK-2C.

[40] Kinney, Exh. SJK-1T at 5:7-9.

[41] Kinney, Exh. SJK-1T at 5:9-10.

must approve a budget, but because Avista holds a 15 percent ownership, it is "a minority owner and cannot unilaterally" approve or deny the budget with its vote.[42]

28 To comply with CETA's mandate to have coal-fired generation removed from its allocation of electricity by December 31, 2025, Avista made several attempts to sell or dispose of its share of Colstrip Units 3 and 4, but maintains there were limited parties interested in acquiring its ownership interest.[43] Specifically, Avista contends that "[b]y the time NWE and Talon [sic] emerged," they were "the only entities both interested and operationally capable of succeeding to Avista's interest," but that "the window for parallel negotiations with alternative buyers had effectively closed."[44] Additionally, because "extracting even a nominal payment would have jeopardized the timetable and invited further transactional failure," and Avista needed to continue "to preserve its contractual and physical rights on the Colstrip Transmission System," it maintains that any "transaction that unduly encumbered, subordinated, or alienated those rights would have effectively impaired Avista's ability to comply with both its resource and adequacy obligations and clean-energy targets."[45] Thus, "only NWE and Talon [sic] remained as viable counterparties…[and] [s]ince Talen was in negotiations with PSE to acquire their ownership interests in Colstrip, Avista began negotiations with NWE."[46] Then on January 16, 2023, Avista entered into the A&A Agreement with NWE, in which Avista transferred its 15 percent ownership interest in Colstrip Units 3 and 4.[47] Avista entered into the A&A agreement with NWE without seeking Commission approval**,**[48] and "the closing of the transactions under the A&A Agreement shall occur precisely at 12:00:00 a.m. Pacific time on January 1, 2026.[49]

DISCUSSION AND DECISION

I. Applicable Law

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[42] Kinney, Exh. SJK-1T at 7:3-5 citing to Kinney, SJK-2C, Section 17(f)(ii) of O&O Agreement.

[43] Kinney, Exh. SJK-11CT at 6:3-4.

[44] Kinney, Exh. SJK-11CT at 6:8-10.

[45]Kinney, Exh. SJK-11CT at 6:11-12, 6:15-16 and 6:18-20.

[46] Kinney, Exh. SJK-11CT at 6:22-23 and 7:1.

[47] Kinney, Exh. SJK-3C, Colstrip Units 3& 4 Interests Abandonment and Acquisition Agreement by and between Avista Corporation and NorthWestern Corporation ("A&A Agreement) (January 16, 2023). *See also* Kinney, Exh. SJK-13cr, Revised A&A Agreement (August 25, 2025).

[48] Mullins, Exh. BGM-1CT at 2:9-11 and 5:3-12.

[49] Kinney, Exh. SJK-30C.

29 The Legislature has entrusted the Commission with broad discretion to regulate and set rates in the public interest[50] that are just, fair, reasonable and sufficient,[51] and to balance the needs of the public to have safe, reliable, and appropriately priced services, while also assuring that the utilities earn enough to remain in business.[52] The Commission has previously interpreted the fair, just, reasonable, and sufficient standard to mean that "rates that are *fair* to customers and to the Company's owners; *just* in the sense of being based solely on the record developed in a rate proceeding; *reasonable* in light of the range of possible outcomes supported by the evidence; and *sufficient* to meet the needs of the Company to cover its expenses and attract necessary capital on reasonable terms."[53]

30 If, after hearing, the Commission finds that the rates charged by the utility are:

> . . . unjust, unreasonable, unjustly discriminatory or unduly preferential, or in any wise in violation of the provisions of the law, or that such rates or charges are insufficient to yield a reasonable compensation for the service rendered, the commission shall determine the just, reasonable, or sufficient rates, charges, regulations, practices or contracts to be thereafter observed and in force, and shall fix the same by order.[54]

31 For proposed rates, as in this case, the Commission may enter an order under this same standard as if the proposed rates were already effective.[55]

32 As a general matter, the burden of proving that a proposed increase is just and reasonable is upon the public service company,[56] and the burden of proving that the presently effective rates are unreasonable rests upon any party challenging those rates.[57]

33 As discussed above, in 2019 the Legislature expanded the meaning of public interest under Title 80 RCW in passing CETA. As Washington state transitions to a clean energy

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[50] RCW 80.01.040(3)

[51] *PacifiCorp v. WUTC*, 194 Wn. App 571 at 587 quoting RCW 80.28.010 (2016).

[52] *People's Org. for Wash, Energy Res. (POWER) v. WUTC*, 104 Wn.2d 798 at 808 (1985).

[53] *WUTC v. Avista Corp.*, Dockets UE-160228 & UG-160229, Order 06 at 47 ¶ 79 (Dec. 15, 2016) (emphasis in original).

[54] RCW 80.28.020.

[55] RCW 80.04.130(1).

[56] *Id*.

[57] *WUTC v. Pacific Power and Light Company*, Cause No. U-76-18 (Dec. 29, 1976) (internal citations omitted).

economy, the Legislature provided that the public interest includes: "The equitable distribution of energy benefits and reduction of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health, economic, and environmental benefits and the reduction of costs and risks; and energy security and resiliency."[58] In achieving these policies the Legislature directed that, "there should not be an increase in environmental health impacts to highly impacted communities."[59]

34 Further, in enacting of RCW 80.28.425, which requires utilities to propose multi-year rate plans (MYRP) when filing a general rate case (GRC), the Legislature permitted the Commission to consider equity as part of its public interest evaluation.[60] Following the enactment of the MYRP statute, the Commission indicated its commitment to considering equity while regulating in the public interest: "So that the Commission's decisions do not continue to contribute to ongoing systemic harms, we must apply an equity lens in all public interest considerations going forward."[61] The Commission also explained that regulated companies should be prepared to address equity considerations in future cases: "Recognizing that no action is equity-neutral, regulated companies should inquire whether each proposed modification to their rates, practices, or operations corrects or perpetuates inequities."[62]

II. Application of RCW 19.405.030 - Interpretation of "*Retirement*"

35 CETA requires the following:

> The commission must allow in rates, directly or indirectly, amounts on an investor-owned utility's books of account that the commission finds represent prudently incurred undepreciated investment in a fossil fuel generating resource that has been retired from service when:
>
> (a) The retirement is due to ordinary wear and tear, casualties, acts of God, acts of governmental authority, inability to procure or use fuel, termination or expiration of any ownership, or a operation agreement affecting such a fossil fuel generating resource; or

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[58] RCW 19.405.010(6).

[59] *Id*.

[60] RCW 80.28.425(1)

[61] *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755 Order 10 ¶ 58 (Aug. 23, 2022).

[62] *Id.*

(b) The commission finds that the retirement is in the public interest.[63]

36 Avista argues as follows: (1) that RCW 19.405.030(3) provides for recovery of prudently incurred, "undepreciated investment of fossil fuel generation resources;"[64] (2) that the statute "expressly allows for direct or indirect recovery" or the "full value of investments placed in service in 2024 and 2025;"[65] (3) that the A&A Agreement constitutes a "termination of ownership" under the statute and provides the "reason for the Commission to allow recovery"[66] of its undepreciated investments in fossil fuel generating resources;[67] and that (4) Avista's "retirement of the facility is in the public interest."[68] Additionally, Avista argues that "it is well within the Commission's authority to approve recovery of the full value of the Colstrip investments that are or will be placed in service in 2024 and 2025, regardless of their depreciable lives."[69] To support its argument, Avista cites the definitions of '*retire*' and '*retirement'* provided by the Financial Accounting Standards (FASB), which codifies the Generally Accepted Accounting Principles (GAAP) as instructive. FASB defines '*retirement*' as:

> The other-than-temporary removal of a long-lived asset from service [that]…encompasses, sale, abandonment, recycling, or disposal in some other manner…[and] [a]fter an entity retires an asset, [treats] that asset [as] no longer under the control of that entity, no longer in existence, or no longer capable of being used in the manner for which the asset was originally acquired, constructed, or developed."[70]

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[63] RCW 19.405.030(3).

[64] Kinney, Exh. SJK-1T at 10:24-27 and SJK-11CT at 11:5-9.

[65] Kinney, Exh. SJK-1T at 11:1-3.

[66] Kinney, Exh. SJK-1T at 11:4-5, and SJK-11CT at 11:10-11.

[67] Avista explains that the plain language of RCW 19.405.030(3) "clearly embrace more than just a coal-fired resource" to employ a more expansive use of this term "to allow recovery of undepreciated investment in a gas plant, given the intent and requirements of the Chapter…to eliminate use of fossil fuel generation by 2045. *WUTC v. Avista*, Docket UE-240891, Post-Hearing Brief of Avista (Avista's Post Hearing Brief) at 27- 28 ¶¶ 84-87 (October 24, 2025).

[68] Kinney, Exh. SJK-1T at 11:9-11.

[69] Docket UE-240891, Rebuttal Testimony of Elizabeth M. Andrews, Exh. EMA-1CT at 1:19-20 (August 25, 2025).

[70] Andrews, Exh. EMA-1CT at 20:3-11 citing Financial Accounting Standards Board (FASB) and Accounting Standards Codification (ASC), which codifies GAP definition for retirement 410-20-20 at: https://asc.fasb.org/MasterGlossary.

37 Avista further maintains that the accounting definition is consistent with that of the Office of Washington State Auditor, which considers the retirement of a tangible asset to include abandonment.[71] Andrews reasons that "when using these appropriate definitions of retirement…the [A&A] Agreement between Avista and NWE ("divestiture") clearly meets the definition…contemplated by the legislation,"[72] which includes "termination or expiration of any ownership."[73]

38 Respectively, based on varying interpretations of the term "retirement" under CETA and the different application of prudency and used and useful standards, Staff, Public Counsel, NWEC and AWEC disagree with Avista's contention that CETA does not restrict allowance of non-life extending assets in rates.

39 Specifically, Staff argues that Avista failed to meet its burden to recover capital investments under RCW 19.405.030(3)(a) or (b) because the Company did not demonstrate it made prudent investments in undepreciated property before retirement of that property from service.[74] Staff explains that by using the phrase '*has been retired*,' "the Legislature phrased the retirement requirement in present perfect tense…to express a past event that has present consequences," thus reasoning that Avista "cannot recover costs under RCW 19.405.030(3) unless it has already retired Colstrip."

40 Similarly, Public Counsel argues that "[b]y the plain language of the statute, the provision only applies to a resource that has been retired from service." [75] Given that "Avista may no longer receive power from Colstrip after December 31, 2025, but…will continue operations beyond that date," [76] Public Counsel maintains under RCW 19.405.030(3), the plant will not be effectively "retired from service" after December 31, 2025.[77]

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[71] Andrews, Exh. EMA-1CT at 20:8-11.

[72] Andrews, Exh. EMA-1CT at 20:12-15.

[73] Docket UE-240891, Rebuttal Testimony of Scott J. Kinney, SJK-11CT at 10:24-26.

[74] Docket UE-240891, Post-Hearing and Supplemental Brief of Commission Staff (Staff's Post Hearing Brief) at 13 ¶ 31 (October 24, 2025).

[75] Docket UE-240891, Response Testimony of Jean Marie Dreyer on Behalf of the Washington State Office of the Attorney General Public Counsel Unit (Public Counsel Response Testimony), Dreyer, Exh., JMD-1CT at 4:15-19 (July 24, 2025).

[76] *Id*.

[77] Docket UE-240891, Response Testimony of Jean Marie Dreyer on Behalf of the Washington State Office of the Attorney General Public Counsel Unit (Public Counsel Response Testimony), Dreyer, Exh., JMD-1CT at 4:15-19 (July 24, 2025).

41 NWEC argues that "CETA requires the Commission to allow utilities to recover undepreciated investment in a fossil fuel asset only if '*it has been retired from service,*'" to mean actually physically retired.[78] To support this contention, NWEC applies a used and useful analysis and argues that because CETA mandates electric utilities to eliminate coal-fired resources from their allocation of electricity by December 31, 2025, RCW 19.405.030(3) cannot authorize the recovery of undepreciated investment in fossil fuels remaining in service beyond December 31, 2025.[79] NWEC further argues that Avista rate payers will not benefit from Colstrip's operation beyond December 31, 2025, and therefore cannot be required to pay for Colstrip's long term operation.[80] Additionally, NWEC contends that FASB's "highly specialized accounting" definition of "retirement" should not be used to determine whether Avista qualifies to recover undepreciated investment pursuant to RCW 19.405.030(3).[81] Instead, NWEC proposes the Commission apply a dictionary definition, and interpret *'retirement*' to mean that fossil fuel plants must actually cease operations to be retired from service.[82] Using this standard, NWEC argues, the Commission must treat Colstrip Units 3 and 4 as not having been retired, since these fossil fuel resources will remain in-service and continue operating beyond 2025.[83]

42 Finally, AWEC highlights that although the legislative intent of CETA was to eliminate coal-fired resources from each electric utility's allocation of electricity, RCW 19.3405.030 "did not necessarily mandate retirement, sale, or any other property transactions with respect to coal plants."[84] Rather, AWEC maintains that "the statute only stated that the cost and benefits were to be removed from utility rates," and reasons that "[i]n the absence of a sale or retirement by the deadline, it must therefore be assumed that Colstrip 3& 4 would presumably become a merchant power plant owned and operated by Avista but not recoverable through utility rates."[85]

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[78] Docket UE-240891, Testimony of Bradley T. Cebulko on Behalf of NW Energy Coalition, Cebulko, Exh. BTC-1CT at 11:13-15 (July 24, 2025).

[79] Cebulko, Exh. BTC-1CT at 12:1-3 and 37:12.

[80] Cebulko, Exh. TC at 21:2-22:6.

[81] McCloy, Exh. BTC-1CT at 5:6-12.

[82] McCloy, Exh. BTC-1CT at 5:9-11.

[83] McCloy, Exh. BTC-1CT at 4:14-15 and 5:22-26. *See also* McCloy, Exh. LCM 1T at 8:10-12 and 13:10-16.

[84] Docket UE-240891, Response Testimony of Bradley G. Mullins on Behalf of Alliance Western Energy Consumers, Mullins, BGM-1CT at 6:15-16 (July 24, 2025).

[85] Mullins, BGM-1CT at 6:18-21.

Commission Determination:

43 RCW 19.405.030(3), provides as follows:

> (3) The commission must allow in rates, directly or indirectly, amounts on an investor-owned utility's books of account that the commission finds represent prudently incurred undepreciated investment in a fossil fuel generating resource that *has been retired from service* when:
>
> (a) The retirement is due to ordinary wear and tear, casualties, acts of God, acts of governmental authority, inability to procure or use fuel, *termination or expiration of any ownership*, or an operation agreement affecting such a fossil fuel generating resource; or
>
> (b) The commission finds that the retirement is in the public interest.[86]

44 To understand what the Legislature meant by the word *'retire*,' the Commission begins its review with the canons of statutory interpretation and looks at the language itself to determine intent. [87] If the meaning is plain on its face, then we give effect to that meaning, as an expression of legislative intent.[88] "A statutory provision's plain meaning is to be discerned from the ordinary meaning of the language at issue, the context of the statute in which that provision is found, related provisions, and the statutory scheme as a whole."[89] If after a plain language analysis the provision remains susceptible to more than one reasonable interpretation, only then will we employ the tools of statutory construction to discern its meaning.[90]

45 Here, there are two competing interpretations of the phrase '*that has been retired from service*,' under RCW 19.405.030. Staff, NWEC, and Public Counsel argue that the Commission should rely on the ordinary meaning, or dictionary definition of "retire," and require that the fossil plant must actually cease operations,[91] or otherwise be inoperable

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[86] RCW 19.405.030(3) (emphasis added).

[87] *Tingey v. Haisch,* 159 WN.2d 652, 657, 152.P3d 1020 (2007).

[88] *Id.*

[89] *Tingey v. Haisch,* 159 WN.2d 652, 657, 152.P3d 1020 and *State v. Ervin*, 169 Wn.2d 815, 820, 239 P.3d 354 (2010).

[90] *Id* citing *Dep't of Ecology v. Campbell & Gwinn, LLC*, 146 Wn2d 9, 12 (2002).

[91] NWEC's Post Hearing Brief at 6 ¶14.

"to end the working life of coal power."[92] Additionally, Staff argues that the Commission should "find the [L]egislature's use of verb tense holds significance"[93] in construing the statute. Conversely, Avista argues that the Commission should apply the technical accounting definition of retirement, which is well accepted in the industry, codified by the FASB to support GAAP's definition of retirement, and is consistent with the State of Washington's State Auditor's Office definition.[94] Avista further highlights that the technical accounting definition of "retirement" is more appropriate given that: (1) under both the GAAP and Washington State Auditor's definitions, the asset will be retired as of January 1, 2026; (2) RCW 19.405.030's title itself refers to "Coal-fired resources – Depreciation schedule – Penalties;" (3) standard accounting terms and concepts are referenced throughout RCW 19.405.030 (i.e., "investor-owned utility's books of accounts," "undepreciated investments," "depreciation schedules"); and (4) the consistent requirement in RCW 19.405.030(2) directing the Commission "to accelerate depreciation schedules for any coal-fired resources to a date no later than December 31, 2025."[95]

46 We acknowledge that courts have frequently held that "when a word has a well-accepted, ordinary meaning, a regular dictionary may be consulted to ascertain the term's definition."[96] "However, where any otherwise common word is given a distinct meaning in a technical dictionary or other technical reference and has a well-accepted meaning within the industry, and when the word is used in a rule promulgated by an expert agency familiar with the technical meaning, courts should turn to a technical rather than a general purpose dictionary to resolve ambiguities in its definition."[97]

47 Here, we agree with Avista that it is not a coincidence that the Legislature: (1) included a description in the title for RCW 19.405.030 of "Coal-fired resources – Depreciation schedule – Penalties;" nor (2) referenced standard accounting terms (i.e., "investor-owned utility's books of accounts," "undepreciated investments," and "depreciation schedules") throughout RCW 19.405.030.

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[92] Public Counsel's Post Hearing Brief, at 16 ¶ 49.

[93] Staff's Post Hearing Brief at 13 citing *Crown W. Realty, LLC v. Pollution Control Hearings Board*, 7 Wn.App. 29, 710, 738, 435 P.3d 288 (2019).

[94] Docket UE-240891, Post-Hearing Brief of Avista (Avista's Post Hearing Brief) at 9 ¶ 28-29 (October 24, 2025).

[95] Avista's Post Hearing Brief at 8-9 ¶¶ 25-27.

[96] *City of Spokane ex. rel. Wastewater Mgmt. Dep't v. Dep't of Revenue,* 145 Wn.2d 445, 454, 38 P.3 1010 (2002).

[97] *Id.*

48 In further examining the statutory context, we also give weight to the mandate in RCW 19.405.030(1)(a) that each electric utility "eliminate coal-fired resources from its allocation of electricity" on or before December 31, 2025. Under RCW 19.405.020(1), "' [a]llocation of electricity' means, for the purposes of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state."[98] In other words, because CETA regulates electricity as a commodity, it does not "not necessarily mandate retirement, sale, or any other property transactions," [99] or require that the plant actually cease operations or otherwise be inoperable to end the working life of coal power. Rather, it only states that the cost and benefits are to be removed from utility rates.

49 Next, regarding Staff's argument that a Legislature's use of verb tense holds significance, we acknowledge that a statute framed in the "present-perfect tense can refer to either (1) an act, state, or condition that is not completed or (2) a past action that comes up to and touches the present…[where] one might employ the present-perfect tense to describe situations involving a specific change of state that produces a continuing result."[100] However, we are not persuaded that the semantics of the single phrase, "has not been retired", is controlling here because such framing of the issue is overly narrow and fails to account for the fact that by the time the rates go into effect on January 1, 2026, the plant will effectively be retired in Washington state.

50 While we acknowledge that RCW 19.405.030(3)(b) does not explicitly define each of the triggering events for retirement, we find that at least two of those triggering events exist here. These include: (1) acts of governmental authority (i.e., CETA's December 31, 2025, deadline mandating that coal be out of rates for Washington ratepayers); and (2) Avista's "termination or expiration of ownership" by entering into the A&A Agreement with NWE to transfer its 15 percent ownership of Colstrip Units 3 and 4 effective January 1, 2026. Simply stated, the purpose of CETA's mandate incorporated in RCW 19.405.030(1)(a) is to remove coal-fired electricity from Washington's electricity supply by the end of December 31, 2025; and such mandate may still be accomplished if Colstrip Units 3 & 4 are transferred and no longer providing electricity in Washington, even if they are not entirely shutdown.

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[98] RCW 19.405.020(1).

[99] Mullins, BGM-1CT at 6:15-16.

[100] *Hewitt v. United States*, 606 U.S. 419, 427-428, 145 S.Ct. 2165, 2172-74, 222 L.ED.2d 613 (2025) citing the Chicago Manual of Style §5.132, p. 268 (17th ed. 2017).

51 Based on the above, we find that Avista will have retired coal-fired electricity from its electrical supply in accordance with the requirements set forth in RCW 19.405.030. Accordingly, to facilitate a fair, equitable and just transition, we hold that Avista shall not be precluded from recovering undepreciated investments in Colstrip Units 3 and 4, and shall be afforded the opportunity to recover any prudently incurred and used and useful capital investments in Colstrip, as discussed in detail below in Section VI, Investments in Colstrip.

III. Asset Transfer

52 Avista entered into the A&A Agreement with NWE on January 16, 2023, to comply with the CETA requirement to eliminate coal-fired resources from its allocation of electricity in Washington rates after December 31, 2025. The A&A Agreement transfers the Company's 15 percent ownership interest in Colstrip Units 3 and 4 to NorthWestern Energy (NWE).[101] On October 1, 2025 the parties amended the agreement to reflect a change in the timing of the actual transfer of ownership, which will now occur on January 1, 2026, after the December 31, 2025 deadline in CETA.[102]

53 AWEC argues that the A&A Agreement should have been brought before the Commission for approval under RCW 80.12.020. AWEC states in its brief that the disposal of such property is within the sole jurisdiction of the Commission to authorize "so long as the property or facility is necessary or useful in performance of the utility's duties." [103] AWEC acknowledges that beginning January 1, 2026, Colstrip would not be necessary or useful in the performance of any Avista duties to Washington customers, and that even if the agreement were to close in 2026, the Commission should nevertheless exercise jurisdiction over the A&A Agreement because the agreement transferred Avista's interest in Colstrip Unit 3 and 4 prior to the time when CETA precludes its inclusion in rates."[104] AWEC further argues that the A&A Agreement has significant impacts on Avista's Washington ratepayers.[105] AWEC points out the inconsistency between Avista's position that the Commission does not have jurisdiction

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[101] Kinney, Exh. SJK-1T at 14:15-16; Kinney, Exh. SJK-11CT at 6:19-20.

[102] Kinney, Exh. SJK-30C.

[103] Post Hearing Brief on Behalf of Alliance of Western Energy Consumers (AWEC's Post Hearing Brief) at 3 ¶ 6 (October 24, 2025).

[104] AWEC's Post Hearing Brief at 2 ¶ 6, 11 (citing Docket No. UE-001878, Fourth Supplemental Order at ¶ 15 (Jan. 25, 2002).

[105] AWEC's Post Hearing Brief at 5-6 ¶ 11-12 (citing Response Testimony of Bradley G. Mullins on Behalf of Alliance Western Energy Consumers, Exh. BGM-1CT at 7:8-9:14 (July 24, 2025).

over the agreement under RCW 80.12.020 and its separate argument that it should fully recover its investment in the assets transferred in the A&A Agreement as a "retirement" under RCW 19.405.030(3). AWEC emphasizes that "it is unreasonable for the Company to request cost recovery of life-extending investments in a proceeding where it is also arguing that the A&A Agreement, which obligates Avista to pay for and then transfer the value of those investments to NorthWestern for the benefit of NorthWestern's ratepayers, is outside of the Commission's jurisdiction."[106] AWEC further argues that it would be similarly unreasonable for the Commission to rely on the time of transfer to avoid asserting jurisdiction over the agreement.[107] Finally, AWEC argues that in the absence of a sale, Avista could have retained its ownership share and operated its portion of Colstrip as a merchant plant that is not recoverable through utility rates without impact or consequence to ratepayers.[108]

54 NWEC argues that Avista never obtained Commission approval prior to assigning its Colstrip assets in the A&A Agreement upon the January 2023 execution of the agreement in violation of RCW 80.12.020(1).[109] NWEC further argues that Avista's argument that Colstrip will no longer be used and useful to the public as of December 31, 2025, is circular, because Avista is abandoning Colstrip to NWE as of the date of that agreement and suggests that if Avista's interpretation is correct, then "[s]uch interpretation would effectively render RCW 80.12.020 meaningless."[110] NWEC argues that Avista fundamentally mischaracterizes the A&A Agreement as governing only the time period after which Colstrip Units 3 and 4 will no longer provide electricity to the State's ratepayers, and that Avista effectively "contracted away its right to vote on all non-remediation items between January 16, 2024 and December 31, 2025.[111] While NWEC states that it is not asking the Commission to void the A&A Agreement, it maintains that the Commission should not allow Avista to both avoid review of the A&A Agreement and fully recover costs that allow Colstrip to continue operating beyond December 31, 2025.[112]

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[106] AWEC Post Hearing Brief at 6 ¶ 12.

[107] AWEC's Post Hearing Brief at 8-7:2.

[108] BGM-1CT at 6:18-7:2; AWEC Post Hearing Brief at 8 ¶ 16.

[109]Brief of NW Energy Coalition Opposing Avista Corporation's 2024 & 2025 Colstrip Investments (NWEC's Post Hearing Brief) at 8 ¶ 19 (October 24, 2025).

[110] NWEC's Post Hearing Brief at 8-9 ¶ 20.

[111] NWEC's Post Hearing Brief at 9 ¶ 21.

[112] NWEC's Post Hearing Brief at 9 ¶ 23.

55 Staff did not address in its post hearing briefing whether RCW 80.12.020 applies to the A&A Agreement, or if Commission review and approval was required before entering into this agreement. However, Staff witness McGuire does raise concerns that "Avista did not cast its votes on the 2024 and 2025 Colstrip capital budgets in a manner that was consistent with the public interest" and that the A&A Agreement "does not relieve Avista of its obligation to adhere to the terms of the 2019 GRC Settlement."[113]

56 Public Counsel suggests that the Commission consider the transfer agreement in its prudence analysis and "order that the Company prorate the recovery of those investments in rates and disallow the remainder based on a finding that their transfer is imprudent."[114] In briefing, Public Counsel states that "unless and until Avista obtains Commission approval for its agreement with NorthWestern, the transaction may be invalid under the statute" and that it "agrees with AWEC's proposal for Avista to submit a separate filing for the Commission to evaluate the prudence of its agreement with NorthWestern."[115]

57 Avista argues on rebuttal that it was not required under RCW 80.12.020 to obtain Commission approval for the A&A Agreement with NWE, which applies to the sale, lease, assignment or other transfer of facilities that are necessary, or useful in the performance of its duties to the public. Further, Avista acknowledges that as of December 31, 2025, by operation of CETA, Colstrip will no longer be necessary or useful in the performance of any of its duties to the public.[116]

Commission Determination:

58 RCW 80.12.020(1) provides:

> [n]o public service company shall sell, lease, assign or otherwise dispose of the whole or any part of its franchises, properties or facilities whatsoever, *which are necessary or useful in the performance of its duties to the public*, and no public service company shall, by any means whatsoever, directly or indirectly, merge or consolidate any of its franchises, properties or facilities with any other public service company, without having secured from the commission an order authorizing it to do so. The commission shall not approve any transaction under this section that would result in a person, directly or indirectly, acquiring a controlling interest in a gas or electrical

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[113] McGuire, Exh. CRM-1T at 41:19-42:3; *see also* Kinney, Exh. SJK-3C.

[114] Dreyer, Exh. JMD-1CT at 9:1-3

[115] Public Counsel's Post Hearing Brief at 18 ¶ 55.

[116] Kinney, Exh. SJK-11CT at 9:13-10:4.

> company without a finding that the transaction would provide a net benefit to the customers of the company.[117]

59 WAC Chapter 480-143 provides the Commission's regulations governing transfers of property. Section 480-143-120 states that:

> [a] public service company may not complete a transfer of property necessary or useful to perform its public duties unless the company first applies for and obtains, commission approval. Transfers include sale, lease, assignment of all or part of a public service company's property, and merger or consolidation of a public service company's property with another public service company.

60 Regarding a public service company's application for approval of an asset transfer, WAC 480-143-170 states that "[i]f, upon the examination of any application and accompanying exhibits, or upon a hearing concerning the same, the commission finds the proposed transaction is not consistent with the public interest, it shall deny the application."

61 Where a public service company is required to bring an agreement to the Commission for approval under RCW 80.12.020(1), and has failed to do so, the Commission "shall deny the application." As a result, when the Commission fails to provide any required approval of an asset transfer, the asset transfer agreement necessarily becomes void. However, RCW 80.12.020(1) makes clear that the requirement for Commission approval applies to the transfer of properties or facilities "which are necessary or useful in the performance of its duties to the public."[118]

62 Pursuant to CETA in RCW 19.405.030(1)(a), each electric utility must eliminate coal-fired resources from its allocation of electricity on or before December 31, 2025, such that the costs and benefits associated with coal resources are removed from the electric utility's retail customer rates.[119] As Staff witness McGuire points out in testimony, CETA defines "allocation of electricity" in RCW 19.405.020(1) as follows: "for the purposes of setting electricity rates, the costs and benefits associated with the resources used to provide electricity to an electric utility's retail electricity consumers that are located in this state [Washington]."[120]

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[117] RCW 80.12.020(1) (emphasis added).

[118] *Id*.

[119] *See* RCW 19.405.020(1).

[120] McGuire CRM-1CT at 34:1-10; RCW 19.405.020(1), 19.405.030(1).

63 During this proceeding, Avista updated its A&A Agreement to make transfer of its Colstrip ownership to NWE effective as of 12:00 AM Pacific Time, January 1, 2026. As such, Avista's transfer of its Colstrip ownership to NWE will occur after CETA's requirement to remove coal from the Company's allocation of electricity takes effect. While the A&A Agreement transfers Avista's ownership interest in Colstrip, it preserves Avista's Colstrip transmission rights.

64 In general, every transfer of property that is useful and necessary from a public service company to another entity is subject to Commission approval pursuant to RCW 80.12.020. However, by prohibiting the use of certain resources for service in Washington, CETA has a unique interaction with the transfer of property statute, insofar as CETA effectively makes certain generating resources neither necessary, nor useful, for service after a specific point in time. For coal-fired resources, that point in time is December 31, 2025.[121]

65 Consequently, the Commission determines that the A&A Agreement is not subject to Commission approval pursuant to RCW 80.12.020 because, at the time Avista's Colstrip ownership is transferred to NWE, Colstrip will not be "necessary or useful in the performance of [Avista's] duties to the public," other than the Colstrip transmission rights, which the Company has retained.

66 The Commission is cognizant of the fact that this conclusion is unique and unusual. However, as will be addressed elsewhere in this Order, the fact that the Commission is not reviewing the A&A Agreement for approval does not mean that the Commission will refrain from examining actions taken pursuant to the A&A Agreement under other Commission standards. The Commission's determination that the A&A Agreement is not subject to review because Colstrip's generation will not be necessary or useful in the performance of Avista's duties to the Washington public is consistent with RCW 19.405.030(3)'s requirement that coal-fired resources be removed from Avista's allocation of electricity. Moreover, the Commission is not without recourse to fashion alternative review mechanisms pursuant to its statutory duty to regulate in the public interest.[122]

67 In order to facilitate future review of the transfer of property that will become unable to serve Washington customers in the future due to the requirements of CETA, including

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[121] RCW 19.405.030(1)(a).

[122] RCW 80.01.040.

but not limited to RCW 19.405.030-.050,[123] the Commission requires Avista to comply with the following condition:

> Going forward from the date of this Order, where Avista executes an agreement transferring assets for the purpose of complying with a requirement in CETA, Avista must file that agreement with the Commission for review and, if deemed necessary by the Commission, approval within five (5) days of entering into the agreement, even where the resource may no longer be necessary or useful in the performance of its duties to the public by operation of CETA. In its review of the agreement, the Commission will consider whether the agreement is consistent with the public interest and equity concerns of CETA.

68 The Commission intends Avista's compliance with this condition going forward to provide sufficient time for the Commission to review and take appropriate action within the scope of its regulatory authority, with input from the Company and interested parties, to ensure that agreements executed to comply with CETA do not contradict or undermine the goals and intent of CETA or result in consequences otherwise inconsistent with law.

69 Had Avista brought forward the A&A Agreement for Commission approval, considering the January 2023 execution date of the agreement, it would have afforded the Commission and the non-company parties considerable additional time leading up to the CETA deadline of December 31, 2025, to address the unique circumstances presented by RCW 19.404.030(1) and provide input on any other extant circumstances that may have appeared relevant to the transfer and how it may have impacted or benefitted customers.

70 For example, Avista appears to have executed the A&A Agreement, in which it agreed to vote consistent with NWE on any investments in Colstrip, despite Avista's earlier agreement in Avista's 2019 GRC settlement that Avista would "not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life beyond December 31, 2025."[124] The six other parties who joined

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[123] NWEC's Post Hearing Brief at 2 ⁋ 4 (discussing future decisions the Commission may be asked to make related to the treatment of fossil fuel generating resources that use fossil fuels other than coal and that are subject to CETA requirements in RCW 19.405.030); *see also* Staff Brief at 16 ⁋ 39; Avista Post Hearing Brief at 26 ⁋ 83-88; Supplemental Brief of Public Counsel at 4 ⁋ 5.

[124] *WUTC v. Avista Corp.*, Dockets UE-190334, UG-190335 and UE-190222 (*Consolidated*) Final Order 09, Approving and Adopting Partial Multiparty Settlement Stipulation Appendix A at 12-13 ⁋ 14(j) (March 25, 2020). *See also* Order 10 Granting Petition to Amend Final Order 09 to Reflect Modified Stipulation (December 14, 2020) (The Commission approved a proposed amendment to the settlement that was supported by all settling parties at Paragraph 14(d), which set a date for feedback from Avista's Energy Efficiency Advisory Group. No changes were made to ¶ 14(j).

and argued in support of the settlement presumably abandoned any litigation positions they otherwise may have pursued, and that may have influenced a Commission decision setting rates in the 2019 GRC, absent Avista's agreement not to pursue certain investments that extended the operating life of Colstrip.[125] The Commission further addresses the Settlement approved in Final Order 09 in Dockets UE-190334, et al., in Section IV of this Order.

71 As the Commission has determined that the A&A Agreement is not subject to approval under RCW 80.12.020, it is unnecessary to resolve the arguments regarding whether Avista could have operated its portion of Colstrip as a merchant plant. However, the Commission observes that Avista presented credible evidence that the Company faced financial and legal risks if it elected to operate Colstrip as a merchant plant, Avista had a difficult bargaining position with respect to Colstrip. Furthermore, insofar as CETA prohibits the cost and benefits from coal-fired resources from being included in retail electric customer rates, it is unclear how the operation of Colstrip as a merchant plant would have any direct or indirect value to Avista's Washington customers. There is no analysis in the record before the Commission regarding what those benefits could be, and the Commission will not presume that such benefits exist in the absence of supporting evidence. Finally, issues regarding decommissioning and remediation costs are not properly before the Commission in this case and will be reviewed in a later proceeding when such costs are proposed for inclusion in rates.

72 Finally, although RCW 80.12.020(1) does not apply to Avista's transfer of its Colstrip ownership interest in the A&A Agreement, the Commission clarifies that it applies a public interest standard in its review of agreements that are subject to RCW 80.12.020. While the Commission reviews utility investment decisions for prudence for the purpose of cost recovery, the Commission does not make prudence determinations when reviewing asset transfer agreements under RCW 80.12.020.

IV. Avista's Commitment in the 2019 GRC Settlement Not to Support Life-Extending Investments at Colstrip

73 Staff and NWEC have referenced Avista's participation in the Partial Multiparty Settlement that the Commission approved without condition in partial resolution of

[125] Dockets UE-190334 et. al., Final Order 09, Appendix A at 1 ⁋ 1 (The seven parties who joined the settlement were Avista, Staff, Public Counsel, AWEC, NWEC, The Energy Project, and Sierra Club.).

Avista's 2019 GRC Settlement.[126] All of the non-company parties in this docket also participated in Avista's 2019 GRC and supported the terms of the 2019 GRC Settlement in which Avista made commitments regarding how it would approach "life-extending" investments at Colstrip going forward. The relevant language is in paragraph 14.j of the 2019 GRC Settlement, beginning with the following:

> Avista agrees that it will not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life, beyond December 31, 2025. Capital costs associated with protecting human health and safety are generally acceptable to the Parties.

74 Paragraph 14.j also provides the settling parties' agreement regarding prudence determinations for Avista's capital expenditures at the Colstrip plant, including those related to SmartBurn:

> Avista recognizes and confirms that all Colstrip capital expenditures after December 31, 2017, will be subject to a prudence determination in future rate proceedings and Avista will provide detailed information, including a complete record of the decision making, and a full accounting of the costs related to those project expenditures on an annual basis. This means that Colstrip capital additions after December 31, 2017, are not included in Avista's rate base at this time."

75 The Commission approved these terms in Final Order 09, finding, based on the Joint Testimony, that the Settlement "represents a deliberate effort to align the plan for the recovery of Colstrip costs with the requirements of CETA," and that it "seizes the opportunity to find a solution for the remaining production plant balance for Colstrip, while mitigating intergenerational inequity issues."[127]

76 The Commission referenced the terms of Paragraph 14.j in Avista's 2020 GRC in disallowing recovery for Avista's dry ash project costs, which at the time were not known and measurable.[128] The Commission explained further that it was "uncertain that Dry Ash is not a life-extending capital addition."[129] The Commission did not view Dry Ash as a

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[126] Dockets UE-190334 et. al, Final Order 09.

[127] Dockets UE-190334 et. al, Final Order 09, at 20-21 ¶ 54.

[128] *WUTC v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-200900, UG-200901, and UE-200894 (*Consolidated*), Final Order 08/05 at 98-100 ¶¶ 275-279 (September 27, 2021).

[129] Dockets UE-200900 et. al., Final Order 08/05 at 100 ¶ 279.

routine capital maintenance measure and, absent a sufficient showing by Avista that Dry Ash was not life-extending, the Commission was "unconvinced that it should be allowed in rates."[130]

77 Here, despite its agreement in the 2019 GRC Settlement not to support life-extending investments beyond 2025, Avista argues that it should recover "the full undepreciated value of the capital investments" it made in the Colstrip plant in 2024 and 2025. The investments offered for recovery in the initial filing include 73 capital projects, all of which have useful lives beginning in either 2024 or 2025 and extending to varying degrees beyond December 31, 2025, despite Avista's agreement in its 2019 GRC that it "will not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life, beyond December 31, 2025."[131]

78 Avista nevertheless asserts that that it did not "support" these 73 investments despite being subject to the O&O Agreement and maintains that it acted reasonably to avoid unnecessary investments even at the full value of capital investments.[132]

79 Avista argues further that:

> [i]t is not uncommon (indeed, it is to be expected) that the purchaser of an operating facility would insist on the delivery of the asset to be in good working order at closing (January 1, 2026); to that end, it is common-place for the purchaser to "direct" the voting of the seller to satisfy itself that the plant would be delivered in good working order, not only at closing but for the foreseeable future. No reasonable purchaser would allow the plant to be starved of needed capital investment in the meantime, so it has to somehow play catchup on needed investments for years to come.[133]

80 Additionally, Avista argues: (1) that the overall level of capital spending for 2024 and 2025 was consistent with prior years and was not trying to "load up" unnecessary capital investments to NWE's benefit in future years;[134] (2) that non-company parties were unable to demonstrate that the 2024 and 2025 investments were unnecessary for the

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[130] *Id*.

[131] *Id*.

[132] Avista's Post Hearing Brief at 9 ¶ 30.

[133] Avista's Post Hearing Brief at 10 ¶ 31.

[134] Avista's Post Hearing Brief at 10 ¶ 32.

ongoing operation of the plant; and (3) that Avista had a legal obligation to deliver the plant in good working order consistent with sound maintenance practices.[135]

81 Avista attempts to distinguish its agreement in the 2019 GRC Settlement to "not support" capital projects at the Colstrip plant that are life-extending beyond 2025, from its "voting" to support the investments consistent with NWE's direction under the A&A Agreement during the interim period between the January 2023 execution and the January 1, 2026 closing.[136] Avista differentiates its supporting votes in favor of the investments from its participation in budgeting, in which Avista states that it "did not lend 'support' (operative language of settlement) for projects that provided no value for Avista's customers."[137] To bolster its argument, Avista points to its efforts to pro-rate the share of dollars assigned to "long-lived enhancement work," reflected in Exhibit I to the AA Agreement, which allocates responsibility for outage and capital costs over time.[138]

82 While all the non-company parties in this docket oppose Avista's recovery of at least the portion of the life-extending capital expenditures attributable to services after December 31, 2025, NWEC and Staff also assert that because Avista violated the 2019 GRC Settlement, it should be prohibited from recovery of these amounts.[139]

83 NWEC points to the Commission's disallowance of Avista's Dry Ash Waste Disposal System in Avista's 2020 GRC as an indication of the Company's agreement to not support life-extending investments at Colstrip and argues that Avista has a duty to demonstrate that its investments in Colstrip are not life extending before it can recover those investments in rates.[140] NWEC asserts that if "a project's useful life and function materially extend Colstrip's ability to operate past December 31, 2025, it violates both the spirit and the letter of Avista's commitment in the 2019 Settlement," and "urges the Commission to give Avista's doublespeak little weight, use common sense, and conclude that voting for something is supporting it."[141]

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[135] Avista's Post Hearing Brief at 10 ⁋ 33

[136] Avista Post Hearing Brief at 18 ⁋ 54.

[137] Avista's Post Hearing Brief at 18 ¶ 55 (quotations included).

[138] Avista's Post Hearing Brief at 18 ¶¶ 55-56, Kinney, Exh. SJK-11CT at 30:14-18, 31:3-9 and AA Agreement Section 7.1(b)(iv)(B).

[139] Mullins, Exh. BGM-1CT at 2:12-18, 10:3-9; Dreyer, Exh. JMD-1CT at 4:1-21; Cebulko, Exh. BTC-1CT at 6:4-10, 27:3-14; McGuire, Exh. CRM-1CT at 40:6-11, 41:3-5, 42:15-43:17.

[140] NWEC's Post Hearing Brief at 3-4 ¶ 8.

[141] NWEC's Post Hearing Brief at 4-4 ¶¶ 9-12.

84 Staff also asserts that Avista bargained away the right to seek recovery of certain costs related to its Colstrip investments "by settling its 2019 general rate case, in part, by agreeing not to support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life beyond December 31, 2025."[142] Staff also points to the Commission's reference to this term in its disallowance of Colstrip investments in 2020 where Avista failed to show sufficiently that its investments were not life extending.[143]

85 Staff cites the Merriam-Webster dictionary definition of "support" as "to argue or vote for." Staff asserts that Avista's commitment in the A&A Agreement constituted support for investments that extend the life of the Colstrip plant, contrary to Avista's commitment in the 2019 GRC Settlement that it would not support life-extending investments at Colstrip.[144]

86 Staff witness McGuire states that Avista now seeks recovery of "numerous investments in long-lived plant that appear to go well beyond recurring maintenance work."[145] Specifically, McGuire notes that of the 73 projects, 29 of them do not fit Avista's definition of recurring maintenance work, 25 of those have an expected service life of ten years or greater, and ten have an expected service life of 25 years or greater.[146]

Commission Determination

87 Avista's arguments regarding whether voting in support constitutes actual support focus more on whether Avista's investment decisions were prudent rather than whether those decisions were consistent with the 2019 GRC Settlement. Either way, there is no dispute that the text of the 2019 GRC Settlement states that Avista "will not support capital expenditures at Colstrip that go beyond routine capital maintenance costs that extend the plant's operational life, beyond December 31, 2025."[147]

88 Whether Avista's investments in the 73 projects at issue in this proceeding were in accordance with "standard operating procedure" or not, Avista made financial

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[142] Staff's Post Hearing Brief at 15 ¶ 35.

[143] Staff's Post Hearing Brief at 15 ¶ 35; McGuire, CRM-1CT at 10:14-11:8, 16:5-7, 37:5- (citing Avista 2020 GRC Order at 100 ¶ 279).

[144] Staff's Post Hearing Brief at 5-16 ¶ 37.

[145] McGuire, Exh. CRM-1CT at 29:5-6.

[146] McGuire, Exh. CRM-1CT at 38:20-39:1-6.

[147] McGurie, Exh. CRM-1CT at 40:9-11.

investments in, and thereby supported, the projects to ensure that Colstrip Units 3 and 4 were "delivered in good working order, not only at closing but for the foreseeable future." To the extent the foreseeable future extends beyond 2025, Avista has acted contrary to its agreement in the 2019 GRC Settlement.[148]

89 We presume Avista's commitment not to support capital expenditures in Colstrip beyond routine capital maintenance costs that extend the plant's operational life beyond December 31, 2025, factored in the decisions of six other parties to join the settlement in Avista's 2019 GRC and to abandon litigation positions that otherwise might have influenced the Commission's decision in that case. The Commission set rates in that case based on the joint support of the settling parties who relied on Avista's commitment not to support life-extending investments beyond the CETA deadline for the removal of coal-fired resources from Washington customers' allocation of electricity.[149] Absent an amendment to Final Order 09 in Dockets UE-190334 et.al., the terms of the 2019 GRC Settlement were in effect in January 2023 when the A&A Agreement was executed and remain in effect now and going forward.

90 However, because this docket concerns Avista's request to recover its investments in the Colstrip plant and is not a complaint for penalties that would have otherwise put Avista on notice of violations of the 2019 GRC Settlement, the Commission is not imposing penalties for any such violation in this Order.

V. Inclusion of 2025 Plant Additions Despite the "One-Year Lag" Language in Avista's 2022 GRC Settlement

91 Staff witness McGuire recommends that the Commission take action pursuant to WAC 480-07-370(3)(a) to "amend the Final Order of the Company's 2022 GRC and relieve Avista of the requirement under the Settlement that Avista include Colstrip plant additions in Schedule 99 rates on a one-year lag."[150] However, neither Staff nor any other party continues this recommendation on brief. As discussed below, we decline to amend Final Order 10/04, because both the Final Order 10/04 and the 2022 GRC Settlement include language that contemplates Avista's ability to recover 2025 Colstrip plant additions through a Colstrip Tracker Schedule 99 filing.

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[148] Final Order 09 Appendix A at 12-13 ¶ 14(j).

[149] *See* Partial Multiparty Settlement Stipulation, Final Order 09, Appx. A at 1, ¶ 1 (Mar. 25, 2025) (The seven parties who joined the settlement were Avista, Staff, Public Counsel, AWEC, NWEC, The Energy Project, and Sierra Club.); RCW 19.405.030(1).

[150] McGuire, Exh. CRM-1CT at 36:18 - 37:3.

92 The Commission approved the Colstrip Tracker and Tariff Schedule 99 in its resolution of Avista's 2022 general rate case (GRC) in Final Order 10/04 approving with conditions a Full Multiparty Settlement Stipulation (Settlement or 2022 GRC Settlement). The Colstrip Tracker is discussed in paragraph 14.b of that settlement, in which Avista agreed that "it would track all Colstrip costs other than transmission investment and costs included in Avista's Energy Recovery Mechanism including but not necessarily limited to O&M expense, depreciation expense, D&R costs, and return on rate base."[151]

93 All future Colstrip investments, including pro forma Colstrip investments that were included in the 2022 GRC, were to be recovered separately through this tracking mechanism, subject to review, including but not limited to an examination of prudence. Under the 2022 GRC Settlement, the review of Colstrip investments proposed for inclusion in this mechanism will occur through Avista's annual tariff revision for the Colstrip tracker for separate ratemaking treatment.

94 In the Joint Testimony supporting the Settlement, parties stated that for recovery of any unrecovered Colstrip net rate base costs after December 31, 2025, "the Company will have an opportunity in a future proceeding or Tariff Schedule 99 Compliance filing to propose recovery of any unrecovered balances deemed prudent by the Commission as of December 31, 2025, that still allows the Colstrip balances to be removed as required at December 31, 2025."[152]

95 The Joint Testimony explains that the Colstrip Tracker would be administered through Tariff Schedule 99 with the initial rate effective date of December 21, 2022, concurrent with the 2022 GRC, and would be reset each January 1st thereafter, via a filing made each October 31st *until all prudently incurred costs are recovered*.[153] Prudency of the incurred costs would be reviewed in each year's annual filing, and the tracker would recover non-O&M items "on a one-year lag, using actuals through August 31st and estimates through December 31st of the filing year" and "[a]mounts that were included in Schedule 99 on a forecast basis will be trued-up to actuals in each annual tariff filing."[154]

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[151] Settlement at 6-7, par 14b (citing 2019 PSE GRC Final Order 08/05/03, Dockets UE-190529, UG-190530, UE-190274, UG-190275, UE-190991, AND ug-190992 (*consolidated*), at par. 388 & 425 (discussing why Staff believes a tracking mechanism is the appropriate way to recover these costs).

[152] Staff Response to Bench Request No. 1, Attachment A, Supplemental Joint Testimony, JT-3T at 12:20-24.

[153] JT-3T at 6:7-10 (emphasis added).

[154] JT-3T at 6:20-21

96 In addition, the Joint Testimony states that "[e]xcept for costs associated with regulatory assets and liabilities, all costs for Colstrip capital investment and operating expenses will be removed from Tariff Schedule 99 and customer rates effective January 1, 2026, per the Clean Energy Transformation Act ("CETA")." This discussion references the CETA deadline in RCW 19.405.030(1)(a), which requires:

> [o]n or before December 31, 2025, each electric utility must eliminate coal-fired resources from its allocation of electricity. This does not include costs associated with decommissioning and remediation of these facilities.[155]

97 That Avista would recover Colstrip plant investments on a "one-year lag" is also stated in the illustration that appears in the Joint Testimony Exhibit JT-3T and Exhibit JT-4.[156] As Staff witness Chris McGuire explains, "2023 rates would include plant additions through 2022, 2024 rates would include plant additions through 2023, and 2025 rates would include plant additions through 2024." For 2026, however, the December 31, 2025, CETA deadline appears to disallow utility recovery of costs for coal-fired resources from Washington customer rates.[157]

98 To address recovery of 2025 plant additions despite CETA's December 31, 2025, coal-fired resource deadline, the settling parties state in Exhibit JT-3T that to recover Colstrip net rate base costs after December 31, 2025, "the Company will have an opportunity in a future proceeding or Tariff Schedule 99 Compliance filing to propose recovery of any unrecovered balances deemed prudent by the Commission as of December 31, 2025."[158]

99 Final Order 10/04 acknowledges this cost recovery on a one-year lag, but also recognizes the CETA requirement "to remove the total costs for Colstrip capital investment and operating expenses, excluding Colstrip transmission investments and ongoing D&R costs from customer rates after December 31, 2025," referencing the Joint Testimony discussion of the opportunity to recover the unrecovered balances deemed prudent by the Commission as of December 31, 2025. Final Order 10/04 also states that "beginning

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[155] RCW 19.405.030(1)(a).

[156] JT-4; JT-3 at 7:1-9.

[157] RCW 19.405.030(1)(a).

[158] JT-3T at 12:20-24.

January 1, 2026, the Colstrip Tracker will include only annually updated ongoing D&R net rate base balances and Colstrip Regulatory amortization expense."[159]

Commission Determination:

100 Staff witness McGuire discusses possible confusion between the CETA December 31, 2025, deadline, the one-year lag language in the 2022 GRC Settlement, and in certain paragraphs of Final Order 10/04. However, the Commission determination language of Final Order 10/04 does not disallow recovery of 2025 plant additions or otherwise restrict Avista's recovery of those costs to a "one-year lag" that would be impossible to implement by virtue of CETA. Accordingly, no party argues on brief in this docket that an amendment is required, and we do not view Avista's recovery of prudently incurred used and useful 2025 plant additions as a violation of the 2022 GRC Settlement, or Final Order 10/04.

VI. Investments in Colstrip

101 In its October 31, 2024, initial Tariff Schedule 99 filing, Avista requested a rate increase of approximately $18.2 million, or 2.7 percent, for recovery of 2024 and 2025 costs associated with Colstrip Units 3 and 4, and allocated $10.9 of the $18.2 million in plant additions to Washington.[160] However, on rebuttal Avista revised its position "to include approximately $12.0 million in system-wide Colstrip plant investments for 2024 and 2025,"[161] and effectively reduced its Washington's share of plant additions from $10.9 to 7.7 million.[162]

102 In response, Staff, AWEC, and NWEC proposed Colstrip 2024 and 2025 capital investment recovery amounts of $5.6 million, $3.0 million, and $1.98 million respectively, as illustrated in Table 1 and discussed in further detail below.[163]

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[159] *Wash. Utils. Transp. Comm'n v. Avista Corp., d/b/a Avista Utils.*, Dockets UE-220053, UG-220054, and UE-210854 (consolidated) (Avista 2022 GRC) Final Order 10/04 at 23, ¶ 66 (Dec. 12, 2022).

[160] Kinney, Exh. SJK-1T at 7:11-13 and SJK-9C. Of the $10.9 million, $3.2 million is attributed to 2024 plant additional and $7.7 million to 2025 plant additions. Kinney, Exh. SJK-8C (2024 Capital Budget) and SJK-8C (2025 Capital Budget).

[161] Avista's Post Hearing Brief at 3 ¶ 7.

[162] Avista's Post Hearing Brief at 2 ¶ 5 and Andrews, Exh. EMA-1CT at 2:5-10.

[163] Avista's Post Hearing Brief at 2 ¶ 6.

103 Staff separated its analysis of the 73 capital expenditures at issue in this proceeding into six categories, recommending that "the Commission disallow recovery of all, or a portion of 25 of the 73 projects."[164] The 73 capital expenditures at issue consist of:

(1) 6 SmartBurn projects;[165]
(2) 3 projects not likely to go into service in 2025;
(3) 16 long-lived assets, which have longer useful lives than four years;
(4) 21 routine maintenance projects;
(5) 11 human safety projects; and
(6) 16 de minimis costs.

104 Staff did not contest the last three of those categories but did recommend disallowing all or portions of the others.[166] NWEC categorizes the projects similarly to Staff,[167] but treats the majority of the projects it disputes as long-lived assets with two of the projects that Staff categorized as de minimis, as intending to promote human safety. Unlike Staff who states that there are a total of 11 human safety projects, NWEC maintains there are a total of 13.[168] Specifically, NWEC recommends disallowing recovery of the first three categories and allowing a pro rata share of cost recovery for major maintenance, and full recovery of the 13 human safety projects.[169] Conversely, AWEC and Public Counsel recommend "prorating all capital additions based on their useful life," with in-service dates prior to December 31, 2025,[170] and do not contest the inclusion of the 13 human safety projects' allowance in rates. While Public Counsel did not provide a specific breakdown of the amounts that Avista should be allowed to recover, Public Counsel

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[164] McGuire, CRM-1CT at 3:6-7.

[165] Avista's six 2024 and 2025 capital investment projects related to SmartBurn are:(1) Separate Over Fire Air (SOFA) Bucket Replacement (U3) system; (2) Boiler Burner Aux Air Replacement U3; (3) Top Over Fire Air (TOFA) Bucket Replacement U3; (4) Boiler Burn Aux Air Replacement U4; (5) SOFA Bucket Replacement U4; and (6) TOFA Bucket Replacement U4.

[166] Staff's Post Hearing Brief at 2 ¶ 5 and footnote 3, and McGuire, CRM-1CT at 3:8-13. Specifically, "Staff did not contest Avista's request to recover routine maintenance costs, based on Staff's reading of Avista's 2019 GRC Settlement…which imply that Avista may recover routine, "non-life extending assets." Additionally, Staff did not contest the 16 de minimis projects because they did not materially impact rates or the recovery of the human safety projects because the benefits justified the costs. *See also* McGuire, Exh. CRM-1CT at 6:10, and 6:19-7:10.

[167] Cebulko, BTC-1CT at 19:10-15.

[168] Cebulko, BTC-1CT at 35:13-22 and 36:1-3 (Table 6).

[169] Cebulko, BTC-1CT at 3:8-14.

[170] Dreyer, Exh. JMD-1CT at 3:11-14 and JMD-2T at 3:6-18 citing to Mullins, Exh. BGM-1T at 11:18-20.

agrees with AWEC's proposed approach of "prorating all 2024 and 2025 capital additions based on their useful life," with in-service dates prior to December 31, 2025.[171]

105 To provide an overview of each of the parties' proposals for recovery of Colstrip capital investments in rates, we have incorporated the table below, which has been adapted from Avista's redacted rebuttal testimony,[172] and cross-referenced each party's responses and cross-answer testimony.

Table 1 –2024 and 2025 Investment – Summary of Positions[173]

2024 and 2025 Capital Investment Proposals by Party (in millions)					
	Avista Revised[174]	**Staff**	**AWEC**	**NWEC**	**Public Counsel**
	10,802	**10,932**	**10,932**	**10,932**	(1)
SmartBurn	(65)	(578)		(641)	
Long-Life (Pro-Rate to NWE or Remove)	(1,171)	(2,892)	(7,914)	(6,436)	
Not Used and Useful (Remove)	(1,824)	(1,873)		(1,873)	
Total to Remove	(3,060)	(5,343)	(7,914)	(8,950)	
Proposed Recovery	**7,742**	**5,589**	**3,018**	**1,982**	
Difference between Proposals		(2,153)	(4,724)	(5,760)	
(1) Public Counsel did not provide a breakdown of their proposal.					

106 As illustrated above in Table 1, Avista's revised position for Colstrip 2024 and 2025 Capital investments includes recovery in Schedule 99 for calendar year 2025, totaling $7.7 million. The $7.7 million revised amount is comprised of "a $4.8 million reduction

[171] Dreyer, Exh. JMD-1CT at 3:11-14 and JMD-2T at 3:6-18 citing to Mullins, Exh. BGM-1T at 11:18-20.

[172] Andrews, Exh. EMA-1CT at 13:1-8.

[173] See Table 2, excerpted from Kinney, SJK-11CT at 23:1-9 and Table 6, Andrews, EMA-1CT at 13:1-8.

[174] Avista notes that there were minor differences in the "As-filed" amount of $10.8 million based on estimated as-filed monthly transfers to plant of 2024 and 2025 additions and that the "As-field" amount of $10.9 million reflects detailed balances by project provided with the Company filing. *Id*.

in total system investments," and "a $3.1 million decrease in Washington's share,"[175] and "reflects the removal of three general categories of disputed investments, including: (1) the removal of $65,000 in SmartBurn-related investments mistakenly included in the Company's initial filing; (2) $1.2 million of investment prorated to NWE; and (3) $1.8 million in investment deemed not used and useful by December 31, 2025, and assigned to NWE."[176] Accordingly, if the Commission were to exclude the 2024 and 2025 capital investments proposed by Staff and the other parties, Avista maintains that the portions of investments removed "would require an immediate write-off on Avista's books of record in 2025, ranging between $2.2 million (Staff) to $5.8 million (NWEC)," which would adversely impact the Company's actual earnings and credit rating. [177]

107 To demonstrate that it has met its burden to recover its 2024 and 2025 Colstrip capital investments, Avista focuses its arguments on the four factors the Commission typically considers when determining prudency, and addresses to a lesser degree how the Company's capital additions satisfy the used and useful standard.[178] In addition, each of the other parties' arguments do not necessarily distinguish clearly between the concepts of prudence and used and useful. Despite the parties' intermingling of these concepts in testimony and briefing, the Commission will first consider how each party addresses the requirement that the capital project investments for which a utility company request cost recovery are used and useful for service to Washington customers.

A. Used and Useful

108 As mentioned above, the Company does not discuss how its Colstrip investments meet the Commission's used and useful standard with the same level of particularity as it does in its prudence arguments.[179] Specifically, Avista argues that its Colstrip investments at issue in this docket are necessary to maintain safe and reliable operation of Colstrip Units 3 & 4 for the benefit of Avista's customers.[180] Avista further discusses the regular

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[175] Andrews, Exh. EMA-1CT at 7:7-9.

[176] Andrews, EMA-1CT at 7:16-18 and 8:1-2.

[177] Andrews, EMA-1CT at 3:27-28. 4:1-4 and 13:9-12.

[178] The four factors include the: (1) Need for the Resource; (2) Evaluation of Alternatives; (3) Communication with and Involvement of the Company's Board of Directors; and (4) Adequate Documentation as set forth the Commission's Standard for Prudence.

[179] Kinney, Exh. SJK-1T at 4:1-2.

[180] Kinney, Exh. SJK-1T at 2:1-2.

periodic maintenance of the plant in the context of the cost-benefit considerations Avista considered when making the investments.[181]

109 To support its contention that customers benefit from the lower power supply costs enabled by these investments, Avista argues that without operation of Avista's Colstrip Units 3 and 4, system power costs would have been at least $84.2 million, or nine percent higher than what was included in its 2024 GRC compliance filing that set rates for 2025. Avista also contends that this does not include the cost of replacing Colstrip's contribution to Avista's capacity and reliability requirements that would have added an additional $120.5 million, system-wide.[182] Avista further explains that the investments "were necessary to address reliability and safety of Colstrip from the time they are installed through their end of life," but acknowledges that "Avista's customers have and will continue to receive the benefit of energy generated by Colstrip through" and "until the end of 2025."[183] For these reasons, Avista maintains that the capital projects at issue are used and useful as follows.

Projects that May Not be In Service and Used and Useful Before the End of 2025

110 First, Avista requests recovery of three specific projects for which the in-service dates have been "in flux."[184] These include: (1) the U4 Generator Exciter; (2) the North Cheyenne AAQ system; and (3) the Baghouse. On rebuttal, Avista acknowledges that the Baghouse project will not be in-service in 2025 and removes its request to recover the $65,000 in costs for this project.[185] However, Avista seeks a pro rata recovery of four percent of the costs incurred for the U4 Generator Excitor based on the A&A Agreement it entered into with NWE, in which the remaining 94 percent was apportioned to NWE.[186] Avista also seeks full recovery of the Northern Cheyenne AAQ system, and it contends that both of these projects will be completed in October 2025 and are necessary projects to continue operating the plant in 2025.[187]

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[181] Kinney, Exh. SJK-1T at 7-8.

[182] Kinney, Exh. SJK-1T at 13:1-9.

[183] Kinney, Exh. SJK-1T at 11:16-21, 13:17-18, 15:15-22, 17:14-21.

[184] Kinney, Exh. SJK-11CT at 18:2-4; *See also* Mullins, Exh. BGM-1CT at 10:10-18; McGuire, Exh. CRM-1CT at 9-11.

[185] Kinney, Exh. SJK-11CT at 18:2-4; *see* Mullins, Exh. BGM-1CT at 10:10-18; McGuire, Exh. CRM-1CT at 9-11.

[186] Avista's Post-Hearing Brief at 17 ¶ 51 and Kinney, Exh. SJK-11CT at 28:2-6.

[187] Kinney, Exh. SJK-11CT at 28:4-7.

111 In response, Staff, Public Counsel, NWEC, and AWEC accept Avista's rebuttal position on the Baghouse project, given that this investment does not qualify for recovery and will not go into service until after December 31, 2025.[188] However, with respect to the other two projects, Staff recommends the Commission only allow Avista to recover a prorated share of the U-4 Generator Excitor and North Cheyenne System "because their useful lives will exceed Colstrip's four-year routine maintenance cycle."[189] Similarly, Public Counsel[190] and AWEC [191] recommend that the Commission prorate these capital additions based on their useful life and only provide Avista recovery for the portion in service prior to December 31, 2025.[192] NWEC continues recommending that the investments be denied on the basis that they explicitly extend the life of the plant.[193]

Routine Maintenance and Long-Lived Asset Projects

112 As for the 21 routine maintenance projects and 16 long-lived assets,[194] Avista argues that the Commission should reject NWEC's proposal to prorate routine maintenance and disallow long-lived assets and instead adopt the Company's and Staff's position[195] to allow recovery of the 21 routine maintenance projects.[196] Avista explains that "Colstrip major maintenance projects operate at a cycle that years of experience by plant staff have found meet efficient and safe operating cadence."[197] Avista also argues that the Company's agreement in the 2019 GRC Settlement not to support investments at Colstrip beyond routine capital maintenance and that extend the plant's operational life beyond

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[188] Staff's Post Hearing Brief at 5 ¶ 12, Public Counsel's Post Hearing Brief at 22-23 ¶ 68, NWEC's Post Hearing Brief at 2 ¶ 5, Cebulko, BTC-1CT at 25:8.

[189] Staff's Post Hearing Brief at 5 ¶ 12.

[190] Public Counsel Post Hearing Brief at 22-23 ¶ 68.

[191] Mullins, Exh. BGM-1CT at 10:17-18.

[192] Mullins, BGM-1CT at 11:18-21 and Mullins, Exh. BGM-3C.

[193] Cebulko, BTC-1CT at 25:7-9 and BTC-5C (Avista's Response to NWEC DR 016, Attachments A and B).

[194] Kinney, Exh. SJK-1T at 8:17-18 citing to McGuire, CRM-1CT at 15:12-15, and McGuire, Exh. CRM-2C.

[195] McGuire, Exh. CRM at 9-11 and CRM-2C at 2:28-48. Staff categorizes 21 projects as routine maintenance, which it defines as needing to be replaced every four years or less, and maintains that since "routine capital maintenance costs as Colstrip are generally accepts it does not dispute recovery of these projects.

[196] Avista's Post Hearing Brief at 17 ¶ 52 and Kinney, Exh. SJK-11CT at 29:1-4.

[197] Kinney, Exh. SJK-11CT at 29:1-17.

December 31, 2025, meant only that it would not support capital projects, but did not apply to "voting per se."[198]

113 To further bolster the argument that it did not support long-lived assets that did not benefit Washington customers, Avista argues that it challenged "the allocation of dollars assigned to long-lived enhancement work, so as to only accept a smaller, pro-rated share of the items that would otherwise extend the useful lives of the Project beyond 2025," and successfully apportioned certain long lived costs to NWE.[199] Avista argues that this process was successful because it was able to garner NWE's agreement and support to reduce Avista cost responsibility of several 2024 and 2025 capital expenditures as well as the proration of long lived assets, effectively allocating $1.17 million of the Washington share of costs away from Avista to NWE, and reducing the Company's overall requested capital down from $10.8 million to $7.7 million.[200]

114 Staff recommends that the Commission prorate the costs associated with Avista's 16 long-lived projects that represent investments in long-lived plant, which it argues Washington ratepayers will not benefit from beyond December 31, 2025.[201] Staff defines '*long-lived*' "as an asset with an expected service life greater than four years, which distinguishes those assets from routine maintenance projects."[202] Staff asserts that while the investments provide some benefit to Washington customers, the investments will not be able to provide the full benefit associated with their respective useful lives due to CETA's prohibition on coal power in Avista's allocation of electricity.[203] For support, Staff refers to the Commission's final order in Avista's 2020 GRC, where the Commission rejected Avista's request to recover costs of its Dry Ash Disposal Project because Avista had not shown that the project was not life-extending.[204] Staff maintains that because CETA prohibits coal in the Company's allocation of electricity beginning in

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[198] Avista's Post Hearing Brief at 18 ¶¶ 53-54 citing Dockets UE-190334 et.al., Final Order 09 Appendix A at 12-13 ⁋ 14(j) (March 25, 2020).

[199] Avista's Post Hearing Brief at 18 ¶ 55 and 19 ¶ 58 citing to Kinney, Exh. SJK-14C, Long Lived Assets with NWE.

[200] Avista's Post Hearing Brief at 20 ¶ 60, and Kinney, SJK-11CT at 4-6. See also Table 1 at ¶ 95 of this Order.

[201] McGuire, Exh. CRM-1CT at 3:12-13, 11:18-20.

[202] McGuire, Exh. CRM-1CT at 15:4-5. See McGuire, Exh. CRM-2C at 2:58-73 for the 16 long-lived plant additions Staff is contesting in this case.

[203] McGuire, Exh. CRM-1CT at 15:21-22, 16:1-7.

[204] Staff's Post Hearing Brief fn. 3 (*citing WUTC v. Avista Corp*., Dockets UE-200900 et. al., Order 08/05 at 100 ¶ 279.

2026, the Company should only be authorized to recover a proportional share of costs associated with long-lived assets because they will only benefit Washington customers for a portion of their overall useful life.[205]

115 NWEC argues that the Commission should prorate Avista's recovery based on the portions of the investments that are used and useful from the perspective of Washington customers considering CETA's timelines and disallow the portion of useful life extending past December 31, 2025.[206] NWEC cites Commission precedent that utilities generally cannot require their ratepayers to pay for investments unless they are used and useful, which requires a showing that an investment provided a benefit to Washington ratepayers either directly, such as through the flow of power from a resource to customers, and/or indirectly such as the reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits.[207] NWEC argues that because Avista ratepayers will not benefit from Colstrip's operation beyond December 31, 2025, they cannot be required to pay for Colstrip's long-term operation.[208]

116 Public Counsel argues that investments in Colstrip Units 3 and 4 will not be used and useful to Washington ratepayers after December 31, 2025, and that costs associated with capital additions related to Colstrip operations after that date must be excluded from rates.[209] Public Counsel further argues that requiring "Washington ratepayers to subsidize coal-fired power for customers in Montana or elsewhere violates the statutory used and useful standard, defeats the purpose of CETA," and "belies the…[Commission's] directive to regulate in the public interest."[210] To support its contention that there is no direct benefit of operating Colstrip facilities to Washington customers after December 31, 2025,[211] Public Counsel further asserts that including costs associated with Colstrip capital assets in service beyond 2025 will result in rates that are not fair, just, reasonable, and sufficient because Washingtonians will be unable to attain any value or benefit from the investments and will be harmed from an economic and environmental perspective by the inclusion of these investments in rates, which are contrary to the "letter and spirit" of

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[205] Staff's Post Hearing Brief at 21-22 ¶ 53.

[206] NWEC's Post Hearing Brief at 2 ⁋ 4 and 13 ⁋ 31.

[207] NWEC's Post Hearing Brief at 2-3 ⁋ 6 (citing *Wash. Utils. & Transp. Comm'n v. PacifiCorp., PacifiCorp, d/b/a Pacific Power & Light Co.*, Dockets UE-050684 & UE-050412, Order 04/03, ¶ 50 (Apr. 17, 2006)).

[208] *Id.*

[209] Public Counsel's Post Hearing Brief at 14 ¶ 44

[210] Public Counsel's Post Hearing Brief at 1-2 ¶ 4.

[211] Public Counsel's Post Hearing Brief at 3 ¶ 10

CETA.[212] Finally, Public Counsel maintains that Avista has not presented any evidence that allowing only a prorated portion of its Colstrip capital additions into rates will result in insufficient revenue for the Company to continue operating.[213] Therefore, Public Counsel recommends the Commission allow recovery of Avista's capital investments on a prorated basis so that Avista customers "only pay for a share of each plant addition proportional to their share of that plant addition's expected service life."[214]

117 Similarly, AWEC expresses concerns of Avista's request for "cost recovery of life extending investments," in the plant "that do not benefit Avista's ratepayers," and emphasizes that NWE "should be obligated to pay a fair value for that share, including reimbursement for the value of capital additions made by Avista that will benefit its customers."[215] AWEC requests that the Commission "reaffirm its used and useful standard as part of this proceeding,"[216] and recommends "disallow[ing] recovery [of] the portion of all capital investments with a depreciable life beyond December 31, 2025, attributable to service after that date, consistent with the cost recovery requirements that plant included in rates be both used and useful and prudent."[217] Finally, AWEC requests that Avista be required to "create a regulatory liability for any over-collection from customers" and be ordered to refund any over-collected amounts "[i]f actual in-service dates are December 31, 2025, or later…consistent with Avista's compliance filing proposal."[218]

De Minimis Projects

118 Avista requests to recover the 14 projects that Staff deems "de minimis" and having an immaterial impact on rates. NWEC, AWEC, and Public Counsel argue that the Commission should apply the used and useful standard and prorate Avista's recovery of

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[212] Public Counsel's Post Hearing Brief at 18-19 ¶¶ 57- 58.

[213] Public Counsel's Post Hearing Brief at 19 ¶ 59.

[214] Public Counsel's Post Hearing Brief at 24 ¶ 72.

[215] Mullins, Exh. BGM-1CT at 2:12-18.

[216] AWEC's Post Hearing Brief at 9-10 ¶ 19 citing to Dockets UE-050684, UE-050412, and UE-060669 (Consolidated), Order 06/05/02 at ¶ 15 (July 14, 2006) (recommending the Commission continue to interpret plant to be 'used and useful' when it benefits ratepayers in Washington either directly or indirectly.

[217] Mullins, Exh. BGM-1CT at 3:7-8 and 3:11-14. See also Mullins, Exh. BGM-3 in support of its recommended 2024 and 2025 reductions to capital.

[218] Mullins, Exh. BGM-1CT at 10:21, 11:1 and 11:3-5 citing to Mullins, Exh. BGM-4, Avista's Response to Staff's Data Request No. 12.

these project costs corresponding to the portion of the useful lives during which they were used and useful to Washington customers.

Human Health & Safety Projects

119 Avista requests recovery of 13 human health and safety projects in its initial filing. The non-company parties do not contest recovery of these projects. Staff witness McGuire discusses the extent of health benefits of these projects conferred on ratepayers versus the costs of the investments. NWEC cites the 2019 GRC Settlement language in which the settling parties agreed that capital costs associated with the protection of human health and safety are generally acceptable.[219]

Commission Determination:

120 RCW 80.04.250 provides, in relevant part, that:

> The commission shall have power upon complaint or upon its own motion to ascertain and determine the fair value for rate making purposes of the property of any public service company used and useful for service in this state by or during the rate effective period and shall exercise such power whenever it deems such valuation or determination necessary or proper under any of the provisions of this title.

121 When calculating a utility's rate base for ratemaking, if the Commission determines that the utility plant "is neither employed for service nor capable of being put to use for service…such a plant is not 'used and useful' for service."[220] In interpreting the phrase "used and useful," the Washington State Supreme Court has explained "'Used' is defined as 'employed in accomplishing something;' 'useful' is defined as 'capable of being put to use: having utility: advantageous: producing or having the power to produce good: serviceable for a beneficial end or object.'"[221] The Court further explained "RCW 80.04.250 empowers the Commission to determine, for ratemaking purposes, the fair value of property which is employed for service in Washington *and* capable of being put to use for service in Washington."[222]

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[219] Cebulko, Exh. BTC-1CT at 23:18-27 (citing Final Order 09 at Appendix A ¶ 14.j.

[220] *POWER*, 104 Wn.2d at 815.

[221] *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984) (*citing Webster's Third New International Dictionary* 2524 (1976)).

[222] *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984).

122 By extension, "[w]hen calculating a utility's rate base for ratemaking, if the WUTC considers utility plant that 'is neither employed for service nor capable of being put to use for service; . . . such plant is not 'used and useful' for service' and the [Commission] exceeds its statutory authority."[223] The Commission has also previously interpreted "the phrase 'used and useful for service in this state' to mean providing benefits to ratepayers in Washington, either directly (e.g., flow of power from a resource to customers) and/or indirectly (e.g., reduction of cost to Washington customers through exchange contracts or other tangible or intangible benefits)."[224]

123 CETA states in RCW 19.405.030(3) that the Commission must allow in rates directly or indirectly, amounts on an investor-owned utility's books of account that the commission finds represent *prudently* incurred undepreciated investment in a fossil fuel generating resource that has been retired from service . . . ."[225]

124 The presence of "prudently incurred" in this section of CETA, coupled with the absence of "used and useful" calls into question whether the Washington Legislature might have intended for the Commission to dispense with the used and useful standard in applying that section of CETA. However, critically, in the same bill in which the Legislature enacted CETA in 2019, the Legislature revised RCW 80.04.250, affirming the used and useful standard. The Commission concluded in the Used and Useful Policy Statement that CETA did not alter the used and useful standard.[226] Therefore, we continue to apply the used and useful standard here: the Commission has determined utility property to be "used and useful" when it provides a benefit to ratepayers in Washington, either directly or indirectly.[227]

125 Given that CETA requires that Avista remove the benefits and costs of coal power from its retail customer rates no later than December 31, 2025, the Commission finds that any costs associated with investments in Colstrip based on benefits that are realized after

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[223] *Office of the Atty. Gen., Pub. Counsel Unit v. Wash. Utils. & Transp. Comm'n*, 4 Wn. App. 2d 657, 682 (2018) (quoting *POWER v. State Utils. & Transp. Com*, 101 Wn.2d 425, 430 (1984)).

[224] *WUTC v. PacifiCorp*, Dockets UE-050684 & UE-050412 (*consolidated*), Order 04/03 at 21-22 ¶ 50 (Apr. 17, 2006).

[225] RCW 19.405.030(3) (emphasis added).

[226] *In the Matter of the Commission Inquiry into the Valuation of Public Service Company Property that Becomes Used and Useful after Rate Effective Date*, Docket U-190531, Policy Statement on Property that Becomes Used and Useful After Rate Effective Date (January 31, 2020) at 4 ¶ 5 citing LAWS of 2019, Ch. 288 § 20(3) (January 31, 2020).

[227] *Id.*

December 31, 2025, must be excluded from rates by prorating Avista's recovery of costs based on the portion of their useful lives in service prior to the CETA deadline. Such approach appropriately removes coal power from Avista's allocation of electricity while assigning fair and equitable costs to ratepayers relative to the benefits received from the Colstrip investments.

126 Accordingly, for 57 of the 73 capital expenditures at issue, the Commission allows Avista to recover an amount prorated by the percentage of the useful life of each project during which that project was used and useful to Washington customers on or before December 31, 2025. As we discuss more fully below, we disallow three projects, two of which are the TOFA Bucket Replacement projects U3 and U4, and the third, the Baghouse project, which Avista affirmatively removed from its request on rebuttal, which will not be in-service before the CETA December 31, 2025, deadline. Lastly, we allow full recovery in rates for the 13 Human Safety projects.

127 Of the 73 total projects for which Avista seeks recovery for 2024 and 2025, we allow prorated recovery for the following 57 projects:

(1) 4 of the SmartBurn projects, which include the SOFA Bucket Replacement U3 and U4 projects and the Boiler Burner Aux Replacement U3 and U4 systems;

(2) 2 of the three projects which may go into service in 2025, including the U4 Generator Exciter and Northern Cheyenne AAQ;

(3) 16 Long-Lived Asset Projects;

(4) 21 Major Maintenance Projects; and

(5) 14 De Minimis Projects

1. Disallowing the Two TOFA Bucket Replacement U3 and U4 Projects and Prorating the Four Remaining SmartBurn SOFA and Boiler Aux Projects

128 As discussed above, we disallow the two TOFA Bucket Replacement U3 and U4 projects, which Avista affirmatively removed from its request on rebuttal. The remaining four SmartBurn projects for which Avista seeks recovery were in rates prior to Avista's 2020 GRC. As explained in subsection VI.B. below, we view those projects as prudently incurred and allow Avista to recover a prorated amount corresponding to the percentage

of the useful lives of these projects that were in service and used and useful to customers on or before December 31, 2025.

2. Proration of Two Projects that May Go into Service Before 2025: Disallowance of the Baghouse Project

129 We disallow recovery of the Baghouse project because it will not be in-service before the end of 2025, a fact that Avista acknowledges in its rebuttal testimony. However, for the Generator Exciter-U4 project for which Avista seeks a 4 percent recovery and the Northern Cheyenne AAQ system, which Avista claims will be in service in October 2025, we expect Avista to provide documentation in its compliance filing in response to this Order demonstrating the actual in-service dates for these projects.

130 Based on the documentation Avista provides in its compliance filing, we will allow Avista to recover the prorated amount based on the percentage of the useful lives of these two projects that were in service and used and useful to customers on or before December 31, 2025. We note that the Commission would not ordinarily keep the record open to confirm in-service dates, but we do so here due to the unique and novel circumstances of this docket relating to the CETA requirement to remove coal-fired resources from Washington rates by the end of 2025.

3. Routine Maintenance and Long-Lived Asset Projects

131 Given the benefits conferred to ratepayers by the 21 routine maintenance and 16 long-lived asset projects that were in service before December 31, 2025, we concur with Staff, AWEC, and Public Counsel that Avista should be allowed to recover the prorated amount corresponding to the percentage of the useful lives of these investments that were in service on or before December 31, 2025.

4. De Minimis Projects

132 Consistent with our decisions above on other projects, we allow Avista to recover a prorated amount corresponding to the percentage of the useful lives of the 14 de minimis projects that were in service and used and useful to customers on or before December 31, 2025.

5. Human Health & Safety Projects

133 For the projects that relate to human health and safety, the Commission agrees with Staff

and NWEC that these projects "provide near term human health benefits that exceed the costs of the investments," and therefore Avista should recover these projects in full.[228] The Company's ratepayers benefit from reasonable human safety investments that reduce the Company's risk of liability in the event of an incident resulting in injury or death to plant workers. Absent such investment, investors may be led to perceive the Company as relatively riskier, which could in turn require a greater degree of compensation to investors to account for that risk, thereby increasing overall future rates to customers.[229] Although utilities must transition away from certain resources to comply with CETA, the Commission does not want to create an incentive for utilities to avoid reasonable safety investments for such resources that place workers in threat of harm, which generally would be contrary to the public interest.[230] The Commission has no desire to see the transformation of Washington's energy supply to clean energy built upon a foundation of unnecessary hazards and risk of harm to workers.

B. Prudence

134 Now turning to Avista's prudency arguments, the Company addresses the four factors the Commission has considered when determining prudency. For the first factor, Avista reiterates its need for resources by arguing that the investments are necessary to operate Colstrip Units 3 and 4 at a 1480 MW capacity to maintain the plant in a safe and reliable manner while generating its 15 percent share of the plant in accordance with its O&O Agreement.[231] Avista further highlights that the contracts governing its investments in Colstrip: (1) "have never, themselves, been deemed to be imprudent;"[232] and (2) provide for upkeep, ongoing maintenance, preventative work to dispose of coal ash residuals, replacement of plant equipment, and periodic work, which are "based on the original

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[228] McGuire, Exh. CRM-1CT at 8:18-9:5.

[229] RCW 19.405.010(2) ("In implementing this chapter, the state must . . . provide safeguards to ensure that the achievement of this policy does not impair the reliability of the electricity system or impose unreasonable costs on utility customers."

[230] *See,* RCW 19.405.010(4)(" The legislature finds that Washington can accomplish the goals of chapter 288, Laws of 2019 while: . . . maintaining safe and reliable electricity to all customers at stable and affordable rates[.]"); RCW 80.28.425(1) (stating in part ""[i]n determining the public interest, the commission may consider such factors including, but not limited to, . . . health and safety concerns . . . to the extent such factors affect the rates, services, or practices of a[n] . . . electrical company.").

[231] Kinney, Exh. SJK-1T at 4:16-20 and 5:3-10 and SJK-2C, O&O Agreement Sections 10 and 17.

[232] Kinney, SJK-1T at 5:17-18.

equipment manufacturer's recommendations [and] adjusted over time by plant personnel based on their operational experience."[233]

135 Avista also notes that historically coal-fired plants have required significant capital maintenance due to "fuel handling, high operating temperatures, emissions controls, and coal ash handling."[234] To support its contention that it has acted reasonably to avoid unnecessary investments, Avista emphasizes its "overall level of capital spending for 2024 and 2025 being at a consistent level with prior years;" and that NWE did not request levels of capital investment beyond the ordinary course of business.[235]

136 For the second factor regarding alternatives considered, Avista argues that as a minority owner of Colstrip, it had no acceptable alternatives. Avista explains that it could not "unilaterally deny the approval of a budget by voting its 15 percent share" to prevent approved capital projects[236] or refuse to pay its 15 percent portion of any approved plant additions as this would result in the Company violating its contractual obligations under its O&O Agreement and expose customers to unreasonable risks of financial penalties.[237] Avista further highlights that the regulatory, financial, and transactional constraints it was facing relating to: (1) federal Mercury and Air Toxic Standard (MATS) compliance obligations;[238] (2) CETA's mandate prohibiting it from serving its Washington retail load with coal-derived electricity after December 31, 2025;[239] (3) limited availability of willing counterparties;[240] and (4) the Company's need to preserve its' contractual and physical rights of the Colstrip Transmission system;[241] collectively compelled it to abandon the plant at no value as this was "the least-cost, least-risk option available" to the Company and its customers.[242]

137 In short, Avista reasons that the transaction "extricated [it] from imminent MATS compliance liabilities, satisfied the statutory coal-elimination mandate, preserved

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[233] Kinney, SJK-1T at 6:3, 7:10-11 and 8:4-6.

[234] Kinney, SJK-1T at 8:11-13. See also SJK-1T at 8-9.

[235] Avista's Post-Hearing Brief at 14:9-10 citing Kinney SJK-1T at 9-10.

[236] Kinney, SJK-1T at 7:3-4.

[237] Kinney, SJK-1T at 14:4-9 citing to Exh. SJK-2C at 24, Section 21 (e-f) of O&O Agreement.

[238] Kinney, SJK-11CT at 4:10-17.

[239] Kinney, SJK-11CT at 5:9-10.

[240] Kinney, SJK-11CT at 6:5-13.

[241] Kinney, SJK-11CT at 6:15-16.

[242] Kinney, SJK-11CT at 7:10-11.

valuable transmission entitlements, and avoided the protracted litigation that would have ensued had Avista attempted unilateral retirement outside the consent of its co-owners."[243] Accordingly, Avista concludes that its actions were reasonable given the available information and maintains that any other "hypothetical alternative would have required [it] to retain a non-economic asset, pour capital into environmental controls it could never recover, or surrender transmission benefits needed to ensure adequate energy supply…worth tens of millions of dollar annually."[244]

138 Next, Avista counters AWEC's suggestion that it could have retained its ownership and operated Colstrip as a merchant plant. Specifically, Avista argues that its 15 percent ownership share would make such arrangement untenable because it would prevent the Company from controlling dispatch decisions, and force it "to participate in projects under the requirements of the operating agreement when market prices are relatively low," and demands from the majority of the other owners need it to serve customer loads.[245] Avista also argues that such arrangement would require it to operate as a non-regulated subsidiary and create greater uncertainty with benefits arguably flowing solely to shareholders instead of to customers, and if the plant were fully depreciated, then customers would bear all the costs of the depreciated asset.[246]

139 For the third prudency factor, communication and involvement of the Company's Board of Directors, Avista maintains that its owner representatives actively exercised their ownership interests concerning capital spending by meeting both annually with the Plant Operator, to discuss the Operating and Maintenance, Capital and Asset Retirement Obligations budgets,[247] and every other month to review plant operations and discuss other projects being vetted.[248] Avisa also notes that its Board of Directors and senior leadership were involved in the Company's decision to approve Colstrip Unit 3 and 4 plant additions, and regularly answered questions as they arose, made recommendations, and approved the overall levels of annual capital expenditures and investments.[249]

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[243] Kinney, SJK-11CT at 7:12-15.

[244] Kinney, SJK-11CT at 7:17-20.

[245] Kinney, SJK-11CT at 8:11-16.

[246] Kinney, SJK-11CT at 8:17-22.

[247] Kinney, SJK-1T at 6:10-22 and Exh. SJK-2C at12, Sections 10, 17-21, Section 17 of O&O Agreement.

[248] Kinney, SJT-1T at 16:4-11.

[249] Kinney, SJK-1T at 16:14-23 and 17:1.

140 With respect to the fourth prudency factor of adequate documentation, Avista contends that it maintained relevant contemporaneous documentation related to its decisions on plant additions and operations costs, as well as its cost-benefit analyses provided in the Company's exhibits marked SJK-4C, SJK-5C, and SJK-6C.[250]

141 In response, Staff and NWEC criticize Avista's consideration of project alternatives by arguing that the Company's net present value (NPV) analysis is flawed, because it is not risk adjusted for the probability of a Colstrip shutdown, and incorrectly includes benefits beyond 2025.[251] Staff argues that the NPV analysis included in Avista's Exhibits SJK-4C and SJK-5C were not: (1) calculated in a manner to allow parties to assess whether the benefits to Washington ratepayers outweigh the costs; and (2) risk adjusted and calculated to account for the probability of the existing equipment failing in the near term.[252] By not limiting its consideration to the costs and benefits of investments "incurred or accrued before January 1, 2026, the time after which Avista needed to remove Colstrip from its allocation of electricity," Staff reasons that the Company was guided by an "unreasonably flawed analysis."[253] Namely, Staff asserts the Company: (1) implicitly assumed 100 percent probability of an asset failure resulting in an outage if the investment were not pursued; and (2) artificially increased and overstated the benefits associated with replacing particular investments in plant.[254] Staff further maintains that Avista did not adequately support its assertion that the cost of short term power would exceed the cost of further capital investment because it relied on post-decisional analysis from Kinney's rebuttal testimony, "which did not exist" when Avista initially made these investments.[255] Staff thus concludes that the subsequent calculations Avista performed to risk adjust its NPV analysis should not carry any weight in the Commission's determination of prudence.[256] Finally, despite Staff's arguments of the methodological flaws and failure of Avista to comport its decision making processes with each of the prudency factors, Staff acknowledges that these investments do provide some benefits to

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[250] Kinney, SJK-1T at 17:5-11; Kinney, SJK-11CT at 19:8-9; SJK-4C; SJK-5C; and SJK-6C.

[251] McGuire, CRM-1CT at 17-24 and Cebulko BTC-1CT at 16:3-12.

[252] McGuire, Exh. CRM-1CT at 18:15-21 and 19:1-2. See also Staff's Post Hearing Brief at 6 ¶ 13.

[253] Staff's Post Hearing Brief at 9 ¶ 20.

[254] McGuire, CRM-1CT at 22:1-11.

[255] Staff's Post Hearing Brief at 16-17 ¶¶ 40-42. See also Kinney, TR at 41:16-21 (October 3, 2025).

[256] Staff's Post Hearing Brief at 17 ¶ 41.

ratepayers.[257] Therefore, to reconcile the methodological flaws against the benefits conferred to ratepayers, Staff recommends "prorating recovery based on the number of months each asset will serve Washingtonians (meaning the time between the in-serve date and the end of 2025) divided by the total number of months in the service life of the asset."[258]

142 Like Staff, NWEC argues that there is insufficient information in the record demonstrating that Avista met its burden to demonstrate that its costs were prudently incurred.[259] NWEC argues that Avista's NPV analysis was flawed because the Company limited its analysis to just 12 projects and assumed a single probability of failure rather than differentiating the risk of an outage between each project.[260] By improperly assuming a 100 percent probability of failure in the event that a capital asset was not pursued, NWEC reasons that Avista overstated the benefits of the plant continuing to operate without such investment.[261] NWEC further maintains that Avista failed to present contemporaneous evidence to support a prudence finding for its sixteen investments extending life beyond December 31, 2025,[262] and proposes that the Commission reject Avista's proposal to allow full recovery of such investments. NWEC also argues that Avista failed to demonstrate that it conducted a sufficient analysis of its power cost by: (1) "only focus[ing] on the benefits of investing in Colstrip in a single year as compared to what power costs would have been in that year if Avista relied on market power;" (2) "overestimat[ing] the availability of Colstrip Units 3 and 4, given the increasing frequency with which Colstrip has faced forced outages;" and (3) only considering "fuel costs, not capital investments."[263] Accordingly, NWEC requests that the Commission disregard the informal "risk-adjusted" analysis Avista incorporated in its rebuttal testimony on the basis that it did not provide evidence that it developed its analysis contemporaneously with its decision-making.[264]

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[257] Staff's Post Hearing Brief at 21 ¶ 52 citing to McGuire, Exh. CRM-1CT at 25:6-15.

[258] Staff's Post Hearing Brief at 21-22 ¶ 53 citing to McGuire, Exh. CRM-1CT at 26:13-18.

[259] Cebulko, BTC-1CT at 8:6-9.

[260] NWEC's Post Hearing Brief at 1 ¶ 2.

[261] Cebulko, BTC-1CT at 16:8-10.

[262] NWEC's Post Hearing Brief at 1-2 ¶ 3.

[263] NWEC's Post Hearing Brief at 10 ¶ 24.

[264] NWEC's Post Hearing Brief at 12 ¶ 28.

143 However, unlike Staff and NWEC,[265] AWEC and Public Counsel[266] recommend that the Commission prorate the 2024 and 2025 capital additions based on the number of months each asset will serve Washingtonians prior to December 31, 2025, and only allow recovery of costs that are prudent and used and useful.[267]

144 Avista contends on rebuttal (1) that the parties disregard the value and significant benefits customers have received from the long-lived power plant in the form of lower power supply costs during peak demand and high price events; and (2) that "[a] simple cost benefit analysis has never been the sole determinant of prudence."[268] Despite the concerns Staff and NWEC raise, Avista maintains that it did perform a cost benefit analysis and demonstrated a favorable present value of plant additions in its "hurdles sheets contained in Exhibits 4C-5C," which are "project-by-project risk assessments" that are used to aid the project operator in determining the need and timing for each capital project.[269]

145 Finally, although Avista acknowledges that it did not initially risk adjust its NPV analysis, it argues that the financial risk of having Colstrip out of service on an equipment failure would be more cost prohibitive in nearly all cases than supporting the costs of replacement.[270] To support this contention, Avista explains that when it did perform subsequent calculations to risk adjust its NPV analysis, it applied a 12.6 percent annual forced outage rate from its 2024 general rate case and removed any assumed benefits after 2025 for the 12 disputed capital projects in 2024 and 2025 and ultimately determined that the 12 projects had "a higher risk adjusted outage cost than the investment itself."[271] Thus, Avista concluded that even "a 'risk adjusted' NPV analysis

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[265] Staff's Post Hearing Brief at 21-22 ¶ 53 citing to McGuire, Exh. CRM-1CT at 26:13-18.

[266] Dreyer, Exh. JMD-1CT at 3:11-14 and JMD-2T at 3:6-18 citing to Mullins, Exh. BGM-1T at 11:18-20.

[267] Mullins, Exh. BGM-1CT at 3:11-16 and Public Counsel's Post Hearing Brief at 17 ¶ 53.

[268] Avista's Post Hearing Brief at 13 ¶ 40 citing to Kinney, SJK-11CT at 19:1-5 (emphasis in original).

[269] Avista's Post Hearing Brief at 13 ¶ 41.

[270] Kinney, SJK-11CT at 19:2-3 and 19:17-20. To support its contention Avista provides an example of a cooling tower fill replacement (Project No. 10028050-900). Avista explains that the fill replacement for Unit 4 was estimated at approximately $413,000 for its 15 percent share, and that if such repair were not performed and led to a de-rate or shut-down of the plant, obtaining replacement costs of power could range from as low as $7 million at a 12.6 percent risk of outage and be as high as $22.3 million in a high market time for just a seven day period. Avista's Post-Hearing Brief at 13-14 ¶ 42-44 and SJK-11T at 20:5-20.

[271] Avista's Post-Hearing Brief at 14 ¶44 citing to Kinney, SJK-11CT at 21:1-18 and 22:1-8.

shows that the benefits of keeping the plant fully operational throughout 2024 and 2025 far outweigh the costs" of the capital investments at issue in this proceeding.[272]

SmartBurn Projects

146 In its initial filing, Avista argues that the six SmartBurn projects are needed to allow the boiler system to continue to work to "maintain a functioning and crucial system regarding the combustion and NOx controls" since "the tips of the air ducts are subject to a furnace environment – extreme heat and coal dust abrasion – that causes the tips to distort, and in some cases fail."[273] Avista explains that Smart Burn was commissioned to study different design options to better control NOx emissions, and that the SOFA Bucket Replacement U3 and Boiler Burner AuxAir Replacement U3 systems were installed between 2007 and 2009.

147 The result of these efforts was "the design and supply of new top over fire air (TOFA) air system burners,[274] which was the work related to the SmartBurn investment previously denied by the Commission in Docket UE-200900, et. al,[275] not the work performed on SOFA and the Aux Burners.[276] Accordingly, Avista maintains that the SOFA and Aux Boiler Burners should be recoverable because they "existed prior to installation of the SmartBurn technology and would have continued to operate had the TOFA technology never been installed.[277] However, in rebuttal Avista removes the 2024 and 2025 TOFA Bucket Replacement U3 and U4 investments, which it asserts were included in error in its initial filing.[278] Additionally, Avista notes that although NWEC calls for the disallowance of SOFA, it "mistakenly places costs related to the Control Room Operator (CRO) Simulator Replacement, Project No. 10082239-900, in the same category as

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[272] Kinney, Exh. SJK-11CT at 13:18-20.

[273] Kinney, SJK-11CT at 24:9-11. See also Staff-DR-001C Supplemental Confidential Attachment A.

[274] Avista Witness Kinney explains that the Commission specifically disallowed only the TOFA ports installed in 2016 and 2017, not the SOFA Burners and Burner Aux Air System), which was installed in 2007 and 2009, well before 2017 when the SmartBurn TOFA technology was installed. Kinney, SJK-11T at 25:22 and 26:1-4.

[275] Dockets UE-200900 et.al., Final Order 08/05 at 94 ¶¶ 264-265.

[276] Kinney, SJK-11CT at 24:20-23, 25:21-23 and 26:2-4. Avista emphasizes that in that Order, the Commission only disallowed the TOFA ports installed in 2016 and 2017, not the SOFA or Boiler Aux Air System, which were installed in 2007 and 2009, well before the 2017 Smart Burn technology was installed.

[277] Kinney, SJK-11CT at 26:14-16.

[278] Kinney, SJK-11CT at 26:19-21.

SmartBurn."[279] Avista explains this is an error, because the "CRO simulator is not specific to the operation of SmartBurn equipment only," and "would have been installed whether or not Avista had invested in SmartBurn." [280] As such, Avista concludes that it should be allowed.

148 While all non-company parties initially contested Avista's request for recovery of the six discrete SmartBurn projects, following Avista's removal of the 2024 and 2025 TOFA Bucket Replacement U3 and U4 investments, Staff accepted in its post-hearing brief Avista's revised position on rebuttal.[281]

149 However, NWEC continues to recommend that the Commission "fully disallow recovery of the SmartBurn-related investments."[282] Specifically, NWEC argues that although Avista claims that its SOFA and Boiler Burner Aux investments preceded the time period that the TOFA ports were installed, and are meaningfully distinct, that Avista failed to support either contention.[283] NWEC further argues that while these two investments might not have been at issue in Avista's 2020 GRC in Docket UE-200900, et. al., the Commission's reasoning for disallowing SmartBurn in that docket should broadly apply to all SmartBurn related investments "because the Company did not 'address Staff's primary concern that SmartBurn was not required by law.'"[284] As such, NWEC concludes that the Commission should reject Avista's attempt to mischaracterize its prior decision and deem the investments imprudent.[285] Finally, in response to Avista's contention that NWEC witness Cebulko misclassified the CRO Simulator as a SmartBurn project, NWEC "now recommends that Commission classify the CRO Simulator as a life-extending investment" and disallow recovery on the basis that its useful life is longer than 3-4 years and thus should not be classified as major routine maintenance.[286]

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[279] Kinney, SJK-11CT at 17:103 citing Cebulko, BTC-1CT at 31:10-13.

[280] Avista's Post Hearing Brief at 16 ¶ 49, Kinney, SJK-11CT at 27:4-6, and Evidentiary Hearing TR at 96:10-13 (October 3, 2025) quoting Staff Witness McGuire disagreeing with NWEC's assessment ("stating…Staff does not agree with that assessment. The simulator was not part of what the Commission disallowed in its final order in the 2020 Avista general rate case.").

[281] Staff's Post Hearing Brief at 5 ¶ 11.

[282] NWEC's Post Hearing Brief at 14 ¶ 32.

[283] NWEC's Post Hearing Brief at 14 ¶ 33.

[284] NWEC's Post Hearing Brief at 14 ¶ 34 citing Dockets UE-200900 et. al, Final Order 08/05 at 94 ¶ 264.

[285] *Id*.

[286] NWEC's Post Hearing Brief at 15 ¶ 36.

150 While AWEC and Public Counsel's response testimony did not specifically address whether SmartBurn investments, previously disallowed in Avista's 2020 GRC should be recovered, each continue to support disallowance of these costs in this proceeding on the basis that they were previously determined to be imprudent.[287] However, AWEC clarifies in its post hearing brief that while it generally "supports the exclusion of SmartBurn costs previously disallowed," that "[t]o the extent the Commission finds that some or all of the SmartBurn costs have not been previously disallowed, these investments should be prorated."[288]

Commission Determination

151 During general rate case proceedings, the Commission determines the prudence of utility actions by reviewing whether the utility made reasonable business decisions in light of the facts and circumstances known or that reasonably should have been known to the utility at the time decisions were made.[289] What is reasonable requires assessment of choices made, in light of circumstances and possible alternatives, based on industry norms and practices.[290] Prudence does not require a single, ideal decision, but requires the utility to make a reasonable decision among a number of alternatives that the Commission might find prudent.[291] The prudence review "requires evaluation of the Company's decisions not just from the perspective of management for the benefit of shareholders, but also for the benefit of customers."[292] The fundamental question for decision is whether management acted reasonably in the public interest, not merely in the interest of the company.[293]

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[287] AWEC's Post Hearing Brief at 9 ¶ 18, 11 ¶23, and Dreyer, JMD-1CT 5:7-11. See also Dreyer, Exh. JMD-4C (Avista's Response to Staff Data Request No. 1C, Attachments A&B) and JMD-5 (Avista's Response to Staff Data Request No. 7).

[288] AWEC's Post Hearing Brief at 11-12 ¶ 23.

[289] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 12 at ¶ 19 (Apr. 7, 2004).

[290] *Id*.

[291] *WUTC v. Puget Sound Energy, Inc.*, Dockets UE-090704 & UG-090705 (*consolidated*), Order 11 at 119 ¶ 337 (Apr. 2, 2010).

[292] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14 at 34-35 ¶ 65 (May 13, 2004).

[293] *WUTC v. Puget Sound Energy, Inc.*, Docket UE-031725, Order 14 at 34-35 ¶ 65 (May 13, 2004) (quoting Goodman, The Process of Ratemaking, at 857).

152 The prudence standard applies to both the question of need and the appropriateness of the expenditure.[294] The Commission considers three broad questions when evaluating prudence: (1) Was the initiation of the project prudent; (2) Was the continued implementation of the project prudent; and (3) Were the expenses prudently incurred?[295] The second and third factors are examined using the same prudence test as the first factor, but applied at a different point in time and necessarily premised on a reevaluation of the project.[296] Consequently, the Commission's prudency review is not limited to a single point in time and encompasses the implementation and construction phases of a project to ensure that a regulated utility continues to reasonably control and evaluate a project.

153 As noted above, when evaluating prudence, the Commission reviews utility decision-making at the time decisions were made. Stated differently, the Commission will not use the benefit of hindsight when evaluating prudence.[297] Consequently, regulated utilities are required to maintain contemporaneous records of their decision-making process and analysis to satisfy the Commission's prudency standard.[298] A utility's "robust discussions" about a project, with a "consensus" on decisions, is not sufficient to demonstrate prudence.[299] Rather, "the parties and Commission should be able to follow the company's decision-making process, knowing what elements the company used, and the manner in which the company valued those elements. Such a process should certainly be documented."[300] "Documentation and evidence of prudence decision making must be kept contemporaneously with a company's decision making or the Commission's ability to evaluate prudence is thwarted."[301]

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[294] *WUTC v. PacifiCorp*, Docket UE-152253, Order 12 at 33 ¶ 94 (Sept. 1, 2016).

[295] Docket UE-152253, Order 12 at 34 ¶ 95.

[296] *Id* at 34 ¶ 95.

[297] *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 34 ¶ 94 (Sept. 1, 2016).

[298] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order, at 15-16 (Sept. 27, 1994) ("The company's lack of contemporaneous evaluation and documentation is, at best, poor management practice."); *WUTC v. PacifiCorp,* Docket UE-152253, Order 12 at 36 ¶ 102 (Sept. 1, 2016) ("However, this memo was prepared after the final decision to proceed was made, and therefore cannot be shown to have played a part in the Company's decision-making.").

[299] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order at 16 (Sept. 27, 1994).

[300] *WUTC v. Puget Sound Power & Light Company*, Dockets UE-920433, UE-920499, & 921262, 19th Supp. Order at 16 (Sept. 27, 1994).

[301] *In re Investigation Regarding Prudency of Outage and Replacement Power Costs*, Docket UE-190882, Order 5 at 12 ¶ 43 (Mar. 20, 2020).

154 The Commission has previously explained that its review of prudence typically focuses on four factors:

> (1) The Need for the Resource: The utility must first determine whether new resources are necessary. Once a need has been identified, the utility must determine how to fill that need in a cost-effective manner. When a utility is considering the purchase of a resource, it must evaluate that resource against the standards of what other purchases are available, and against the standard of what it would cost to build the resource itself.
>
> (2) Evaluation of Alternatives: The utility must analyze the resource alternatives using current information that adjusts for such factors as end effects, capital costs, dispatchability, transmission costs, and whatever other factors need specific analysis at the time of a purchase decision. The acquisition process should be appropriate.
>
> (3) Communication With and Involvement of the Company's Board of Directors: The utility should inform its board of directors about the purchase decision and its costs. The utility should also involve the board in the decision process.[302]
>
> (4) Adequate Documentation: The utility must keep adequate contemporaneous records that will allow the Commission to evaluate the Company's decision-making process. The Commission should be able to follow the utility's decision process; understand the elements that the utility used; and determine the manner in which the utility valued these elements.[303]

1. Prudence of the Prorated Portion of the Four SmartBurn Projects

155 Each of the non-company parties recap in their briefing and testimony the Commission's disallowance of SmartBurn NOx control system investments in Avista's 2020 GRC, in which the Commission found that "Avista failed to demonstrate that SmartBurn was necessary and failed to produce documentation sufficient to demonstrate that its costs were prudently incurred."[304] On rebuttal, Avista removed its two TOFA investments it included in its initial request in this docket in error but maintained its request for the remaining four SmartBurn projects. Avista clarified that the four SmartBurn investments it seeks to recover in this docket were related to components installed in 2007 and 2009

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[302] *WUTC v. Puget Sound Energy*, Dockets UE-111048 and UG-111049 (consolidated), Order 08 at 148 ¶ 409 (May 7, 2012) (citation omitted).

[303] *WUTC v. Puget Sound Energy*, Dockets UE-111048 and UG-111049 (consolidated), Order 08 at 148 ¶ 409 (May 7, 2012) (citation omitted).

[304] Avista 2020 GRC Order at 98 ¶¶ 264-265, 274.

and were not part of its request in its 2020 GRC.[305] Staff revised its position in its post hearing brief and now supports recovery of the four SOFA and Boiler Burner Aux Air Replacement U3 and U4 projects.

156 For Avista's remaining four SmartBurn investments at Colstrip for which it continues to request recovery, we find prudent only the used and useful portion of these investments, which corresponds to the percentage of the useful life that was in service before the CETA deadline of December 31, 2025, and that provided a benefit to Washington customers. As discussed in greater detail in subsection B.2 below, Avista's investments at Colstrip enabled Avista to provide necessary and reliable electric service to Washington customers through the end of 2025. The Company provides evidence showing that the investment decisions were made in communication with its management considering the alternative of replacement power. In addition, the four remaining SmartBurn projects for which Avista seeks recovery are related to components that were operational and found prudent prior to Avista's 2020 GRC and were not subject to the same analysis that disallowed TOFA component investments in Avista's 2020 GRC. Accordingly, we find the used and useful portion of the four investments in this docket related to the SOFA and Boiler Burner Aux Air Replacement U3 and U4 projects to be necessary and prudently incurred.

2. Prudence of the Prorated Portion of the Remaining Capital Projects

157 Consistent with our determination above for the four SmartBurn projects for which Avista seeks recovery on rebuttal, we find prudent the used and useful portion of the Company's Colstrip capital project investments, which corresponds to the percentage of the useful life of the investments in service on or before the CETA deadline of December 31, 2025.

158 The Commission disagrees that investments that extend the life of Colstrip are categorically prohibited under the prudence standard. Both Staff and NWEC cite to the Commission's order in Avista's 2020 GRC to support their argument that investments that extend the life of Colstrip must be excluded from the Company's rates.[306] However, the Commission's consideration of whether the Dry Ash Disposal project was life

[305] Kinney, SJK-11CT at 24:20-23, 25:21-23, 26:2-4, and 26:14-16.

[306] Staff's Post Hearing Brief at 10 ¶ 23; NWEC's Post Hearing Brief at 6 ¶ 15.

extending in Avista's 2020 GRC was a product of Avista's settlement obligations from a prior GRC, not a component of the Commission's general prudence standard.[307]

159 The Commission finds that the Company has sufficiently demonstrated that the used and useful portions of the Company's Colstrip capital project investments are prudent.[308] With regard to the question of need, the record provides a reasonable showing that the used and useful portion of Avista's investments at Colstrip allowed Avista to continue providing necessary and reliable electric service to Washington customers by supporting continued Colstrip operation through the end of 2025.[309]

160 Regarding consideration of alternatives, no party in this case brings forward evidence showing that any other reasonable, let alone more economically beneficial, option was available to Avista, and that it failed to pursue at the time it made the Colstrip investment decisions at issue in this docket. Similarly, no party here argues that the alternative cost of market replacement power, which Avista considered at the time of incurring these investments, would not have surpassed the costs of continuing to support Colstrip operations through the end of 2025.

161 Accordingly, while Staff and NWEC argue at length that Avista performed an imperfect cost benefit analysis, no other reasonable resource option exists in the record for comparison. The prudence standard is one of reasonableness, and here it appears that Avista chose a more reasonable lower cost alternative to provide necessary service to its customers.

162 The Commission rejects the premise that the prudence standard requires a specific form of cost-benefit analysis. While a utility must include a reasonable analysis as part of its demonstration of need and consideration of alternatives, the Commission does not require a particular type of analysis under the general prudence standard, leaving the utility with discretion to develop a cost analysis that is reasonable under the circumstances. The Commission has found previously that, while the Commission will not "preapprove" a

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[307] *WUTC v. Avista Corp.*, Dockets UE-200900, UG-200901, & UE-200894 (*consolidated*), Order 08/05 at 100 ¶ 279 (Sept. 27, 2021) ("Lastly, we are uncertain that Dry Ash is not a life-extending capital addition. Our 2019 Avista GRC Final Order approved a settlement that included an agreement by Avista not to support capital expenditures beyond routine capital maintenance costs that would extend Colstrip's operational life beyond December 31, 2025.").

[308] The Commission declines AWEC's invitation to articulate a prudence standard regarding all investments that extend the life of fossil fuel resources that departs from its longstanding prudence framework. The Commission is not persuaded that a modification of its well-established standard is necessary or warranted.

[309] Staff's Post Hearing Brief at 21 ¶ 52 citing to McGuire, Exh. CRM-1CT at 25:6-15.

particular type of analysis to support prudence, a utility risks a disallowance if it presents an analysis that has insufficient detail or otherwise lacks credibility.[310] Therefore, while cost-benefit analysis may be probative of a company's decision-making process, we reaffirm that a particular form of cost-benefit analysis is not strictly required, nor is it the only thing required, to demonstrate prudence.

163 The Commission further finds that Avista's NPV analysis is sufficiently reasonable even though it is not performed from the perspective of Washington ratepayers. While the Commission will not proscribe the type of analysis that a utility may utilize to support its showing of prudence, if such analysis is based on general rather than Washington-specific data, the utility should be able to explain how that data supports prudence from the perspective of Washington ratepayers. In some cases, there may be no distinction between the general benefit and the Washington specific benefit, insofar as the Washington benefit is a proportional share of the general benefit. But, in circumstances where the Washington benefit may materially diverge from the general benefit, such as when a resource may no longer be used to provide service in Washington, further analysis should be performed to verify that the investment is still prudent with respect to Washington ratepayers.

164 Avista provided contemporaneous documentation showing that in consultation with its board of directors in the budgeting process the Company considered the cost of replacement power in lieu of making the 2024 and 2025 plant investments at Colstrip. In addition, the favorable NPV analysis Avista conducted for the projects constitutes sufficient analysis to support the investment decisions for the portion of projects' use through the end of December 2025. Up to the CETA deadline, the NPV analysis provides a reasonable weighing of costs versus benefits that would accrue to Avista's Washington customers.

165 We agree with Staff that Avista's additional post-decisional analysis does not constitute contemporaneous documentation probative of what the Company considered when making decisions to invest in the capital projects at issue here. Nevertheless, we view the contemporaneous material Avista provided as sufficient to meet the reasonableness standard of prudence for service prior to December 31, 2025. Avista's additional analysis

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[310] *WUTC v. Avista Corp*, Dockets UE-150204 & UG-150205 (*consolidated*), Order 05 at 69 ¶ 193 (Jan. 6, 2016) ("While we do not make a decision regarding the prudence of this project in this proceeding, we note the considerable uncertainty surrounding the business case analysis Avista prepared. . . .We look forward to a more refined cost-benefit analysis in a future proceeding, including a fuller discussion of "non-quantifiable benefits" suggested by Mr. Kopzcynski.").

provides nothing more than a post hoc after-the-fact analysis that would have lent additional support, had the Company performed the analysis at the time of the decision to invest in the Colstrip capital additions.

166 Given the above discussion, the Commission finds that the Company has demonstrated a need for the prorated portions of the Colstrip assets in this case based on the NPV analysis and forecasted replacement power costs. The same evidence also supports a finding that the Company considered alternatives to continuing to fund Colstrip and that it documented its reasoning contemporaneously and demonstrates that Avista informed and consulted its management about the investment decisions related to Colstrip.

167 No party in this docket disputes that replacement power is a more expensive option to provide needed service to customers and would increase the burden and decrease benefits to ratepayers had Avista chosen to abandon the use of Colstrip electricity earlier than necessary under CETA. Thus, we find Avista's decisions to invest in the used and useful portion of its capital expenditures at Colstrip for 2024 and 2025 were reasonable and prudent.

168 As to the equity considerations raised by Public Counsel regarding Avista's request in this docket, the Commission has addressed this issue by prorating Avista's recovery of Colstrip costs.[311] Prorating Avista's recovery of investments in Colstrip promotes equity by appropriately assigning costs to Washington customers relative to the benefits that they will receive before coal-fired resources can no longer be included in Avista's allocation of electricity. The Commission's analysis in this matter is also informed by the numerous public comments filed in this docket raising concerns about affordability and opposing continued support for coal-fired resource operations past 2025 despite CETA's mandate to remove coal from the allocation of electricity.[312]

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[311] *WUTC v. Cascade Natural Gas Corp.*, Docket UG-210755, Order 09 at 19-20 ¶ 59 (Aug. 23, 2022) (retaining discretion to evaluate equity on a case-by-case basis). However, the Commission declines to consider the articles cited by Public Counsel in its briefing, as those articles are not part of the record in this case, and Public Counsel has not motioned for the Commission to take official notice of those articles or explained why they could not have been previously submitted to the record. *See* Public Counsel's Post Hearing Brief at 21-22 ¶ 64-65.

[312] *See generally* Offer of Public Comment, Exh. BR-4, Public Comment Exhibit and UTC Matrix Attachment A at 4-7.

VII. Inventory Balances

169 AWEC recommends disallowing Washington's share of Avista's Colstrip inventory balances of $4.0 million, which result from the Materials and Operating Supply Inventory in the amount of $2.8 million and the Colstrip Fuel Stock Coal Inventory (FERC Account 151.120) in the amount of $1.2 million. AWEC raises concerns about Avista's response to a Staff data request asking why the Company "increased certain inventory costs to just over $4.0 million when the 2024 values were $0." Avista responded that "it moved outstanding fuel stock and inventory balance to Colstrip tracker as a way to allow the Company to recover the balances by the end of the year 2025."[313] AWEC questions that this was the first time Avista identified these balances, and that the amounts were not included in the Company's Colstrip 99 tracker when it was first established.[314]

170 On rebuttal, Avista witness Andrews explains that AWEC is correct "that the Company had not specifically identified these inventory balances when the Colstrip Schedule 99 tracker was first established," and that it did not include these balances in its prior 2023 or 2024 Schedule 99 filings.[315] Andrews clarifies that the Materials and Operating Supply Inventory includes "essential materials and parts needed to keep the Colstrip plant running smoothly," and "covers items known to wear out or fail out during normal operations . . . to prevent forced outages."[316] The Colstrip Fuel Stock Coal Inventory a/k/a 'Dead Storage,' "allows Colstrip to maintain a 28-day reserve of coal fuel to safeguard against long-term supply disruptions from the Westmoreland mine caused by weather, equipment failure, regulations, or labor issues."[317] Andrews maintains that the reason Avista did not initially include these inventory balances was "because these balances were not [a] capitalized plant or a regulatory asset that was incurring depreciation or amortization expense.[318] While it had not been appropriate to include the expenses associated with these balances prior to the current filing, it now seeks to recoup and begin amortizing these balances through December 2025.[319]

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[313] Mullins, Exh. BGM-1CT at 11:6-16 citing to Mullins, Exh. BGM-4, Avista's Response to Staff's Data Request No. 12.

[314] Mullins, Exh. BGM-1CT at 11:6-16.

[315] Andrews, Exh. EMA-1CT at 29:6-9.

[316] Andrews, Exh. EMA-1CT at 29:19-21 and 30:1.

[317] Andrews, Exh. EMA-1CT at 30:8-10.

[318] Andrews, Exh. EMA-1CT at 30:19-21.

[319] Andrews, Exh. EMA-1CT at 31:15-30 and 32:1-17.

171 Accordingly, when Avista began the process of preparing the 2025 Schedule 99 filing and "realized it had failed to remove these inventory balances from Working Capital,[320] currently included in base rates,"[321] to proactively prevent any double recovery, Avista proposes to: [322]

> credit customers within the Colstrip Tariff Schedule 99, effective January 1, 2025, the same return amount on these inventory balances included in base rates of approximately $270,000, so as to result in a $0 impact in 2026."[323]

172 In short, with the completion of Avista's GRC in Docket UE-240006, and approval of an overall rate of return of 7.32 percent, Avista is requesting to create a separate accounting so that "the amount included in error in 2026 [totaling] $393,000," can be "credit[ed] against the 2026 Schedule 99 balances owed to and from customers – resulting in a net $0 customer impact effectively January 1, 2026."[324]

173 Given that Avista "appropriately accounted for the amortization expense in this proceeding, as well as identified the approximate amounts to refund customers in 2026 to return the 'return on' these inventory balances included in base rates in error," AWEC confirms that it is satisfied with Avista's proposed treatment concerning the outstanding Colstrip inventory amounts.[325] No other party raised any concerns or objected to the proposal Avista witness Andrews makes on rebuttal regarding recovery of the inventory balances.

Commission Determination.

174 We find Avista's proposal to account for inventory balances in Colstrip Schedule 99 to avoid double recovery from customers to be appropriate. Avista has properly accounted for the amortization expense and identified the approximate amount customers should be

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[320] Andrews, EMA-1CT at 32:25-29 and 33:1-10 (Avista explains that "the Colstrip Materials and Supplies Inventory (FERC Account 154.400) and Colstrip Fuel Stock Inventory (FERC Account 1541120) balances were inadvertently included in base rates within Washington Electric Working Capital, rather than removed from base rates and alternatively included in Colstrip Tariff Schedule 99 with the effective date of Schedule 99 on December 21, 2023. Furthermore, these inventory balances were included in Washington electric Working Capital in the Company's current general rate case UE-240006 on an AMA basis as of June 30, 2024.").

[321] Andrew, EMA-1CT at 32:18-21.

[322] Andrew, EMA-1CT at 32:18-21.

[323] Andrews, EMA-1CT at 33:5-8.

[324] Andrews, EMA-1CT at 33:10-15.

[325] AWEC's Post Hearing Brief at 13 ¶ 26.

refunded in 2026 for "the return on" the inventory balances, which were inadvertently included in base rates. However, we require Avista to provide the actual adjustment for the 2025 return and to refund the "return on" for 2026 in its compliance filing confirming the removal of the inventory balances (now amortized through Schedule 99) and from working capital in Avista's next GRC filing.

VIII. Process for Refund—True-up and Compliance Filing Requirements

175 Avista proposes a "true-up" for actual Colstrip-related costs "by updating any forecasted balances," from its 2024 and 2025 Colstrip investments, inventory balance and O&M expenses in Schedule 99 from its October 31, 2024 filing, "with the actual costs incurred during the 2025 year."[326] Specifically, after calculating the difference between forecasted and actually approved Colstrip-related costs, Avista proposes that "[i]f the actual costs are lower than revenue recovered through Schedule 99 during 2025 . . . [that] the over-collected amount would be deferred for refund."[327] However, if "the actual costs exceed the forecast, Avista will not seek additional recovery through Schedule 99 . . . as no surcharge for these costs (excluding costs associated with ARO regulatory balances and amortization expenses) are allowed beyond 2025 year-end."[328]

176 While Avista agrees with the non-company parties that any refund to customers should be determined as part of its compliance filing in this proceeding, "anticipated no later than March 31, 2026," Avista proposes "to offset this refund against expected 2026 Colstrip Schedule 99 Tariff balances."[329] Specifically, Avista proposes to submit its Colstrip Schedule 99 filing by October 31, 2025, then after performing a true-up of the final costs, reduce "the 2025 Schedule 99 tariff rate to $0 effective January 1, 2026," then during 2026 offset the actual AROM amortization and other related costs by the 2025 Schedule 99 refunds through December 31, 2026.[330] Further, Avista proposes to defer any over-collected 2025 Schedule 99 revenue or related refunds, as determined by its

[326] Avista's Post Hearing Brief at 25 ¶ 78.

[327] Avista's Post Hearing Brief at 25 ¶¶ 78-79.

[328] *Id* citing to Andrews EMA-1CT at 14:10-16 and Kinney, SJK-1T at 2:23-3:2 (explaining that any "Colstrip related costs Avista will seek to recover in rates after 2025, will be limited to costs associated with decommissioning and remediation that will go before this Commission, pursuant to RCW 19.405.030(1)(b).

[329] Andrews, Exh. EMA-1CT 18:2-6.

[330] Andrews, Exh. EMA-1CT at 18:17-19.

March 31, 2026, compliance filing, "to be submitted on or before October 31, 2026, with an effective date of January 1, 2027."[331]

177 In response, the non-company parties recommend that the Commission order Avista to recalculate its annual 2025 Colstrip Schedule 99 filing in compliance with the Commission's final determinations to ensure that customers are appropriately refunded any amounts to which they are entitled. Additionally, Public Counsel argues that since there "is time value to money," that customers are better served receiving a refund now of "excess utility rates they incurred in 2025 rather than by lower rates at an unspecified future date."[332] Public Counsel further recommends that "the Commission order a refund directly to customers as a bill credit (either a one-time basis or over a period not to exceed one year), rather than allowing the Company to credit that amount against decommissioning and remediation expenses."[333]

Commission Determination:

178 We agree with Public Counsel that "there is time value to money," and with the other non-company parties that customers will be best served by receiving the refund earlier than Avista's proposal to do so in its next Schedule 99 submittal date of October 31, 2026, effective January 1, 2027. We recognize that customers across the state, and especially those who are members of historically impacted communities and vulnerable populations, including those in Avista's service territory, are experiencing significant issues with affordability. The Commission therefore finds a timely refund is appropriate to reduce customer bills. We also understand the Company's concerns associated with cash stability in providing service to customers.

179 Accordingly, we order Avista to issue the refund due to customers in either of the following two options:

(1) as a one-time lump sum credit; or
(2) spread over a period not to exceed three (3) months with carrying costs accruing at the Company's actual, after-tax cost of debt.

180 The Commission finds it reasonable to accept Avista's proposal to submit its compliance filing on or before March 31, 2026. Avista shall submit the true-up and refund in its

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[331] Avista's Post Hearing Brief at 25 ¶¶ 78-82.

[332] Public Counsel's Post Hearing Brief at 24 ¶ 73.

[333] Public Counsel's Post Hearing Brief at 24 ¶ 74 and 25 ¶ 75.

compliance filing by March 31, 2026, as directed in this Order, and expects all Colstrip costs to be removed from Avista's Washington customer rates by the end of 2025 consistent with CETA and Avista's Colstrip Tracker Schedule 99 tariff.[334]

FINDINGS OF FACT

181 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

182 (1) The Commission is an agency of the state of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including electrical companies.

183 (2) Avista is a "public service company" and "electrical company" as those terms are defined in RCW 80.04.010 and used in Title 80 RCW and is subject to Commission jurisdiction.

184 (3) On October 31, 2024, Avista filed testimony, exhibits, and supporting documentation and proposed revisions to its rates under the Company's electric service tariff, Tariff WN U-28, Schedule 99 Colstrip Tracker.

185 (4) Avista requested an annual increase of $18.2 million, or 2.7 percent, from $23.9 million in 2024 to $42.6 million, and the Company seeks to recover that balance from customers effective January 1, 2025, over the 2025 calendar year.[335]

186 (5) On December 19, 2024, this matter came before the Commission at the Open Meeting and the Commission voted to suspend the filing.

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[334] Avista's request for revision of its Tariff WN U-28, Colstrip Tracker Schedule 99, in Docket UE-250856 is pending as of the date of this Order.

[335] Docket UE-240891, Direct Testimony of Scott J. Kinney Representing Avista Corporation, SJK-1T at 2:8-16. See also Kinney, Exh.SKJ-9C (confidential native workpapers) and SJK-10 (for non-confidential workpapers. The difference between the 2024 Tariff 99 balance for revenue requirement (AMA basis) versus the 2025 Tariff 99 balance (AMA basis) is an increase of $18.7 million. However, when the total revenue requirement runs through the rate design workpapers based on load and allocation factors, the required change in revenue is $18.2 million as provided in witness Kinney's testimony referenced above.

187 (6) On December 20, 2024, Avista filed revised tariff sheets, and the Commission issued Corrected Order 01, Complaint and Order Allowing Rates Subject to Later Review and Refund; Setting Matter for Adjudication in this docket, requiring Avista to file revised tariff pages no later than December 31, 2024, with an effective date of January 1, 2025, indicating that the increased rates are subject to refund.

188 (7) On October 3, 2025, the Commission held an evidentiary hearing before the Commissioners presided over by ALJ's Amy Bonfrisco and Ann Paisner.

189 (8) Colstrip Units 3 and 4 are coal-fired generating units.

190 (9) At 12:00 a.m. on January 1, 2026, Pacific Standard Time, Avista's ownership interest will transfer to NWE and costs associated with coal-fired generation of electricity will be removed from rates for electricity for Avista's Washington customers.

191 (10) As of January 1, 2026, Colstrip will provide no benefit to Washington electric retail customers.

192 (11) As of January 1, 2026, Colstrip will not be necessary or useful in Avista's provision of electric service to Washington customers.

193 (12) Thirteen Colstrip projects related to human health and safety provide near-term, immediate benefits that shall be included in rates.

194 (13) Avista has not demonstrated that its remaining investments in Colstrip, other than the thirteen human health and safety projects previously identified, provide any benefits to Washington customers after December 31, 2025.

195 (14) The record developed in this proceeding does not indicate when the U4 Generator Exciter and the North Cheyenne AAQ System were placed into service.

196 (15) The Commission accepts Avista's removal from its request in this docket of the TOFA Bucket Replacement U3 and U4 System Burner components.

197 (16) The Boiler Aux Burner Air System, Control Room Operator (CRO) Simulator

Replacement, and Separate Over Fire Air (SOFA) Bucket Replacement Systems U3 and U4 are not SmartBurn components that were previously disallowed in Avista's 2019 GRC Settlement, Final Order 08/05 in Dockets UE-200900 et. al.

198 (17) The record demonstrates a reasonable need for the investments in Colstrip Units 3 and 4, other than the SmartBurn TOFA components that Avista removed from its request on rebuttal. The CRO Simulator Replacement and SOFA Bucket Replacement and Boiler Burner Aux Air UE and U4 Systems may therefore be prorated up to December 31, 2025, after which the assets cannot provide any benefit to Washington customers.

199 (18) For the remaining Colstrip investments and costs, Avista has provided sufficient evidence demonstrating that it considered alternatives to its Colstrip investments and costs, consulted with its management, and contemporaneously documented its analysis.

200 (19) Avista shall issue any refund due to customers in either: (1) a one-time lump sum credit; or (2) spread the refund over a period not to exceed three months with carrying costs accruing at the Company's actual, after-tax cost of debt. Based on the analysis in this proceeding, Avista has over-collected $5.86 million. The Commission's calculation of this amount is included in Appendix A (Confidential). [336]

201 (20) Avista shall refund the return on inventory balances inadvertently included in base rates and remove the inventory balances from working capital in Avista's next GRC filing.

202 (21) Avista shall recalculate its annual 2025 Schedule 99 filing in compliance with the Commission's final determinations to ensure customers are appropriately refunded for any amounts Avista over-collected.

203 (22) The Commission finds it reasonable to accept Avista's proposal to submit its compliance filing with the true-up and customer refund consistent with the direction in this Order on or before March 31, 2026.

[336] Appendix A (Confidential) shall be provided to Avista and parties that have signed the protective order agreement and shall be posted to the docket.

CONCLUSIONS OF LAW

204 Having discussed above all matters material to this decision, and having stated the following summary conclusions of law, incorporating by reference pertinent portions of the preceding detailed conclusions:

205 (1) The Commission has jurisdiction over the subject matter of, and Parties to, this proceeding.

206 (2) Avista is an electric company and a public service company subject to Commission jurisdiction.

207 (3) Avista bears the burden to demonstrate that its provisional rates subject to refund are fair, just, reasonable, and sufficient. The Commission's determination of whether the Company has carried its burden is determined based on the full evidentiary record.

208 (4) Avista has not demonstrated that the rates allowed to go into effect January 1, 2025, subject to refund, are fair, just, reasonable, and sufficient.

209 (5) Colstrip Units 3 and 4 are coal-fired resources as that term is defined in RCW 19.405.020(7)(a).

210 (6) After a careful analysis considering the canons of statutory interpretation, we interpret the terms "retired" and "retirement" in RCW 19.405.030(3) in accordance with Section II above.

211 (7) The provisions of CETA apply to the proceedings in this docket because we find that the Company will have retired Colstrip Units 3 and 4 pursuant to RCW 19.405.030(3) by 12:00 a.m. January 1, 2026.

212 (8) The A&A Agreement between Avista and NWE is not subject to Commission approval under RCW 80.12.020 because, pursuant to RCW 19.405.030(1)(a)'s requirement that coal-fired resources be removed from Avista's allocation of electricity on or before December 31, 2025, Colstrip Units 3 and 4 will not be able to provide any benefit to Avista's Washington customers.

213 (9) The Commission should reject the request to have Avista file the A&A Agreement for Commission approval pursuant to RCW 80.12.020.

214 (10) The Commission should require Avista, as a condition of this order, to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 67.

215 (11) The 13 human health and safety investments in Colstrip are fully used and useful.

216 (12) Avista has not demonstrated that its remaining capital investments in Colstrip are used and useful for service in Washington after December 31, 2025.

217 (13) The Commission should disallow a prorated portion of the Colstrip capital investments based on the portion of the investment's useful lives in service prior to December 31, 2025.

218 (14) Avista shall file an update to this docket detailing when the U4 Generator Exciter and the Northern Cheyenne AAQ System were placed into service along with all supporting documentation. If either asset was placed into service prior to December 31, 2025, Avista should be allowed to recover a prorated portion of the costs associated with those investments, consistent with the proration methodology described in paragraphs 129-130.

219 (15) The TOFA Bucket Replacement U3 and U4 System Burner components of the NOx control system was previously disallowed in Avista's 2019 GRC Settlement, Final Order 08/05 in Dockets UE-200900 et. al, and are imprudent.

220 (16) Avista's remaining investments and costs related to Colstrip that are not disallowed as not used and useful are prudent.

221 (17) Avista should be required to refund over-collected revenue in accordance with our determination in Section VIII of this Order. The computation of the over-collected amounts are attached to this Order as Appendix A (Confidential).[337]

222 (18) Avista shall file its final regulatory accounting for all Colstrip costs, including true-up and refund consistent with the direction in this Order, as of December 31, 2025, on or before March 31, 2026, and other interested parties shall have the opportunity to review and respond to such filing.

223 (19) This Order fully and fairly resolves the issues in these dockets and is in the public

[337] Appendix A (Confidential) shall be provided to Avista and parties that have signed the protective order agreement and shall be posted to the docket.

interest.

224 (20) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order.

225 (21) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order.

ORDER

THE COMMISSION ORDERS:

226 (1) The proposed tariff reviews Avista Corporation d/b/a Avista Utilities filed on October 31, 2024, and suspended by prior Commission Order, are deemed approved, subject to the condition set forth in paragraph 67 of this order.

227 (2) Avista is authorized and required to make compliance filings in this docket including all tariff sheets that are necessary and sufficient to effectuate the terms of this Order. Avista shall file its final regulatory accounting, including true-up and refund consistent with the direction in this Order, for all Colstrip costs as of December 31, 2025, on or before March 31, 2026.

228 (3) Avista is required to comply with the condition for review of future agreements transferring assets for the purpose of complying with a requirement of CETA, as described in paragraph 67.

229 (4) As a condition of compliance with this order, Avista is required to submit an update to this docket indicating when the U4 Generator Exciter and the Northern Cheyenne AAQ System, with supporting documentation, and the record should be reopened for the limited purpose of incorporating this information. If the assets were placed into service prior to December 31, 2025, Avista is authorized to recover a prorated portion of the value of those assets, consistent with the methodology described in paragraphs 129-130.

230 (5) Avista is required to refund over-collected revenue in accordance with our determination in Section VIII of this Order.

231 (6) Avista is required to file its final regulatory account for all Colstrip costs as of

December 31, 2025, as part of its Schedule 99 annual filing on or before October 31, 2026, consistent with the guidance in this Order. As part of such filing, other interested parties shall have the ability to review and contest Avista's investments.

232 (7) The Commission Secretary is authorized to accept by letter, with copies to all Parties to this proceeding, filings that comply with the requirements of this Order.

233 (8) The Commission retains jurisdiction to effectuate the terms of this Order.

Dated at Lacey, Washington, and effective December 19, 2025.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION



BRIAN J. RYBARIK, Chair



ANN E. RENDAHL, Commissioner



MILTON H. DOUMIT, Commissioner

NOTICE TO PARTIES: This is a final order of the Commission. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 or RCW 81.04.200 and WAC 480-07-870.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-69:
Power Council Overview

Northwest **Power** and
Conservation Council



Established to inform and advance a regional vision for power and fish and wildlife in the Columbia Basin

REGIONAL POWER PLAN

The Council develops a 20-year Power Plan, revised every five years, that ensures the Northwest has an adequate, efficient, economical, and reliable power supply.

Key components of the plan include:

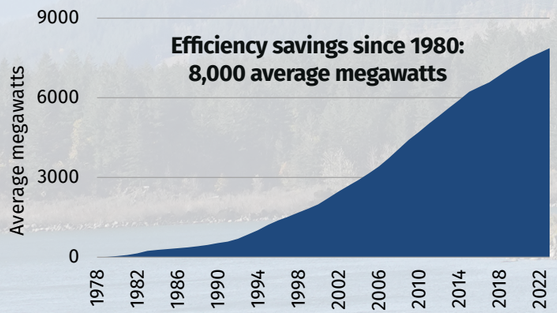
- Electricity demand forecast
- Electricity and fuel price forecasts
- Assessment of cost-effective energy efficiency and demand response
- Least-cost generating resources portfolio
- Ensuring the resource strategy meets the Council's adequacy metrics and thresholds (these standards protect the Northwest power supply's adequacy at peak demand periods)

Bonneville Power Administration funds the Council's work and must act consistently with the Council's plan when acquiring resources. The Council's power planning under the Northwest Power Act emphasizes cost-effectiveness and flexibility, mitigating risk in electric power investments, and ensuring the system's reliability and adequacy. The Power Plan offers regional insights to utilities and regulators.

The Council is in the process of developing its Ninth Power Plan, with a goal of releasing a draft to the public by mid-2026 and adopting it by the end of that year. Challenges include significant regional load growth and a shifting resource mix. Growth in demand for electricity is being driven by data centers, electric vehicles, regional population and economic growth, electrification of buildings, and other sectors.

COST-EFFECTIVE ENERGY EFFICIENCY

Energy efficiency plays a key role in reducing electricity consumption and making loads more flexible and easier to manage in the Northwest. Over the past several decades, energy efficiency has been a go-to way to meet demand at costs much lower than building new plants. This has been an ideal fit with the low-cost, reliable hydropower generated by the Columbia River. Over the past 20 years, power supply shortages have been rare in the Northwest – even as extreme weather events have increased – while regional power costs remain among the lowest in the U.S.



Thanks to effective implementation of the Council's past power plans, the Northwest is a national leader in acquiring cost-effective energy efficiency.

Since 1980:

- The region has met more than half its load growth with energy efficiency
- Almost 8,000 average megawatts has been saved, enough power for more than seven Seattles or the average annual output of three Grand Coulee dams
- $5 billion saved in lower bills for energy consumers and avoided energy costs



COLUMBIA RIVER BASIN FISH AND WILDLIFE PROGRAM

The vision: A Columbia River ecosystem that sustains an abundant, productive, and diverse community of fish and wildlife.

The Council's Columbia River Basin Fish and Wildlife Program represents a 40-year effort to protect, mitigate and enhance salmon and other fish and wildlife in the basin affected by the hydropower system. It is one of the largest mitigation efforts in the world. The Council has tracked important progress on goals and objectives, but significant work still remains.

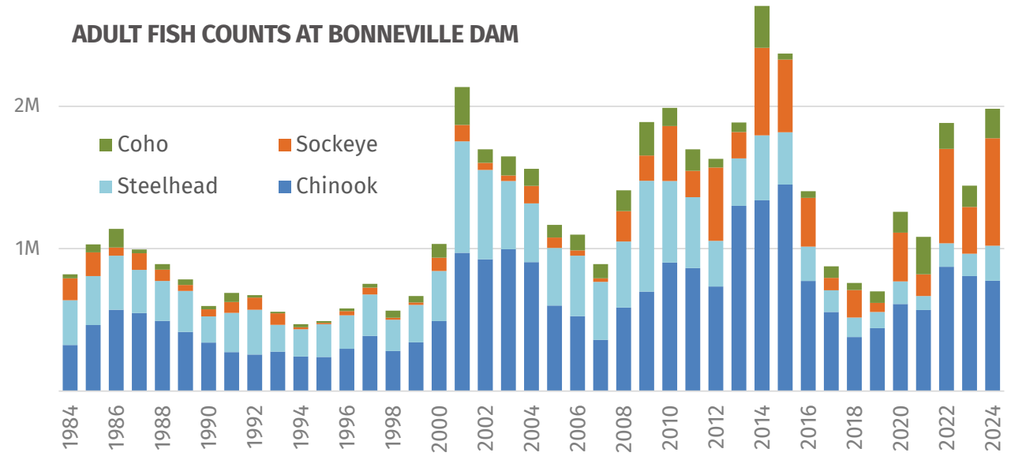
The Program incorporates a variety of strategies, including recommendations for dam operations that improve conditions for fish passage and survival, habitat mitigation, and hatcheries. Target species include salmon, steelhead, and resident fish such as sturgeon and bull trout.

The Council updates the Program every five years based on recommendations from state and federal agencies, tribes, and others. Relevant projects are reviewed by an independent scientific panel.

To date, the Program has:

- Improved water management, flow, and passage to protect and increase survival at Columbia and Snake River dams
- Protected more than 300,000 acres of habitat through purchase or conservation easement*
- Improved over 760,000 acres of habitat through restoration actions**
- Protected 44,000 miles of undammed Northwest rivers and streams

* 1992-2022 ** 2005-2021





In 1980, Congress passed the Northwest Power Act, authorizing the states of Idaho, Montana, Oregon, and Washington to form the Northwest Power and Conservation Council, an interstate compact agency, giving the region a greater voice in how we plan our energy future in the Pacific Northwest and manage natural resources in the Columbia River Basin.

The Act requires the Council to develop, with broad public participation, a regional power plan and a fish and wildlife program.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-70:
Power Council 2021 Power Plan



THE 2021 NORTHWEST POWER PLAN

Northwest **Power** and **Conservation** Council

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document 2022-3 / March 10, 2022

Section 1: Introduction

Electricity generating resources in the Northwest – carbon-free hydropower and nuclear, gas, coal, wind, and solar – plus energy efficiency – have served the region's electricity needs well, providing capacity and energy supporting a reliable, adequate, efficient, and economical power system. In the years since the Council last revised the power plan, however, the power system has experienced changes that place more emphasis on renewables, such as wind and solar generation.

In this 2021 Power Plan, the Council recognizes those states that have requirements and policies pursuing emission reductions that support cleaner electricity generation. Influenced by these policies, this plan includes significantly more renewable generation than all our previous power plans. The Power Act requires that the Council review the plan at least every five years. For this reason, the Council's work focuses most intently on the period between its release and the next one – the time we call the action plan period. However, the plan's forecast through 2041 indicates the region can expect a more substantial transformation in the fleet of regional resources used to generate electricity. Through this transformation into the future, hydropower and energy efficiency will continue to be a fundamental part of the region's power system.

The plan recognizes that there are social, political, and economic drivers leading to the region's turn toward cleaner sources of generation, primarily wind and solar. These intermittent or variable technologies are becoming less expensive to build and are seen as the primary path to reducing emissions associated with generating electricity. This emerging paradigm shift in how the region produces electricity is addressed in the plan's resource strategy. To forecast the potential impacts of this shift, the plan reflects the results of several energy models, public policy, technology, a blend of climate change assumptions, and economics in preparing for the action-plan period and for the longer 20-year plan.

This paradigm shift's attendant risks and the critical importance of reliability raises reasonable questions about the amount of future development of the low-cost renewable resources called for by the plan and the availability of transmission capacity needed to move these resources to load centers. There is also uncertainty regarding whether Western market resources identified by the plan will be available to the region when needed to reduce costs or meet

demand, in particular those periods when reliability is at greater risk. Electrification-focused policies in certain states could potentially increase utility loads rapidly, requiring building resources beyond the recommendations laid out in the plan. The plan's recommendations balance a range of uncertainty described both by the underlying analytical work and the wide-ranging expert assessment considered by the Council. These uncertainties that expose anxiety over meeting regional demand with a rapidly evolving electric system have been addressed by the plan using the best information available to the Council and its advisory committees. As the future unfolds, the Council recognizes that new information could prompt reconsideration of the recommendations and that the Council's work to monitor and evaluate the region's evolving system and policies must keep pace and not be tied to traditional timelines.

The Council's work has focused on developing a resource strategy during a time when the region is undergoing significant changes and uncertain futures. This strategy will assure the region an efficient, adequate, economical, and reliable power supply that is available, sufficiently dispatchable, and deliverable within the region's transmission system, where electricity is produced to where it is needed. The Council's work also indicates that as more intermittent or variable generation from wind and solar power is added to the system, a corresponding increase in reserves is necessary. These reserves are accommodated by our existing hydropower, gas, nuclear, and remaining coal generation. In the end, the region's resources must be instantaneously balanced with the region's demand to reliably provide electricity across the entire Northwest power system.

The 2021 Power Plan contains 12 sections that provide more detail and specifics on its components. Section 6 details new and existing resources anticipated to meet future demand for electricity. Our work indicates that the region's large amount of hydropower, nuclear, and traditional thermal resources, including those that burn natural gas and coal, remain an essential part of providing reliable electricity for the region. We also expect that continued acquisition of energy efficiency now and in the future will play a critical role in meeting the region's future demand for electricity. As the Western electricity market changes in such fundamental ways, one thing remains true and certain: Energy efficiency is a very important and fundamental way to address resource adequacy, and its contribution to capacity makes it an important resource during periods of uncertainty. In addition, the future system will be supported by the ongoing development of new renewable resources that are anticipated to provide needed energy while reducing greenhouse gas emissions. We also recognize new demand response opportunities that can

be expected to support and reduce system capacity needs. Finally, trading electricity with our neighboring regions in energy markets will continue to support current and future reliability.

The plan is intended to help transition the region into a new paradigm of cleaner energy that includes the use of our abundant hydropower, existing gas, nuclear, and remaining coal generation to provide reliability during the action plan period, while also integrating current and expected future renewables into the power system. As we look to the future, we anticipate that the transition to a new paradigm will be accompanied by risk and uncertainty. The region has dealt with and overcome risk and uncertainty in the past, and it can be expected to do so in the future. Through ranges in values (e.g., natural gas price forecasts, hydro conditions) and in scenario analyses, the plan embraces and addresses uncertainty and risk and provides a strategy for a low-cost, reliable, and adequate system to meet the electricity needs of this time. Implementing the strategy in this plan will require the same flexibility and collaboration used in the past to address the challenges of a new era, while maintaining the reliability expected by Northwest electricity customers.

The Council's work to monitor and evaluate the region's evolving system and policies will keep pace with new data and analysis in this rapidly changing industry. Any changes or unexpected developments will be reported as available, and reflected in the 2021 Power Plan's mid-term assessment.

Section 2: Power Act Requirements and the Power Plan

In December 1980, in direct response to a set of linked problems the region faced concerning increasingly difficult resource issues and the decline of Columbia River salmon and steelhead runs, Congress enacted a comprehensive and innovative legislative solution–the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). The Northwest Power Act was enacted 1) to encourage conservation and efficiency in the use of electric power and the development of renewable resources within the Pacific Northwest; 2) to assure the Pacific Northwest an adequate, efficient, economical, and reliable power supply; 3) to provide for the participation and consultation of states, local governments, consumers, customers, users of the Columbia River system, federal and state fish and wildlife agencies, Indian tribes, and the public at large in the development of regional plans and programs, facilitating orderly planning of the region's power system, and providing environmental quality; and, 4) to protect, mitigate, and enhance the fish and wildlife of the Columbia River and its tributaries, including related spawning grounds and habitat.

The Act was groundbreaking in its use of the Federal Columbia River Power system to achieve cost-effective conservation, its prioritization of conservation and renewable resources, its fish and wildlife protection and mitigation obligations, as well as its required considerations of environmental quality, and, ultimately, its regional power planning process. Remarkably, the Act also implicitly recognized the inherent uncertainty in planning for a future electric power system, with its power planning provisions and planning process providing a venue to accept and manage that uncertainty.

To carry out the Act's purposes, the Northwest Power Act authorized the states of Washington, Oregon, Idaho, and Montana to form an interstate compact agency–the Council–and directed the Council to: 1) prepare and review a "regional conservation and electric power plan" not less than once every five years; 2) prior to each plan, prepare and periodically amend a program

to protect, mitigate, and enhance fish and wildlife affected by the Columbia River Basin hydropower system; and 3) develop both the power plan and the fish and wildlife program in a highly public process with broad consultation and participation.

Beyond charging the Council with these specific responsibilities, the Act also specifies, in Sections 4(d) through 4(g) of the Act, the process the Council is to follow in developing and amending the plan; what the Council must include in the power plan; what the Council must do prior to the review of the power plan (undergo a separate process to develop or amend the fish and wildlife program addressed in Section 4(h)); and finally, in Sections 4(d)(2) and Section 6(a) through 6(c), how the Bonneville Power Administration is to use the power plan in implementing conservation measures and acquiring new generating resources.

Public Engagement and Process for Developing the Power Plan

While the Council is directed to prepare a regional conservation and electric power plan, a corresponding directive to the Council, and principal purpose of the Act, is to provide for broad public participation and consultation in the development of that power plan; Sections 4(d)(1) and 4(g) describe how the Council is to implement this mandate and engage the public throughout development and review of the power plan.

Per section 4(g)(3), in the preparation, adoption, and implementation of the power plan, the Council and the Bonneville Power Administration administrator (Bonneville), must encourage the cooperation, participation, and assistance of appropriate federal agencies, state entities, political subdivisions, and Indian tribes. And, Sections 4(g)(1) and (2) add that the Council and Bonneville, in forming regional power policies, must maintain comprehensive programs to inform the public of major regional power issues, obtain public views concerning major regional power issues, and secure advice and consultation from Bonneville's customers and others. Further, the Council and Bonneville must consult with Bonneville's customers, include the comments of such customers in the record of the Council's proceedings for the power plan and fish and wildlife program, and recognize and not abridge the authorities of state and local governments, electric utility systems, and other non-federal entities responsible for the planning, conservation, supply, distribution, and operation of the electric generating facilities.

In practice, these provisions result in a multi-year, highly public process to develop the Council's regional conservation and electric power plan. For the 2021 Power Plan, the Council officially began the power planning

process in February 2019 with a webinar that was open to the public and provided information regarding the history of the Act, the planning process, and opportunities for public participation, including through the Council's advisory committees, groups of technical and policy experts from around the region. Early and throughout the process, the Council utilized these advisory committees to gather information on priority issues for the region; conduct analytical work for the power plan; and discuss and review the findings for the power plan.

All advisory committee meetings, and their materials, are open to the public, with broad public notice provided through the Council's website and email distribution lists. The Council discussed substantive issues in its power committee and at regularly scheduled full Council meetings. All meetings are open to the public, again with broad public notice provided through the Council's website and via email distribution, with opportunities for public comment during full Council meetings. In addition, the Council welcomed comment and informal participation and collaboration throughout the planning process through one-on-one meetings with staff and written communications. The comments provided through these opportunities were closely considered by the Council and informed the development of the power plan.

Once the draft power plan is issued, Section 4(d)(1) of the Act requires that the Council hold public hearings on the draft power plan in each of the Northwest states. In addition to the public hearings required under the Power Act, the Council also largely follows the notice and comment procedures of the federal Administrative Procedures Act. Therefore, the Council also provides wide public notice of the draft power plan and ample opportunity to submit written comments, as well as opportunities to provide comment at regularly scheduled monthly Council meetings and testimony at the public hearings. Further, the Council uses this public comment period to conduct consultations with Bonneville, Bonneville's customers, Indian tribes, state and federal agencies, and non-governmental entities to solicit their advice and comment as contemplated under Section 4(g).

Lastly, as a component of the final power plan, the Council explains and describes how comments were considered and responded to during the development of the power plan, including any changes from draft to final. While the process presents unique challenges, broad public participation, engagement, and consultation remain constant in the development of each plan.

Substantive Considerations and Elements in the Power Plan

Section 4(d)(1) provides the basic directive to the Council–to prepare, adopt, and transmit to Bonneville a regional conservation and electric power plan. However, Sections 4(e) and 4(f) provide the substantive priorities, considerations, and elements that the power plan must contain. Section 4(e)(1) specifies that the power plan is to give priority to resources that the Council determines to be cost-effective, with priority given first to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency, and fourth to all other resources.[1] Given this set of priorities, Section 4(e)(2) then focuses on what the Council is to deliver in its power plan, and that is a "scheme for implementing conservation measures and developing resources…to reduce or meet the Administrator's [Bonneville's] obligations." Further, Section 4(e)(2) requires that the Council must develop this resource scheme (or resource strategy) "with due consideration for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) other criteria which may be set forth in the plan." Therefore, taken together, these provisions require that the Council develop a cost-effective resource strategy to reduce or meet Bonneville's obligations, and, in doing so bring each of these considerations to bear.

Section 4(e)(3) lists the following specific elements the Council is to include in the power plan, but leaves it to the Council to describe the elements "in such detail as the Council determines to be appropriate":

A. An energy conservation program, including model conservation standards

B. Recommendations for research and development

C. A methodology for determining quantifiable environmental costs and benefits under Section 3(4) of this Act [definition for cost-effective]

D. A demand forecast of at least 20 years, to be developed in consultation with Bonneville, customers, states (including state agencies with ratemaking authority over electric utilities), and the public,

1 Cost-effective is defined in the Act in Section 3(4)(A), and a resource is cost-effective if it has an "estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof." Therefore, cost-effectiveness is a comparative exercise of resources.

in such a manner the Council deems appropriate, and a forecast of power resources estimated by the Council to be required to meet the administrator's obligations and the portion of such obligations the Council determines can be met by resources in each of the priority categories. The forecast of power system resources shall also include (i) regional reliability and reserve requirements, (ii) the effect, if any, of the requirements of the Council's fish and wildlife program on the availability of resources to Bonneville, and (iii) the approximate amounts of power the Council recommends should be acquired by Bonneville; this may include, to the extent practicable, an estimate of the types of resources from which such power should be acquired

E. An analysis of electricity reserve and reliability requirements and cost-effective methods of providing reserves designed to insure adequate electric power at the lowest probable cost

F. The fish and wildlife program promulgated prior to the power plan by the Council under Section(h) of the Act

G. Any surcharge recommendation relevant to implementation of the model conservation standards and a methodology for calculating the surcharge

Lastly, Section 4(f) provides and details the model conservation standards to be adopted into the plan and the associated surcharge authority, both addressed as elements of the plan in Section 4(e)(3). While the Act prescribes the elements, it also provides the Council with a substantial amount of discretion to use its expertise to develop and craft these elements for each plan.

For this power plan, the Council decided to structure the plan in such a way that each plan section corresponds with an element identified under the Act. For example, Section 5 details the energy conservation program and Section 9 details the cost-effective methods of providing reserves, while Section 6, Resource Development Plan, comprehensively describes the resource strategy for the 2021 Power Plan. However, specific components from the energy conservation program are also included in the resource strategy discussion of Section 6, as well as analysis and findings from the cost-effective methods of providing reserves detailed in Section 9, which illustrates the way each of these elements work together to inform the Council's power plan.

Relationship of the Power Plan to the Region and Bonneville

As noted above, per Section 4(d)(1), the Council is to prepare, adopt, and transmit to Bonneville a regional conservation and electric power plan, and, per Section 4(e)(2), the Council's power plan is to set forth a "scheme for implementing conservation measures and developing resources… to reduce or meet the Administrator's obligations." Therefore, under the Act, the Council's power plan must consider the entire region while planning for Bonneville's resource obligations. This is because when adopting the Northwest Power Act, Congress envisioned that Bonneville, the federal power marketing agency selling the electrical power produced by the Federal Columbia River Power System, would be the major engine for adding new resources as needed for the region and the purposes of the Act would be achieved through the use of the federal system. Thus, Sections 6(a)(2)(A) and (B) of the Act authorize and obligate Bonneville to acquire sufficient resources to (A) meet the agency's contractual power sales obligations and (B) to assist the agency in meeting the requirements of Section 4(h) of the Act, which is the Council's fish and wildlife program. Moreover, Section 4(d)(2) and Sections 6(a), 6(b), and 6(c) tie Bonneville's implementation of conservation and acquisition of new resources directly to the Council's power plan by requiring that Bonneville's resource acquisitions and conservation implementation be consistent with the Council's power plan, with certain narrow exceptions.

Accordingly, the Act requires the Council to include in the power plan a number of elements concerning Bonneville's resource acquisitions, specifically: A resource strategy to reduce or meet Bonneville's obligations (Section 4(e)(2)); an energy conservation program to be implemented under the Act (Section 4(e)(3)(A)); and a forecast of power resources estimated by the Council to be required to meet Bonneville's obligations and the portion of such obligations the Council determines can be met by resources in each priority category.

The forecast is required to include the approximate amounts of power the Council recommends Bonneville acquire on a long-term basis and may include, to the extent practicable, an estimate of the types of resources (Section 4(e)(3)(D)). For the 2021 Power Plan, to more explicitly recognize this relationship between the Council's power plan and Bonneville, the Council included specific plan sections for Bonneville (See Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity and Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation).

Even though the only legal link provided in the Northwest Power Act to the Council's power plan is to Bonneville and its resource acquisition decisions and conservation implementation, because Bonneville is the primary provider and marketer of electric power in the region, the Council's power plan necessarily affects those entities that purchase power from Bonneville. In addition, the State of Washington's Energy Independence Act tied Washington utilities' conservation potential directly to the Council's methodology for conservation. The Council's power plan is also an influential resource for other entities making resource decisions, as well as for legislators, regulators, and state energy offices around the region. The power plan remains a proper venue for examining the potential implications of policy decisions on the regional system, and how to plan and manage in the face of uncertainty.

Fish and Wildlife Program

One final important piece of the Council's power plan is the development of the Council's fish and wildlife program pursuant to Section 4(h) of the Act. Specifically, Section 4(h) requires that the Council, "prior to the development or review of the plan, or any major revision thereto," call for recommendations from state and federal fish and wildlife agencies and tribes and adopt or amend a program to protect, mitigate, and enhance fish and wildlife, including related spawning grounds and habitat, affected by the development and operation of any hydroelectric facilities on the Columbia River and its tributaries. The fish and wildlife program process is heavily circumscribed, with the recommendations requested at the start of the process becoming the base from which the Council builds the program.

Per Section 4(e), the Council's fish and wildlife program is an element in the Council's power plan, and the Council has an obligation to develop the power plan's resource strategy with due consideration for the protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish. Additionally, pursuant to Section 6 of the Act, Bonneville has an obligation to acquire sufficient resources consistent with the Council's plan to not only reduce or meet the administrator's obligations but to also meet the fish and wildlife protection and mitigation requirements reflected in the Council's fish and wildlife program. Thus, the Council's fish and wildlife program necessarily comes before the Council's power plan so that the Council may determine the non-power constraints on the hydrosystem necessary to protect, mitigate and enhance fish and wildlife, and then use the power planning

process to assure an adequate, efficient, economical, and reliable power supply for the region. Sections 11 and 12 further discuss the integration and consideration of the fish and wildlife program.

Supporting Materials

Throughout this power plan, there are references to supporting materials–information, data, and analysis–that provide the basis for the conclusions, recommendations, and explanations in the plan. For example, Section 5 describes the conservation program, which is a required element of the power plan; however, sitting beneath Section 5 in the supporting materials is data and analysis to inform the conservation program, including the Council's methodology for estimating the energy efficiency resource potential for the region, estimated energy efficiency potential by sector, as well as the energy efficiency supply curve bins and workbooks. For another example, Section 6 provides the resource strategy, and sitting beneath that section are supporting materials providing detailed information and analysis on the existing system, potential system needs, and resource costs developed in the supporting materials. These are just a few examples of the data and information found in the supporting materials that support the power plan's recommendations and explanations addressing each of the required elements outlined in the Power Act. The supporting materials are available for review at: nwcouncil.org/2021powerplan_sitemap

Section 3: Demand Forecast

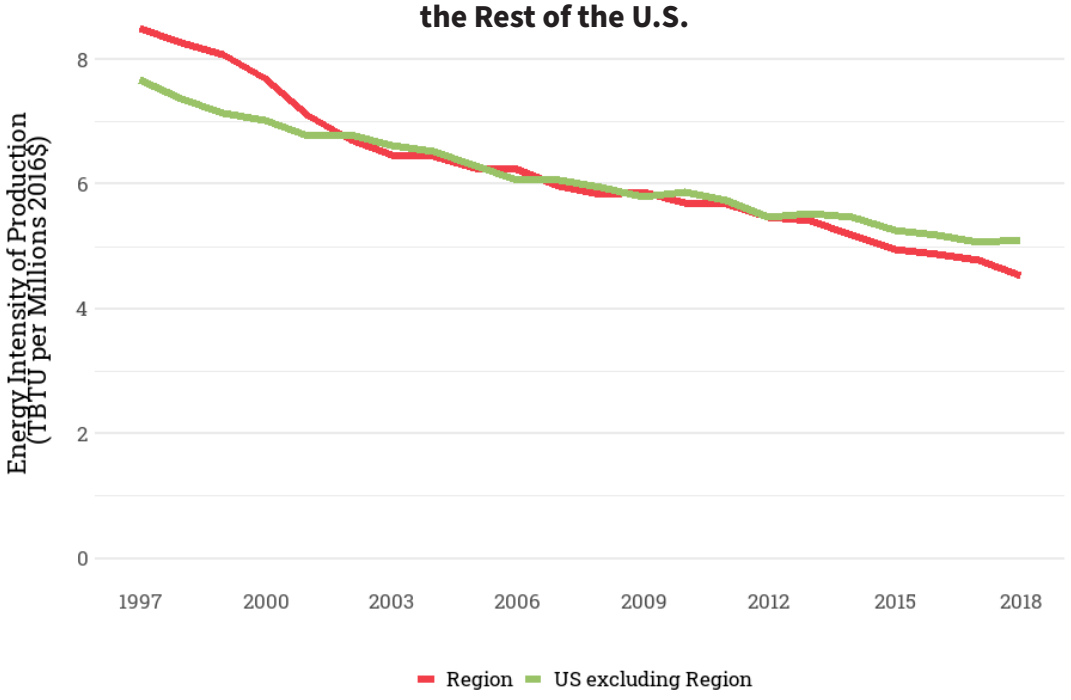
The Evolving Role of Electricity in the Northwest

Electricity is so ubiquitous it's often overlooked. Our economy would hardly function without electricity. But increasingly, society is looking to electricity as a solution to reducing greenhouse gas emissions. Whether in electrification of light-duty vehicles or reducing fossil-fuel use in industrial applications, the use of electricity is broadening rapidly. At the same time, technologies like LED lighting have greatly increased the efficiency of long-standing uses for electricity.

The Northwest historically had industries with higher energy consumption than the rest of the United States, but that shifted over the last couple of decades. Now the regional consumption of energy is lower than the rest of the United States per dollar of production.

Increasing the efficiency of our energy use and expanding the electricity available at a

Energy Intensity of Regional Production is Falling Faster than the Rest of the U.S.



reasonable cost helps both grow the regional economy and accomplish the region's goals for reducing greenhouse gas emissions. An important requirement of the power plan is the development of a demand forecast. The Council develops a demand forecast for both electricity and natural gas use in homes and buildings and examines both risks and opportunities in its forecast.

Potential New Sources of Load

Transportation – the movement of people and goods – is a large energy consumer. According to the U.S. Energy Information Administration, as much as 28 percent of all the energy consumed annually is for transportation, and most of that energy is delivered from petroleum-based fuels like gasoline and diesel. As a result, total greenhouse gas emissions from the transportation sector have reached parity with the emissions associated with electricity generation. Light duty plug-in electric vehicles provide better efficiency and lower fuel and maintenance costs than their gasoline counterparts and are gaining favor with the consumer. Electric passenger vehicles are also gaining favor with state clean policymakers as the vehicles have zero tailpipe emissions and are poised to disrupt the automobile and petroleum-product business models over the next decade.

For the 2021 Power Plan, we have developed a forecast of transportation and its related fuel usage. In the near term, the electrification of light duty cars, trucks, and vans results in cleaner and more efficient use of energy. Over the longer term (more than 10 years), heavy-duty vehicles, like long-haul trucks, offer further opportunity to electrify. Heavy vehicles are more challenging for plug-in battery technologies. The development of hydrogen fuel-cell powered trucks may become key for continued electrification of transportation, and the associated production of hydrogen required to fuel these vehicles could result in significant growth in the demand for electricity in the region.

The Council recommends policymakers and utilities that are pursuing regional emissions reductions utilize strategies that increase the adoption and use of zero- or low-emission vehicles. Battery electric vehicles are especially suited to meet passenger car and light truck requirements. Consumers in some areas within the region may be more concerned with range anxiety related to reduced battery electric vehicle performance in severe cold weather. Plug-in hybrid vehicles with gasoline engine range extenders, or hydrogen fuel cell vehicles may provide a better option. The hybrid and fuel cell vehicle technologies may also provide a solution for some heavy-duty vehicles like delivery trucks and large freight trucks. As these strategies are pursued, we recommend working with the Council, other regional bodies, and power planners to ensure an adequate electric system through the vehicle stock transition.

Direct Use of Natural Gas Forecast

To form a more comprehensive understanding of expected regional emissions, we forecast the need for energy end-uses like transportation or space heating. An end-use is the need or purpose that is served by energy, such as electricity delivered over the electric distribution system, gasoline bought from a fueling station, or natural gas delivered by a pipe to a home or a business. We then estimate the proportion of the different end-uses that are served by different types of fuel. A residence can be heated either by a heat-pump that uses electricity or a furnace that burns natural gas.

End-use consumption of natural gas tends to be seasonal, with peaks in the winter months and lulls in the summer. Homes with gas hookups are the largest consumer of natural gas. Many residences use a gas furnace for heating during the winter, and roughly 75 percent of the residential usage occurs in the months of November through March. Overall, the forecast is showing slight growth in the end-use of natural gas through the planning horizon; roughly 0.5 percent per year on average.

Renewable Natural Gas

Renewable Natural Gas (RNG) is biogas that has been conditioned and upgraded so that it can directly displace fossil natural gas. The ability of RNG to replace fossil natural gas use is limited in scope – recent studies suggest that regionally produced RNG could replace less than 10 percent of the natural gas end-use demand.[2] For this power plan, the Council modeled a blended RNG/ fossil gas supply as part of the forecast for end uses. This blend reflects the impact of regional RNG supply entering the existing natural gas pipeline system and displacing conventionally sourced fossil natural gas that is currently imported from Canada and the U.S. Rocky Mountain region.

The end combustion of RNG emits CO_2 just like fossil natural gas, and it is not always a net zero carbon product as its carbon intensity varies by feedstock. RNG, however, generally provides a lower carbon footprint than fossil natural gas. RNG that is produced from organic waste streams that

Forecast of End-Use Natural Gas Consumption

Units in TBTU	2020	2025	2030	2035	2040	2045
Total Natural Gas	478	476	460	508	510	533
Fossil Natural Gas	478	473	451	487	479	492
Renewable Natural Gas	0	2	9	21	31	41

2 nwcouncil.org/2021powerplan_renewable-natural-gas

would otherwise release methane directly may be especially beneficial because the warming potential of methane is over 80 times that of carbon dioxide over a 20-year timeframe. RNG that displaces natural gas use can also reduce upstream methane emissions associated with the extraction and transportation of fossil gas. Reliable, locally sourced RNG could also help reduce gas price volatility.

The Council recommends incorporating renewable natural gas into utility and other regional long-term planning, including identifying the least-cost and lowest net emission profile projects to produce renewable natural gas that may be blended into the gas system. The Council also recommends regional utilities support renewable natural gas, when appropriate, as a method to reduce end-use natural gas emissions, supply low-carbon fuel for transportation, and provide diversity and price stability with a regionally sourced fuel product.

The Impact of Climate Change on the Use of Electricity

When looking at the impact of climate change on the use of electricity, the Council considers both the direct and the indirect effects. The direct effects look at existing buildings and businesses and their current equipment that uses electricity and estimates the impact of changing temperatures and precipitation on the amount of electricity needed. For example, as temperatures increase, the air conditioning equipment currently installed at homes and businesses uses more electricity.

To estimate the direct impact of climate change on the use of electricity, the Council uses temperature projections downscaled for our region from three different General Circulation Models.[3] These models were selected to represent a broad range of possible conditions associated with an increased concentration of greenhouse gasses in the atmosphere.[4]

The indirect impacts of climate change look at decisions or events where we anticipate different outcomes because of climate change. For example, more people moving to the region from hotter climates increases

3 The three models selected were CanESM2, CCSM4, and CNRM, further details on these models and the selection process can be accessed using the link for the supporting material at the end of this section

4 For more information on the River Management Joint Operating Committee efforts on downscaling General Circulation Models see: www.bpa.gov/p/Generation/Hydro/Pages/Climate-Change-FCRPS-Hydro.aspx

the population. The increase in population in turn increases the need for energy.

To estimate the indirect effects of climate change, the Council examined a broad range of sources and consulted with regional experts on climatic and demographic data. These data needed both sufficiently detailed projections and near-term impacts that fit within the 20-year forecast period we include in this plan. They also needed to be related to the demand for electricity.

Direct Impacts of Climate Change

The models we use to estimate the need for electricity estimate the number of days the region is likely to use cooling or heating for buildings. These are represented as Cooling Degree Days and Heating Degree Days.[5] Fewer heating degree days means that there is less

Projection of Average Heating and Cooling Degree Days for each Global Climate Model

	Heating Degree Days			Cooling Degree Days		
	2020-2029	2030-2039	Decrease	2020-2029	2030-2039	Increase
CanESM2						
Oregon	4409	4116	6.7%	451	486	7.8%
Washington	4669	4350	6.8%	364	403	10.9%
Idaho	5726	5398	5.7%	785	815	3.8%
Montana	6965	6527	6.3%	410	423	3.2%
CCSM4						
Oregon	4542	4417	2.7%	385	401	3.9%
Washington	4847	4717	2.7%	299	327	9.1%
Idaho	5892	5534	6.1%	641	746	16.3%
Montana	7242	6966	3.8%	330	393	19.1%
CNRM						
Oregon	4686	4222	9.9%	371	450	21.4%
Washington	4962	4482	9.7%	309	358	15.9%
Idaho	6073	5499	9.5%	673	713	5.9%
Montana	7378	6721	8.9%	353	362	2.6%

5 Cooling Degree Days are calculated by adding up the degrees above 65 degrees Fahrenheit of the average daily temperature for each day in the period being examined. Heating Degree Days are calculated similarly by

of a heating need in the winter, lowering the use of energy. Whereas, more Cooling Degree Days means that there is more energy needed in the summer.

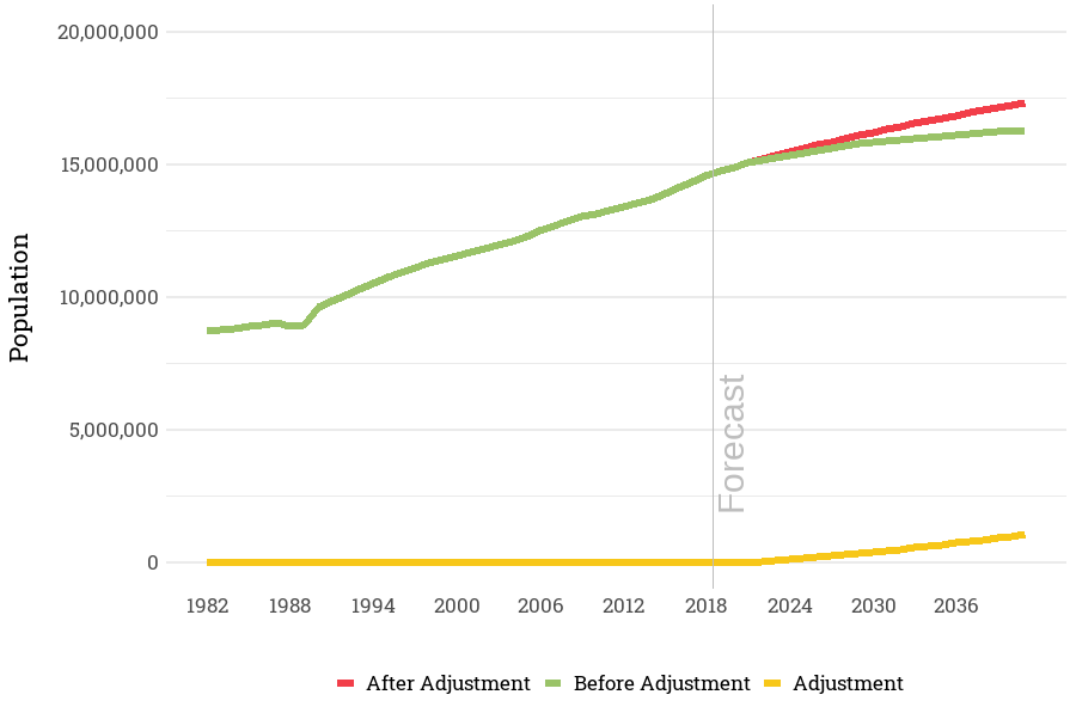
Projection of Average Heating and Cooling Degree Days for each Global Climate Model

Another direct impact of climate change we anticipate is a change in regional precipitation. Our models look at the electricity used to pump water for agricultural irrigation. The use of electricity for agriculture and irrigation averaged about 690 average megawatts per year between 1986 and 2018. With more precipitation, less water needs to be pumped to fields for irrigation which, in turn, uses less energy. With less precipitation, the opposite holds, and more energy is used. However, an increase in irrigated land based on increasing regional population is included in our forecast as an indirect effect of climate change.

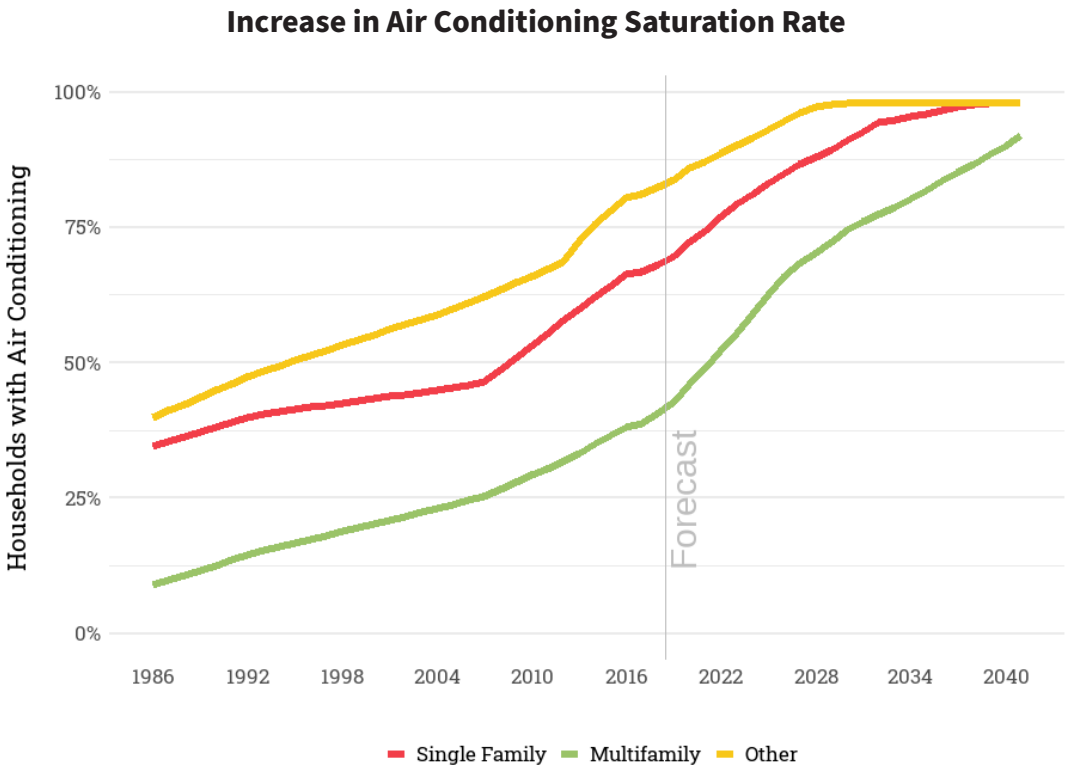
Indirect Impacts of Climate Change

There are many indirect impacts of climate change that could impact the demand for electricity. Events like flooding and wildfires with destructive effects on buildings and infrastructure that use electricity are difficult to forecast and quantify. In those cases,

Regional Population Adjustment for Indirect Climate Change Impacts



adding up the degrees below 65 degrees Fahrenheit of the average daily temperature for each day in the period being examined.



we are unable to incorporate the potential impacts into our demand forecast but acknowledge these are potential impacts to electricity use in our region that deserve continued study.

Some effects of climate change are easier to estimate. Where it has been possible to do so in a robust manner, we have included those impacts in our forecast. One adjustment we made is an increase to forecast population. Studies looking at the impact of climate change on migration[6] show a net increase in regional population. Using these studies, we have adjusted population projections in our forecasts.

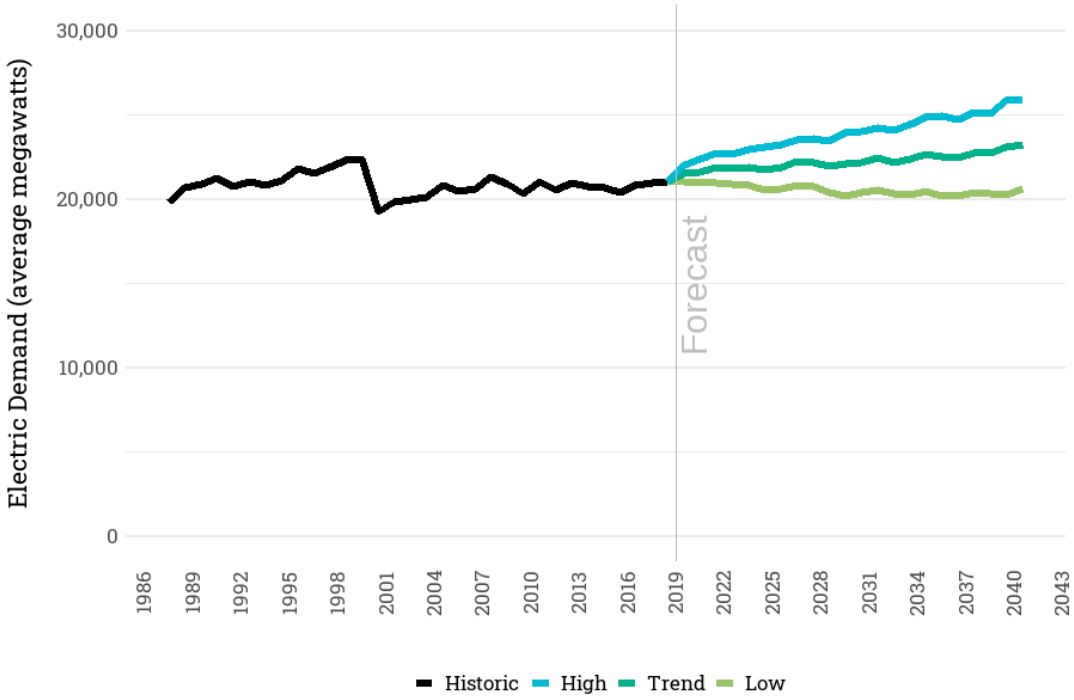
We also adjusted the saturation of air conditioning in new construction for the region. We have seen a growing penetration of air conditioning installed in residential construction. With climate change, we see that penetration continuing to climb and have adjusted our forecasts to grow to a 98 percent penetration by 2050.

Forecast of Regional Demand for Electricity

Over the next 20 years, the Council forecasts the demand for electricity will be driven by many factors including economic growth,

6 For detailed information on the studies and the population adjustment, see the supplemental material link at the end of this section.

Range of Regional Demand for Electricity Based on Economic Conditions



climate change, regional demographics, and expanding applications of electricity to reduce the use of fossil fuels. With all these considerations, we realize that no single forecast could appropriately capture the risks and opportunities to consumers and suppliers of electricity. To better assess the impact on the region, we forecast a possible range for electricity demand.

These forecasts are more uncertain further into the future. To some extent that is considered when we use a range in our analysis. However, our ability to predict what will drive demand for electricity has limits. Thus, the Council updates our forecasts as we get new information. Our forecasts in this power plan are updated and do not match the forecasts included in the last power plan. It should be expected that forecasts beyond the first 5 or 6 years could be missing key drivers that lie outside what would be considered a reasonable forecast at this time. Those drivers will be much clearer in the power plan that follows this one. The Council also forecasts based on current state and federal legislation and does not attempt to predict future legislative change. While recent experience demonstrates it is unlikely that there would be no legislation impacting the use of energy over the next 6 years, exploring this type of uncertainty is left to our scenario analysis. Our scenario analysis includes an examination of added demand for electricity driven by policies or activities aimed at reducing greenhouse gas emissions. Details

of our scenario analysis are included in the *Section 6 Resource Development Plan*.

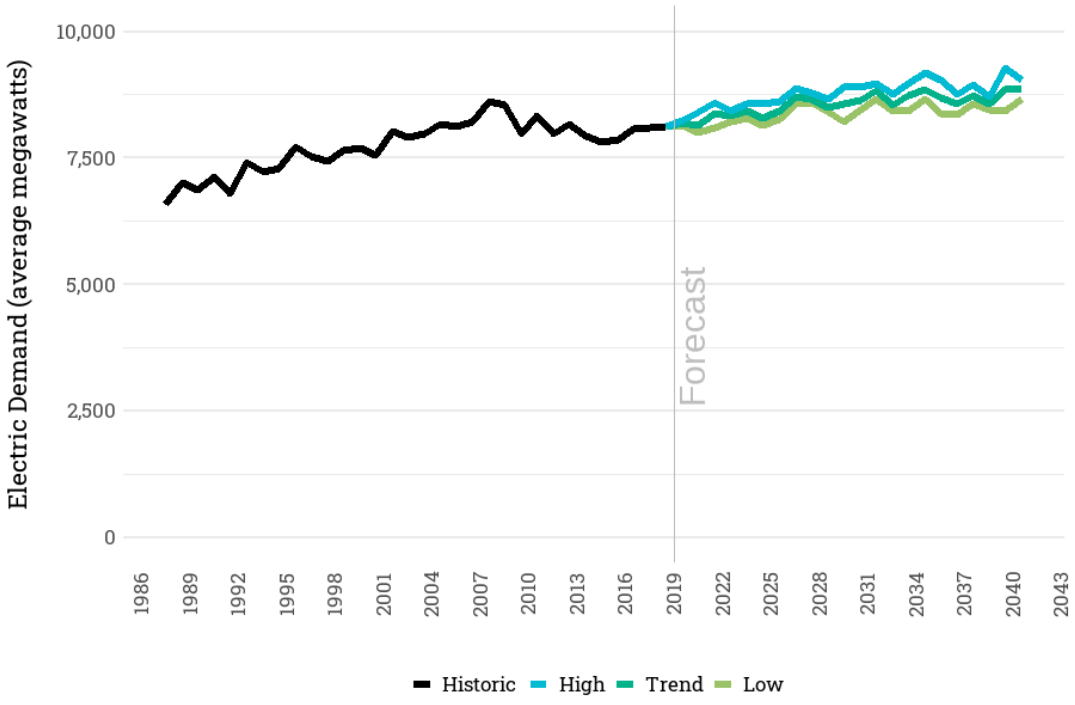
For economic growth, we forecast a range of conditions with a pessimistic estimate of around -8% and an optimistic estimate of +7%. Higher economic output drives higher use of electricity, and so demand for electricity is highest in the optimistic estimate. During the action plan period, the range of uncertainty is lower, + 4% and -5%.

The Council uses this forecast to estimate what additional resources and reserves are adequate to supply the region's need for electricity.

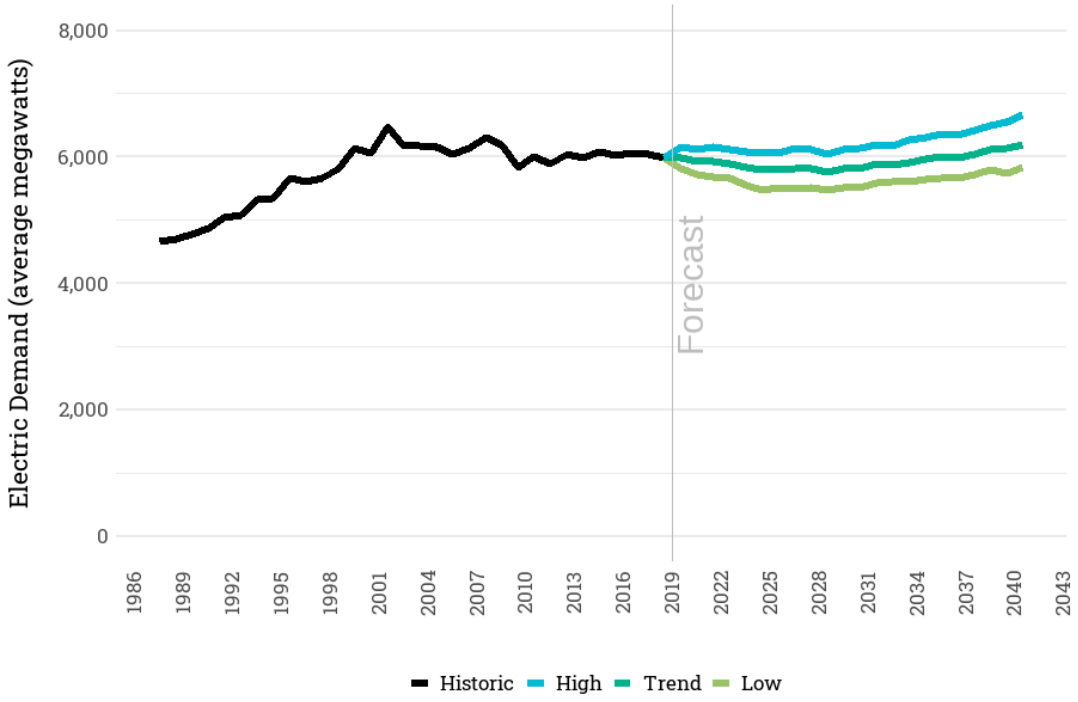
Demand by Sector

The Council's forecast is an end-use forecast. That is, it starts with the different uses for electricity, e.g., lighting or drying clothes, and builds up to sector-level forecasts. We anticipate a range of future loads. We estimate different economic and demographic drivers and then incorporate simulated temperatures from general circulation models. Including these temperatures means the forecasts are not smooth like forecasts that do not include weather variation. For example, anticipated energy needs for the residential sector are particularly sensitive to temperature variation. The loads range from 8,014 average megawatts to 9,726 average megawatts. An

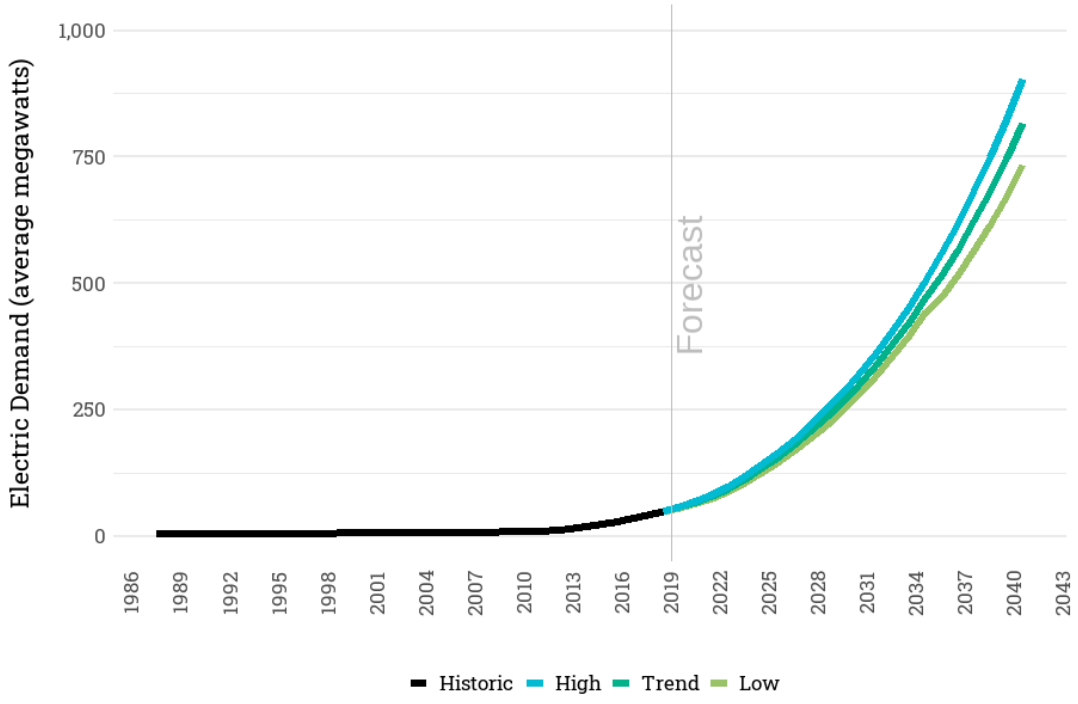
Residential Sector Electricity Use Forecast



Commercial Sector Electricity Use Forecast



Transportation Sector Electricity Use Forecast



average megawatt[7] represents one megawatt of load for a full year. But the minimum and maximum happen in different years. While this means that each year may not reflect a specific likelihood of a load above or below our forecast, the use of these loads as a way of testing different resource strategies and helps highlight the natural variation in electricity use that will happen with different temperatures.

By contrast, the commercial sector load forecast shows less variation based on weather. The range of the commercial load is forecast to vary from around 6,000 average megawatts in the near-term to a high of around 7,359 average megawatts.

Industrial loads in our forecast range from a low of under 4,000 average megawatts to a high of just shy of 8,000 average megawatts. Irrigation loads are anticipated to grow to a range of 937 average megawatts to 1,734 average megawatts. Municipal loads like street lighting are anticipated to stay flat or decline at or under 300 average megawatts.

Our forecast also includes a quickly growing regional electric load in the transportation sector and for data centers. In the case of transportation, we anticipate substantial growth relative to the amount of electricity used today. Whereas with data centers, we've seen substantial regional growth already that we are projecting will continue.

Taking the whole picture together creates a regional forecast for the use of electricity that shows a range of energy needs anywhere from 20,580 average megawatts to 25,895 average megawatts in 2041. The table below shows the range of loads in 2041 by the different sectors compared to the expected load in 2021. These forecasts have

Forecast Range of Electricity Use in Average Megawatts by Sector

Sector Forecast	Expected Electricity Use in 2021	Forecast Electricity Use in 2041		
		Low	Medium	High
Residential	8148	8674	8860	9049
Commercial	5938	5833	6202	6673
Industrial	6186	4147	5892	7541
Transportation	67	733	816	904
Street Lighting and Water Services	271	252	280	303
Irrigation	1016	941	1164	1465
Data Centers	657	952	1179	1369

7 For context on what you can power with a megawatt see nwcouncil.org/news/megawatt-powerful-question

interactive effects so they do not add to the same range of loads as the total regional load, but they should give a sense of which sectors have more uncertainty and how they are anticipated to change throughout the forecast.

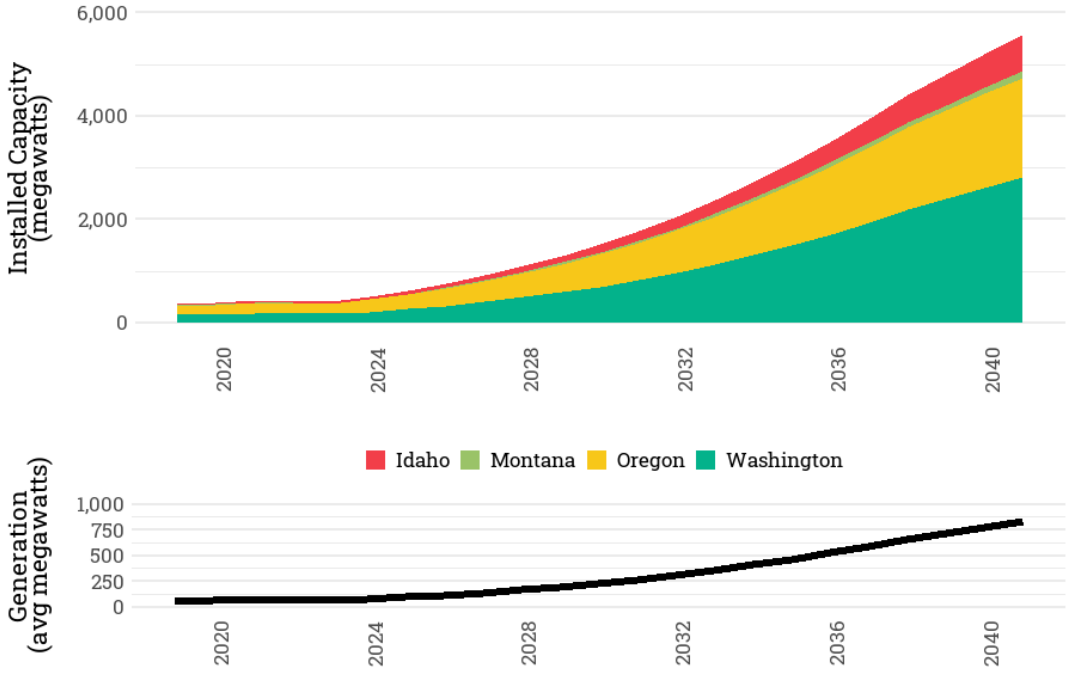
The Impact of Rooftop Solar on the Demand for Electricity

The Council's forecast includes an outlook for behind-the-meter solar installations in the region, which are generally rooftop-mounted systems in the residential, commercial, and industrial sectors. Solar panels are relatively simple to install and operate on homes and businesses. The cost to install and operate home solar has significantly declined and it is expected to continue to decline in our forecast.

Behind-the-meter solar installations in the Northwest have tripled in the five years from 2014 through 2018. By the end of 2018, nearly 90 percent of the 326 megawatts of overall capacity in the region was installed in Oregon and Washington.

The forecast for solar from our model is fairly aggressive. Because of cost declines, we anticipate the growth of installations could be rapid. The graph below shows our forecast of behind-the-meter solar installations by state for our region.

Forecast of Behind-the-Meter Solar Installed Capacity and Generation by State



Section 4: Forecast of Regional Reserve and Reliability Requirements

The fundamental objective of power system operations is to continuously match the supply of energy from electricity generators to customers' electrical demand at all times. This involves proper long-term planning to ensure that the power supply has sufficient generating capability, and that the transmission system can deliver that power within an acceptable range of frequency[8] and voltage.[9] The United States Federal Energy Regulatory Commission (FERC) defines ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas[10] and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."

8 Frequency is controlled by maintaining a stable net interchange between neighboring balancing authority areas. The basic test of success for this is called the Area Control Error (ACE). ACE is a measurement, calculated every four seconds, based on the imbalance between load (demand for electricity) and generation within a balancing area, taking into account previously planned imports and exports and the frequency of the interconnection. The North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards govern the amount of allowable deviation of the balancing authority's ACE over various intervals, although the basic premise is that ACE should be approximately zero. The ACE is maintained through a combination of automatic and operator actions. The automatic part is done through a computer-controlled system called Automatic Generation Control (AGC), which monitors the frequency of the system and correspondingly adjusts participating generators' output (within seconds) to bring the frequency back in line.

9 Voltage can be controlled in several ways with different types of system components installed at generating stations and the transmission system.

10 Control areas (also referred to as Balancing Authorities) are entities, often utilities, that ensure the power system demand and supply are balanced on a section of the electric grid. When supply and demand become too far out of balance, equipment on the transmission and distribution system will disconnect creating local or widespread electric power outages.

In general, ancillary services provide frequency and voltage control, load-following capability,[11] short-term protection for system component outages and flexibility to cover daily, hourly, and moment-to-moment variations in the electrical demand and generation.

While the fundamental objective will not change, the electricity grid seems poised to go through a paradigm change with an increasing penetration of new variable renewable generation displacing an increasing amount of the electricity that would have otherwise been generated by the existing fossil-fuel-based thermal generating fleet. The region and the rest of the West in the future will likely need to rethink how system capacity needs are measured and what different resources accomplish in providing for those needs.

Power Act Definition of Reserves

The Northwest Power Act defines reserves as "the electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator… (A) from resources or (B) from rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to customers." Electric power that averts operating shortages (operating reserves) falls into four general categories and are either spinning (available for immediate dispatch) or non-spinning (must be at full output within 10 minutes).

- Regulation reserves – provide minute-to-minute increases or decreases in generation to match electrical demand
- Load following reserves – bridge the gap between regulation reserves and hourly energy markets
- Balancing reserves – cover within-hour variations in electrical demand, and variations in wind and solar generation
- Contingency reserves – provide short-term (up to 60 minutes) protection against system component outages (transmission and generation)

The Council's adequacy model assigns operating reserves (regulation, load following, and balancing) and contingency reserves to appropriate resources.

What Does it Mean for a Power System to be Adequate?

While the terms "adequacy" and "reliability" are related, they have specific and distinct

11 In the utility industry, the electrical demand is often called load. Load-following refers to a service provided by electric generators that increases or decreases the output of electricity to match the use of electricity.

meanings for power system planning. A power system is defined to be reliable if it is both adequate and secure, where adequacy generally refers to having sufficient generating capability and security generally refers to having a robust transmission system.

- An adequate power system can supply the aggregate electrical demand of all customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements, and
- A secure power system can withstand sudden disturbances, such as electrical short circuits or unanticipated loss of system elements

The Council uses assumptions established by transmission planning organizations to estimate the ability to deliver electricity around the Western electric grid. However, substantial retirements or additions of generation on the system may go beyond the scope of these limits. The Council in our work assumes that transmission planning organizations and utilities will work together to ensure appropriate investment is made into the transmission system to at a minimum maintain the current ability to deliver electricity around the West. While we do not study expansion of the transmission system in this plan, we recommend the region work with transmission planning organizations to explore the costs and benefits of doing so.

Council's Resource Adequacy Standard

One of the key objectives of the Council's power plan is to develop a resource acquisition strategy that will ensure the region of an adequate, efficient, economical, and reliable power system, while taking uncertain future conditions into consideration.

The Council's overarching goal for its adequacy standard is to *"establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."*

The standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity in future years. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

The metric used to measure resource adequacy is the annual loss-of-load probability (LOLP). The LOLP is assessed by simulating the operation of a future year's power system many times with different

combinations of river flows, temperatures,[12] wind and solar generation, and generator forced outages. Whenever demand for electricity is not served, it is considered a shortfall event. The LOLP is calculated as the number of simulations in which at least one shortfall event occurred divided by the total number of simulations. The Council deems the power supply to be adequate if the LOLP is 5 percent or less. That is, the power supply is adequate if the likelihood of having one or more shortfalls in an operating year is 5 percent or less.

Method for Assessing Regional Power System Needs to Maintain Adequacy

The Council uses its evaluation of the adequacy of the existing system to establish a method for assessing potential regional power system needs to maintain resource adequacy under a broad range of different scenarios and conditions. In projecting how the region could meet these system needs we evaluate both the magnitude of those needs and the varying capability of different generating technologies or demand-side resources to meet them.

Gaps Between Existing System Capabilities and Anticipated Future Requirements

Using the Council's adequacy standard, the needs to maintain adequacy are defined as any gaps between existing system capabilities and anticipated future requirements that fall outside that standard. The existing system capabilities are evaluated on an hourly basis accounting for operational and fueling limitations, in addition to generating or demand-reduction capability for all the resources in the existing regional power system. The anticipated future requirements incorporate both regional demand and reserve requirements. The gaps between existing system capabilities and anticipated future requirements are evaluated for each quarter, which broadly can be defined as the fall, winter, spring, and summer seasons using a broad range of estimated hydro conditions, electrical demands, and renewable generation output.

The methodology to identify the size of shortfall events that need to be addressed to maintain adequacy is as follows:

1. The shortfall events in our simulations are sorted from highest magnitude to lowest magnitude on an annual basis, including the simulations where we have no shortfall events or the magnitude of the shortfall event is zero.

12 Temperatures impact the amount of electricity used; for example, during extremely hot days the regional needs more electricity for air conditioning

2. The top 5 percent of the simulated shortfall events (those of the highest magnitude) are assumed to be acceptable under the Council's standard. We do not consider these further.

3. We take the highest magnitude shortfall events remaining for each season as the gap between the existing system capabilities and anticipated future requirements necessary to maintain the Council's adequacy standard. If there are shortfalls greater than zero in more than 5 percent of the simulations, then these seasonal gaps will be non-zero.

The size and composition of the gaps varies between scenarios. When we implemented the climate change projections into the analytics that support the plan, we have projections on temperatures and precipitation going into the future. These projections are not intended to be used as what the expected weather will be in any individual future year, rather they illustrate the types of temperatures that can be expected and the data are designed so that the range of weather over each decade represents an estimate of the range of conditions driven by climate change. The following table shows the maximum energy need (in average megawatts) with the decade for the calendar quarters[13] generally associated with winter and summer. This helps illustrate how much the needs varied between the different scenarios explored in this plan with some scenarios showing substantial needs even within the

Highest Decadal Increment Energy Needs for Select Scenarios (average megawatts)

	2022 to 2029	2030 to 2041
July to August – Early Coal Retirement		
Average	1071	1429
Maximum	2987	3579
January to March – Early Coal Retirement		
Average	1008	1393
Maximum	2884	3648
July to August – Partial Decarbonization		
Average	2461	11120
Maximum	5201	15689
January to March – Partial Decarbonization		
Average	2857	9578
Maximum	6012	14420
July to August – Organized Markets		
Average	0	1
Maximum	0	189
January to March – Organized Markets		
Average	14	742
Maximum	514	2744

13 Our Regional Portfolio Model uses estimated distributions of hourly loads for each calendar quarter. It is certainly possible to have a heat event in June or a cold event in December. These are included in the analysis but not explicitly listed here for the sake of brevity.

2020s. We discuss the gaps resulting from this method for different scenarios in *Section 6: Resource Development Plan*.

Future Resource Capability to Fill Gaps

When exploring the capability of future resources or reserve additions to fill the gap described above, the Council evaluated the attributes of each resource and how they interacted with the existing system to change the total regional capability to meet anticipated future requirements. The existing system, including the region's hydropower generation, can adapt in different ways that fill these gaps. When adding resources that increase the need for reserves, like wind and solar generation, it may reduce the existing system's peak capability.

The ability of the regional hydropower system to support the regional electric grid in different ways is a valuable attribute. However, the demands on the system must be balanced, making sure not to double count the contribution of these resources. Further, the regional hydro system has many purposes beyond generating electricity that take priority and must also be accounted for in any future projections of what the power system can rely on from these resources. The Council models reserves required from both the existing system and any new resources to capture this important dynamic. The examination of future resource characteristics included operational and fueling limitations on an hourly basis in addition to generating or demand-reduction capability within the context of the existing regional power system.

To determining how a resource or combination of resources[14] fill the gaps in the existing system capabilities, we:

1. Simulate the regional power system in 2031 with high demand, all the regional coal units retired, and no new resource additions, then record the maximum gap between existing system capability and system obligations.
2. Simulate the regional power system in 2031 with high demand, all the regional coal units retired, and with a combination of new resource additions. Then record the maximum gap between existing system capability and system obligations.
3. Take the difference in the gaps from the simulations step 1 and 2 and divide that difference by the total nameplate resource additions from the combination of new resources in step 2.
4. Use that percentage as a multiplier when assessing the capability of a combination of new resources to meet any identified gaps.

14 For all combinations not explicitly tested, a multilinear interpolation allows the capability of any new combination of new resources considered in the resource strategy analysis to be identified and considered when attempting to address gaps associated with peak conditions.

Section 5: Energy Conservation Program

Background on Energy Efficiency in the Northwest

Energy conservation is defined in the Power Act as "any reduction in electric power consumption as a result of increases in the efficiency of energy use, production or distribution."[15]

In recent years, the Northwest region's utilities have spent about $480 million dollars per year on energy efficiency. This includes investments in incentive programs, market transformation initiatives, evaluation, and research such as in market research, building stock assessments, and emerging technologies. Estimates indicate that in our region, over 100,000 people are employed working with energy efficiency at utilities, the Northwest Energy Efficiency Alliance (NEEA), the Energy Trust of Oregon, state agencies, and at the many trade allies and contractors that work to implement programs and deliver efficiency services.[16]

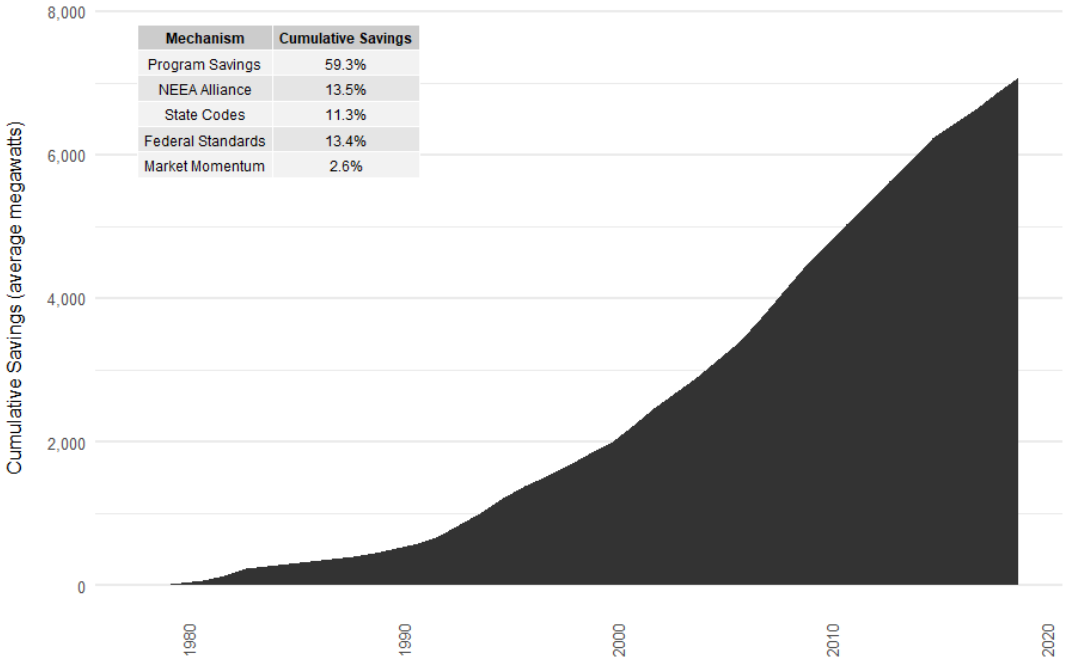
This investment has resulted in more than 7,200 average megawatts of savings since 1978. About 60 percent of those savings are from direct utility program incentives.[17] The remainder is from NEEA market transformation initiatives, improvements in codes and standards, and other market adoption. These savings amount to a regional resource second only in magnitude to hydropower and are equivalent to the annual energy consumption of around 5.1 million Northwest homes. By reducing electricity generation from fossil-fuel power plants, the savings have avoided more than 22.2 million metric tons of carbon dioxide emissions. The cumulative efficiency savings since 1980 have reduced consumer electricity bills by about $4 billion per year. Efficiency has also shown to provide reductions in other non-energy consumables, such as water, and provide additional benefits to consumers in the form of health, comfort, and productivity.

15 Northwest Power Act Section 3(3), 94 Stat 2698

16 U.S. Energy and Employment 2020 report www.usenergyjobs.org

17 More information on conservation achievements can be found on the Regional Technical Forum website rtf.nwcouncil.org/about-rtf/conservation-achievements/2019

Cumulative Regional Energy Efficiency Savings by Mechanism



In recent years, with all the accomplishments and increasing efficiency levels, the future amount of low-cost efficiency available has diminished. One key example is LED light bulbs that have transformed the industry; a 9-watt LED bulb provides at least as much illumination as the traditional 60-watt incandescent. These are significant savings, and future lighting improvements cannot be as profound. However, savings remain[18] in lighting and other end uses, and continued investment is needed to ensure low-cost efficiency remains available.

Regional Recommendations on Energy Efficiency

Amount of energy efficiency the region should acquire

The Council recommends that the region acquire between 750 and 1,000 average megawatts of energy efficiency by the end of 2027 and at least 2,400 average megawatts by the end of 2041.[19] The lower end of this recommended range represents cost-effective energy efficiency acquired at a

18 See New Opportunities for Energy Efficiency in Section 6: Resource Development Plan for further details.

19 More details on the basis for the level of the recommendation can be found in the supporting materials, here: nwcouncil.org/2021powerplan_Cost_Effective_Conservation_Recommendation_Summary

moderate pace, whereas the higher end of the range represents cost-effective efficiency that is acquired more rapidly.[20]

We expect that most of the short-term savings will be via direct-funded utility programs, but this recommendation also includes efficiency accomplished through market transformation initiatives through NEEA, building codes, appliance standards, and natural market adoption. Regional support of all mechanisms is needed for long term achievement and continued availability of energy efficiency.

The Council's regional recommendation includes efficiency acquired at all regional utilities, including the Bonneville customer utilities. Our specific recommendations to the Bonneville Administrator regarding energy efficiency are included in *Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation*.

To achieve this overall goal, all utilities within the region will need to deliver energy efficiency to their end-use customers. For utilities within urban centers, efficiency may be more readily accomplished, given greater availability of contractors and suppliers of efficient products and easier access to a large and diverse number of customers. In contrast, utilities with a rural customer base (primarily residential and agricultural) have significant challenges and fewer resources for implementing cost-effective efficiency programs. These challenges are recognized, and Bonneville and/or other regional organizations such as NEEA should support these rural utilities in reaching efficiency goals.

Continued investment in NEEA and efficiency-related research and development[21] is critical to achieve the long-term goals. To help ensure a robust efficiency infrastructure, work is needed all along the product adoption curve: Continuing research into emerging technologies to introduce new efficiency opportunities; working with retailers and manufacturers to increase the availability of efficient products; and encouraging acceptance by consumers. NEEA and utilities will need to be diligent in ensuring progress in all these facets of the market. As such, to help ensure that the necessary levels of cost-effective conservation are acquired, we recommend the region's utilities:

1. Maintain ratepayer-funded efficiency programs (utility direct programs and market transformation initiatives) at a funding level sufficient to achieve the 2027 goals;

20 The cost-effectiveness methodology for conservation can be found here: nwcouncil.org/2021powerplan_cost-effective-methodology

21 See Section 10: Recommendations for Research and Development for more discussion on this topic.

2. Continue to fund research and development on emerging technologies in an amount commensurate with 2020 levels or greater;

3. Continue to fund regional market research, stock assessments, and related analysis in an amount commensurate with 2020 levels or greater;

4. Support initiatives to enhance building codes and appliance standards, at both the state and federal government-level.

In addition to the amount accomplished under the target, we recommend the region continue to invest in weatherization programs, targeting those homes that are leaky (in need of duct or air sealing) and/or have zero or limited insulation. These measures are critical to provide livable homes for all people.[22] Much of this work is currently being accomplished through low-income weatherization programs, co-sponsored by utilities and state and federal agencies. However, there may be homeowners or renters who do not qualify under those programs but live in substandard housing, and utilities should strive to weatherize those structures as well. In some cases, the structures' needs may be beyond weatherization services, and home replacement programs should be considered.[23] Utilities should consider coordinating with other agencies (such as community action agencies, state agencies, and/or nonprofits) and explore co-funding options to best serve these homes.

Utilities should also begin utilizing energy use intensity (EUI) data for commercial buildings to identify buildings that have consumption levels significantly higher than other comparable buildings. This approach can provide a market-sector-neutral way of identifying those customers in the greatest need of efficiency measures and otherwise previously missed by programs. For example, utility program managers have indicated (and supporting data suggest) that small commercial customers typically have higher EUIs than their larger counterparts. All customers with these higher-than-average EUIs should be targeted for implementation of cost-effective conservation.

Objectives of Conservation Programs

All conservation actions or programs should be implemented in a manner consistent with the long-term goals of the region's electrical power system, as established in the 2021 Power Plan. To achieve this goal, the following objectives should be met:

1. Conservation acquisition programs should be designed to ensure levels of efficiency that are cost-effective for the

22 Some of these measures will not be cost effective relative to the plan but should still be included in the programs.

23 For example, some utilities have programs replacing an old manufactured home with a new efficient model.

region and economically feasible for the consumer.

2. Conservation acquisition programs should target conservation opportunities that are not anticipated to be developed by consumers.

3. Conservation acquisition programs should be designed so that their benefits are distributed equitably.

4. Conservation acquisition programs should be designed to secure all measures in the most cost-efficient manner possible.

5. Conservation acquisition programs should be designed to take advantage of naturally occurring "windows of opportunity" during which conservation potential can be secured by matching the conservation acquisitions to the schedule of the host facilities or to take advantage of market trends. In industrial plants, for example, retrofit activities can match the plant's scheduled downtime or equipment replacement; in commercial buildings, measures can be installed at the time of renovation or remodel.

6. Conservation acquisition programs should be designed to capture all cost-effective conservation savings in a manner that does not create lost-opportunity resources. A lost-opportunity resource is a conservation measure that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken to develop it or hold it for future use.

7. Conservation acquisition programs should be designed to maintain or enhance environmental quality.

8. Conservation acquisition programs should be designed to enhance the region's ability to refine and improve programs as they evolve.

Not all energy efficiency provides equivalent value to the regional electric system. Some distinguishing attributes, such as cost and savings shape, have been captured in the portfolio analysis. However, energy efficiency's ability to improve building resilience[24] and grid flexibility[25] is not well modeled. These attributes are important to maintaining a robust electric system infrastructure, and energy efficiency that provides these values should be prioritized,

24 Building resilience refers to the building's ability to withstand a power outage or extreme weather event. For example, a well-insulated home will maintain its conditioned temperature for longer during an outage or extreme temperatures.

25 Grid flexibility refers to a building's ability to respond to the needs of the grid. Energy efficiency that enables this flexibility could have additional value. For example, an efficient lighting system that has embedded controls could be tapped by a utility to balance the grid.

and we will endeavor to improve our estimates over the action plan period. The Council's Regional Technical Forum (RTF) should explore the mutual benefits of energy efficiency and demand response in providing grid flexibility.

Consequences of not achieving the regional recommendations

The minimum of 750 average megawatts of energy efficiency by the end of 2027 is what we have determined to be more cost-effective than pursuing other resources when considering risk and uncertainty of meeting adequacy needs, decarbonization, renewable resources availability and reliability, and future market pricing. Not achieving this efficiency may result in higher costs to the system and impede development of a more equitable energy system. This efficiency will maintain jobs, lower greenhouse gas emissions, reduce energy burdens for households and businesses, and avoid adequacy shortfalls. In developing this target, the Council also considered specific values for measures to improve a home's resilience to power outages and enable future interconnectedness with the electric grid. Thus, the cost-effective efficiency will help enable a robust electric power system. In addition, investment in measures to improve livability of poorly insulated houses will help toward achieving equity of residential energy burden.

Model Conservation Standards

The Northwest Power Act directs the Council to adopt and include in its power plan a conservation program that includes model conservation standards (MCS). The MCS are applicable to (i) new and existing structures; (ii) utility, customer, and governmental conservation programs; and (iii) other consumer actions for achieving conservation. The Act requires that the standards reflect geographic and climatic differences within the region and other appropriate considerations. The Act also requires that the Council design the MCS to produce all power savings that are cost-effective for the region and economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

In addition to the requirements set forth in the Act, the Council believes the model conservation standards in the plan should produce reliable savings and that the standards should, where possible, maintain and improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles) found in typical buildings constructed before the first standards were adopted in 1983.

The Power Act provides for broad application of the MCS. In the earlier plans, a strong emphasis was needed to improve residential

and commercial building construction practices beyond the existing codes. Beginning with the first standards adopted in 1983, the Council has adopted a total of seven model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions to electric heating systems, and the standard for conservation programs not covered explicitly by the other model conservation standards.[26] Since the Council adopted its first model conservation standards, all four states within the Northwest have adopted strong energy codes that largely incorporate the standards.

The MCS for the 2021 Power Plan have two main components. The first is that the Council adopts two specific components to the standards to ensure equity in efficiency adoption through codes and standards. The second component provides the standard for conversions (similar to prior MCS) to an electric space or water heating system from another fuel.

The focus of the codes and standards component of the MCS is on two areas intended to improve equity around efficiency acquisition through codes and standards. These areas include supporting common appliance standards in the Northwest and discouraging backsliding or reducing codes or standards.

In addition, as municipalities around the region are considering reducing their carbon footprint, electrification of end-use equipment has gained interest. The second component of the MCS is the standard for conversions (similar to prior MCS) to an electric space or water heating system from another fuel. The Act definition of conservation clearly excludes fuel switching as energy efficiency. However, if fuel switching were to be promoted, this MCS directs action to ensure the switching is performed with all cost-effective electric energy efficiency incorporated.

Common Appliance Standards

The minimum efficiency requirements of many appliances and equipment are regulated at the federal level.[27] These standards are a low-cost, equitable means of achieving cost-effective efficiency. For products without a federal standard, states may adopt their own minimum efficiency requirement. In the past few years, several states have adopted their own standards,

26 The 2021 Power Plan model conservation standards and surcharge methodology supersede the Council's previous recommendations.

27 www.energy.gov/eere/buildings/appliance-and-equipment-standards-program

including Washington[28] and Oregon.[29] Often, these standards are consistent with those in California, allowing for a uniform market in the western-most United States. This commonality is preferred by manufacturers to minimize regulatory confusion and multiple product lines. To further efficiency and limit market disruption, Northwest states should consider adopting common standards and work to synchronize updates. Coordinating with additional states, such as through initiatives by the Appliance Standards Awareness Project,[30] would strengthen the likelihood of compliance and manufacturer buy-in.

No Backsliding on Codes or Standards

Once a code or standard has been adopted, no state or federal agency should change the standard such that a subset of buildings or appliances are subject to a less stringent standard. Codes and standards are a low-cost, equitable means of achieving cost-effective conservation. When markets are segmented into product classes and thus subject to differing requirements, this dilutes the efficacy of the code or standard and decreases efficiency. This in turn has impacts on the ability for the region to equitably provide low-cost energy efficiency to all Northwest consumers.

Conversion to Electric Space Conditioning and Water Heating

Per the Power Plan analysis, jurisdictions pursuing economy-wide decarbonization goals should pursue multiple approaches to reduce carbon, including significant energy efficiency investment. While the Power Plan does not include electrification of end uses in its resource strategy, the Council recognizes that some jurisdictions may pursue electrification as part of a decarbonization strategy. Those jurisdictions (state or local governments) or utilities with such decarbonization goals that include electrification should take actions through codes, service standards, user fees or alternative programs, or a combination thereof, to achieve electric power savings from buildings. The efficiency level of new electric space conditioning or water heating equipment in these jurisdictions should be at least equivalent to the lowest-efficiency measure included in the 2021 Plan or adopted by the RTF (whichever is more recent). While some of the measures may not be cost-effective under the Council's current methodology, the Council believes they would be for jurisdictions with deep decarbonization initiatives. Similarly, for those jurisdictions, any existing inefficient electrical space or water heating equipment

28 www.commerce.wa.gov/growing-the-economy/energy/appliances
29 www.oregon.gov/energy/energy-oregon/Pages/Appliance-Standards.aspx
30 appliance-standards.org

should also be upgraded to a minimally efficient level at time of replacement.[31]

Surcharge Recommendation and Methodology

The Power Act authorizes the Council to recommend a surcharge that the Bonneville administrator may impose on customers that have not implemented conservation measures that achieve energy savings comparable to those that would be obtained under the Model Conservation Standards in the plan. Section 4(f)(2) of the Northwest Power Act directs the Council to include a surcharge methodology in the power plan. The surcharge must, per the Act, be no less than 10 percent and no more than 50 percent of the administrator's applicable rates for a customer's load or portion of load. The surcharge is to be applied to Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards.

The Council does not recommend a surcharge to the administrator under Section 4(f)(2) of the Act at this time. The Council intends to continue to track regional progress toward the plan's MCS and will review its decision on the surcharge recommendation, should accomplishment of these goals appear to be in jeopardy. Should utilities fail to enact these standards, then Bonneville may need the ability to recover the cost of securing those savings. In this instance the Council may wish to recommend that the administrator be granted the authority to place a surcharge on those utilities' rates to recover those costs.

The purpose of the surcharge is twofold: 1) to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives. The surcharge mechanism in the Act was intended to ensure that Bonneville's utility customers were not shielded from paying the full marginal cost of meeting load growth.

As stated above, the Council does not recommend that the administrator invoke the surcharge provisions of the Act at this time. However, the Act requires that the Council's plan set forth a methodology for surcharge

31 There may be cases where the savings are minimal relative to the expense (e.g., installing ductless heat pumps in small multifamily units) and may not be a priority efficiency investment. Jurisdictions will need to consider policy goals in determining what a reasonable cost-effectiveness limit should be.

calculation for Bonneville's administrator to follow.

Should the Council alter its current recommendation to authorize the Bonneville administrator to impose surcharges, the method for calculation is as follows:

Identification of Customers Subject to Surcharge

The administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards set forth within this chapter.

Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is to be calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

2. If the customer is not purchasing firm power from Bonneville under a power sales contract but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; plus b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources.

Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

Section 6: Resource Development Plan

How the Electric Sector Has Changed

The Council's 2021 Power Plan is significantly different than its Seventh Power Plan, adopted just five years ago. This is due to changes in the economics of renewable resources and the adoption of regional clean energy policies. The rapid cost reduction for solar and wind power technologies, when coupled with federal and state inducements, has provided an incentive for building large amounts of utility-scale solar and on-shore wind power across the region and put increased competitive pressure on thermal generators that operate at higher costs.[32]

Along with this changing economic landscape, the plan also recognizes clean-energy policies and goals implemented at state, city, and utility levels in many jurisdictions across the Western electricity interconnection and their impact on the future development of significant renewable and non-carbon emitting resources. The combination of increased competitive pressure and clean energy policies has resulted in the early retirement of less efficient thermal generators, and increased thermal generator planned retirements during the initial five-year "action period" of the plan. This indicates that the capacity of coal-fired power plants in the region will be reduced by more than 60 percent over the next decade.[33] Furthermore, uncertainty remains over the role of existing natural gas-fired power plants beyond this decade, and the future development of new gas-fired generators within the region.

Perhaps even more uncertain is the extent to which clean energy policies will affect other sectors of the economy and the demand for electricity. There is an increasing number of jurisdictions within the interconnection that have established policy goals and timelines to reduce greenhouse gas emissions economy-

32 To this point, the accelerated addition of renewable generators operating without fuel costs to the power supply has led to lower electricity prices, sometimes crossing below zero during intra-day trading.

33 Uncertainty regarding the future of existing coal plants in the region was apparent during preparation for the Seventh Power Plan, becoming a central issue for utility resource planning. Accordingly, the planned retirements of Centralia units 1 and 2, Boardman, and North Valmy units 1 and 2 between 2020 and 2026 were incorporated into the power plan.

wide, leading to potentially high levels of new demand. For example, in the transportation sector, the focus is on converting fossil fuel-fired vehicles to electricity or hydrogen. The widespread use of electric- and hydrogen-fueled vehicles would have a substantial impact on future electricity load growth. To this point, our early modeling work indicates significant electric system demand devoted to hydrogen fuel production for transportation – demand perhaps double the average output of the existing hydroelectric system. Combined, these actions signal a major paradigm shift for the electricity sector in the region (and elsewhere), presenting challenges to maintaining and enhancing an adequate, efficient, economical, and reliable power supply.

In the Seventh Power Plan, energy efficiency – the priority resource in the Northwest Power Act – was the clear, least-cost resource, with cost-effective energy efficiency acquisitions meeting most of the load growth through 2035. The region was undergoing a shift from a focus on energy needs to a focus on capacity - in particular peaking capacity - and ensuring an adequate system in poor water years or extreme weather conditions when the hydropower system has limited flexibility to meet peak needs. Deployment of demand response was also recommended to meet and reduce system capacity needs. Following energy efficiency and demand response, new natural gas-fired generation was the most cost-effective resource. The plants, and greater utilization of existing gas-fired plants, were part of the least-cost strategy to meet remaining resource needs and reduce carbon dioxide emissions from the electricity system. Finally, renewable resources were acquired near the end of the 20-year planning period to meet state renewable portfolio standards (RPS). Utilities were largely in compliance with near-term RPS targets due to earlier wind resource development, which saw the region build about 8 gigawatts in five years in the late 2000s and early 2010s.

For the 2021 Power Plan, the outlook is much different. There is less low-cost energy efficiency potential available due to the same price competition from solar and wind resources that now impacts thermal units, although the total cumulative potential at the end of the planning period remains the same. Ongoing construction of inexpensive renewable resources is influencing the wholesale electricity market, with low prices, particularly in the middle of the day, when solar PV is producing at its peak. In light of the construction of renewable resources anticipated in this plan, these low prices are likely to become increasingly negative through time, making it very difficult for resources with variable operating costs (like thermal plants) to commit and compete, leading to concerns about the adequacy and reliability of the system. The region's hydropower system – the biggest generating resource and "battery" in place – will also

be facing long-term alterations in flow from climate change effects on weather and precipitation, as well as ongoing requirements to spill water to enhance fish passage. Water that is spilled cannot be used to generate power. These challenges are magnified when the hydropower system is increasingly used for flexibility and integrating new renewable resources.

In summary, the electric grid is shifting to renewable resources at an aggressive pace. This shift, along with the speed at which the system must react to demand for power, creates potential risks to system operations that we address in the plan. These changes also point to significant levels of low- or no-cost power available to the region during most daylight hours throughout the year. It is through the efficient management of these resources that the region will assure a reliable and economical power supply.

Recommended Resource Strategy

The Northwest Power Act requires the Council to prepare a regional conservation and electric power plan that assures the region an "adequate, efficient, economical, and reliable power supply." Since the first power plan in 1983, the Council considers a range of uncertainties and potential futures to determine its preferred resource strategy. The strategy balances analytical findings, policy expectations, and operational limitations within the grid. The resource strategy covers the entire plan horizon of 20-years (2022-2041) with a focus on a near-term, six-year action plan period (for this plan, the action plan period is 2022-2027).[34]

The resource strategy provides guidance to the entire Pacific Northwest region – encompassing both public and private utility territories - on how best to meet the electric power system needs. It is similar to integrated resource plans (IRPs) conducted by many utilities in the Northwest and around the country. Both consider supply- and demand-side resources as comparable means to meeting future needs and account for state policies that influence resource options. However, the Council's plan differs from IRPs in some important respects. By being a regional strategy, specific balancing authority or utility nuances are not necessarily captured. For example, the plan's strategy does not have specific requirements for additions to the transmission or distribution systems.[35] In addition, as a regional plan, there is less specificity on resource

34 The years represent water year, or October 1 – September 30.

35 *Section 10: Recommendations for Research and Development* includes a recommendation for the region to conduct a study on the ability of the transmission system to incorporate the proposed renewable power additions. The recommended resource strategy accounts for an estimated value of deferring transmission and distribution; however, utilities may have location-specific needs that are high-value that would have a costs and

acquisition recommendations than what may be provided in an IRP.

Regional Resource Recommendations

The 2021 Plan resource strategy includes recommendations on energy efficiency, generation, and demand response. Together, these will help support an adequate, efficient, economical, and reliable power supply while limiting greenhouse gas emissions. The recommendations for the Bonneville Power Administration, in part highlighted here, are specified in *Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation*.

The Council recommends Bonneville and the regional utilities plan to acquire between 750 and 1,000 average megawatts of cost-effective energy efficiency by the end of 2027 and a minimum of 2,400 average megawatts by 2041. This level of efficiency is cost-effective for meeting energy needs and is a low-risk approach to meeting adequacy needs (further described in *Section 9: Cost Effective Methodology for Providing Reserves*) by providing a hedge against reliance upon the availability of other resources at the time needed and supporting opportunities to unlock additional hydropower system flexibility. The addition of efficiency-based resources will also defer need for transmission and distribution system upgrades, reduce emissions, and support jurisdiction-specific decarbonization goals. In addition to the energy efficiency acquisition recommendation, *Section 5: Energy Conservation Program*, outlines other recommendations related to ensuring this efficiency is prudently acquired. Section 5 also provides the Model Conservation Standards and Surcharge Recommendation and Methodology, two required components of the plan.

Our recommendation is based on energy efficiency supply curves developed using estimated costs and savings data available through early 2020 for many different potential energy efficiency measures. We understand and expect the costs to acquire energy efficiency measures will vary between utilities and from one year to the next. This will likely alter the mix of efficiency measures available through utility programs in the region during the action-plan period. How much any particular utility invests in conservation, and which measures the utility invests in, are decisions for the utility to make based on a number of factors, including whether it makes economic sense to the utility in its particular circumstances. Given this reality, there will always be some

benefits that differ substantially from an estimated regional value. For more information see the supporting material at nwcouncil.org/2021powerplan_global-assumptions-power-plan. The analytics in the plan do not co-optimize individual utilities specific investment opportunities in generation, transmission, and distribution infrastructure. Regional utilities should consider the Council's recommendations within this context.

uncertainty of whether the amount of conservation that is cost-effective regionally will be acquired. Because of these factors, we believe it prudent to monitor progress in the acquisition of energy efficiency resources over the action plan period, including the cost to deliver such resources to customers. Further, we encourage greater collaboration between utilities to advance the overall effectiveness of energy efficiency resources.

For generation resources, the Council recommends the region acquire at least 3,500 megawatts of renewable resources by 2027, as a cost-effective option for meeting energy needs and reducing emissions. The Council also recommends that policymakers and utilities pursuing aggressive emissions reductions evaluate adding more renewables as a means of displacing emissions both within their portfolio and in the broader market. While these recommendations are part of the least-cost resource strategy, it is also important to note that we project there will be times that market conditions will result in substantial generation curtailment of both these new renewable resources and the existing renewable resources in the region. That is, there will be times when there is more electricity being produced than demand for electricity, and the region, as well as the broader West, will need to reduce the amount of generation on the system, in part by not using the total capability of renewables.

The plan evaluates broad regional trends but should not be seen to preclude more local and site-specific needs and opportunities. The Council acknowledges regional utilities will evaluate the suitability and efficacy of a broad range of resources, including resources not explicitly modeled as options in the power plan to meet those needs. Further, the Council acknowledges that all energy infrastructure development and construction – including new solar and wind plants and any potential new or upgraded transmission required to deliver that energy – has an impact on the environment. The Council recommends that the region be mindful of individual and cumulative impacts when siting new resources so that new renewable resource development is carried out in a manner that also protects the wildlife, fish, and cultural resources of the Pacific Northwest.

These resource additions will depend on sufficient transmission capability on the system to deliver electricity from the source of generation to the locations where electricity is needed. The Council understands that utilities with existing transmission rights should be compensated for the investments needed to construct large transmission projects. In our resource strategy, we do not identify what rights are available for adding renewable resources, but we understand regional utilities building these projects will need to use a variety of approaches to fit this expansion of renewable

resource generation into the existing transmission system, respecting the rights of the transmission system owners and operators.

The Council recommends utilities examine two demand response products: residential time-of-use (TOU) rates[36] and demand voltage regulation (DVR) to offset the electric system needs during peaking and ramping periods and to reduce emissions. A given utility's time of need may differ from the region's, but these products are likely still part of a cost-effective strategy. Our assessment shows about 520 megawatts of DVR and 200 megawatts of TOU available by 2027.

With unique assets at each utility and across the region, the most strategically valuable program offerings may vary, so there may be other similar products that are also frequently deployable, low cost, and with minimal customer impact that could provide similar benefits; those should also be considered in utility planning. In addition to benefits on the power system side, demand response could be used to relieve transmission constraints and defer transmission and distribution system upgrades. The Council will track regional demand response implementation to assess progress, recognizing that the lack of a regionwide economic signal for capacity makes adopting demand response challenging. Based on the scenario analysis, the Council recommends Bonneville and regional utilities consider the value of adequacy, capacity, and emissions reduction when evaluating demand response in integrated resource plans and other analyses. As organizations and utilities develop demand response capability, they should do so by leveraging existing energy efficiency infrastructure and considering them together as part of an integrated demand-side management approach to optimize delivery of both resources holistically and equitably. We recognize, however, that our demand-response target recommendation depends, in part, on investments made by utilities to install advanced meters (AMI) across their service territories. While many utilities have installed advanced meters and the back-office architecture necessary to implement TOU rate designs, those that have not may need financial support to accomplish it. Therefore, we encourage Bonneville, regulators, and utility leadership to support investment in AMI architecture as a tool to encourage the most efficient use of grid resources.

36 The Council included both price (or tariff)-based and control-based products in the demand response supply curves. As a tariff-based product, TOU is not dispatchable and does not have a cash incentive for customers to participate and thus utilities have less ability to deploy for emergency needs. However, for a consistent, short-duration period of need, TOU can be beneficial. TOU was included in our demand response supply for analytical purposes, utilities may choose different analytical approaches in determining the value for their system.

In addition to these resources, the Council recommends Bonneville and the regional utilities, along with their associations and planning organizations, work together and with others in the Western electric grid to explore the potential costs and benefits of new market tools, such as capacity and reserves products, that contribute to system accessibility and efficiency. We would expect to see significant cost savings from greater regional collaboration to drive more efficiency into the system operations. A more aggressive examination would expand such a cost and benefit analysis to include the development of an organized or independently operated electricity market across the region. While any market design should protect the region's investments in its existing generation and transmission system, there may be reliability and cost benefits from the central dispatch of resources across a broad footprint. We also recommend the region concurrently work toward more collaborative understanding of the impacts of changes in market liquidity outside the region and the implications, especially for peaking and ramping periods, and pursue additional collaborative approaches to mitigate identified risks.

Historically, the Council has prepared a mid-term assessment of the plan a few years after its release and before work begins on the next plan. The primary purpose of the mid-term assessment is to check on the region's progress in implementing the plan.

The 2021 Northwest Power Plan includes many recommendations to the region and to Bonneville. We recognize that the regional power system is in an extraordinary time of change with many uncertainties associated with future system operations. The Council monitors the region closely and prepares annual adequacy assessments, forecasts, and other reports.

In the mid-term assessment for the 2021 Power Plan, we will update and examine its findings and examine any changes since it was finalized. While some circumstances will undoubtedly change after publication of the plan, we will examine if anything calls into question its fundamental strategy.

The Process of Developing the Recommended Resource Strategy

To make a recommendation to the region on how to meet the future needs for electricity most effectively, the Council assesses capabilities of the existing system and estimates the cost of adding new resources to keep up with system demands. The Council also needs to understand the costs of building and operating the system and how those costs change with different strategies to meet future energy needs. But both the system needs and the future cost of the system are uncertain. So, we project

more than just an expected future need and associated costs; rather, we look at a wide range of potential system costs and needs.

This is done with a combination of computer-based mathematical models and analysis. The Council uses the Energy2020 model[37] to estimate the future need for energy. The output demand for electricity, which is part of the total energy need, is then carried into the AURORA model[38] that is used to estimate electricity prices and the GENESYS model[39] used to evaluate if the regional electric system can adequately meet the demand for electricity. We also use the output demand for electricity to formulate supply curves for energy efficiency and demand response. And we use the output of all these models and analyses in our capacity expansion model, the Regional Portfolio Model[40].

These models, used in conjunction with our staff expertise and consultation with regional experts, inform the Council's recommended resource strategy. All these models are made to explore a range of possible future conditions and outcomes. We cannot pinpoint the future the region will experience, but we can hope that by exploring how resource strategies perform under a wide range of potential future uncertainty, our recommendations will be adaptable and reduce the risks our region faces going forward.

Forecasts Used in Developing the Recommended Resource Strategy

To estimate the impacts of the recommended resource strategy, the Council forecasts elements that impact the cost, operation, environmental impact, and reliability of the regional electric system. Some elements that impact the cost of supplying electricity include the price for importing electricity from outside the region and the cost of fuel for power plants that operate inside the region. There are dozens of power plants operating in the region that consume fossil fuels like natural gas and coal; in particular, natural gas-fired generation has been growing. These fossil-fuel-based power plants become especially important to the region during low-water years when hydropower generation is limited. The price of fuel for these generating resources, or power plants, is a key determinant of the cost of the electricity they generate. This makes the fuel price forecast an important input for the power plan.

While these forecasts are directly tied to the cost of providing electricity, we also need to estimate how much electricity will be

37 www.energy2020.com

38 energyexemplar.com/solutions/aurora

39 nwcouncil.org/energy/energy-advisory-committees/system-analysis-advisory-committee/ genesys-–-generation-evaluation-system-model

40 nwcouncil.org/regional-portfolio-model

needed. The Council uses its 20-year demand forecast, which covers a range of future potential electricity needs, when developing the resource strategy.

The electric system is part of the broader regional use of energy, and increasingly there are technologies that can switch between using fossil fuels and electricity. One example of this is electric vehicles that use electricity to charge a battery rather than the traditional internal combustion engine vehicle that uses gasoline or diesel. Understanding the future need for electricity requires that the Council adopt a broader view of energy use in the region. This allows the Council to forecast how much of the demand for energy will be served by electricity and gain a holistic view of greenhouse gas emissions related to different energy choices in the region.

Electricity Price Forecast

To forecast the future electricity price, the Council must look at the broader Western electricity grid. How many and what types of power plants utilities and other power producers around the West operate, build, or retire impacts the price of electricity in our region. The ability or lack of ability to move electricity from where it's generated to where it's needed also impacts the price we pay for electricity.

There are many factors that impact what power plants are built in the Western electric grid – the cost of different generating technologies, state and federal legislation intended to limit greenhouse gas emissions, the services and support needed to maintain the balance of supply and demand for electricity, and the regulatory barriers to building new fossil-fuel-based power plants, are examples of the influences that affect where a facility is located and its technology.

Further, no power plant is built without available transmission to deliver its output to the utility network or location paying for the output. The Council looks at a variety of scenarios that have different compositions and magnitudes of the plants built to produce electricity. These are developed in consultation with regional experts to understand the factors that will influence electric utility decisions.

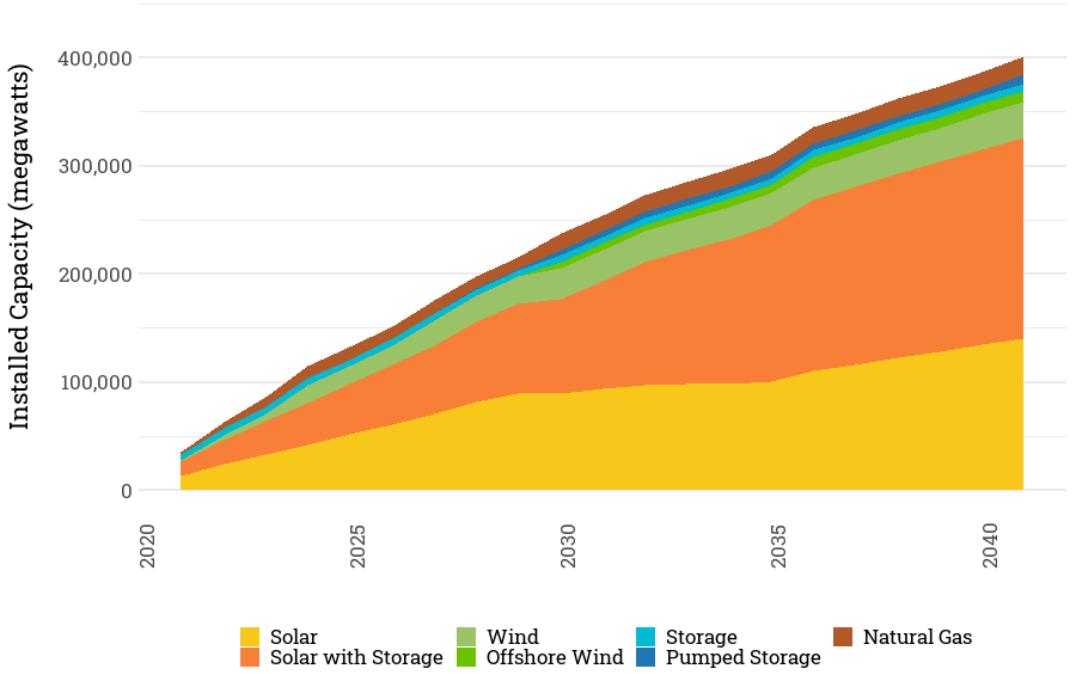
Considering the Council's' duty to assure an adequate and economically efficient supply of electricity for the region while respecting the renewable and clean energy targets of many Western states, the Council forecasts an extremely large addition of renewables. For example, the Council's baseline electricity price forecast adds around 400 gigawatts of nameplate capacity[41] to the Western electric

41 The nameplate capacity of a power plant is the maximum amount of electricity it can generate when it's fully functional and under optimal conditions or using the maximum amount of fuel. Another way of representing nameplate capacity is the manufacturer's rated output of the generator. Nameplate capacity should not be seen as representing the capacity contribution to system peak needs for any of the generating technologies

grid by 2041. The size of this addition meets the estimated reliability requirements for utilities outside the region and the states' requirements for renewable and clean power. It also limits the amount of new natural gas power plants to be built within region. To be clear, this forecast doesn't represent a forecast of power plants the Council expects will be built in the future. Rather, it shows what we estimate it would take to meet all the various requirements put on Western electric utilities.

However, such a large addition of new renewable power plants leads to a substantial oversupply of electricity during certain hours of the day and seasons in the year. The amount of electricity that could have been produced but instead is expected to be curtailed increases substantially through time with an addition of this magnitude. The next chart shows how the

Projected Generation Additions



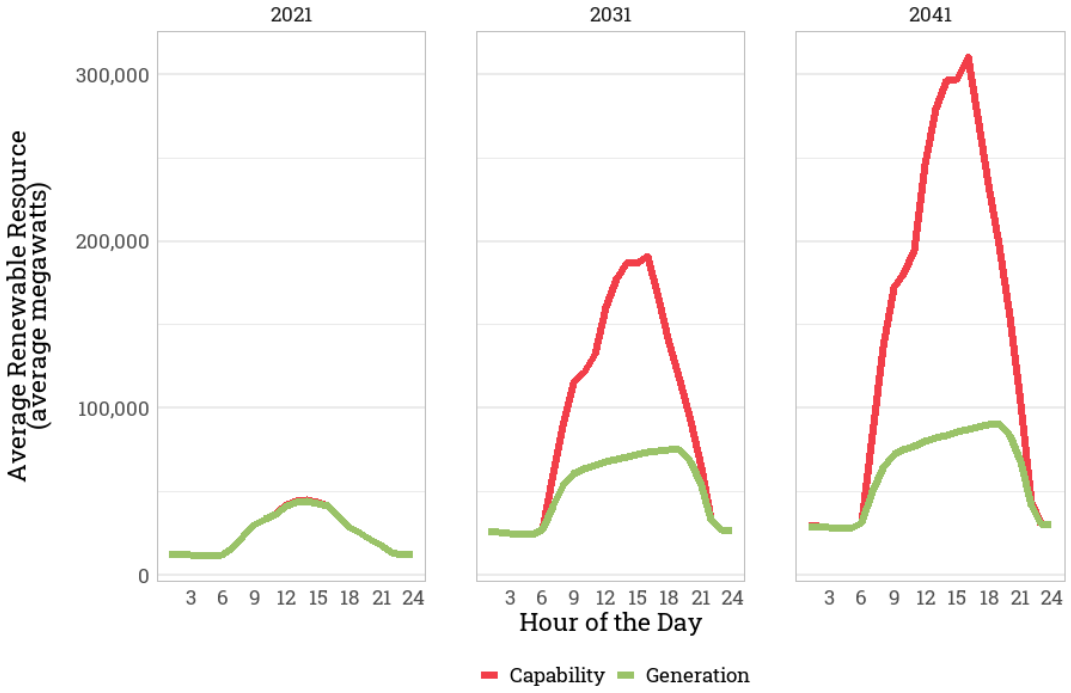
examined in this plan. For example, a wind plant with a 100-megawatt nameplate capacity will generate 100 megawatts when every turbine in the wind plant is at maximum output. However, during many hours when there is not enough wind, the wind plant will produce less electricity. Depending on location, a wind plant may average between 30 and 40 megawatts of generation over a whole year. In this case, the wind plant has between a 30- and 40-percent capacity factor. Further, neither nameplate capacity nor capacity factor should be confused with the capacity contribution to system peak needs, which is discussed in Section 4: Forecast of Regional Reserve and Reliability Requirements.

average amount of curtailed renewable generation increases substantially in 2031 and 2041 compared to 2021.

Regardless of how many power plants are built, the Council expects electricity prices to vary from year-to-year based on natural variability in demand for electricity and the available supply of electricity. In our region, electricity generated by hydropower is a substantial portion of the electricity we use. But the amount of electricity that can be produced depends on the weather. The weather can also drive demand for electricity, with extreme cold in winter or extreme heat in summer increasing the need for heating or air conditioning, requiring more electricity than normal.

From the River Management Joint Operating Committee (RMJOC) recent report on climate data analysis,[42] the Council selected three out of nineteen RMJOC climate scenarios to analyze the boundary conditions of potential regional climate change impacts.[43] From analysis of the temperature and streamflow data of the three RMJOC climate scenarios, the Council projects, in general, increasing winter hydropower generation due to increasing fall and winter streamflows from

Renewable Resources in the Western Electric Grid: Average Generation Versus Capability by Hour of the Day



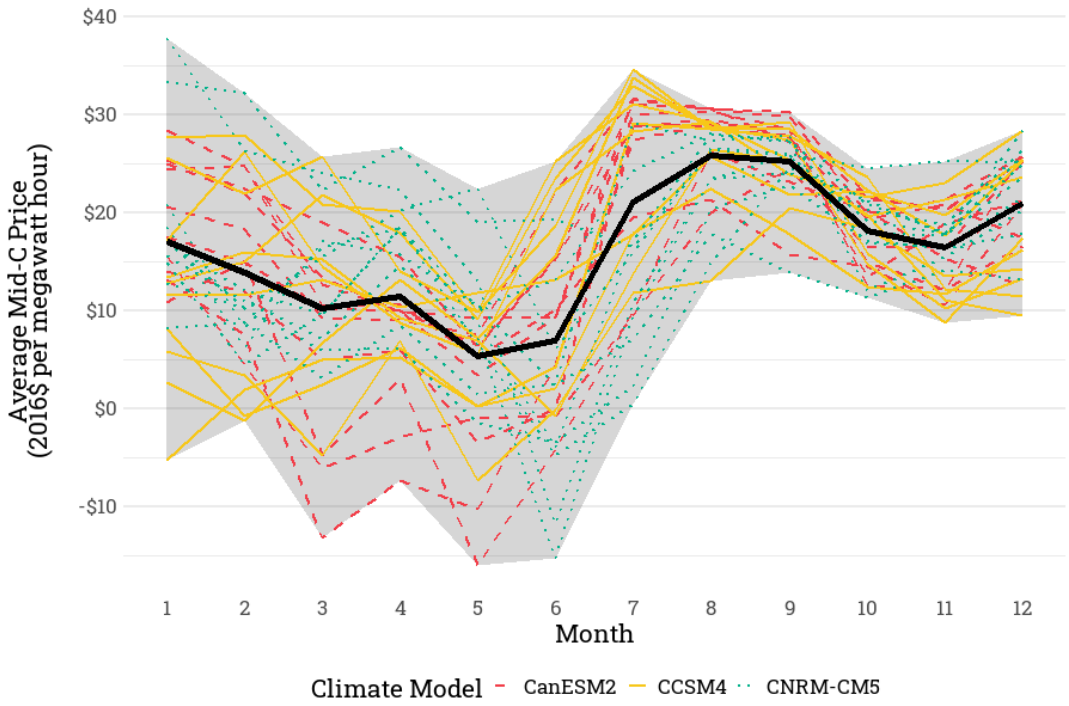
42 nwcouncil.org/2021powerplan_summary-climate-change-scenarios

43 nwcouncil.org/2021powerplan_climate-change-scenario-selection-process

having more precipitation which also falls as rain rather than snow, and in contrast, decreasing summer hydropower generation from decreasing summer streamflows caused by a shrinking snowpack and less summer precipitation.[44] Based on these data, the Council also forecasts, in general, a trend of less frequent extremely cold winter temperatures but more frequent extremely warm summer temperatures.[45] These climate impacts put downward pressure on winter electricity prices and align regional needs in the summer with the predominant electricity use in the Western electric grid. The Western electric grid uses more electricity in the summer than in the winter. All these factors taken together will put upward pressure on summer electricity prices.

The Council selected data for 30 different potential temperature and water conditions from the three climate scenarios for each year of the forecast horizon.[46] These data also include a decadal shift showing different anticipated conditions for the 2020s, 2030s, and 2040s. The changes from one decade

2026 Forecast Electricity Prices by Climate Model Hydro Conditions



44 nwcouncil.org/2021powerplan_trends-in-historical-and-climate-change-river-flows

45 Extremely cold regional winter temperatures are defined as those at or below 20F. Extremely warm regional summer temperatures are defined as those higher than 90F.

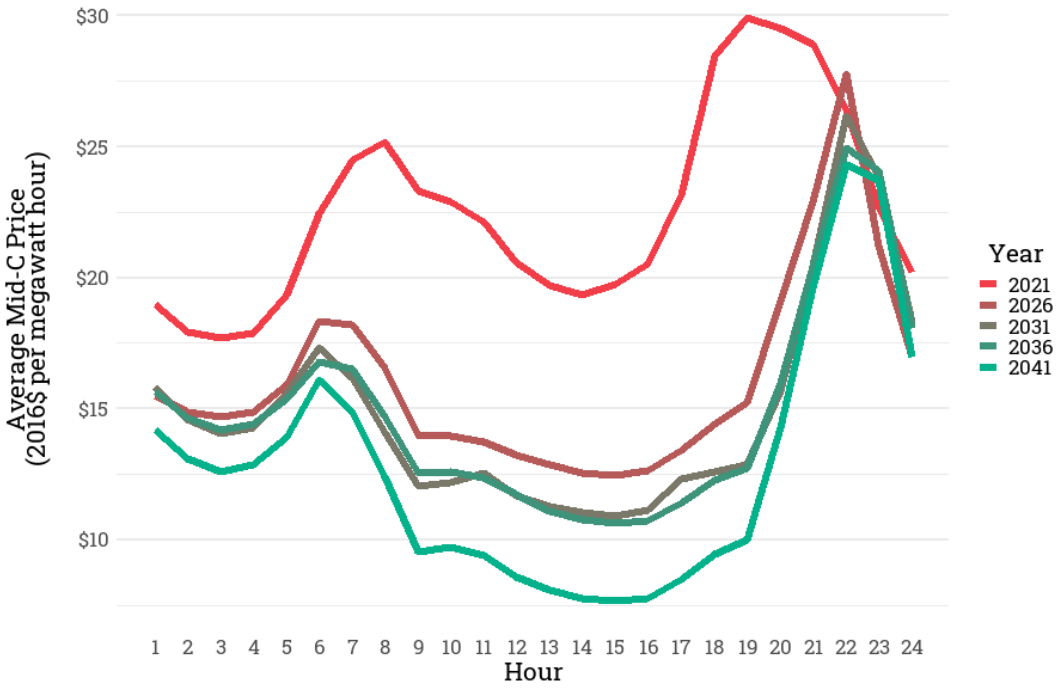
46 nwcouncil.org/2021powerplan_integrating-climate-change-policies-and-data

to the next reflect the continued impact of climate change.[47] Hydropower conditions with more water available for generating electricity cause lower electricity prices, whereas conditions with less water and thus less hydropower generation cause higher electricity prices.

Using the estimated range of electricity demand, the range of expected hydropower generation, and the range of expected wind and solar generation, the Council estimates electricity prices 20 years into the future. These prices help test the resource strategy under a wide range of potential electricity prices. In summary, the Council finds that:

- Timing and magnitude of wind and solar generation and how the generation aligns with electricity demand is a major driver of prices throughout the West
- Different amounts of water going through the hydropower system continue to be a major driver of seasonal price variation within the region
- At some level of building additional renewable generation, extremely low or

Mid-Columbia Average Hourly Prices



47 Specifically, the Council uses the Representative Concentration Pathway (RCP) 8.5 which reflects an end-of-century radiative forcing of 8.5 watts per square meter.

even negative prices occur, and these are aligned with times when we see substantial curtailment of renewable generation

- Prices for natural gas and coal continue to impact the electricity price during hours when fossil-fuel-based power plants are needed to preserve the balancing of the supply and demand for electricity

Altogether, this shows a downward trend for prices when looking at averages. Certain hours, especially during the evening, continue to show potential for higher prices, but prices during the middle of the day are driven down by an increasingly large amount of solar generation throughout the West.

Natural Gas Price Forecast

Generally, the price of fuel is a function of supply and demand. Factors that impact regional supply include how much gas can be extracted and processed, the capability to deliver natural gas to the region over pipelines, and how much gas is stored and ready to be delivered. The natural gas consumed in the Northwest originates from extraction fields in British Columbia, Alberta, and the U.S. Rockies. From there, high-pressure interstate pipelines move the natural gas into the region, where it is distributed to power plants, gas storage facilities, and homes, businesses, and industrial plants. Demand for gas typically peaks in the heating season, and if there are disruptions to supply, such as pipeline ruptures or equipment "freeze-offs," prices on the spot market can quickly escalate.

When this power plan was being developed, natural gas supply in North America was setting all-time high records through extraction techniques like hydraulic-fracturing and horizontal drilling. As might be expected, this resulted in low prices. In 2020, the average daily spot price for natural gas at the Sumas Hub on the Washington-Canadian border was $2.15 per MMBtu. Ten years ago, the price per MMBtu in current dollars was $4.60, and in 2005 it was $9.50. With the expectation of a sustained abundant supply and robust infrastructure, the Council forecasts continued low natural gas prices. However, as the region experienced in October 2018 with a pipeline rupture[48] in British Columbia, as well as the 2021 troubles in Texas,[49] natural gas prices can skyrocket on a daily or even monthly basis.

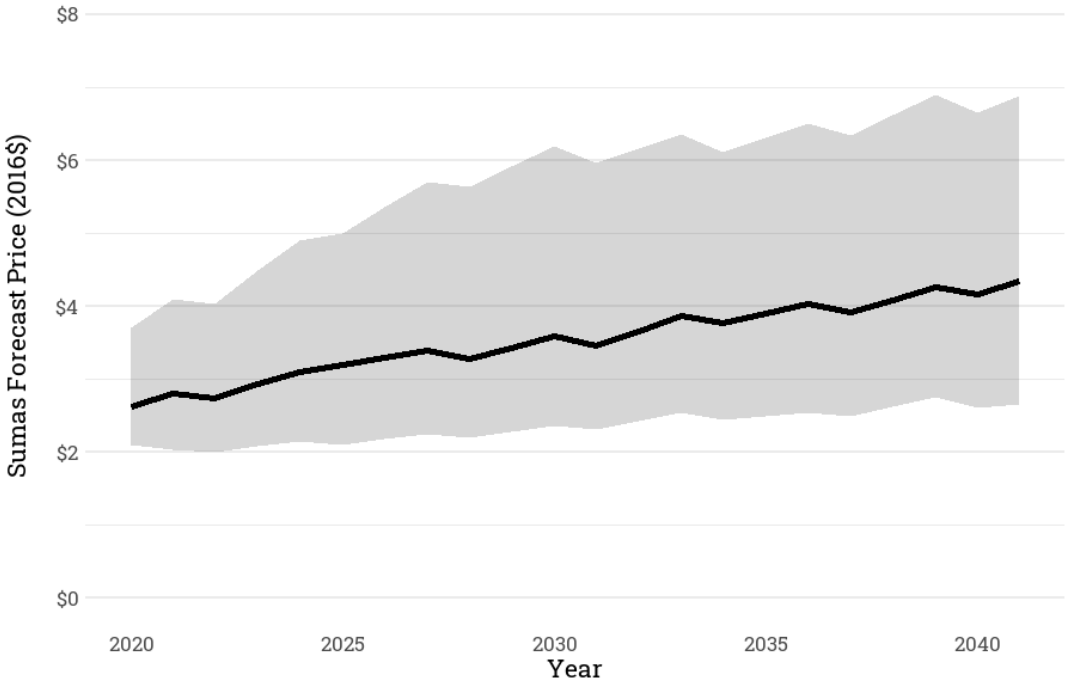
For the plan, the Council developed a range of prices across a suite of gas delivery points, including major gas hubs, power plant delivery points, and the city gate.[50] The figure

48 nwcouncil.org/news/gas-prices-spike-response-late-winter-cold-spell-and-pipeline-constraints

49 www.naturalgasintel.com/texas-investigating-natural-gas-pricing-during-february-winter-storm

50 City gate is the point where a natural gas local distribution company takes the gas off the pipeline system to distribute to customers. City gate prices are a common price point to look at for retail market prices.

Natural Gas Price Forecast for the Sumas Hub



above is the forecast of annual prices at the Sumas gas hub.

Coal Price Forecast

The price forecast for coal – which represents the delivered fuel price to each state from the Powder River Basin in Wyoming – is relatively flat and stable. Wyoming is the largest coal-producing state in the United States and a single mine – the North Antelope Rochelle/ Peabody Mine – supplies 13 percent of the coal in the country.

Forecast of Delivered Coal Price in 2016 $/MMBtu

State	2020	2025	2030	2035	2040	2045
Montana	$1.37	$1.46	$1.51	$1.52	$1.55	$1.56
Oregon	$2.19	$2.33	$2.41	$2.43	$2.45	$2.46
Washington	$1.91	$1.90	$1.89	$1.91	$1.93	$1.94

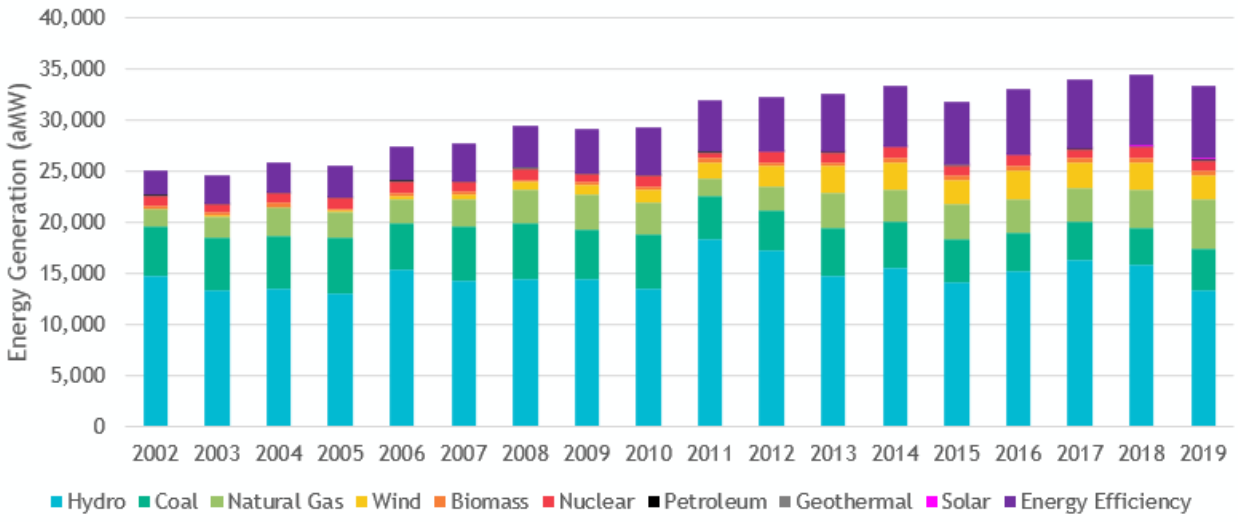
Assessing the Capabilities of the Existing Regional Electric System

The Pacific Northwest power system is undergoing a major shift that will alter the current energy supply landscape over the next several decades. New state and local policies are affecting existing resource dispatch and future resource development. Coal-fired generators are being phased out due to economics and initiatives to reduce greenhouse gas emissions. The future of natural gas development and contributions to the system are uncertain. Inexpensive wind and solar development continue to dominate new construction. Energy storage is becoming more common in the West, both as a stand-alone resource technology and partner to renewables, with the cost for the technology declining substantially in the last few years.

Resources

There are about 63,000 megawatts[51] of generating resource capacity either installed in the Pacific Northwest or located just outside the region and under contract. In addition, some of these megawatts installed in the region are also serving load outside of the region, such as wind projects under long-term power purchase agreements to California and surplus supply exported outside the region through the electricity markets. On average, the region's resource portfolio generates about 26,000[52] average megawatts annually. When energy efficiency

Pacific Northwest Annual Energy Production, including Energy Efficiency



51 See nwcouncil.org/news/megawatt-powerful-question

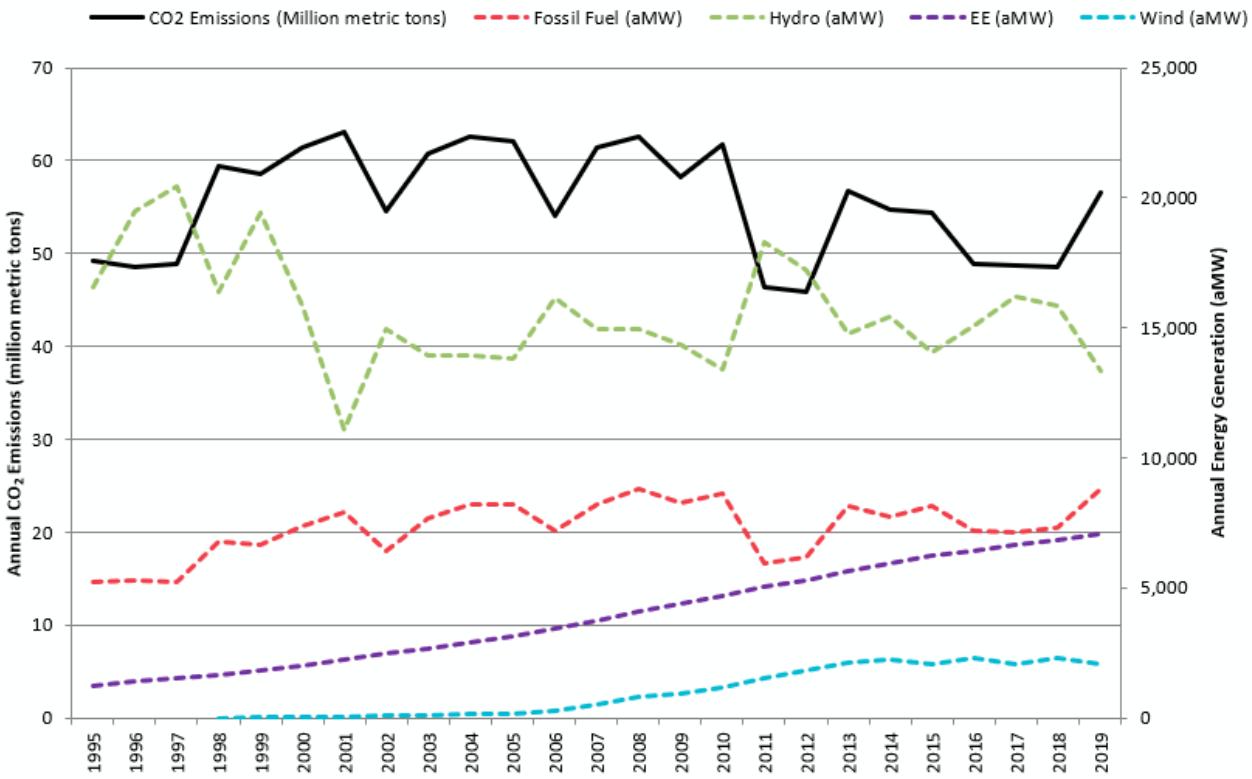
52 From 2012 to 2018 the total generation in the Western electric grid was about 99,131 average megawatts so the region is about a quarter of the total load.

is included, that number increases to about 32,500 average megawatts.

Hydropower generation remains the cornerstone of the Pacific Northwest power system, dominating the regional energy supply. However, hydropower generation varies significantly from year-to-year, depending on weather conditions and snowpack levels. The regional dispatch of fossil fuel resources is directly related to how much electricity is produced with hydropower. In years with lots of water flowing through the hydropower system (for example, 2011), coal and natural gas resources generate less electricity, whereas in years with less water (for example, 2019) they generate more.

The Pacific Northwest has one nuclear plant – Columbia Generating Station – that produces consistent and predictable generation, following a biennial springtime refueling schedule. Onshore wind has made an increasing annual contribution to the region's energy supply, as wind development picked up in the mid-2000s in response to state renewable portfolio standards and federal tax incentives. Solar photovoltaics (PV) began to appear in the region in 2010, and while

Direct Carbon Emissions (left y-axis) from the Generation of Electricity Compared to Amount of Generation by Fuel (right y-axis)



the current solar PV fleet is relatively small compared to other resources, it is expected to increase because the cost of solar has declined so significantly. Rounding out the region's energy generating portfolio are biomass resources, geothermal, and standby petroleum plants.

In addition to generating resources, demand side management resources play a significant role in the region. Energy efficiency is the region's second largest resource. Since 1978, the region has achieved more than 7,000 average megawatts of efficiency savings – around three times the average output of the Grand Coulee Dam, the region's largest generating plant.

Over the past 25 years, annual carbon emissions from the generation of electricity have averaged 55.5 million metric tons of carbon dioxide (not including upstream emissions). The relationship between hydropower generation and fossil fuel dispatch leads to the region's carbon dioxide emissions varying from year-to-year. This can make it difficult to decipher overall trends, although there are indications that demonstrate emissions have been decreasing overall – and that is because of fossil fuel generation dispatch. While fossil fuel generation largely dispatches based on hydropower conditions, overall, fossil fuel generation has been steadily increasing. However, the dynamic between coal and natural gas dispatch is changing. On average, coal generation has been slowly declining in the past few years due to coal plant economics and low natural gas prices. Conversely, natural gas dispatch has been increasing thanks to low fuel prices and increased natural gas availability. In 2018, natural gas generation surpassed coal generation on an annual basis for the first time. As coal units in the region are scheduled to retire, and as energy efficiency, wind, and solar continue to increase, emissions will begin to noticeably decline on a consistent basis.

Upstream Methane Emissions

Natural gas has been undercutting coal economically for some time, and the combustion of gas emits less carbon dioxide (CO_2) than coal. However, the primary component of natural gas is methane (CH_4); a greenhouse gas that when released directly into the atmosphere has a warming potential over 80 times[53] that of CO_2 over 20 years.

There are two primary greenhouse gases related to the combustion of natural gas – CO_2, and CH_4. Direct emissions refer primarily to the CO_2 emissions released at the point of use. Upstream emissions occur as methane is released or accidently leaked to the atmosphere as fossil natural gas is extracted and transported to the point of use.

53 www.epa.gov/ghgemissions/understanding-global-warming-potentials

The global atmospheric concentration level of methane has been steadily growing since NOAA[54] began taking measurements in 1983. Some of the largest annual increases have occurred in recent years, indicating the problem is getting worse. It's not clear what all the causes are, but oil and natural gas activities contribute to the overall global methane emissions. By estimating upstream methane emissions related to fossil fuel use in the region, the Council gets a more accurate picture of greenhouse gas emissions related to regional energy use. With an increased focus on the upstream methane release issue, the Council expects there will be fewer releases in the future.

Policies

The adoption of state renewable portfolio standards (RPS) in Washington, Oregon, and Montana[55] in the mid-2000s, combined with federal and state tax incentives and renewed opportunities for PURPA-qualifying facilities, contributed to a significant increase in renewable resource development over the last two decades. Now, as tax incentives phase out and upcoming RPS targets are on track for compliance, a new policy movement is developing – decarbonization of the electricity system. States, utilities, and communities have instituted aggressive clean-energy targets and economywide greenhouse gas reduction goals that will influence the future construction of generating plants in the region, Western electric grid, and national electric system. In the Northwest, Washington and Oregon have statewide clean-energy regulations, requiring a 100-percent clean, non-emitting electricity supply by 2045 and 2040, respectively. Idaho and Montana also have state greenhouse gas reduction goals, and utility- and community-level clean electricity goals that, in addition to a state RPS, lead to considerable aggregate state clean-energy goals.

Retirements

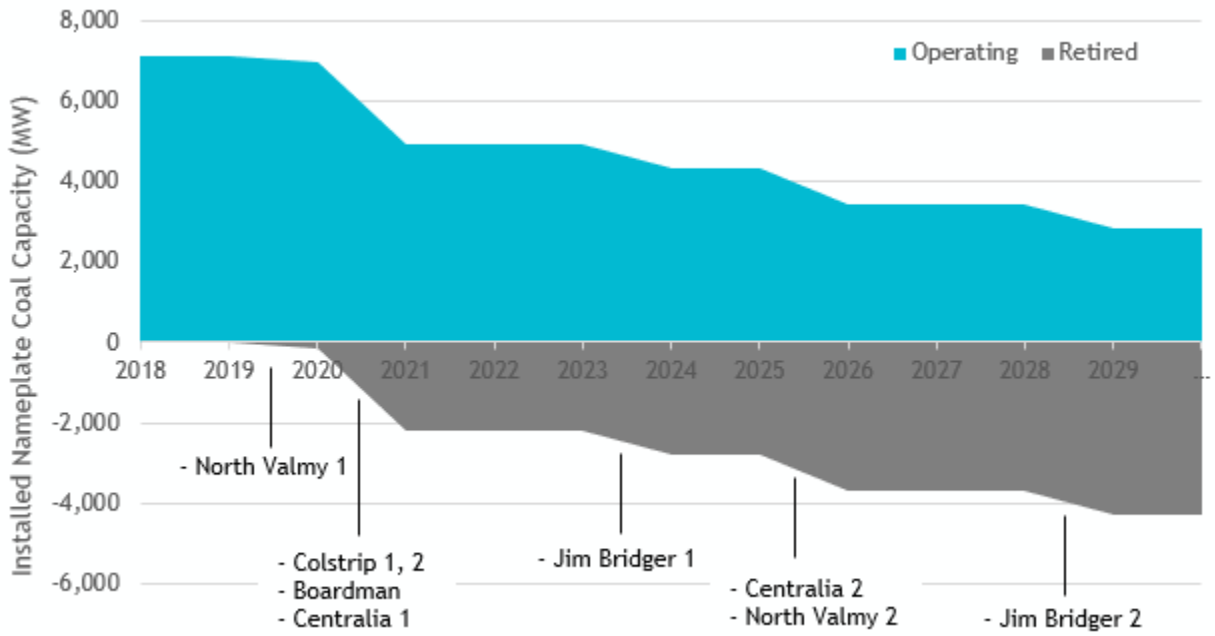
With the increasing emphasis on decarbonization, specific policies that prohibit coal-fired generation in the future have been enacted in several states in the West – including Oregon and Washington. In addition, the economics that previously favored inexpensive coal-fired generation have dramatically swung to favor natural gas generation due to consistently low natural gas prices and low-cost renewable resources that have low or no variable operating costs. This has led to the early closure of coal-fired generators in the region and across the West.

In 2018, the region's coal fleet totaled around 7,000 megawatts of capacity. In just a few short years, with the retirement of Colstrip units 1 and 2, Boardman, Centralia unit 1, and Idaho Power's exit from North Valmy unit 1, the coal fleet is now just under 5,000

54 gml.noaa.gov/aggi/aggi.html

55 Montana repealed its RPS in May 2021

Pacific Northwest Coal Fleet: Unit Retirements



megawatts. By the end of 2028, that number will decrease even more to around 2,400 megawatts through the planned retirements of Jim Bridger units 1 and 2, Centralia 2, and North Valmy unit 2. While some coal units remain in 2029, with multiple owners and competing interests for each remaining unit, the future of these resources is uncertain.

Assessing the Potential for New Resources

In assessing the potential for new electricity resources, the Council considers not only the cost of maintaining and fueling the existing electric system, but also the cost of adding new resources to meet changing and expanding needs for electricity in the region. The Council estimates the cost and potential for resources that the region can use to meet these needs. This helps in getting a complete picture of the cost of supplying the region's future electricity needs. In developing a resource strategy, the Council analyzes the difference in cost and performance of potential additional resources to make recommendations for the most effective way to adequately meet regional demands for electricity.

New Opportunities for Energy Efficiency

Energy efficiency is a reduction in the use of electric energy from the increased efficiency of energy use, production, or distribution. Historically it has been the least cost resource acquired by energy providers. As such, energy efficiency acquisition reduces system costs and is specifically referenced in the Act as the priority resource to be selected by the plan before renewables, natural gas

plants, and other generators are considered. Energy efficiency has helped the region avoid the need for, and the costs associated with, building and maintaining numerous power plants, as well as the price risk associated with fuel purchases needed for thermal plant operations. In addition, energy efficiency supports system reliability and hydro system flexibility, and it has been used to avoid or delay distribution system investment to serve peak load. For these reasons, assessing the potential for energy efficiency to meet future system needs is an essential part of the plan. The Council assesses all efficiency completed through utility programs, energy codes, appliance standards, and natural market impacts prior to the start of the plan. These are included as part of the demand forecast and not included in the forward-looking energy efficiency potential estimates.[56]

The starting point for assessing the potential for energy efficiency as a resource is to define each unit of savings, or "measure." A few examples of these measures[57] include efficient light bulbs, insulation, better windows, heat pump water heaters, and more efficient fans. The energy savings per unit (e.g., electricity consumption of a heat pump water heater relative to a standard electric resistance unit), combined with the number of units (e.g., number of homes with electric water heating) provides the amount of savings potential for a given measure. Adding up all the possible measures for homes, businesses, and industries results in a forecast of efficiency potential.

In addition to the electricity savings, a measure is defined by the incremental cost to install or implement the efficiency and a variety of other costs (e.g., maintenance cost) or benefits (e.g., additional water savings). The Council takes all the costs and benefits and adjusts the total cost[58] of these measures to come up with a cost that can be compared to other types of resources.

The amount of energy efficiency available during the planning horizon is developed and formulated into a supply curve, which gives the amount in average megawatts of savings at different measure costs (in dollars per megawatt-hour). The energy efficiency supply curve below shows all energy efficiency

56 Energy building codes and appliance efficiency standards established prior to the end of 2019 are accounted for in the Council's baseline forecast.

57 To define the individual measure costs and savings, several sources are used. Primary among them is the Regional Technical Forum (RTF). For measures not considered by the RTF, the Council relies on secondary studies from both regional (e.g., NEEA) and national sources (e.g., DOE). The total number of units (e.g., number of homes) in the region is largely based on the sector-specific stock assessments conducted by NEEA.

58 The measure costs include total system cost (per the Northwest Power Act), and both costs and benefits combined into a net levelized cost, referred to as the Northwest Resource Cost. This levelized cost is the net present value of the measure costs divided by the measure savings. In this manner, the costs for conservation are developed consistently with other generating resources.

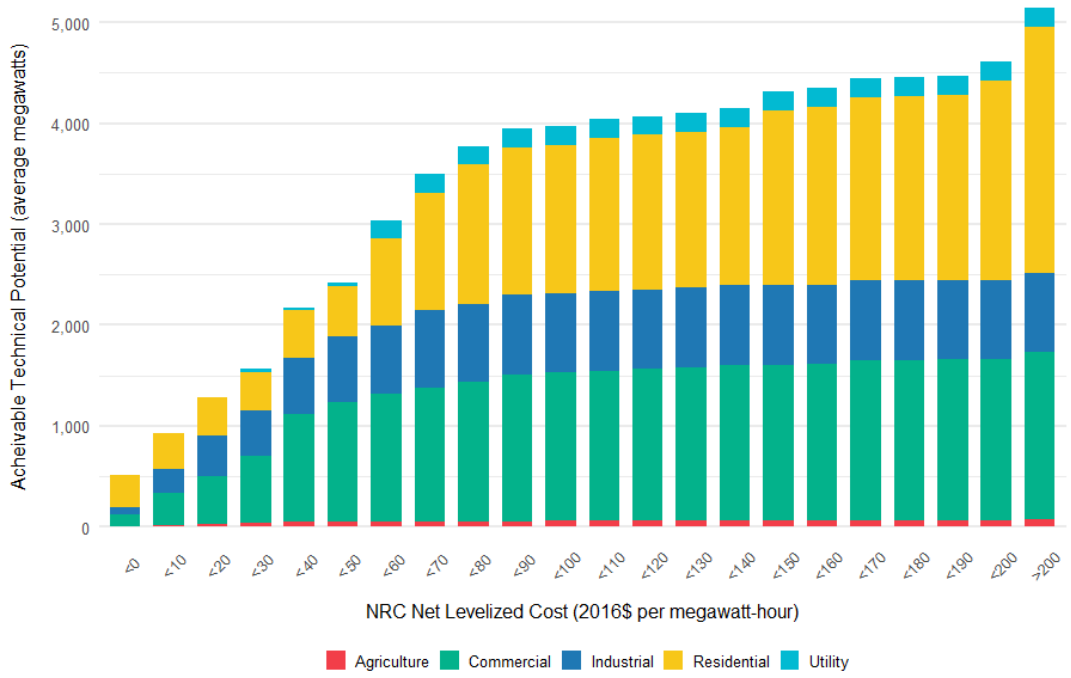
available through 2041, differentiated by sector and by cost. The figure shows 1,337 average megawatts as the total amount of energy efficiency potential by 2027 and 5,144 average megawatts by 2041, accounting for technical and feasibility limitations. The supply curve is used to compare energy efficiency to other electricity resources, providing an amount of efficiency available at increasing costs, and can be used to meet future regional electric system needs.

The timing of when the savings from energy efficiency occur is also an important part of our analysis. As the price of electricity varies by day and by season, the value of the energy efficiency will also vary, depending on the timing of savings. For the supply curves, energy savings are greater during winter than summer. The shape of the savings for the complete set of energy efficiency is developed by combining all the individual measure shapes.

Demand Response Supply Curve

Demand response (DR) is "*a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/ transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating*

Energy Efficiency Supply Curve, Differentiated by Sector for 2041



parties."[59] The need for demand response arises from the mismatch between power system costs and consumers' prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is that consumers do not have the information that might encourage them to curb consumption at high-cost times and/or shift consumption to low-cost times. The ultimate result of the mismatch of costs and prices is that the increased power system needs require building more peaking capacity, building more transmission, and incurring more system upgrades than would be necessary if customers changed their use in response to price changes in the market. Programs and policies to encourage demand response are efforts to provide this information to consumers and create the infrastructure to allow them to respond to price signals in the market.

The Council evaluated demand response products that impact residential, industrial, commercial, and agricultural sectors, as well as the utility distribution system. Demand response products evaluated include utility-controllable and price-responsive options across the sectors. Utility-controllable products give the utility the ability to change the operation of end-use equipment to reduce peak. Price-responsive products give the end-use customer the ability to choose how to modify loads based on a price signal from the utility. In general, price-responsive products are less expensive because equipment needs are lower, but the utility has less control over the resulting impact.

In total, 23 demand response products were incorporated into demand response supply curves. The Council estimates about 3,721 megawatts of summer load reduction potential and 2,761 megawatts of winter load reduction potential.[60] This potential was focused on reducing load during times of system need, though it is recognized that demand response could also be used to increase loads during low or negative prices to balance with supply. The potential is based on an estimated impact per participant and the potential number of participants based on eligibility (e.g., customers need to have air conditioning to participate in an air conditioning control program); assumptions of willingness to participate; and participation rates for any given demand

59 This definition was developed by the Demand Response Advisory Committee nwcouncil.org/energy/energy-advisory-committees/demand-response-advisory-committee

60 The difference in load reduction is based on the underlying demand response measures. Some programs, like curtailment of residential air conditioning only impact the summer season, while other programs like space heating only impact the winter season. While the potential numbers referenced here give a sense of the impact of demand response relative to other resources, the deployment of demand response by utilities could differ based on needs.

response event (a customer may opt out of any given event).

Products range in cost from $5 per kilowatt-year up to $250 per kilowatt-year (2016 dollars). These costs include setup, operation and maintenance, equipment, marketing, and incentives. The Council also incorporates benefits (or negative costs), such as deferring buildout of the transmission and distribution system by reducing electricity use during times of the highest electricity need.

New Generating Resources Potential

New generating resource technologies are assessed based on their cost, operating, and performance characteristics, and developable potential in the region. Resources that are commercially available and proven and have the potential to meet future needs in the region are further developed into reference plant estimates representative for the Pacific Northwest – with a designated plant size and configuration, performance attributes, costs, and other attributes such as construction schedule and economic life.

The Council developed reference plants for utility-scale solar photovoltaics (PV), solar PV + battery storage, stand-alone battery storage, onshore wind, natural gas combined cycle turbines, natural gas peakers, and pumped storage. In addition, one emerging technology reference plant was developed as a proxy for the many promising new technologies (for example, offshore wind, small modular nuclear, and enhanced geothermal systems) that could provide value to the region in the future.

The costs of renewable resources – and in particular solar PV – have decreased significantly.[61] Despite recent price fluctuations due to tariffs on imported materials and cells, the cost of solar PV is expected to further decrease in the future. While the cost of natural gas combined-cycle plants has largely remained the same, the cost of a natural gas frame unit – operated in simple cycle mode as a gas peaker – has decreased due to lower equipment costs and greater competition among vendors to secure fewer project development contracts. The costs of conventional geothermal and pumped storage hydropower resources are extremely site-specific, so it can be difficult to see any major trends.

61 According to the Lawrence Berkeley National Lab, over the past decade the installed cost of solar has declined about 70 percent and the installed cost of wind has declined about 40 percent. (emp.lbl.gov/webinar/utility-scale-wind-and-solar-us)

New Generating Resource Reference Plants: Capital Cost (2016$/kW) Trends

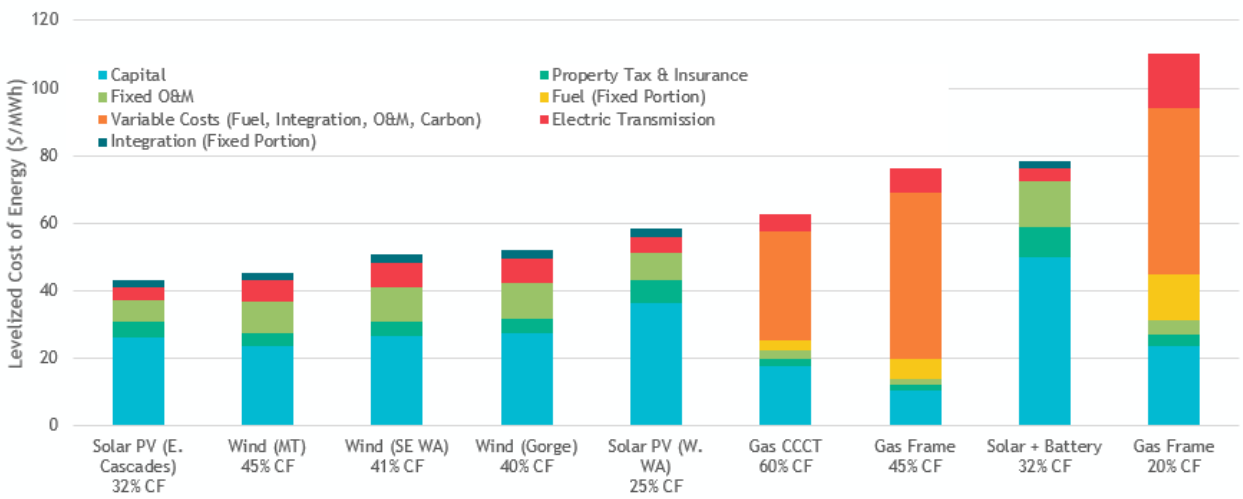
Resource	Seventh Plan (2016$/kW)	2021 Plan (2016$/kW)	Trend
Onshore Wind	$2,382	$1,450	Significant decrease
Solar PV	$2,566; $1,792 (low cost)[62]	$1,350 (E. Cascades); $1,465 (W. WA)	Significant decrease
Solar PV + Battery Storage (4 hr)	–	$2,568	–
Battery Storage (4hr)	–	$1,400	–
Pumped Storage	–	$2,300	–
Geothermal	$4,575	$5,400	No significant change
Natural Gas - Combined Cycle Combustion Turbine	$1,220	$1,150	No significant change
Natural Gas – Peaker (Frame)[63]	$859	$550	Decrease
Proxy Emerging Tech – Small Modular Reactor	–	$5,400	–

One way to compare the cost of a resource against another is to look at the levelized cost of energy, which is a metric used to estimate the cost of energy across a resource's expected economic life. It is calculated as the cost per unit of energy a resource is expected to generate (under an assumed level of dispatch or capacity factor) that also includes variable costs such as fuel. Although the initial cost for solar and wind may be higher than gas resources, with minimal operating costs (no fuel purchases), the overall cost of producing energy can be significantly less.

62 When the Council was evaluating solar PV in 2015 for the Seventh Power Plan, costs were dropping so quickly that a lower-cost solar PV resource option was added to the model analyses.

63 This price decrease also reflects a change in the reference plant technology class

New Generating Resource Reference Plants: Levelized Cost of Energy ($/MWh)[64]



While the Council doesn't explicitly model all new resource options, there are other commercially available resources with smaller-scale, location-specific potential in the Pacific Northwest (for example, biomass, small hydropower, distributed generation) that if cost-effective should be considered viable resource options for future power planning.

Planning for an Uncertain Future

The electric sector is in a time of transition. A wave of coal unit retirements will happen over the next decade. Climate change is altering hydropower generation, and policies designed to limit greenhouse gas emissions constrain how the electric sector expands the supply of electricity.

Utilities and regulators are looking to replace coal with completely different generating technologies like wind and solar generation. The cost of building solar and solar with on-site batteries has fallen substantially. But relying more on new technologies requires changing how the electric grid operates. The expansion of the Western Energy Imbalance Market makes the operation of the Western electricity grid more automated and intertwined. But it's just a start on the scope of change needed to transform the way electricity is generated.

The future of Northwest utilities will be different than the past.

64 In this graph, CF denotes capacity factor. For each generator, the capacity factor indicated the average amount of energy over a year relative to the installed capacity that was used in the levelized cost calculations for comparison.

Exploring Key Power Supply Questions Through Scenario Analysis

Understanding the potential future risk that will impact the electric sector of the economy takes a broad range of analyses. Some analyses involve creating a range for potential risks. For example, the Council forecasts a range of natural gas prices. The Council uses analytical approaches to consider the implications of natural gas prices that deviate from our expectation.

Other risk analyses involve setting up scenarios, or a set of high-level questions, that help assess future alternatives. The Council builds these scenarios by asking what conditions and processes would change and then reflecting them in our analytics.

Ultimately, scenario analyses help inform decisionmaking when developing the recommended resource strategy for the region and for Bonneville.

How the Scenarios Were Selected

The Council looked at high-level themes in the electric sector and the Northwest Power Act in constructing the scenario analyses. To incorporate Power Act requirements, the Council first focused on analyses that examined the adequacy of generating resources to meet the regional needs. Given the expansion of the Energy Imbalance Market in the West since the last power plan, the Council saw changing and expanding markets for electricity as an important theme for this plan.

The Council also used analyses to distinguish between the impacts of a resource strategy on Bonneville's portfolio of resources and the demand for electricity Bonneville is obligated to serve with those resources. Finally, the Council expected that understanding the implications for greenhouse gas emissions for the region was an important part of looking at future strategies on how the region can meet the demand for electricity.

After identifying these high-level themes, the Council examined seven scenarios to guide the analyses. The scenarios connected to one or more of the high-level themes and created distinct narratives that the Council determined would help construct an overarching resource strategy.

How the Scenarios Were Constructed

To construct the scenarios, the Council developed models and analyses that would be part of this plan. The Council then identified, given the narrative for each scenario, where the models and analyses had parameters that would differ. Each scenario involved exploring a range of different values and combinations for these parameters.

Scenarios Explored

The Council explored a range of scenarios designed to answer key questions about the future of the electricity grid. These scenarios

echo previous Council plans and also break new ground. The scenarios are:

Change in Reliance on Extra-Regional Markets for Resource Adequacy – an analysis of the impacts of relying on markets outside the region for resource adequacy.

Organized and Limited Markets for Energy and Capacity – an analysis of potential impacts from changing the structure and reliability of markets outside the region.

Early Retirement of Coal Generation – an analysis of the implication of accelerating planned retirement dates for coal generation throughout the Western electricity grid.

Robustness of Energy Efficiency – an analysis of how the resource strategy would change with different estimates and assumptions regarding the supply of energy efficiency.

Analyze the Bonneville Portfolio – an analysis of the Bonneville administrator's obligation to provide electricity and the available federal resources dedicated to meeting that obligation.

Greenhouse Gas Regulation and Cost Impacts – an analysis of the impacts of limitations, financial or otherwise, on greenhouse gas emissions from the electricity sector.

Pathways to Decarbonization – an analysis of the impact on the electricity sector of efforts to substantially reduce economywide greenhouse gas emissions.

Findings From Our Scenario Analyses

The Council has different methods for accounting for uncertainty. While some uncertainty or risk is modeled using ranges of values, for example the range of future electricity prices, some uncertainty does not lend itself to using a range of values. For those types of uncertainty, the Council uses scenario analysis. While scenario analysis is a useful method to describe uncertainty, it often looks at very unlikely outcomes to help in understanding the direction that policies or goals lead. The following descriptions of our scenario analyses focus on what we learned from these exercises. They should not be taken as a forecast of what is likely or as the sole basis for how we formulate a resource strategy.

Change in Reliance on Extra-Regional Markets for Resource Adequacy

The Northwest spent billions building transmission to connect to the rest of the West. This enables surplus electricity sales that offset the regional cost of electricity and allows purchases when the regional need exceeds the capacity of regional generators. Relying on electricity purchases from outside the region defers the need to build new generators, which reduces the cost of using electricity. However, maintaining reliable electricity requires both transmission to the Northwest and available generators outside the region.

Our baseline setup limits the amount of imports from the external market. After accounting for imports from power plants that are located outside the region but have contracts or obligations to deliver electricity to the region, the analysis limits regional imports to no more than 2,500 megawatts in the winter and 1,250 megawatts in the summer. Those limits are well below the ability of the region to import electricity on our transmission system. Because the Council has less information on the supply and demand for electricity outside the region, the Council uses these limits to represent uncertainty about the availability of electricity during times when the region is short of generation and fuel.

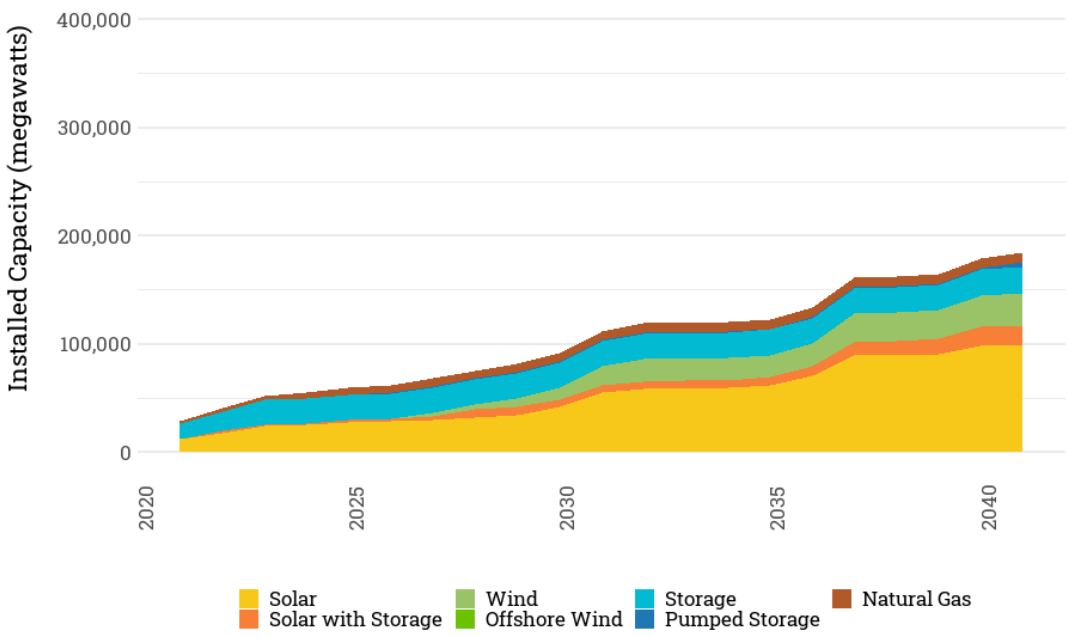
For this scenario, the Council relaxed these limits to allow the region to import up to the capability of the transmission system. While this reduced the adequacy-needs input into our resource analysis, the results from our models had minimal changes to the resource additions examined. While there were some minor changes to the pace at which renewable generators are built within the region, the overall results did not indicate removing these limitations would change the resource strategy.

Organized and Limited Markets for Energy and Capacity

The Council's analysis for this power plan has shown that the costs and risks faced by the region are connected to the policies and decisions beyond our borders. The choices of utilities in the rest of the West on what resources to build and retire directly impacts cost and reliability of power in the region.

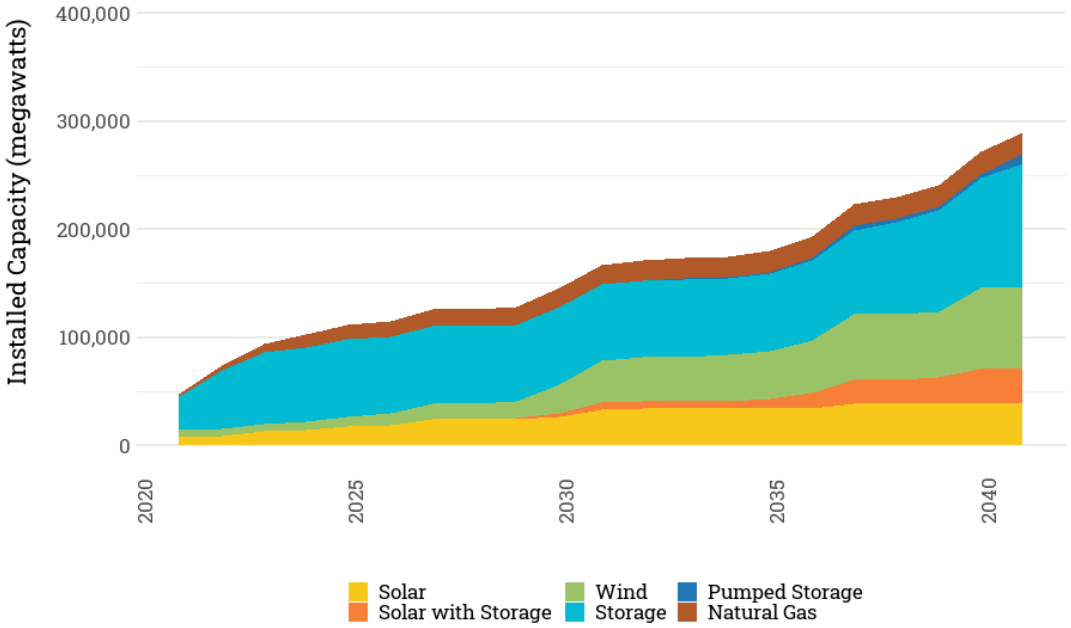
To help explore the impacts of electricity markets outside the region, the Council developed several different external generating resource addition projections and looked at the impacts of those different additions on the resource strategy.

Projected Generation Additions With Limited External Market Supply



In one projection, the Council substantially limited the supply of electricity outside the region. This projection met the current renewable portfolio standard or RPS requirements and the clean-energy requirements that limit the types of generation used in some Western states through about 2035, but fell slightly short of meeting these policies after then. By intent, the Western grid outside the Northwest did not have sufficient generation to meet the demand for electricity under stressful conditions. However, the Council did still see a substantial addition of solar power to both meet policy goals and at least partially replace retiring generation.

Projected Generation Additions With a Unified Market



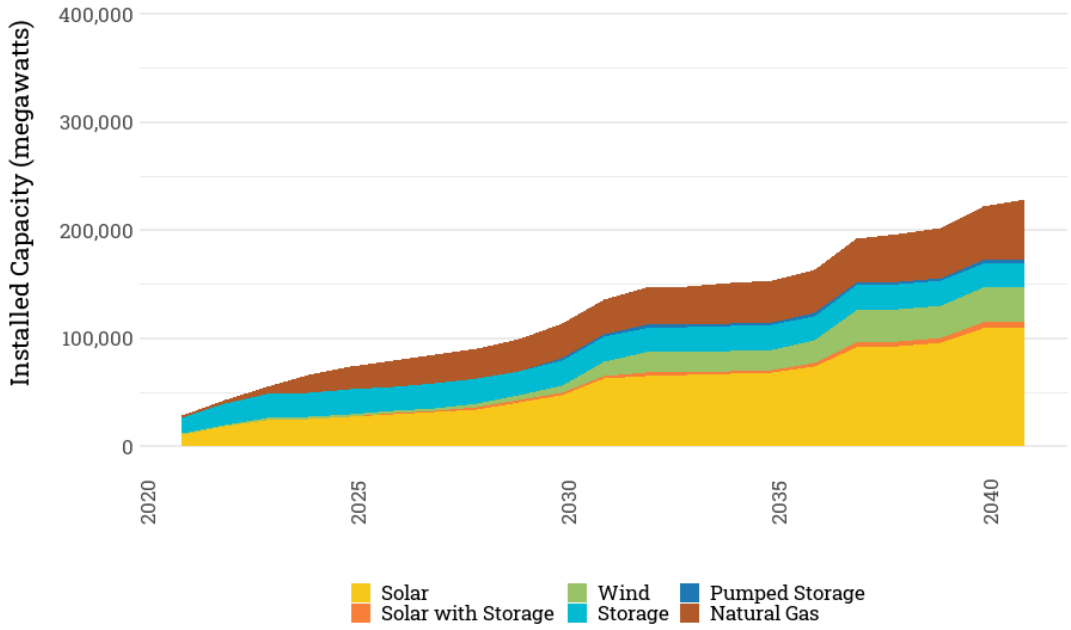
In another projection, the Council also explored resource additions if utilities created a combined approach to planning for new resources and created a unified transmission rate.[65] This was a proxy for how centrally dispatched markets with a consistently applied adequacy standard could impact decisions about resource additions.

Currently the Western electric grid has many different markets with a variety of manners for determining when generating resources are dispatched. There are standards that grid operators must meet set by FERC and NERC, but the operators in an inadequate system may be forced to selectively shut down electricity to parts of the grid to meet these requirements. Consistently applied adequacy standards would make the chances of curtailing electric service both lower and consistent from one region to the next.

In both projections, the Council included limits on the amount of new natural-gas-fired generation that could be built within

65 The important distinction is that access to the transmission system is available at the same rate everywhere, so dispatch is not driven by different transmission charges in different regions of the electric grid. This does not mean a unified transmission rate is necessarily cheaper, nor does it mean that transmission owners would all get the same return. This scenario should not be considered an indication that transmission right owners would either benefit or be disadvantaged from unifying a transmission rate. Discussing how unifying a transmission rate would work is beyond the scope of this scenario analysis.

Projected Generation Additions Without Limiting Natural Gas Builds



the Western electricity grid. These limitations were based on both Council expertise and consultation with regional experts on their expectation about resource selection around the West.

However, these limitations substantially increased the addition of solar and wind generation outside the region. To assist in understanding the impact of limiting new natural-gas-fired generation, the Council removed these limits and projected what adding natural gas generation would look like. In this case, the Council saw over 26 gigawatts of natural gas generation added by 2027, and over 55 gigawatts added by 2041. There was also a corresponding reduction in the addition of renewable resources, though there still were over 33 gigawatts of solar generation built by 2027, and over 115 gigawatts built by 2041.

The Council also wanted to isolate the impact of renewable generation included in the regional resource addition to help show the impact of additions within the region compared to additions outside the region. To implement this, the Council removed renewable generation from the resource selections in our analysis and examined the impact to the resource addition.

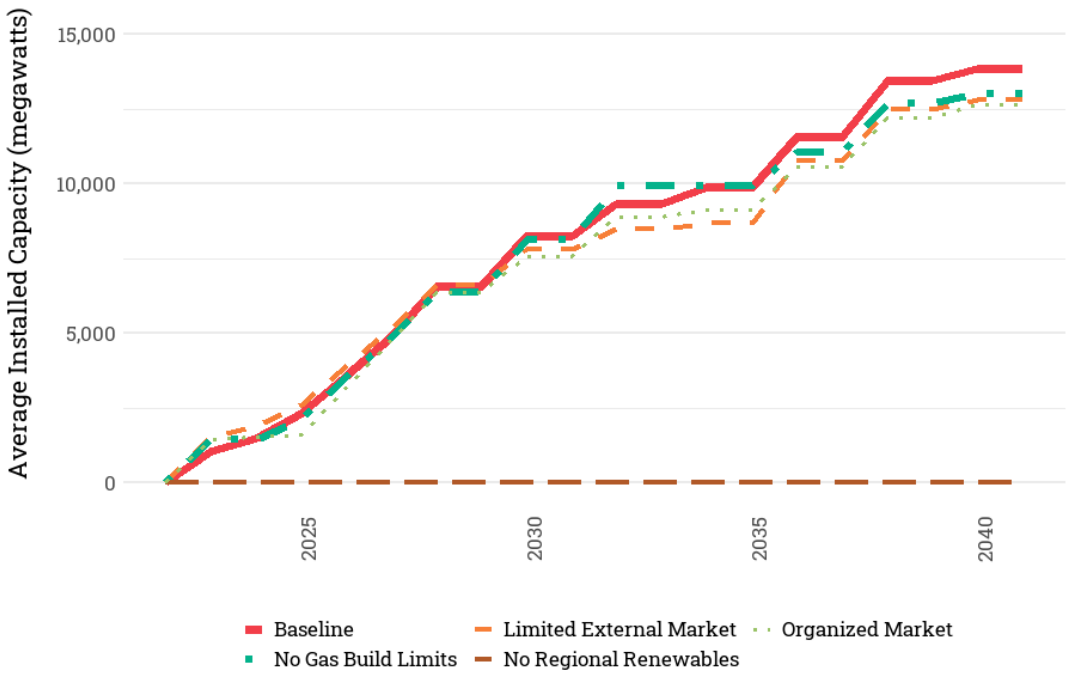
While the regional electricity prices associated with these additions varied, the addition of renewable resources only had minimal changes throughout all these projections except the one where renewable generation in the region was specifically excluded.

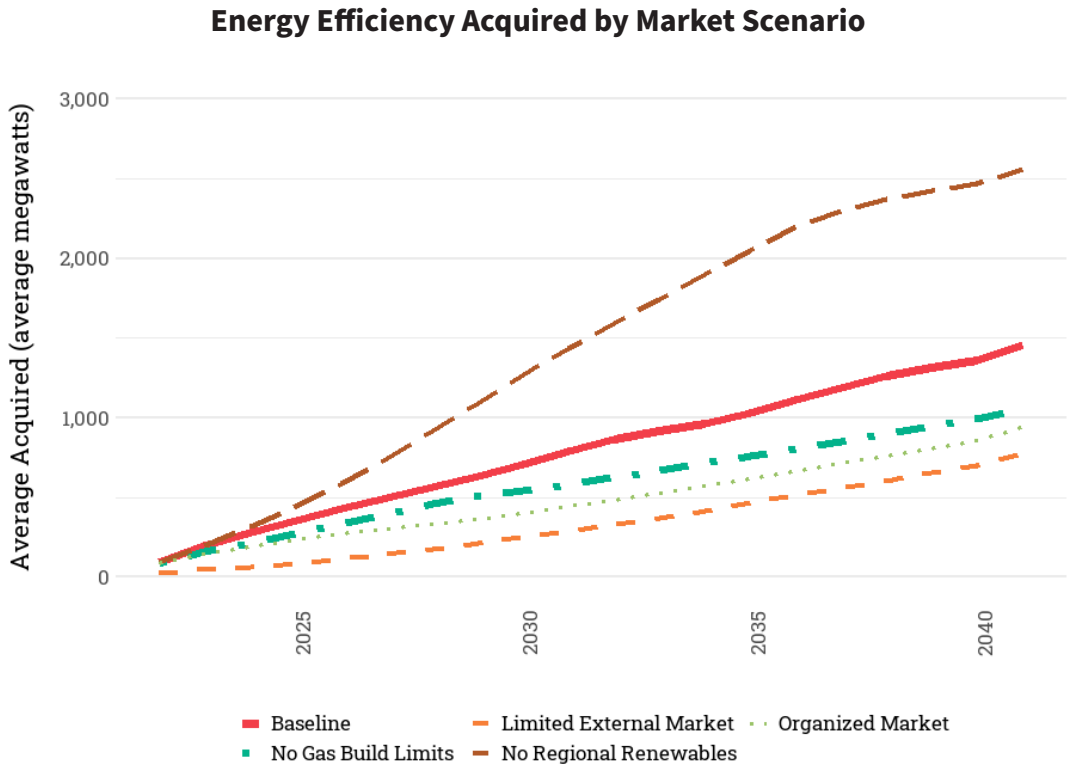
This indicates that renewable resource additions at this level are likely required to meet regional policy targets, in addition to being part of the least-cost portfolio under various assumptions about external markets.

In the projection where the Council eliminated regional renewables, there was a requirement for new natural-gas-fired generation to meet adequacy requirements. In this scenario, there was a high probability of adding at least one new power plant.

However, the biggest impact was on the addition of energy efficiency. In the projection where no renewables were built in the region, almost 750 average megawatts of energy efficiency were developed. In the projection with limitations on the external market, less than 150 average megawatts were developed.

Average Renewable Resource Builds by Market Scenario





These results show that while the regional addition of renewable generation was not particularly sensitive to electricity market prices, the addition of energy efficiency was sensitive.

Early Retirement of Coal Generation

Since the last power plan, utilities in the region and outside the region have announced the retirement of coal-fired power plants at dates that precede the end-of-useful-life dates that have been previously assumed in analyses by the Council and others. The Council understands that there is risk in retiring resources sooner than planned, especially coal-fired generation. This scenario explores this risk using the coal-fired generation fleet in the West. There are likely other types of generation that could have retirement dates accelerated based on economics or regulation. The Council did not analyze the likelihood of early retirement for all types of generation. Thus, this should be considered a directional analysis that was used to help the Council understand this observed risk.

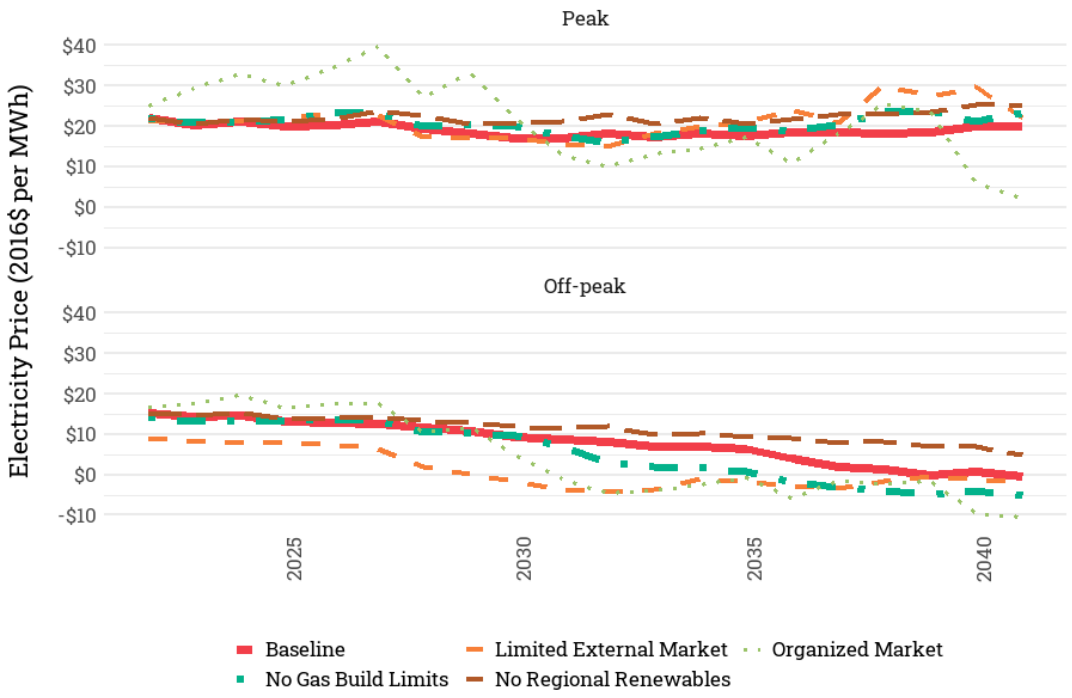
To implement this, the Council assumed that all regional coal-fired power plants were retired by the end of 2026. For coal plants

outside the region, the Council assumed that all plants were retired by 2030.[66]

Our analysis shows with this scale of retirement, emissions in the West would decrease just under 40 percent after all the coal plants are fully retired. Emissions in the Northwest would decrease over 80 percent.

The emissions reductions are greater in the region because the hydro generation in the region has resulted in a smaller natural gas-fired generation fleet relative to the rest of the West.

Regional Electricity Price by Market Scenario



66 These dates are not intended to represent likely dates that the coal-fired power plants would retire, rather they are intended to be a stress test of the power system and be informative on coal-fired generation's impact on greenhouse gas emissions.

Regional Coal Plant Unit Retirement Scenario Assumptions

Coal Plant Unit	Nameplate Capacity (MW)	Announced/ Existing Retirement Date (EOY)	Baseline Conditions Retirement Assumptions[67]	Early Coal Retirement Scenario Assumptions
Colstrip Unit 1	358	2019		
Colstrip Unit 2	358	2019	Retired	Retired
Boardman	601	2020	Retired	Retired
Centralia 1	730	2020	Retired	Retired
North Valmy 1	277	2019[68]/2021	Retired	Retired
Centralia 2	730	2025	2025	2025
North Valmy 2	289	2025	2025	2025
Jim Bridger 1	608	2023	2023	2022
Jim Bridger 2	617	2028[69]	2028	2026
Colstrip 3	778	–	2037	2025[70]
Colstrip 4	778	–	2037	2025
Jim Bridger 3	608	–	2037	2026
Jim Bridger 4	608	–	2037	2026

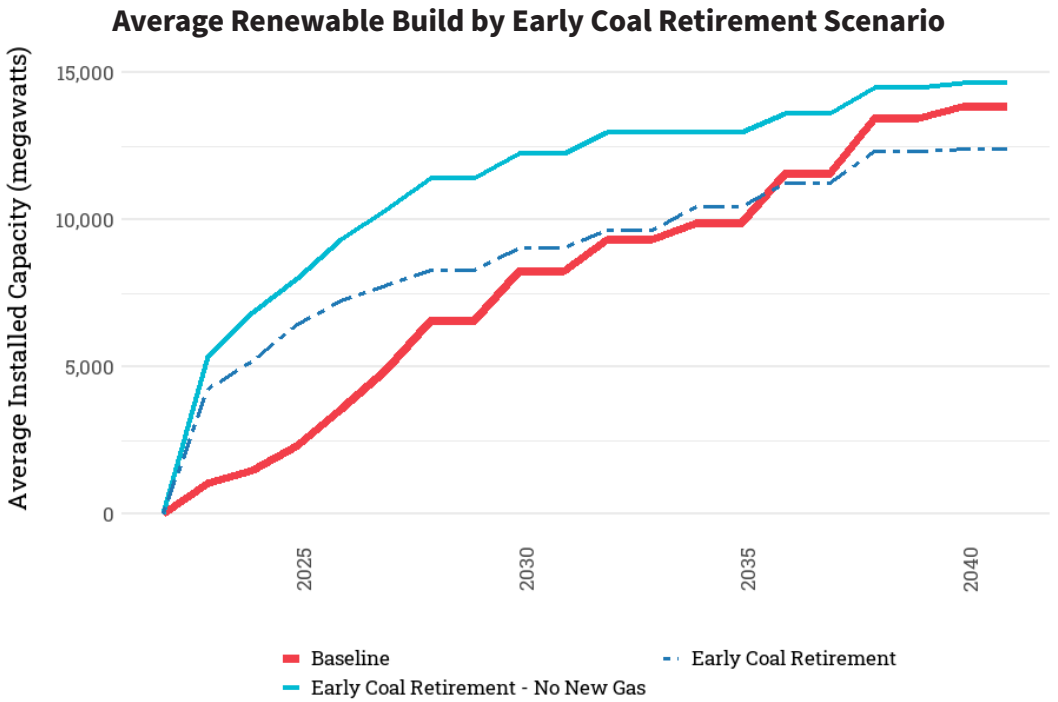
Without limiting the types of new generation, the expected resource addition by 2030 includes around 1,400 megawatts of nameplate capacity of new natural-gas-fired generation. Considering the decisions that would lead to early coal retirement, it seems unlikely that new natural-gas-fired generation would be considered for replacing retired coal generation. By eliminating new natural gas-fired generation from consideration, the expected renewable-energy addition in the region substantially increases.

67 For our baseline assumptions we use either the announced retirement dates or end-of-useful life dates used in utility IRPs.

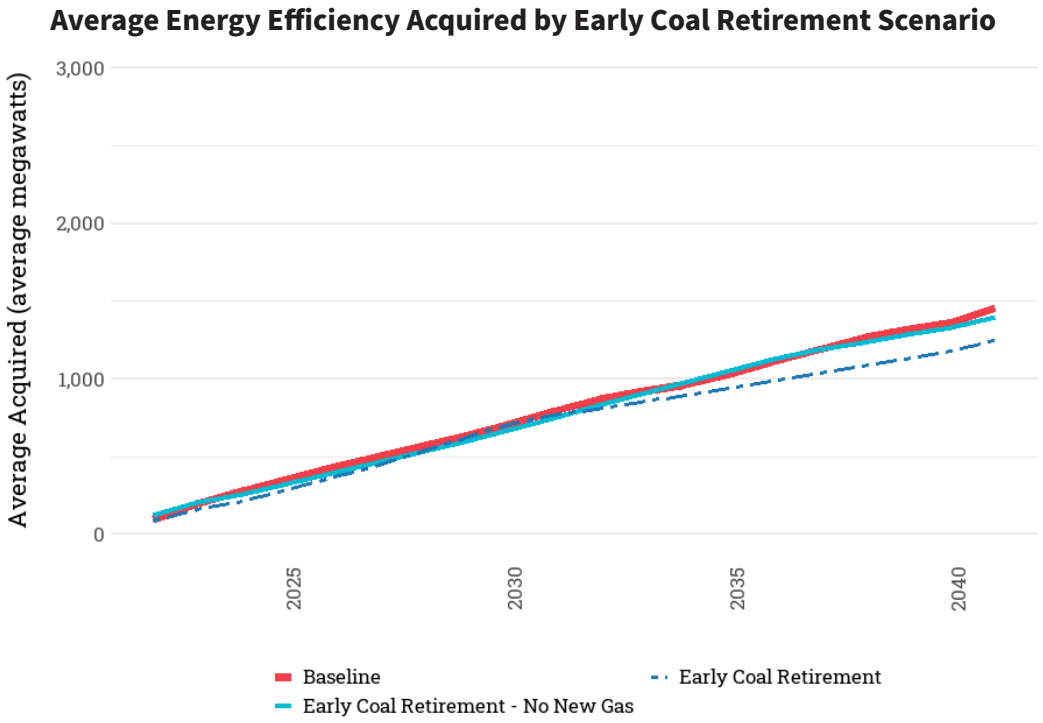
68 Idaho Power ended its participation in this unit in 2019.

69 PacifiCorp and Idaho Power are still working out details of the accelerated retirement of Bridger 2, this date should be considered tentative.

70 For a potential early retirement date for Colstrip Unit 3 and Unit 4, 2025 was selected based on the Washington state utility requirements in the Clean Energy Transformation Act.



While the Council sees a response in the renewables addition for this scenario, there is relatively little change in the addition of energy efficiency.



The Council also sees an expected increase of 7.2 percent in residential electricity bills in this scenario.

Robustness of Energy Efficiency

Energy efficiency has been the cornerstone resource of the Northwest since the first power plan. For this scenario, the Council explored assumptions about the supply of energy efficiency and the drivers that impact acquiring more or less of this resource.

Specifically, the Council looked at the impacts of differing regional adequacy needs, rate of acquisition, the amount available, the contribution to regional capacity needs, and the impact of varying our treatment of emissions on portfolio costs. The Council examined how it collects supply curves for portfolio analysis and then ran a sensitivity on how other resource decisions would change under high and low acquisition of energy efficiency.

When the Council increased or decreased the regional adequacy need, especially when testing an extremely high regional need to develop new generating resources, the energy efficiency resource acquired came close to doubling.

Altering the rate of acquisition of energy efficiency and the amount available resulted in more and less energy efficiency acquired for faster and slower ramps respectively. The increase and decrease of energy efficiency were driven by the differing availability of efficiency in the early years of the study. However, in both cases the Council also observed an increase in the overall system cost. In the case where there was an increase in energy efficiency, there was not a significant difference in the unit cost of the energy efficiency being acquired, but the increased amount resulted in more money spent on the resource in total. In the case of decreasing energy efficiency acquisition, the increased costs manifested in purchasing more expensive resources. While acquiring more energy efficiency absent other changes would increase the reliability of the system, the Council saw the faster acquisition of energy efficiency alter other resource decisions in a manner that resulted in no meaningful increase in the reliability of the system.

The contribution of energy efficiency to capacity needs is estimated using the best data that are available to the Council on the timing of the use of electricity. However, some of these data are outdated, and the region is currently conducting research that will allow for updated information to be used in the next power plan.[71] The Council tested how resource additions would respond if the capacity contribution of energy efficiency was increased. In part, this test assumed that the updated data may show better alignment between peak electricity needs and energy efficiency. The test showed changes in other types of resources built in response to the overall change in system need based on the contribution of energy efficiency to the peak

71 neea.org/data/nw-end-use-load-research-project

system need. However, the Council did not see additional acquisition of energy efficiency in this test.

When the Council constrained energy efficiency to look at the impact of suboptimal acquisition, acquiring more energy efficiency led to a more expensive system by displacing less expensive resources and by acquiring more resource than was needed. With less energy efficiency acquired, the result was a less reliable system.

In our baseline for our analyses, the Council incorporated an emissions cost based on the Social Cost of Carbon from the Intergovernmental Panel on Climate Change into the portfolio cost. For this scenario the Council tested the impact of this on the acquisition of energy efficiency. When removing this impact on portfolio costs, the Council saw some reduction in the near-term acquisition of energy efficiency and a larger reduction in the total energy efficiency acquired over the 20-year plan duration.

Analyze the Bonneville Portfolio

Bonneville is a central part of the Northwest electric system. A large portion of the transmission in the region is owned and operated by Bonneville. The Council considers a broad array of information from all the various analyses included in this plan when making recommendations to Bonneville. One key part of that perspective is understanding the obligations Bonneville has to provide electricity and the federal resources and contracts that are designated to be used to meet those obligations – that is, the Bonneville portfolio.

The Council analysis see a small need for additional resources. The Council describes the existing federal resource capability and

Energy Efficiency Acquired in Robustness of Energy Efficiency Tests

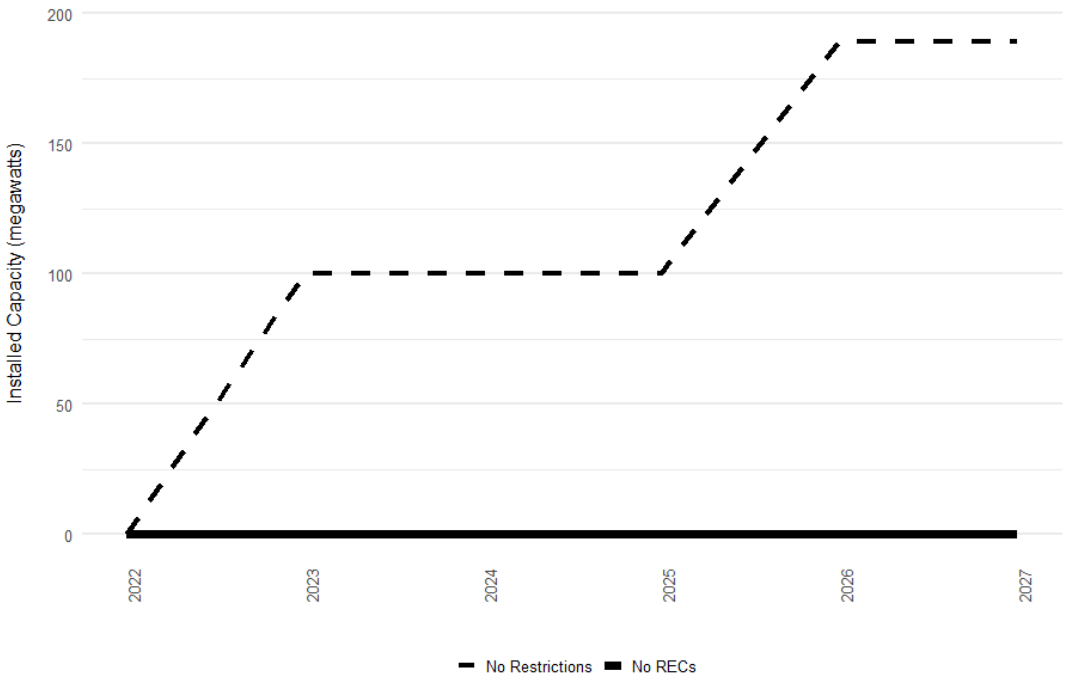
Scenario / Test	Energy Efficiency Acquired (average megawatts)	
	2027	2041
Baseline Conditions	500	1462
Change Supply Curve Binning	470	993
Increased Acquisition Ramp and Potential	1362	2562
Decreased Acquisition Ramp and Potential	370	1235
No Emissions Related Portfolio Cost	175	780
Increased Adequacy Requirements	932	2656

obligations in *Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity*. Under many of the forecasts for an increase in the Bonneville obligation, the Council sees that existing resources are sufficient to meet the need. However, there are infrequent circumstances where an increase in the demand for electricity exceeds the seasonal firm energy in the federal power system. Our analysis shows the least-cost way to meet these needs is a combination of energy efficiency, demand response, and renewable resources.

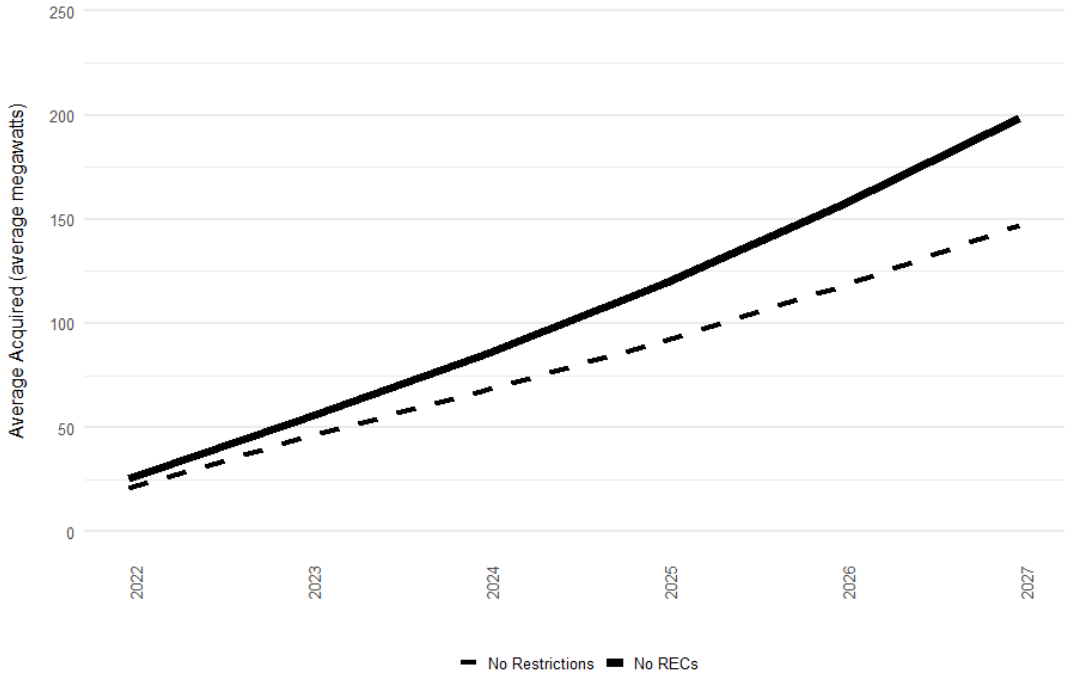
Part of this analysis was looking at the cost of resources. When examining the cost of renewable resources, the treatment of renewable energy credits (RECs) altered the amount of renewable generation additions to the portfolio. When the RECs were assumed to offset the cost, more renewable resources were selected as part of the portfolio. However, currently Bonneville passes RECs through to its customer utilities, so they do not accrue value to the Bonneville portfolio. When excluding the value of the RECs, the addition of renewable generation is much more limited.

The treatment of RECs also impacts the amount of energy efficiency acquired. Because renewable resources meet part of the energy need, there is a reduced need for energy efficiency.

Renewables Build With and Without Accounting for the Value of RECs



Energy Efficiency Acquired With and Without Accounting for the Value of RECs



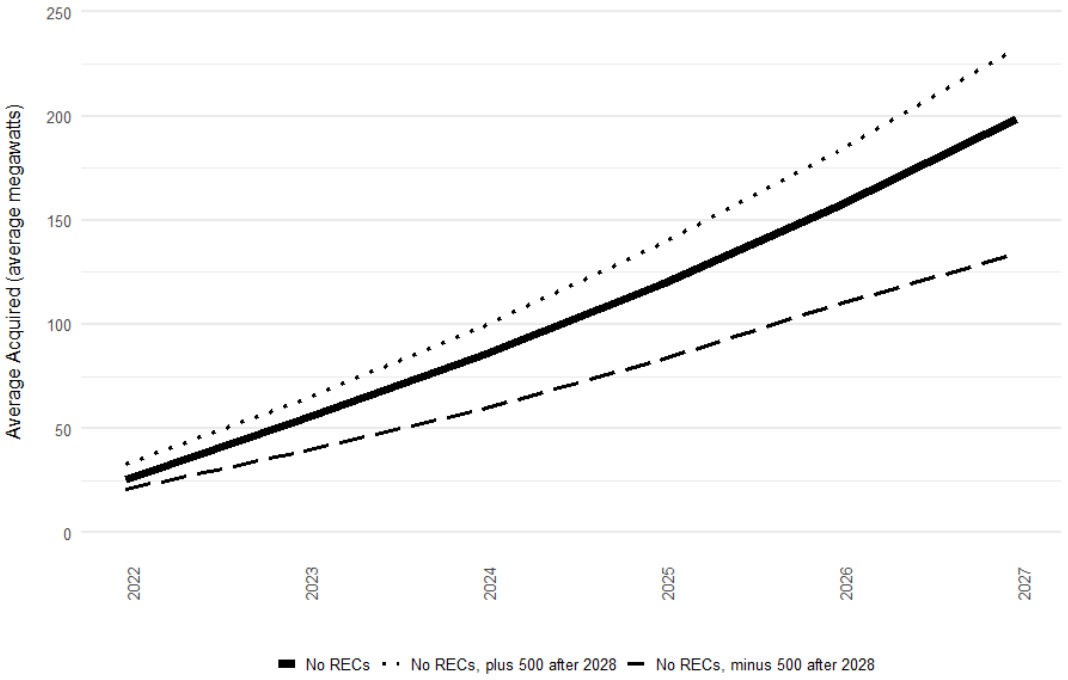
The Council also tested the demand response measures seen to be low-cost and part of the resource additions in the regional analyses. The measures examined were demand voltage regulation (DVR) and time-of-use rates (TOU). These measures reached 300 megawatts of capacity by 2027 in the portfolio.

The Council also examined the implications of a change in obligation after the Bonneville contracts expire in 2028.[72] The purpose was to see if there would be near-term changes in resource additions based on the obligation change in 2028. To test this, the Council added and removed 500 average megawatts from the Bonneville obligation in 2028. When adding obligation, the Council saw additional near-term resource additions as the least-cost solution. When removing it, the Council saw lower near-term resource additions. Adding to the obligation in 2028 increased the addition of energy efficiency by 2027 by 35 average megawatts. Decreasing the obligation removed around 65 average megawatts of energy efficiency.

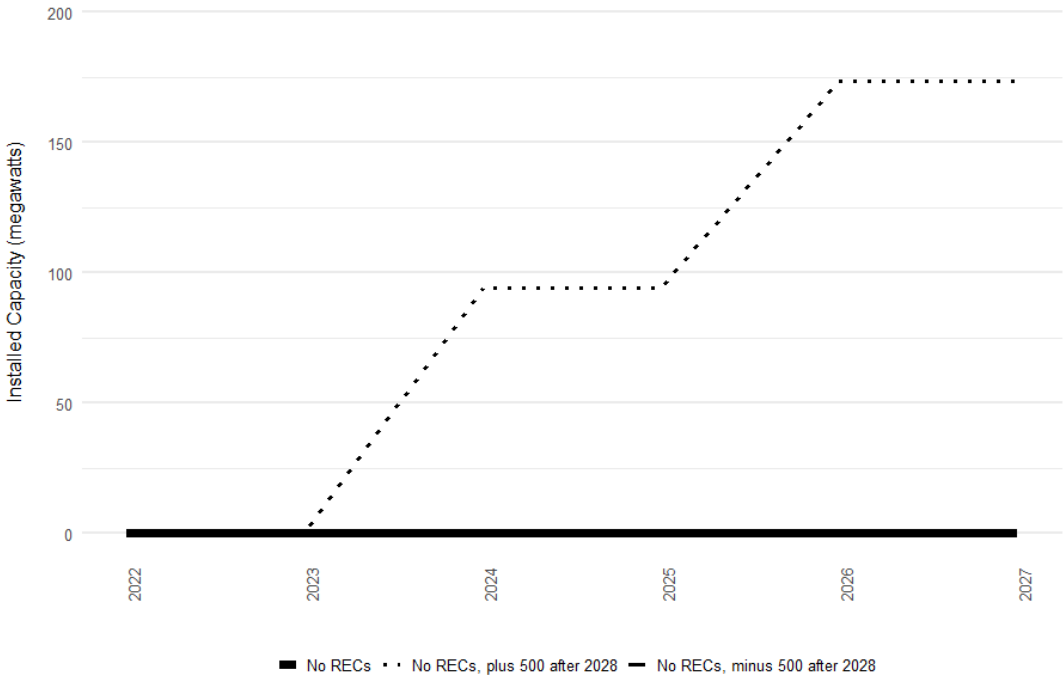
Similarly, for renewable resources – when excluding the value of RECs – our analysis shows an increase of almost 175 megawatts

72 The eventual size of Bonneville's obligation to serve after 2028 adds a level of uncertainty to our needs forecast that may not be fully realized until the end of the plan's action period and may require further analysis by the Council to determine the full impact of Bonneville's future contractual obligations.

Energy Efficiency Acquired with Obligation Changes After 2028



Renewables Build with Obligation Changes After 2028



of nameplate capacity additions by 2027 when the obligation increases in 2028. Decreasing the obligation does not impact near-term resource additions and shows no additions of renewable resources after 2028.

Greenhouse Gas Regulation Cost and Impacts

The Council has been analyzing greenhouse gas emissions and the impact of regulation to reduce emissions on the electricity sector throughout most of its history. Analysis of emissions first appeared in the 1991 Power Plan.[73] However, in recent years the scope and variety of regulation related to emissions have expanded, not just in the region but throughout the West.

This plan has aggregate renewable energy requirements and clean-energy requirements. The Council also included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation. However, the Council did not assume generating resources that emit greenhouse gases would dispatch with emission pricing included in their variable cost.

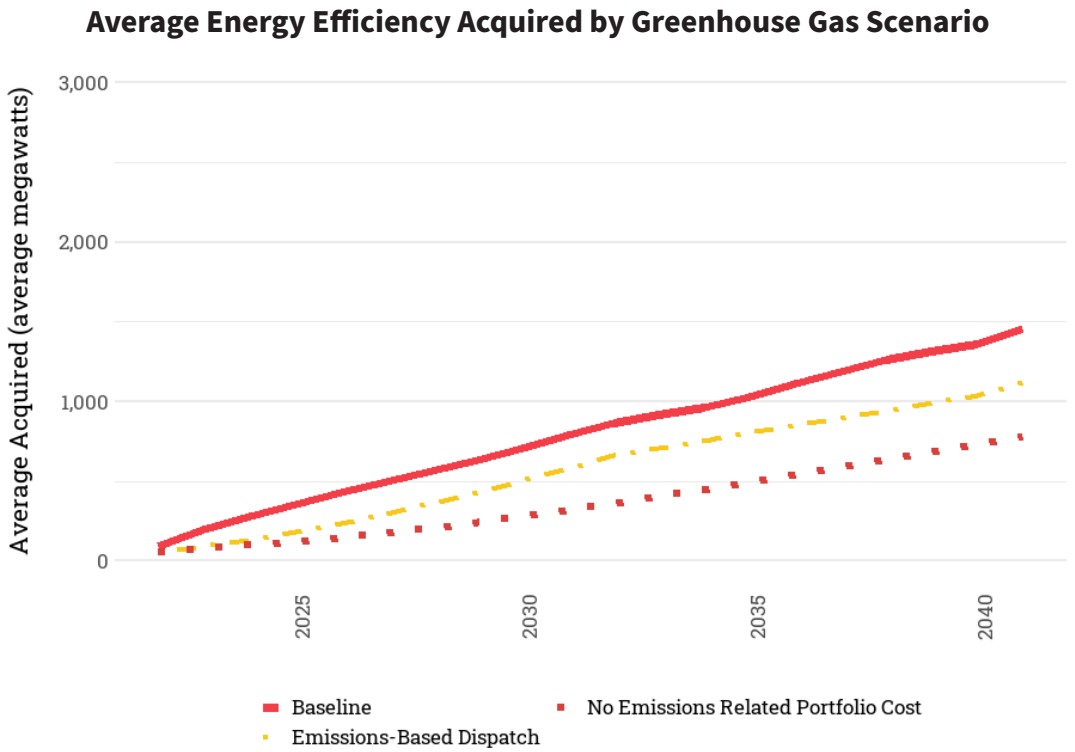
The Council developed this scenario to explore the implications of regulation throughout the West intended to limit or reduce greenhouse gas emissions.

The Council started by examining the implications for adding generating resources outside the region. Like the scenario work on organized and limited markets, this scenario looked at what resources would be built if limitations on new natural gas generation were removed. The scenario showed the addition of almost 60 gigawatts of natural gas generation by 2040 when the scenario was not constrained by resource options.

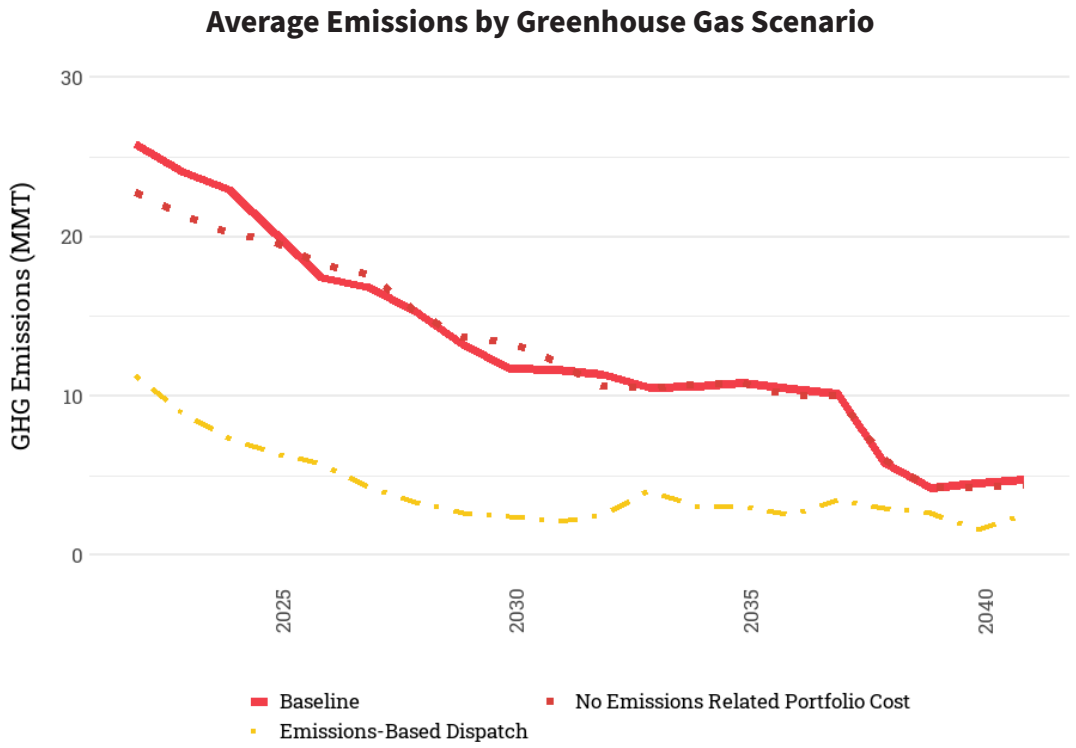
The Council also looked at the implications of explicit emissions pricing included in the dispatch of all resources in the West. In this case, renewable resource additions increased by just over 13 percent in 2040.

The Council's analysis shows that emissions regulation has a substantial impact on the resource strategy. While the Council does not set emissions-related policies either in the region or outside the region, the Council considers the impacts of these policies when making recommendations for a resource strategy. The analysis showed that both including the price of emissions in resource dispatch and removing emissions-related portfolio costs reduced the energy efficiency acquired.

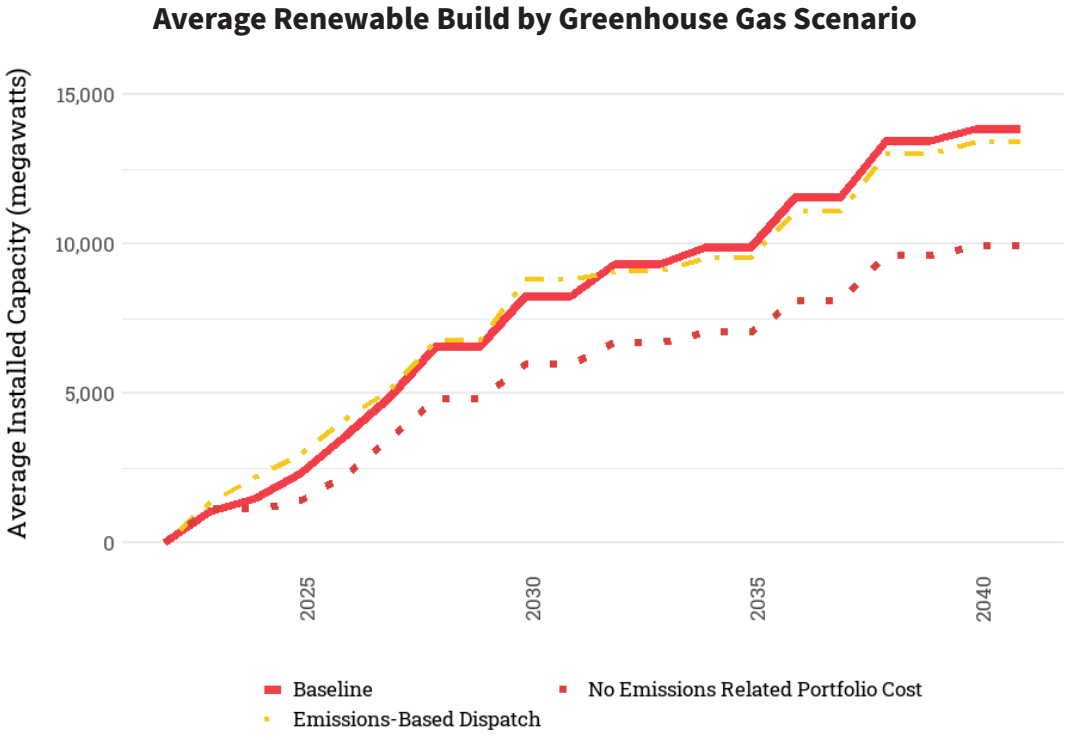
73 nwcouncil.org/reports/1991-northwest-conservation-and-electric-power-plan



While implementing an emissions-based dispatch slightly increased the number of renewable resources built, removing emissions-related portfolio costs decreased the amount of renewable resources built to around 3,500 megawatts of nameplate capacity by 2027.



There was little impact on regional emissions when removing the emissions-related portfolio costs, but changing how regional resources dispatch to include an emissions-based price substantially reduced the amount of emissions in the region.



Pathways to Decarbonization

The states of Oregon and Washington have set goals and limits on future greenhouse gas emissions. Oregon's goal is to reduce emissions 80 percent below 1990 levels by 2050. Washington's goal is to reduce emissions 95 percent below 1990 levels and be at net-zero emissions by 2050.

These goals include the electricity sector in a broad range of emissions. To analyze the impacts on the electric system in this scenario, the Council forecast the region's demand for natural gas, as well as transportation fuels. Including the impact of emissions from the use of these fuels, the resulting estimates show that regional emissions will rise compared to 1990 levels in our baseline conditions.

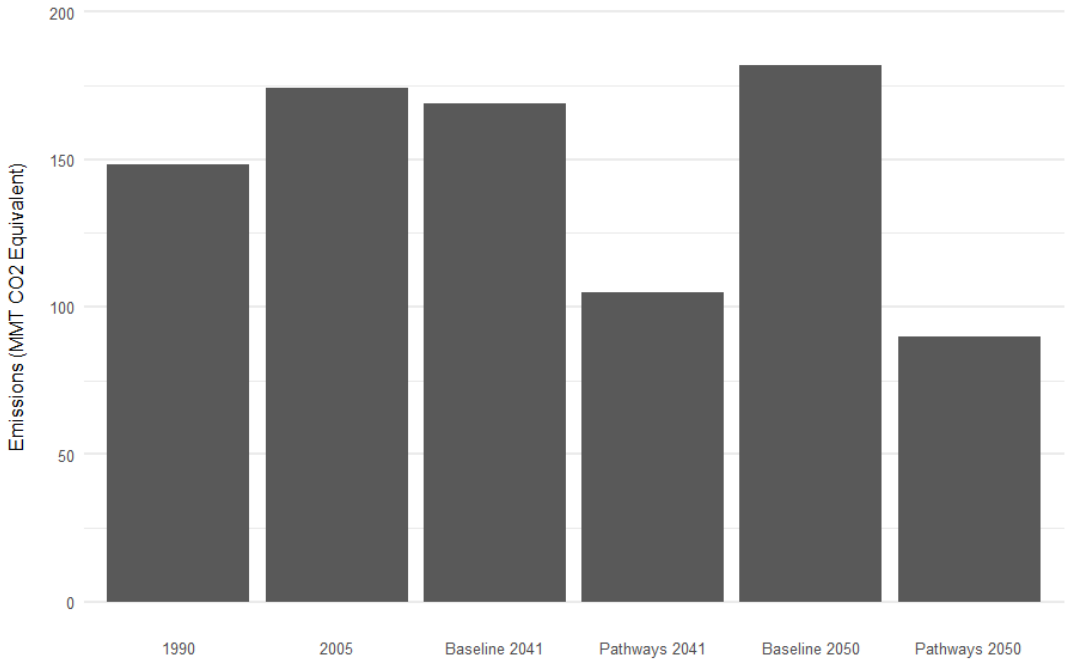
By 2041 under baseline conditions for the analysis, most regional emissions will be associated with the use of fuel for transportation. One potential approach to reducing emissions in the transportation sector would be the electrification of transport and potentially the production of hydrogen through electrolysis as a non-greenhouse-gas-emitting fuel for use in vehicles or other applications. The analysis shows it would be possible to reduce emissions by almost 27 percent by 2040, but it would require more than 12 gigawatts of additional electricity to meet the demand that new transportation technologies would place on the electricity grid.

However, even adding the reduction from aggressive electrification of transportation

Expected Sector Emissions Based on Baseline Conditions



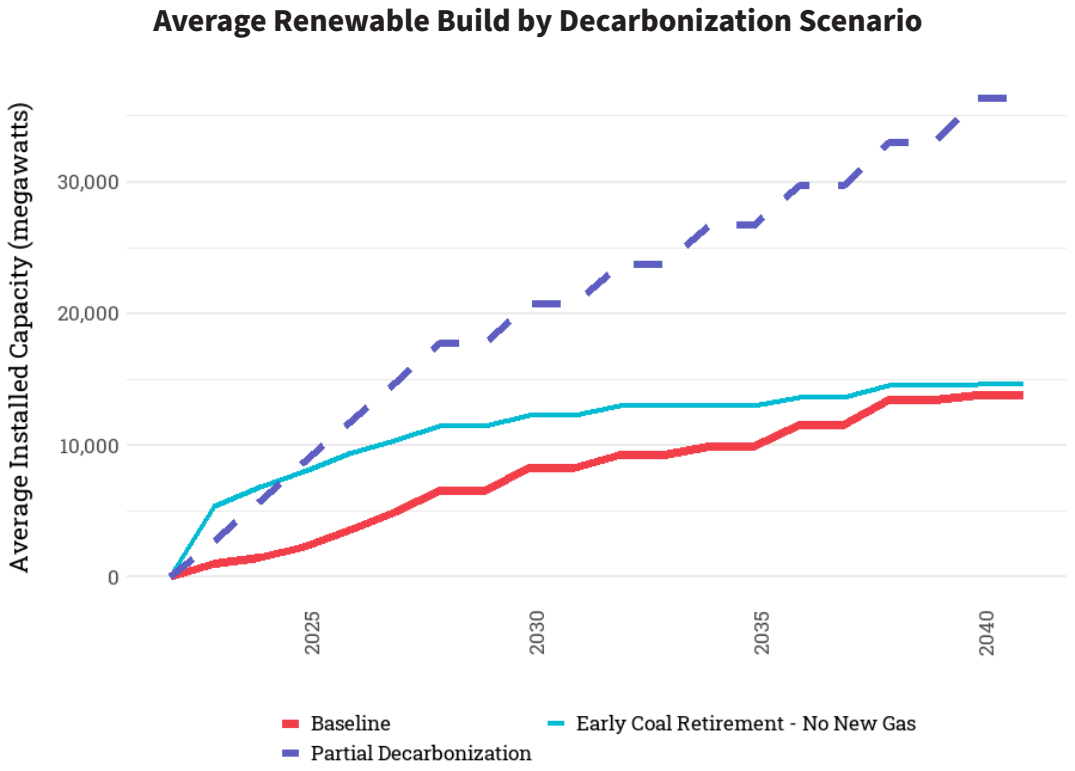
Regional Emissions from Energy Used in Residential, Commercial, Industrial, Agriculture, and Electric Utilities



with a collection of equally aggressive policies to reduce other emissions in the broader regional energy sector, the analysis does not show a path to getting to the targeted reductions within the energy sectors using the current technologies. The policies the Council tested include replacing vehicles and appliances and equipment in homes, businesses, and manufacturing at an accelerated but possibly obtainable pace.

Looking at the scope of change in this analysis, the Council decided the incremental demand to the electric system was beyond the resource expansion that could be supported by the structure of our analysis. To test the impact on the resource strategy, the Council removed a substantial proportion of the demand associated with the production of hydrogen by electrolysis. While this reduced the likelihood of reaching the Oregon and Washington targets for reducing greenhouse gas emissions, it provided a directional analysis of the possible impacts to resource additions. It also still represents aggressive emissions reductions relative to baseline conditions in the analysis. By 2040, this more moderate but still aggressive emission reduction increased the demand for electricity by just over 52 percent.

In response to this increased demand, the analysis showed a substantial increase in the addition of renewable resources relative to other scenarios the Council explored.

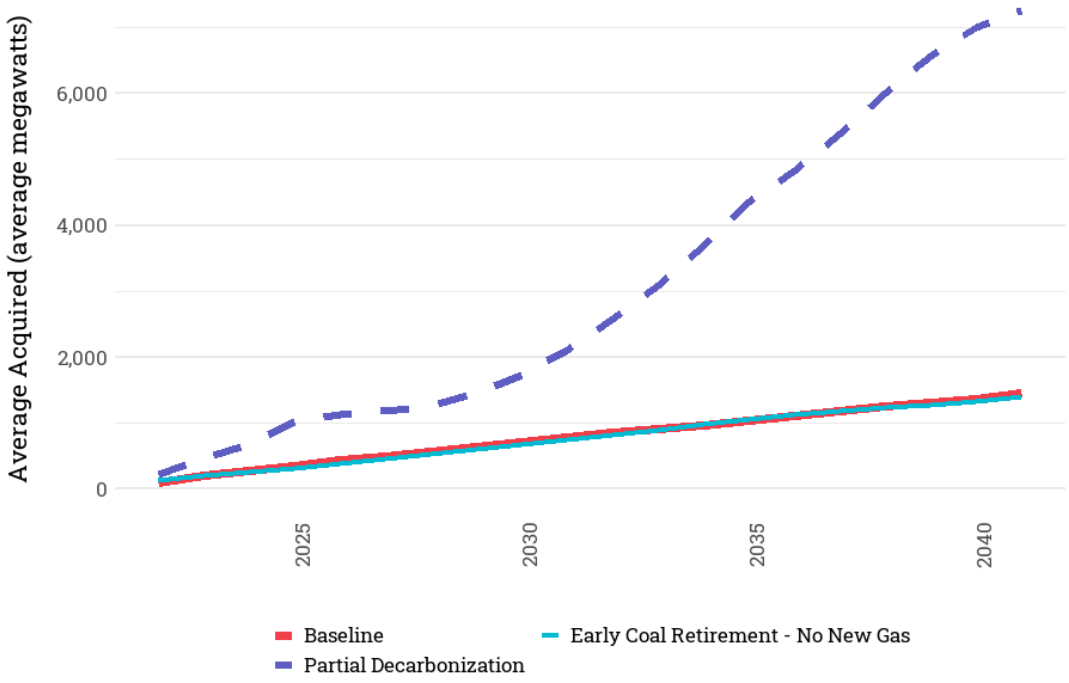


The Council also altered the supply of energy efficiency and demand response to incorporate the additional anticipated demand for electricity. This analysis showed substantial increases in energy efficiency.

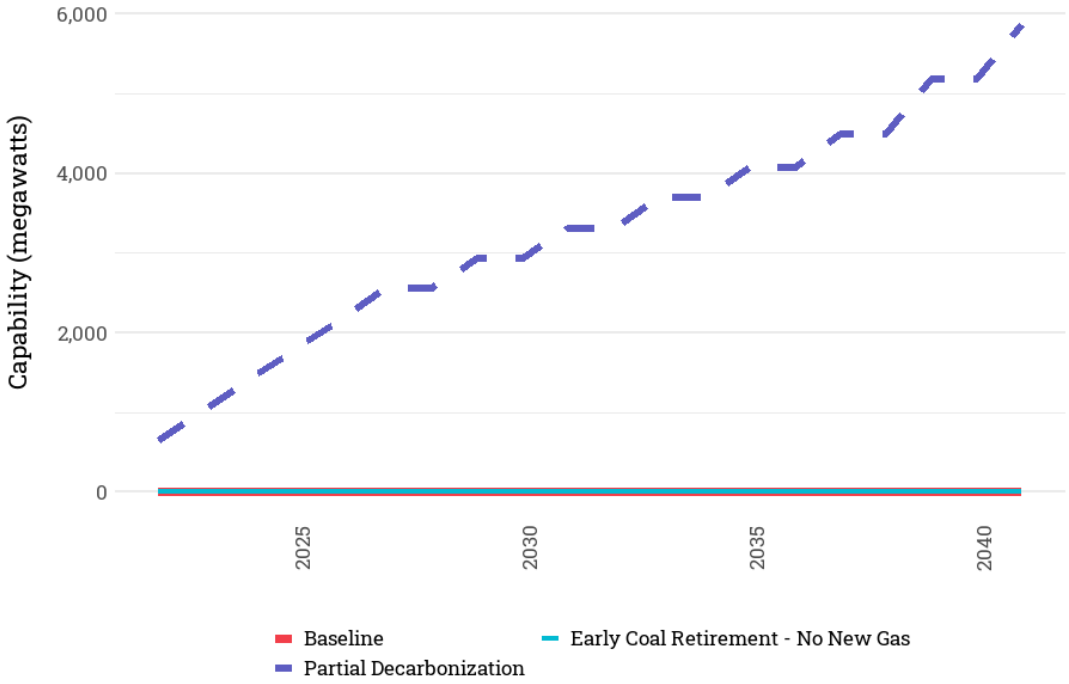
The analysis also showed a substantial uptake of demand response to support system adequacy (next figures).

The resource addition also included an expected 800 megawatts of battery storage capacity. Part of the renewable resource addition included an expected 2,100 megawatts of solar generation nameplate capacity with on-site batteries. In addition, there were some conditions where the increased demand resulted in a conventional geothermal power plant being part of the least-cost resource addition for this scenario.

Average Energy Efficiency Acquired by Decarbonization Scenario



Average Demand Response Acquired by Decarbonization Scenario



Section 7: Forecast of Federal Power Resources and Obligation to Provide Electricity

What the Northwest Power Act Requires of the Council Regarding Bonneville's Resource Acquisition

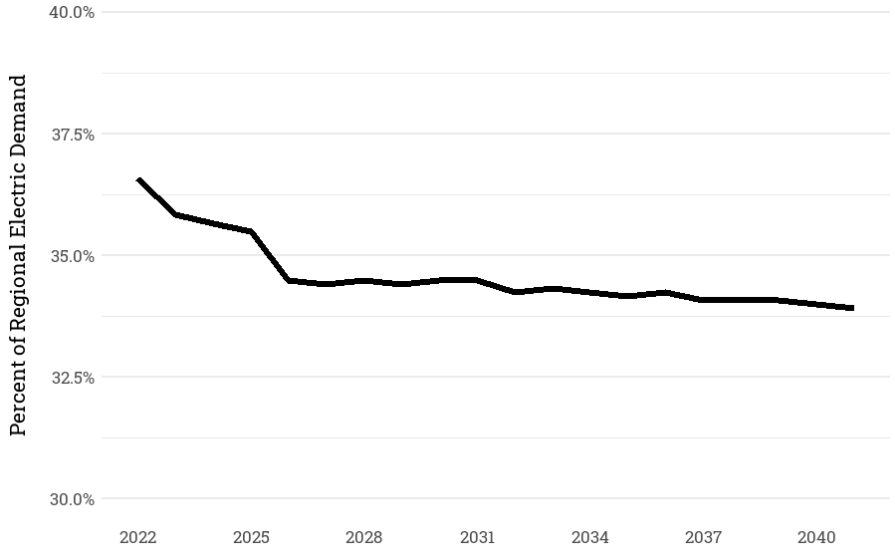
The Northwest Power Act directs the Council to "set forth a general scheme for implementing conservation measures and developing resources […] to reduce or meet the Administrator's obligations." The Council also is required to prepare a demand forecast of at least 20 years and "a forecast of power resources estimated by the Council to be required to meet the Administrator's obligations." Further, the Council is required to include, to the extent practicable, an estimate of the types of resources from which such power should be acquired.

To accomplish these requirements, the Council forecasts both demand for electricity from the Bonneville Power Administration and the electricity currently produced by the Federal Columbia River Power System, which is marketed by Bonneville. Further, the Council is required to make a recommendation to the Bonneville administrator on the amount of power needed to meet or reduce the agency's obligation and what types of resources that power should be acquired from. Our recommendation is included in *Section 8 Recommendation for the Amount of Power and Resources Bonneville Should Acquire to Meet or Reduce the Administrator's Obligation*.

Forecast of Demand for Electricity from the Bonneville Power Administration

The Council estimates[74] that the proportion of the regional demand for electricity that Bonneville is obligated to supply[75] with the federal power resources starts at just under 37 percent in the first year of the 20-year power plan forecast period and falls to just above 32 percent by the end. Through 2028, this estimate is based on the current Bonneville Regional Dialogue contracts.[76] After 2028 the Council assumes the contracts will be substantially similar, but in our scenario analysis we test the implications of both, adding to and subtracting from Bonneville's obligation. That is, in our

Estimated Bonneville Obligation as a Percentage of Annual Regional Electric Demand



This graph shows that Bonneville's obligation decreases as a proportion of the total regional demand for electricity through 2026. After 2026, Bonneville's obligation increases slightly.

74 The Council greatly appreciates Bonneville supplying data and supporting our analysis, which enabled the estimates included in this section. However, these estimates do not correspond to any publicly released forecast from Bonneville, nor are they intended to represent the forecasts Bonneville uses for its various functions and purposes.

75 While Bonneville has broad obligations under the Northwest Power Act, we use "obligation" to refer to the amount of electricity that will be requested from Bonneville by entities that have a statutory right to have Bonneville supply electricity to them.

76 www.bpa.gov/p/Power-Contracts/Regional-Dialogue/Pages/Regional-Dialogue.aspx

analysis we anticipate that Bonneville and its customers will sign new contracts, but we also acknowledge there is uncertainty about any contracts that may follow the current Regional Dialogue.

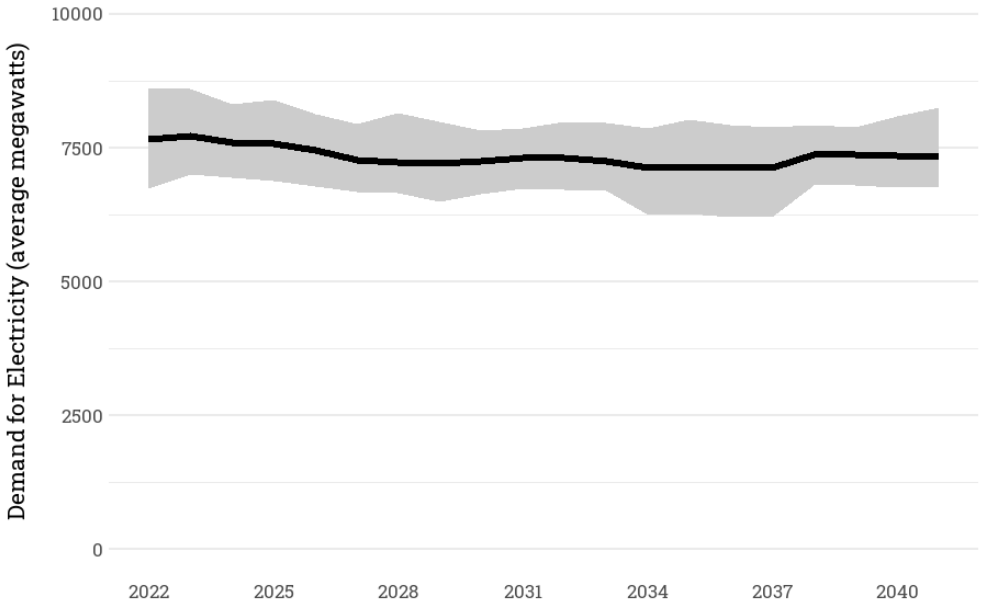
The Council's forecast includes estimates of climate-change impacts. However, Bonneville is less affected by temperature than is the region. To incorporate the impacts of temperature, we partitioned Bonneville's obligation into three categories: contract obligations, subscription obligations, and temperature-sensitive obligations.

Contract obligations are fixed amounts of electricity that Bonneville is obligated to deliver. These amounts do not increase or decrease based on temperatures in the region.

Subscription obligations are driven by the amount of power the federal resources generate. Temperature does not impact the total amount of power Bonneville is obligated to deliver in this category, but it may impact the timing of when that power is delivered.

Temperature-sensitive obligations are deliveries that respond to weather extremes and generally are less than half of Bonneville's obligation, but that changes between different quarters of the year and between forecast years.

Forecast Electric Demand Bonneville Is Obligated to Supply



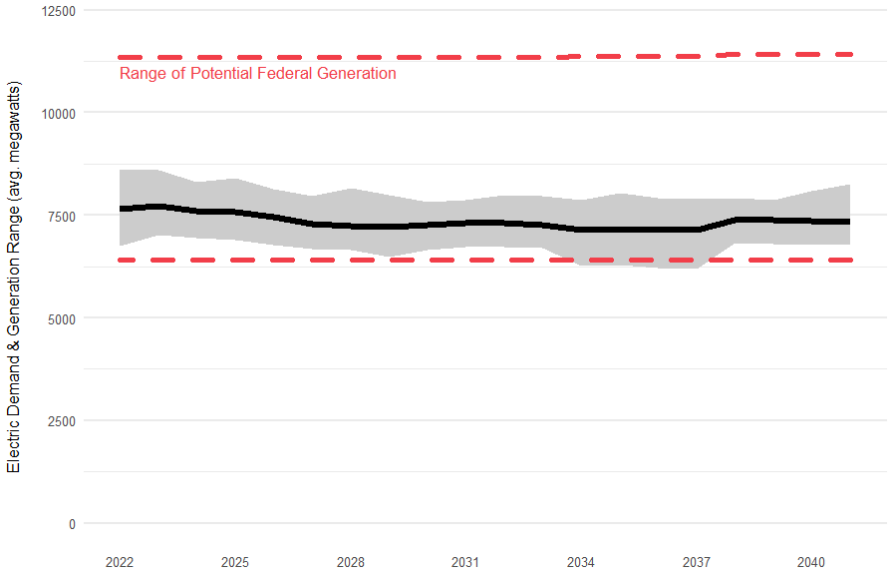
Percentage of Bonneville's Obligation Categorized as Temperature-Sensitive

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4[77]	43.2%	42.5%	43.0%	42.8%
Q1	41.8%	41.5%	42.2%	41.9%
Q2	46.4%	45.9%	47.4%	47.7%
Q3	45.3%	45.1%	46.2%	46.6%

Forecast of Electricity Produced by Federal Resources and Marketed by Bonneville

The Council estimates that generation from the Federal Columbia River Power System generally varies from a minimum of just over 6,400 average megawatts to a maximum of over 11,000 average megawatts. This range is mostly a function of the change in hydroelectric generation from year-to-year. In a year with plentiful water from regional rain and snowpack, the amount of generation from the system far exceeds Bonneville's obligations. In these situations, the excess

Electricity Produced by Federal Resources Compared to Electric Demand



77 The Bonneville and Council fiscal year is October 1 to September 30. The quarters indicated are the calendar year quarters. Thus, Q4 is the first quarter of the fiscal year and contains the months of October, November, and December. The first month of the 2023 fiscal year is October 2022.

electricity would either be sold, scheduled[78] in the secondary markets, or spilled at the federal dams without generating electricity.

Estimated Bonneville Need for Electricity

While under many circumstances Bonneville has surplus electricity relative to its obligation, there are some infrequent circumstances where the electricity produced by the federal system is less than the amount of power Bonneville is obligated to supply. For this analysis, the Council worked with Bonneville staff to adapt the approach taken in the Bonneville Needs Assessment.[79] This approach uses a "critical" energy amount[80] from the federal hydroelectric system to establish a risk preference on the amount of energy from that system set aside to meet the Bonneville obligation. This is added to the non-hydro-based resources in the federal system, and contracts and transmission losses are subtracted to determine the federal system's capability to supply electricity under critical circumstances.

Bonneville, in coordination with the Council, ran simulations using models tuned to estimate the federal system output. These simulations were adapted to the methods the Council uses in its regional modeling. Four years were run through the simulation, as detailed in the following table.

Expected Federal System Generation Under Critical Circumstances in Average Megawatts

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4	7157	7107	6995	7233
Q1	7000	6991	6845	7348
Q2	6007	6037	5843	5521
Q3	7086	7205	7091	6222

The Council's estimate of Bonneville's need for electricity is based on the difference between the Council's forecast of the electricity demand Bonneville is obligated to serve and the expected federal system generation under critical-energy circumstances. The analysis assumes limited market purchases to meet load variation in

78 There are times when the generation from the federal system is not sold in the secondary market but is still scheduled to be exported. See Bonneville's Oversupply Management Protocol, www.bpa.gov/Projects/Initiatives/Oversupply/Pages/default.aspx.

79 The Bonneville Needs Assessment is included in the BPA Pacific Northwest Loads and Resources Study, commonly referenced as the White Book. www.bpa.gov/p/Generation/White-Book/Pages/White-Book.aspx.

80 In this case, "critical" is defined by looking over the range of simulated generation when using regulated flows defined by the climate-change-based precipitation estimates for each of 14 periods, corresponding to the calendar months except April and August are split at the end of the 15th day to form two periods each. In each of these periods, we take an amount of generation that only one out of every 30 simulations would be below (or the 3.33 percentile of the simulated generation for each period).

a particular quarter or season. This results in an estimated margin between critical-energy generation and electricity demand.

For example, in the first quarter of the 2023 fiscal year (October to December of 2022), the Council estimates Bonneville would have sufficient electricity as long as the federal generation under critical circumstances (estimated at 7,157 average megawatts) can meet 88.5 percent or more of Bonneville's need for electricity.

Margin of Critical Resource to Electric Demand

	Fiscal Year			
	2023	**2025**	**2027**	**2031**
Q4	88.5%	88.8%	93.7%	98.0%
Q1	81.6%	83.3%	86.6%	94.0%
Q2	86.6%	88.3%	89.8%	84.1%
Q3	94.6%	96.8%	98.8%	86.6%

When the available federal generation is less than the estimated margin, we project Bonneville would need electricity.

Using this approach, the Council forecasts Bonneville will have a minimal need for electricity. The average expected need is under 7 average megawatts for the first decade of the forecast and under 28 average megawatts for the second decade.[81] However, those expected loads reflect a range of simulations. Within this range, there are some circumstances where the need could be larger than 60 average megawatts in the first decade and almost 145 average megawatts in the second decade. Seasonally these needs are more likely to occur in the summer, with the upper end of the range of forecast being around 300 average megawatts.

81 Assuming Bonneville customer utilities sign substantially similar contracts.

Section 8: Recommendation for Amount of Power and Resources Bonneville Power Should Acquire to Meet or Reduce the Administrator's Obligation

Resource Recommendations

Energy Efficiency

Public power has played an important role in the Northwest energy efficiency achievements over the last 40 years. Since 2008, Bonneville utility customers have acquired roughly 36 percent of the region's energy efficiency savings. Looking forward, the Council estimates that 36 percent of the remaining available energy efficiency is within the Bonneville utility customer service territories. Bonneville's energy efficiency program will continue to be an important piece of our regional power system infrastructure.

To support both Bonneville's and the regional power system's needs, the Council recommends that Bonneville acquire between 270 and 360 average megawatts of cost-effective energy efficiency by the end of 2027 and at least 865 average megawatts by the end of 2041. Aligning with the Council's analysis of remaining potential and historical

achievements, this level represents 36 percent of the overall regional target.[82]

Within the first six years, the Council recommends that Bonneville plan to acquire a minimum of 243 average megawatts of cost-effective efficiency from programmatic savings. This includes savings currently funded through Bonneville's program, whether via the Energy Efficiency Incentive or self-fund utility contributions, as well as the Northwest Energy Efficiency Alliance (NEEA) market transformation initiatives. The remaining efficiency may come through additional programmatic activity, market change, or codes and standards.

Bonneville should use the Council's methodology and associated parameters for cost-effectiveness to identify efficiency opportunities at levels that are cost-effective for the region.[83] This target recognizes the value that Bonneville can provide the region to ensure a reliable power system and achieve decarbonization goals. Additionally, it can mitigate some of the risk associated with potential changes in obligations post-2028 when the current contracts expire.

The Council understands that although Bonneville produces an annual budget, it forecasts its revenues and expenditures on a biennial basis as part of its rate setting process. For the first two years of the 2021 Power Plan, the Council assumes that Bonneville has budgeted appropriately for the agency to successfully achieve the energy efficiency target in this plan. For the remaining years of the 2021 Plan, Bonneville should work with the Council to ensure that a budget is established to successfully meet the plan's energy efficiency targets.

If evaluation of the energy efficiency achievements through the Council's annual Regional Conservation Progress report indicates that Bonneville's achievements fall short of the Council's recommendation, Bonneville and the Council should work cooperatively to understand and address the underlying cause of this shortfall. The Council will continue to work with Bonneville, the NEEA, and the regional utility community to ensure the Regional Conservation Progress report that the Council was directed by Congress to produce annually accurately reflects the regional energy efficiency achievement.

The Council's recommendation for acquiring energy efficiency does not distinguish between energy efficiency

82 The determination of 36 percent as the Bonneville portion of the regional target represents the portion of cost-effective energy efficiency potential located within the Bonneville customer utilities territory. More information on this assessment can be found in the supporting material here: nwcouncil.org/2021powerplan_BPA-CE-Potential-Share

83 The cost-effectiveness methodology can be found here: nwcouncil.org/2021powerplan_cost-effective-methodology

funded through money collected by Bonneville and energy efficiency funded directly by customer utilities. Nor should the Council's recommendation be seen as a recommendation for maintaining or changing the structure of how energy efficiency is funded between Bonneville and its customer utilities. Further, this recommendation is not intended to be proportional to the customer utilities, based on load or potential or any other manner. Our intent is that this recommendation assists individual utilities in determining for their service territory how they can best structure their programs to acquire energy efficiency. Our recommendation is not prescriptive on how individual utilities should run their energy efficiency programs.

The Council recognizes that there are diverse challenges to acquiring energy efficiency across Bonneville's customer utilities. Achieving the efficiency targets will require that Bonneville work to meet each of those utility challenges within the cost-effectiveness considerations. Many of the public utilities with a rural–and primarily residential and agricultural–customer base have fewer energy efficiency opportunities. Additionally, these utilities may lack resources–such as staff, contractors, retailers–and thus have significant challenges implementing cost-effective efficiency programs. To meet its programmatic efficiency goals, Bonneville must work with these utilities and provide territory-wide programmatic opportunities to enhance the infrastructure for small and rural utilities. Continued funding of NEEA initiatives will also provide necessary support for training and other infrastructure to address implementation barriers across its customer utility footprint.

To help ensure the necessary levels of cost-effective conservation are acquired, the Council recommends that Bonneville contribute to all aspects of the regional conservation program, as described in *Section 5: Energy Conservation Program*. This includes continued funding and support in the following areas at levels commensurate with 2020 levels or greater: NEEA; research including regional market research, stock assessments, evaluation, and related analysis; and codes and standards development.

The Council's conservation program also identifies two key opportunities to ensure equitable distribution of energy efficiency. The Council recommends Bonneville continue to invest in weatherization programs, targeting those homes that are leaky (in need of duct or air sealing) and/or have zero or limited insulation. We recognize that these measures, while historically cost-effective, may not be cost-effective under our current paradigm. Nevertheless, the Council believes they are critical to provide livable homes for all people. Bonneville and its customers should consider coordinating with

other agencies (such as community action agencies, state agencies, and/or nonprofits) and explore co-funding options to best serve these homes. Additionally, the Council recommends Bonneville work with its utilities with large commercial loads to utilize energy-use intensity data to identify those buildings with significantly higher consumption than comparable buildings. The Council believes leveraging this data will provide a way to identify those commercial consumers in the greatest need of efficiency measures that were previously missed by programs.

Demand Response

In *Section 6: Resource Development Plan,* the Council recommends that utilities pursue demand response that can be frequently deployed and obtained at a low cost. We identified that demand voltage regulation (DVR) and time-of-use (TOU) rates can help substantially in ramping and peak periods. Additional value may also be obtained to relieve transmission constraints and defer transmission and distribution system upgrades.

Bonneville should work to enable and encourage its customer utilities to pursue these and other low-cost and high-value demand response measures in an equitable manner.

Market Purchases

The Council anticipates that regional wholesale electricity prices will have substantial downward pressure from expanded renewable generation additions throughout the West. We recommend that Bonneville, when it has needs beyond the recommended energy efficiency and demand response resources, look to mid-term and long-term market resources for additional energy.

When Bonneville has needs for electricity in specific locations where the ability to deliver power from the federal system is limited, the Council still anticipates the mid-term and long-term market resources will likely be the low-cost resource alternatives.

Renewable Resources

Costs for renewable resources have substantially fallen. While the Council recommends purchasing market resources to meet Bonneville's needs for additional energy, we recognize that there may be situations where a more general market resource may be more expensive than a direct power purchase agreement, or similar arrangement, tied to a specific renewable resource. The Council recommends that Bonneville compare power purchased in this manner to alternative market products, both in price and capability, to ensure that the lowest-cost product that suffices to meet any need identified is purchased on behalf of the region's electricity consumers.

Supporting Recommendations

Regional Hydro Generation System

The Council's analysis shows a rapidly shifting market dynamic in the Western electricity grid. The impacts, both challenges and opportunities, need to be better understood and explored by all regional entities that have a role in operating the hydro system.

The Council recommends Bonneville play a central role in these future efforts. Bonneville can do this by both incorporating these impacts into its analyses and supporting broader regional efforts, at the Council and other organizations, to study and understand these impacts.

Future Contracts

The Council's recommendations to the Administrator on what power to acquire depend on the obligation placed on Bonneville. Current contracts allow customer utilities to reduce or abandon service from Bonneville at the end of the contract. Currently all contracts end at the same time, leaving an acute risk that could be aggravated by the Council's recommendations. Our analysis shows the lowest-cost strategy for the Bonneville portfolio changes within the action plan period based on whether regional utilities contract for power from Bonneville in the future.

Further, Bonneville's resource decisions may be limited based on this risk. When all the contracts expire at the same time, decisions made close to the end of the contract period are less likely to favor long-term commitments. This could disadvantage lower cost but longer duration power acquisition.

Bonneville should consider in its next contract negotiations how to mitigate the financial risk of acquiring power that may be least-cost but longer duration. Further, it should explore how a wide range of potential future Council recommendations on resource acquisition could be contractually accommodated without substantial risk of shifting costs among regional consumers of electricity at the end of contract periods.

Additionally, in the current contracts, many Bonneville customer utilities see little value in pursuing demand response and are limited in the ability to provide a demand response resource to another utility, both within and external to the pool of Bonneville customer utilities. In future contracts, Bonneville should consider provisions supporting its customer utilities' development and export of demand response resources.

Section 9: Cost Effective Methodology for Providing Reserves

Reserves in the Act

The Power Act indicates the power plan should include an analysis of reserve and reliability requirements and cost-effective methods of providing reserves designed to ensure adequate electric power at the lowest possible cost. Additionally, the Power Act explicitly recognizes that reserves can come either from generating resources or non-generation alternatives, including conservation measures and contract rights to curtail or interrupt power supplied to customers.

Reserves on the power system are held to account for the uncertainty about the expected amount of electricity demand and power generation. The wholesale power market can help address a significant amount of uncertainty in generation and load. However, most often individual utilities or collections of utilities take actions like holding back some existing resources from the market or adding additional generating resources or non-generation alternatives to address these uncertainties on a second-to-second, hour-to-hour, and year-to-year basis.

Types of Reserves

The growth of electricity demand due to changes in the economy or amount of water available for hydro generation in a year based on precipitation are forecast, but due to the uncertainty of those forecasts, reserve power generation capability is held on a planning basis. These types of reserves are often called planning reserves.

Uncertainty in the forecast speed and direction of the wind hitting turbines or the forecast of households who will have their lights on or air conditioning running at any certain time are examples of shorter-term uncertainties that may cause an imbalance between power scheduled to be delivered to demand. Additional power system capability

to meet these schedule imbalances are often referred to as balancing reserves.[84]

While having less fuel uncertainty than solar, wind or hydropower, coal or gas plant generators have the possibility that some aspect of the controlled combustion that creates the power in those plants will go wrong and the entire plant will shut down unexpectedly. Additional power system capability to address these unexpected plant outages are often called contingency reserves.[85]

Since planning for future resource strategies in the power system must explicitly account for these uncertainties, the discussion of the methodology for including reserves in the analytical framework of the resource strategy started with a description of the types of reserves considered: planning, balancing, and contingency reserves. Balancing reserves are held by generating resources that are positioned to ensure that if any errors are made in forecasting load and generation on an hour to hour basis that there is enough of a buffer within the region to make sure generation matches load at all times by increasing or decreasing the amount of electricity being generated.

Contingency reserves are held back to make sure if events like large unexpected forced outages on generators happen that there are enough reserves to match load by increasing electricity generation to replace electricity that becomes unavailable.[86] These operational reserves are part of what makes up planning reserves. The rest of planning reserves account for year-to-year variation in generation and load, such as planning to be able to keep the lights on even during low hydro conditions. All these reserves are incorporated into the calculation of additional resource requirements to maintain the Council's adequacy standard[87] throughout the planning period. The following chart identifies the balancing and contingency reserve requirements that the Council included as inputs into the modeling analysis. The sources of these values are described in the supporting materials.[88]

84 Used maximum of the regional sum of balancing reserves in any hour in the Northwest Power Pool Energy Imbalance Market work as planning assumption for the region.

85 Northwest Power Pool reserve sharing group for contingency reserves

86 Increases in load require increases in generation, called *balancing up reserves* often referenced in the electric industry as *INCs*. Conversely, decreases in load require decreases in generation, called *balancing down reserves* often referenced as *DECs.*

87 5% Loss of Load Probability

88 nwcouncil.org/2021powerplan_reserve-input-assumptions

Operating Reserves

Type	Amount Held
Balancing Up	2,900 megawatts
Balancing Down	3,345 megawatts
Contingency Reserves	3% of load and 3% of generation

Providing Reserves Using New and Existing Resources

Traditionally, additional reserve requirements have more directly translated into needs for additional generating resources, energy efficiency or demand response, but the current analysis indicates that the operations of existing regional generators may play a larger role. In the past, in our region, coal and natural gas generators have complemented regional hydro generation by providing a significant amount of system flexibility. Since the wholesale market electricity price was set by coal or gas generation near times of scarcity, the expectation that those plants would operate if available was a decent assumption.

More Conservative Operation of Existing System to Provide Reserves

In the current and predicted future power system, significant amounts of solar generation throughout the Western grid contributes to very low prices for power midday. These low midday prices can be low enough that coal and gas plants can appear uneconomic to run during the day and plan to shut down to lower overall system cost.

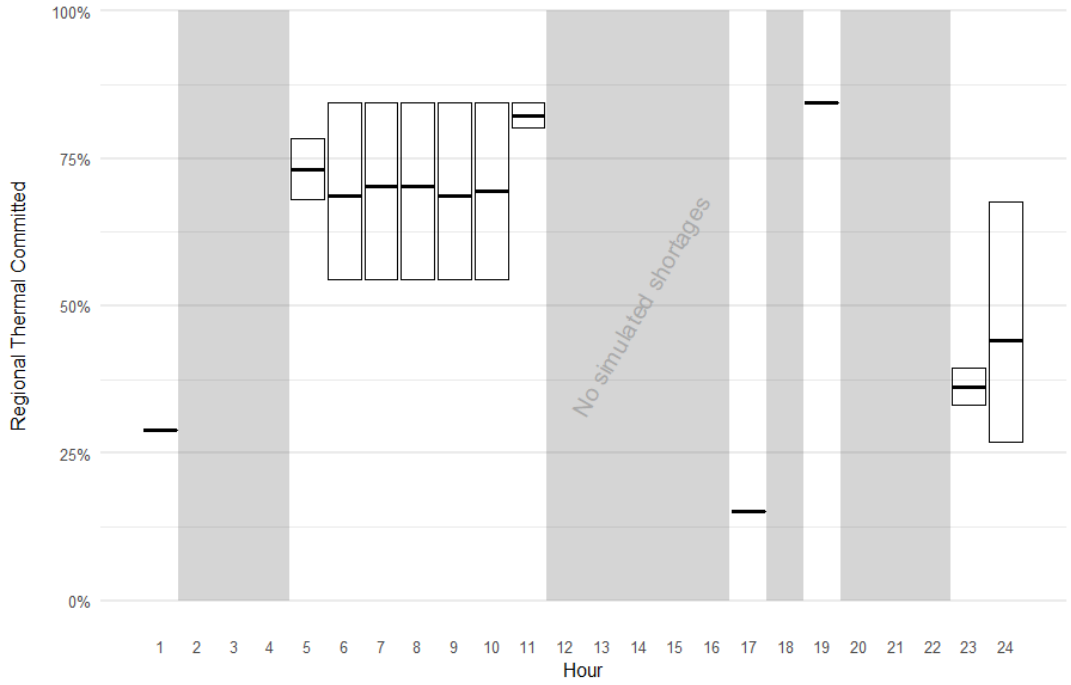
However, when demand for power ramps up in the morning and down at night, there is now significant uncertainty about available generation, along with the uncertainty associated with electricity demand, and that uncertainty introduces some operational challenges.

For example, much of the regional fleet of coal and gas generation need a few hours to ramp up or ramp down from full generation, and fueling larger gas plants requires significant notice ahead of time to order the fuel. Depending on overnight pricing of wholesale power, this could mean that some of these plants might not be seeing an economic signal[89] to stay online or start up with enough time to respond to a potential shortage during those early morning or evening hours where there is significant uncertainty about the amount of electricity demand and generation available.

89 In general, most power plants generate when the cost of producing power is below the price they can receive on the wholesale market for selling power.

These types of operational issues appear to account for almost all the simulated system shortages in the analysis. These issues are not due to a shortage of resources, but in having enough information to operate the existing system economically and adequately.

Maximum Available Thermal Generation During Simulated Shortages[90]



One way to mitigate some of these challenges is to create a signal, in the form of additional reserves, to operate more of these plants to maintain adequacy. This effectively utilizes the existing generators in a way that results in higher overall system cost but less risk of being short generation at a critical time. Plan analysis showed that holding additional reserves overnight does seem to address most of the issues at a slightly higher cost merely by operating the existing system[91] more conservatively.

Additional Resources as a Reserve

Another way to address this issue is to add additional power generation, demand response or energy efficiency. Since reserves are accounted for implicitly in the

90 This graph shows the maximum and average percentage of total thermal generation online during the shortfalls in winter by hour of the day.

91 The existing system providing more reserves is referring mostly to regional hydro, coal and gas generation operated more conservatively

resource strategy analysis,[92] this approach is considered along with all the other reasons to make further investments in the regional power system. Generation resources like wind and solar tend to need more reserves. Generating resources like combined-cycle gas plants have some of the same operational challenges as the existing fleet. Demand response, batteries, and pumped storage can contribute to a solution, but without an explicit reserve signal, are often imperfectly positioned to address adequacy issues. Energy efficiency is the most effective resource at creating more reserve capability in the region; however, it is more expensive than in the past.

Additional Market Reliance

The wholesale electricity market is a valuable tool to take advantage of the diversity of the pool of resources in the Western power grid. Currently, the region has chosen to only rely on resources outside the region on a limited basis (2,500 megawatts per hour in the winter and fall and 1,250 megawatts per hour in the spring and summer). Since Northwest utilities have a limited say in the governance and planning in other regions in the West and due to recent historical events,[93] there has been reluctance on a planning basis to rely more heavily on other region's generation as a hedge against uncertainty, despite the cost advantages.

Cost Effective Reserves as Part of the Resource Strategy

Similar operational issues seen in the analysis have occurred in California power system operations for the last ten years or so, and the market operator in California[94] has multiple strategies[95] to address this issue. One is a more conservative operation of existing system power generators, incentivized by paying extra money to plants with flexibility to stay online. The Pacific Northwest currently has no such market operator,[96] and leveraging off regional collaborations[97] such as the Northwest Power Pool Resource Adequacy effort to achieve a similar mitigation strategy may be advantageous.

92 See Section 6: Resource Development Plan for more details on how these investment decisions are approached.

93 2001 Western Power Crisis

94 California Independent System Operator

95 Market mechanisms to hold more reserves and procure more resources.

96 Other than the limited volume of market trades that are governed within the Western Energy Imbalance market structure

97 Other options include leveraging the current Western Energy Imbalance Market structure and/or further coordinating throughout the West for the day-ahead market via the Enhanced Day-Ahead Market.

Additionally, a slightly more expensive, but effective alternative to this would be to invest more in resources like energy efficiency, beyond what was identified in the resource strategy analysis. A riskier but less expensive mitigation method would be to rely more on the market outside the region.

Major takeaways from the analysis:

1. The least-cost option to maintain an adequate, cost-effective regional system is to couple the investment recommendations (the listed amounts of renewable generation, energy efficiency, and demand response) in the resource development plan with some sort of reserve pooling effort via an organized market or regional collaboration to ensure that sufficient reserves[98] can be held to mitigate the increasing uncertainty from increased investment in renewable generation. Part of the reason this method is recommended as the most cost-effective is that the amount of reserves to maintain an adequate system could be changed to match needs over time.

2. A more expensive, but effective, alternative is to invest in more energy efficiency than identified in the resource strategy analysis. This will increase the fixed cost investments required by the region but may be necessary to maintain adequacy should regional coordination to provide additional reserves proves unsuccessful.

3. A less expensive, but riskier alternative is to plan on more external generation to support the region in times of need. Other regions have varying policies, requirements, and Northwest regional stakeholders have less say in their planning processes. Without a more formalized collaborative process like an organized market, this strategy, while taking advantage of the diversity of a large pool of existing resources, would likely expose the region to significantly more risk.

98 Analysis showed that over 3,000 megawatts of additional reserves may be required by 2023 to sufficiently incentivize enough generation to be online in order to have enough fuel to meet morning and evening ramps.

Section 10: Recommendations for Research and Development

The Northwest Power Act directs the Council to include within the plan a "recommendation for research and development." Given the vastly different and rapidly evolving power system, it is important that the Council reflect not only on what we know today, but on what we need to continue to understand to ensure we meet the needs of all the region's consumers. To that end, the Council recommends additional research and development in four key areas:

1. Research to support effective implementation of the conservation program
2. Exploration into alternative approaches to power system operation
3. Research of emerging technologies to support development of future resource options
4. Development of data and tools to enhance future power planning analysis

These recommendations are for entities across the region, with the Council at times providing a supporting role.

Implementing the Conservation Program

The Council is recommending 2,400 average megawatts of energy efficiency be acquired by 2041. Energy efficiency is a slow-building resource. Achieving this goal requires ongoing research to ensure that it is available, reliable, and acquired at the lowest cost.

It requires steady investment to identify opportunities, design programs to deliver efficiency to consumers, evaluate effectiveness, and then refine and repeat. Therefore, the Council recommends that the region continue to invest in research in the areas of evaluation, market research, regional stock assessments, and end-use load research.

In addition to supporting the *Section 5 Energy Conservation Program*, we believe this research provides important insights for identifying demand response opportunities and ensuring effective delivery of those products. The Council recommends the region consider these wider benefits when determining appropriate investment levels for research.

Evaluation

Evaluation is a critical component of understanding the impacts of energy efficiency measures and demand response products. It conveys whether the planned savings were realized, and it can provide insights on how to improve program effectiveness.

Many of the region's efficiency programs–including the Bonneville Power Administration's on behalf of its customer utilities–have robust evaluation efforts. The Council recommends continued investment in energy efficiency evaluation, at levels commensurate with today's investment. This research should include collecting all measure information required to support cost-effective and equitable application of ratepayer funds. Additionally, we recommend that efficiency programs develop evaluations in accordance with the Regional Technical Forum's guidelines, which support consistent and reliable determination of energy efficiency across all measure types.

Market Research

Market research provides thoughtful insights on efficient products available in the market, the availability of contractors and other experts needed to install efficient products (including those with controls that could be used in demand response programs), and where the largest gaps in efficiency adoption exist.

Over the past several years, the region has increased its investment in market research, providing the information needed to refine and focus efficiency programs on the most promising opportunities. NEEA plays a critical role in market research, using its market expertise to take advantage of economies of scale as a regional entity.

Bonneville, the Energy Trust of Oregon, and the region's utility programs also have an important role, particularly in gathering information to address specific local questions or needs. The Council recommends that NEEA, Bonneville, and the region's efficiency programs continue to invest in market research.

Regional Stock Assessments

Through NEEA, regional stock assessments have been conducted that provide snapshots of the existing building stock. This includes information on numbers of buildings, size, use, types of equipment installed, availability of products with controls, and more.

Stock assessments are an important complement to market research, providing another lens for identifying efficiency opportunities and tracking regional progress. The Council recommends that the region's utilities, through NEEA, continue to invest in regular stock assessments for the residential and commercial sectors. Ideally, these would be completed at least once every five years. As part of this effort, NEEA should explore new data techniques for providing more timely information about fast-evolving changes in the stock.

For commercial buildings, the Council recommends that NEEA, with support from Bonneville, Energy Trust of Oregon, and regional utilities, develop a reliable commercial building energy use intensity dataset. The starting point should be the commercial building stock assessment and other publicly available data sources. This dataset will enable efficiency programs to identify buildings that provide the greatest opportunity for significant investment.

The Council also recommends the region's utilities invest in another stock assessment for the industrial sector (including water and wastewater), with particular focus on motors and motor-driven systems. To the extent practical, data gathered on motor and motor-driven systems should also include the agricultural sector, as the region has a long-standing gap of information on this sector. For this work, we recommend that the region build on existing utility data and leverage efficiency program experts knowledgeable with these facilities as a starting point for this assessment.

End Use Load Research

Understanding the timing of energy use, as well as the timing of energy savings, is critical for identifying measures that provide more value for the power system. Today, the region continues to rely heavily on the results from the End-Use Load and Consumer Assessment Program (ELCAP), which was conducted in the late 1980s to characterize the timing of energy use.

Recently, through coordination at NEEA, the region has undertaken a new effort to meter and characterize energy use in residential and commercial buildings. The findings from this research shine light on how we use energy today and provide insights on how new technologies might shift and reduce the timing of energy use.

With the recent Covid-19 pandemic changing how people live and work, this research will answer questions around how energy use has shifted and whether any of those shifts will continue as the new normal. The Council recommends the region continue to fully fund this research and ensure that the knowledge gained is shared broadly for effective investment in all demand-side opportunities. Additionally, the Council recommends that the Regional Technical

Forum use this data to create load shapes for efficiency measures that can be used by the region's utilities to understand the timing of energy efficiency savings.

Exploring Alternative Approaches to Power System Operation

The rapidly decreasing cost of renewable resources, coupled with various state and utility clean policies and emissions goals, are driving large renewable builds across the West. The result: A very different power system. The system requires flexibility, with resource options that can fill in those valleys when renewable energy is not available and support ramping needs when the sun goes down and the lights come on.

Our modeling suggests that we need to rethink power system operations to ensure not only an adequate, efficient, economical, and reliable power supply, but one that continues to protect, mitigate, and enhance the important fish and wildlife in the region. To that end, the Council recommends the region undertake the following explorations aimed at broadening our thinking of power system operation.

Renewable Generation Impacts on Regional Hydropower Operations

The substantial increases in renewable generation across the West shifts power system generation and transforms power markets. The oversupply of renewable generation during the day rapidly shifts to a need for other resources during the evening when the sun is down. Since hydropower has a low variable cost and is flexible, our analysis shows that it is well positioned to help the region absorb increasing renewable generation and ensure adequacy in the region.

However, it is unclear how these daily river flow fluctuations will affect environmental conditions for fish in the river, particularly for juvenile and adult salmon and steelhead migration and for mainstem spawning and rearing habitat. The Council's 2014 Columbia River Basin Fish and Wildlife Program contains measures recommended by the state and tribal fish managers calling on the system operators to minimize or reduce daily flow fluctuations, and yet the analysis suggests a need for increasing fluctuations for adequacy.

The Council intends to organize and support an investigation into the implications of these changing river flows. This effort will bring together Bonneville, system operators, the federal and state fish and wildlife agencies, and the region's tribes. The goal will be to explore the possible benefits and consequences of different hydropower system operations to identify a path forward that provides greater benefit to both power and fish.

Alternative Approaches to Support Renewable Integration

Our analysis suggests other approaches might provide low-cost solutions to support integrating renewables into the existing system. One example is the role of holding reserves. Plan analysis shows that more regional collaboration on holding reserves can provide a lower cost approach to system adequacy.

When a utility holds more reserves, it has more of its existing generation ready if needed to address unexpected loads. Alternatively, with lower reserve amounts, the market prices diluted by the influx of renewables might not provide a sufficient signal to ensure those existing resources are otherwise available if needed. To better understand the tradeoffs around holding more or less reserves, the Council recommends that the region's utilities, regulators, and Bonneville conduct a study to explore how market liquidity by season and time of day can create price barriers for flexible resources, and the cost of mitigating those barriers through greater reserves. This analysis should take into account different hydro conditions.

Another approach to supporting adequacy is demand response. Balancing the system requires that resources are available to quickly meet loads as they come onto the system and can be curtailed as those loads go away. Demand response is a resource that can shift loads away from those high peaks to other times of the day when loads are otherwise low. The Council recommends that Bonneville and utilities research opportunities to use demand response to support system balancing. This effort should provide insight on how to improve modeling these opportunities for future regional and utility power planning efforts.

Transmission and Non-Wires Alternatives

With a potential significant deployment of cheap, new resources vying for access to the transmission system and competing with established, oftentimes more expensive, resources for dispatch to the grid, it is time for the region to reconsider how we contract, reserve, and schedule transmission access.

It is common for a given transmission path to be fully contractually encumbered on a long-term firm basis while still having substantial available physical capacity most or all hours of the year. New resources may face transmission access queues up to several years, creating a barrier to, or slowing, development. While any unused transmission capacity must be marketed for short-term utilization, this can have limited value to project developers who require deliverability guarantees in order to receive financing.

The Council recommends that the region's transmission providers work with utilities, load-serving entities, NorthernGrid, and others to develop a comprehensive review

of the existing state of the transmission system; research potential short-term and long-term solutions to alleviate new resource development barriers, while balancing existing long-term contracts and compensation to transmission providers; and explore the potential benefits of implementing a regional transmission operator in the Pacific Northwest.

Additionally, the region should continue to explore non-wires alternatives to address transmission and distribution constraints. Battery storage and targeted demand response, for example, can provide significant value to deferring the need for adding transmission. The Council recommends that the region consider the role of battery storage, targeted demand response, and other demand-side resources to address existing transmission capacity challenges.

This research should speak to the role of these resources in alleviating some of the new resource development described earlier. Additionally, the Council recommends that utilities and Bonneville consider the value of these opportunities on a case-by-case basis to address local needs.

The Council's planning work will require a working knowledge of the impact of new and existing transmission on the region's access to market power and the region's ability to interconnect new generators. The Council is committed to engaging with the region's transmission planners and working alongside them to encourage better coordination on all aspects of long-term planning for the regional power system.

Role of Hydrogen and Fuel Cell Technology

Finally, the 2021 Power Plan is the first to explore the use of hydrogen fuel cell technology as a potential clean energy resource. Hydrogen may be especially promising as a replacement for diesel fuel in heavy duty freight transportation[99] and for some high-heat industrial uses. Currently there is limited demand and production in the region, however this may change in the future with the various clean electricity grid and emission reduction goals.

The Council recommends study of the impacts, benefits, and challenges that large-scale demand and production of hydrogen in the region might have on the power system overall, and in particular, hydro and renewable power. For instance, one hydrogen production method–electrolysis–can be turned on and off, which maybe be useful for balancing load and soaking up excess renewable generation.

99 nwcouncil.org/energy/energy-advisory-committees/demand-forecast-advisory-committee

Emerging Technology

In developing the recommended resource strategy, the Northwest Power Act requires the Council to give priority to resources that are cost-effective. This includes resources that are "reliable and available within the time [they are] needed, and to meet or reduce the electric power demand […] at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource."

We recognize that while the resource strategy must focus on those resources available today, there are many potential opportunities that might meet future power system needs at lower costs. To this end, the Council recommends that the region continue to invest in researching emerging opportunities.

As states and utilities progress toward clean, non-carbon emitting energy portfolios, there are opportunities for new, emerging supply-side technologies to compete with established renewable resources–such as onshore wind and solar photovoltaic–and that will play a critical role in the future power system.

The Council recommends that national labs, research institutions, trade allies, and utilities continue to work with developers and manufacturers to research and explore the regional resource potential of supply-side emerging technologies such as offshore wind, small modular nuclear, enhanced geothermal systems, energy storage, carbon sequestration technologies, and other carbon-free resources. In addition, the Council urges the region to identify potential barriers to deployment, including costs, transmission, siting, etc., and work together toward solutions when it is in the best interest of the region.

On the demand-side, new innovations in efficient technologies provide paths to lower cost energy efficiency. To ensure that efficiency measures are readily available and reliable, research is needed to understand the efficacy and applicability of potential technologies.

The Council recommends that efficiency programs, through NEEA, regional universities, national labs, and others should continue to invest in emerging technology research for efficiency measures. This effort includes scanning for emerging technologies, pilot studies to provide case studies for program opportunities, and field research to verify real-world savings.

With less lower cost energy efficiency potential than in prior years, and greater competition with generating resources, this research should also explore opportunities for cost reduction and paths forward that provide the most efficiency benefit at the lowest costs.

The Council also recommends the Regional Technical Forum increase the rigor of its measure cost analysis to support improved comparison with alternative resources in future resource planning. Further, the Council recommends additional research around demand response opportunities.

Our analysis for the plan demonstrates that demand response products that can be frequently deployed at low cost provide significant value to the power system to maintain adequacy and reduce emissions. As utilities and Bonneville explore the value of demand response, the Council recommends that the region continue to develop these non-traditional applications that may provide more value than the standard peak-reducing product.

Development in Support of Future Power Planning

The Council recognizes that power planning is an ongoing effort. The power plan reflects our recommendations based on our understanding of the system today, the availability and costs and benefits of new resources, and existing modeling tools. We recognize, however, that there are enhancements needed to continue to improve our power planning in the future. To that end, the Council recommends developing data and tools in the areas of equity, the valuation of model inputs, and enhanced metrics and tools for improved modeling.

Equity

Through its development of the power plan, and in particular discussions in the System Integration Forum[100] on diversity, equity, and inclusion in the power planning process, the Council identified a gap in equity data that informs equitable representation and accountability in regional and utility resource plans.

The Council recommends that the region convene a series of workshops to investigate existing equity data–encompassing generation, transmission and distribution, and demand-side resources–share publicly available data sources, and perform a gap analysis to identify areas where further research and data are needed.

The goal of this workshop is to develop a regional framework to improve future power planning analysis, including future Council power plans and regional utility integrated resource plans. The workshop participants will need to identify the appropriate entities to manage these efforts long-term. Regional

100 The System Integration Forum brings together multiple Council advisory committees to explore cross-cutting topics. The Forum on diversity, equity, and inclusion was held on February 19, 2021: nwcouncil.org/meeting/sif-2021-power-plan-and-dei-february-19-2021

cooperation and collaboration–broad representation across the region, including many agencies and utility groups–is crucial to the success of this effort. The Council will use its role as convener to assist in launching the first workshop.

Improved Valuation of Model Inputs

Upstream Methane

Despite the focus on renewables, natural gas continues to play an important role in providing energy to the Northwest. Methane, the primary component of natural gas, is an especially potent greenhouse gas, and measures of atmospheric levels have been rising significantly in recent years.[101,102]

The 2021 Power Plan is the first to include an estimate of upstream methane emissions from the natural gas system directly in the planning process. For this plan, the Council–with the expertise of the Natural Gas Advisory Committee–developed an estimate for methane release rate of the natural gas consumed in the Northwest, which is drawn from Western Canada and the Western United States. While we are confident in the approach and assumptions for this analysis, we recognize that there are gaps in our understanding.

Assessing the upstream methane emissions related to the extraction, processing, transportation, and storage of natural gas is a complex undertaking. This has emerged as an important topic, spurring a number of studies that use new methods to assess the overall emissions from natural gas activities in the United States. However, the level of methane releases can vary among specific gas basins. To add a further level of complexity, estimates for the same gas basin can vary depending on the methods and tools that were used to develop the estimate.

The Council recommends working with the Northwest Gas Association and other interested regional bodies to design a study and define a course of action with the goal to more fully quantify the upstream methane emissions related to the natural gas consumed within our region. We also recommend a follow-up study on how best to limit the intended and unintended methane releases related to natural gas consumed in the region.

Valuation of Resilience and Flexibility

Energy efficiency provides values to the power system not readily captured in today's modeling. Two important attributes are resiliency and flexibility. In these terms, resiliency is focused on home and building resilience. For example, some energy efficiency measures provide the ability to ride-through extended power outages or

101 gml.noaa.gov/ccgg/trends_ch4

102 research.noaa.gov/article/ArtMID/587/ArticleID/2742/Despite-pandemic-shutdowns-carbon-dioxide-and-methane-surged-in-2020

extreme weather events. Recent events, like the historic wildfires across the West and the Texas freeze, have demonstrated the importance for home and building resilience during extended outages.

Energy efficiency can also support flexibility. While energy efficiency itself is not a flexible resource, there are many measures that support load management for grid flexibility, whether through integrated control or reducing the impacts on end-users from other load-management efforts.

For both resiliency and flexibility, the Council considered proxy values in the cost-effectiveness valuation to highlight those beneficial measures. The Council recognizes the need to improve this valuation for future efforts. The Council recommends that the Regional Technical Forum investigate methods for quantifying the value of flexibility and resiliency for energy efficiency measures. To ensure symmetrical treatment of energy efficiency with other demand-side and supply-side resources, the Regional Technical Forum should work with other regional experts in developing these values.

Efficacy of Voltage Regulation

The Council recommends that Bonneville, the national labs, NEEA, and regional utilities study the impacts of voltage regulation under current conditions and explore how these results might change with future expected loads.

Utilities may regulate the voltage along the distribution system as a way of changing total energy demand. Reducing the line voltage will reduce the resistive losses in the system, resulting in energy or peak demand savings. The efficacy of voltage regulation is determined by the amount of resistive load on the system. New technological advances and efficiency gains–for example compressor-based equipment replacing electric resistance technologies–have the potential to change the amount of savings from voltage regulation.

Current data for voltage regulation effectiveness are based on older studies that do not represent today's technology mix, nor do they reflect future load sources such as electric vehicles. As the Council and regional utilities base estimates of energy efficiency (conservation voltage regulation or CVR) and demand response (demand voltage regulation or DVR) potential on these studies, updated research will provide more accurate assessments of potential.[103] The analysis for this plan demonstrates the importance of this regulation, particularly DVR as a non-

103 Demand voltage regulation is a product that allows utilities to reduce voltage during peak periods of need and increase it for periods of load building as a way of balancing the system. Alternatively, a consistent reduction in voltage throughout the year can serve as a conservation measure, also known as conservation voltage regulation.

intrusive and regularly available demand response product, for addressing future power system needs.

Valuation of Non-Energy Based Emissions, and Potential Regional Emissions, Sinks, or Offsets

This plan attempts to explore paths toward meeting various economy-wide decarbonization goals. While not in the direct purview of the Council, understanding non-energy sector emissions and viable paths for reducing emissions is important for understanding the interaction between the power sector and these other sources. The Council estimated rough targets in the pathways to decarbonization scenario to explore the tradeoffs between the power sector and other emissions sources in meeting economy-wide emissions goals, but more data would improve future modeling. The Council recommends that the region–including national labs, universities, and state agencies–analyze emissions sources and sinks that may have implications for future power system planning. This data and analysis should be made available to regional stakeholders to support future analysis.

Improved Modeling

Adequacy Metrics for Power Systems With High Renewable Penetration

The Council, and others in the region, have historically used the annual loss of load probability as a measure of power supply adequacy. The changing power system with more prominent seasonal issues requires that the region rethink its assessment of adequacy. Specifically, the Council believes that a set of more detailed adequacy metrics is warranted.

Therefore, the Council recommends that Bonneville and the region's utilities investigate adequacy standards that capture the frequency, duration, and magnitude of potential shortfall events to better understand issues that occur in a system with high renewable generation penetration.

The Council should also investigate underlying system conditions during shortfall events and how adding resources or changing reserves impacts these events. The Council commits to working with Bonneville and the regional utilities on this important issue, with a goal of incorporating improved metrics into future power planning.

Broaden Regional Extreme Event Analysis

In addition to working on how adequacy is assessed, it is important for the region to understand the impact of extreme events on the power system. Major heat waves and cold spells in the Northwest and across the country have emphasized the need for investigation and utility cooperation in estimating the impact and frequency of such events.

The Council recommends that Bonneville and regional utilities, working with the

Council, coordinate in developing methods to estimate their frequency, magnitude, and duration. Further, the Council recommends adapting these methods to allow investigating their impact in the full range of power system models, including those used by the Council in its power planning processes.

Revisit Analytical Approaches to Planning for the Electric System

The models and analytical approaches used by the Council and regional utilities for power planning reflect standard industry practice. These standard industry practices are based on a historic electric system that is different than our present-day electric grid. Furthermore, we expect a substantial transformation of the grid that will diverge even more from the electric system these models and approaches were designed to simulate.

While the timing and extent of this transformation is unclear, the Council recommends the region, including national labs, universities, and other experts, research how effective the current models are at forecasting or simulating system operation and at projecting the future drivers of electricity demand. This research should focus on production-cost models, load-forecasting models, and capacity-expansion models.

Production-cost models, the computer programs most often used to estimate electricity prices, use the marginal pricing theory from economics, which in the current electric system means electricity prices are largely forecast and formed based on what it costs to operate fossil-fuel-based generation.

However, fossil-fuel-fired generation is rapidly being retired and will likely make up a smaller portion of the future electric system. With fewer fossil-fuel power plants in the system there will be fewer power plants ready to respond to market prices and more generators that have minimal or even negative operating costs, such as wind and solar plants.

This shift in generation results in prices being more volatile, likely leading to inefficiencies in the market and possibly a breakdown in the economic theory on how electricity market prices are formed. This impacts the accuracy and efficacy of widely used production-cost models. Since forecasting future electricity prices is fundamental to the Council's analysis, we recommend the next generation of production-cost models directly address this challenge.

In load-forecasting models, we have made progress toward incorporating climate change into our analysis but would also encourage a broader regional conversation on methods that adapt our forecasts to a changing climate. We also see that future demand for electricity depends on the

interaction of the electric system with purposes that have historically been served by other forms of energy, such as electric vehicles replacing those previously powered by gasoline.

The interaction between the different forms of energy used in our region or in the broader Western electric grid could have wide-ranging impacts on our future power plans. In this plan, we have shown the range of potential future electric loads is extremely large, depending on the extent of electrification of transportation and buildings that occurs. We recommend the next generation of load-forecasting models focus on improving estimates of these interactive effects.

Capacity-expansion models generally assume a static demand for electricity is met by adding differing types of generating technologies, while minimizing the capital cost and fixed and variable costs of operating the resulting system. The next generation of capacity-expansion models will likely need to assess trade-offs between different technologies on the demand-side, particularly hydrogen produced by electrolysis, an energy-intensive process.

Also, in using models to test capacity expansion, it's important to capture the impacts on the existing system from dynamically adjusting reserves and storage deployment for different generating technologies. Finally, capacity-expansion models are computationally intensive, therefore we recommend that future models focus on those questions that result in a meaningful difference, recognizing that these may be different questions than in the past.

The Council recommends that analysis of the current generation of models should both address these concerns and explore further implications of how transformation of the electric system will affect our ability to appropriately capture future risks and requirements for power planning.

Section 11: Methodology for Determining Quantifiable Environmental Costs and Benefits and Due Consideration for Environmental Quality, Fish and Wildlife, and Compatibility with the Existing Regional Power System

The production, generation, and distribution of electricity affects the environment, and environmental effects will vary based on several factors, including the resource type and technology, fuel use and extraction processes, the facility size and footprint, and location. Pursuant to the Northwest Power Act, in its power planning, the Council must consider environmental effects related to the power system and integrate these considerations into its analysis through various statutory vehicles. For example,

perhaps reflecting the time when the Act was drafted, when natural resource policymaking shifted to recognize the importance of internalizing environmental externalities, Section 4(e)(3)(C) of the Act requires the Council to include as an element of the power plan a "methodology for determining [the] quantifiable environmental cost and benefits" of new generating and conservation resources.

Further, Section 4(e)(1) of the Northwest Power Act requires that the Council's regional power plan give "priority to resources which the Council determines to be cost-effective." The definition of cost-effective, found in Section 3(4) of the Act, requires that the Council estimate and compare the incremental system costs of different generating and conservation resources, with system cost defined as:

> "an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs (including projected increases), and *such quantifiable environmental costs and benefits as the Administrator determines, on the basis of a methodology developed by the Council as part of the plan, or in the absence of the plan by the Administrator, are directly attributable to such measure or resource."*

Consequently, the methodology for determining environmental costs and benefits not only represents one of the vehicles available to the Council to analyze and integrate environmental effects into its planning, it is also a significant component of the Council's work to estimate and compare the system costs of a particular resource and ultimately determine those resources that are most cost-effective for the region.

In addition, Section 4(e)(2) of the Act requires that the Council set forth a general scheme for implementing conservation measures and developing resources with due consideration for, among other things, environmental quality, and the protection, mitigation and enhancement of fish and wildlife. Therefore, this statutory vehicle introduces a broader set of environmental considerations for the Council to deliberate on as it analyzes new generating and conservation resources, and, importantly, as it assembles those new resources into a regional resource strategy.

The first part of this section describes the Council's methodology for determining environmental costs and benefits for the 2021 Power Plan. Implementation of this methodology is then reflected in the resource strategy discussed in Section 6, with the supporting materials providing additional analysis regarding the resource cost assumptions and analysis (See the

methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials).

The second half of this section describes how the Council, in developing its resource scheme, gave due consideration for environmental quality, compatibility with the existing regional power system, protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and other criteria as set forth in this plan. This last part of the section, describing how the Council gave due consideration to each of these listed factors, captures how the Council grappled with and used these considerations to shape its final resource strategy and planning decisions.

Methodology for Determining Quantifiable Environmental Costs and Benefits

Section 4(e)(3)(C) requires the Council develop and include as an element of the power plan "a methodology for determining quantifiable environmental costs and benefits" of new generating and conservation resources.

The Act does not prescribe a particular procedure or method that the Council must undertake in developing its methodology. However, the sum of the provisions of the Act addressing the methodology, Section 4(e)(3)(C) and Section 3(4)(B), are specific in that the methodology is to consider costs and benefits to the *environment*, not to any other type or category of costs and benefits, and that those environmental costs and benefits must be *quantifiable* and *directly attributable* to the new resource. These terms, "environmental," "directly attributable," and "quantifiable," are not defined in the Act; therefore, the Council has used a common-sense understanding of the terms, guided by the context in the Act, discussions included in the legislative history, and at times, the Council has exercised its judgment on a reasoned basis in making determinations as to what these terms mean and how they apply for purposes of the methodology.

For the 2021 Power Plan, and consistent with previous plans, the Council has identified four primary components to serve as the base of the methodology: 1) compliance with existing regulations; 2) environmental effects beyond regulatory controls, including both residual and unregulated; 3) compliance with proposed environmental regulations; and, 4) environmental benefits.

Each component is discussed in detail below. However, before discussing each component, it should be understood that Section 3(4)(B) of the Act requires a back and forth between the Council and the Bonneville Power Administration's administrator to develop and then apply the methodology that is not workable in practice for development of the power plan. Under the precise language of the Act, as part of the plan, the Council must develop a methodology for determining quantifiable environmental costs and benefits, then on the basis of that methodology, Bonneville's administrator is to determine such quantifiable environmental costs and benefits directly attributable to each resource, and then the Council is to incorporate the administrator's determinations into the estimated system cost of each new measure or resource to determine the cost-effective resource strategy for the power plan.

Following this specific direction does not work, as the Council cannot issue a power plan that includes the cost-effective resource strategy without first estimating and comparing the resource system costs, which requires considering quantifiable environmental costs and benefits. To make these provisions work together, the Council provides Bonneville, and others, including various advisory committees, the opportunity to examine and comment on the Council's methodology and the environmental costs and benefits attributed to each resource both prior to and following issuance of the draft plan. Any concerns identified in comments on the draft plan will be considered and addressed in the final plan.

Components of the Methodology

Cost of Compliance with Existing Regulations

The Council's planning assumes that all new (and existing) generating and conservation resources will comply with existing federal, state, tribal, and local environmental regulations. This includes, for example, compliance with environmental regulations governing air and water emissions, siting and licensing, waste disposal, fuel use (extraction and production), and fish and wildlife protection and mitigation requirements.

Existing regulations reflect policy decisions already agreed upon regarding the environmental costs and the appropriate level of protections to redress that harm, the costs are directly attributable to the resource, and largely quantifiable as a component of capital installment costs and fixed and operating costs.

Therefore, the estimated cost of compliance with existing environmental regulations is the primary method the Council has used to quantify environmental costs of generating and conservation resources in past plans, and it is again the primary method for the 2021 Power Plan.

While the cost of compliance may seem most obvious for generating resources, the costs of compliance also factor into the total system cost of new conservation measures, to the extent there are applicable environmental compliance costs quantifiable and directly attributable to the measure.

The generating resource reference plant section of the new generating resource supporting materials describes the environmental effects of generating resources, with existing systems and policies supporting materials providing additional information on the environmental effects of generating resources and outlining the existing environmental regulations to address those effects.

In addition, the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials, describe and assess resource system costs, including costs of compliance. The supporting materials for the methodology also expound on how the Council applies this method using an existing regulation as an example.

Cost of Compliance with Proposed Environmental Regulations

The Council has typically dealt with the cost of compliance with proposed environmental regulations on a case-by-case basis depending on the proposal, the effects the proposal addresses, and the quantitative data available. The Council is again deciding to address costs of compliance with proposed regulations on a case-by-case basis for the 2021 Power Plan. However, at the time of drafting this plan, there were no environmental regulations proposed that set stricter standards than those previously established for new resources. Consequently, there were no costs of compliance with proposed regulations added to any new resource system costs.

Environmental Effects Beyond Regulatory Controls

Existing environmental regulations control or mitigate for some amount of the targeted environmental effects from generating or conservation resources, but existing regulations do not control or mitigate for all environmental effects of resources– including residual. Residual effects remain after compliance with current regulations. For example, not all discharges from an electric generating facility, whether to the air or water, are controlled or prevented by the limitations and standards established pursuant to the Clean Water Act or the Clean Air Act, nor are all bird kills from wind turbines prevented by current regulations.

In addition, there are unregulated effects, which are environmental effects not yet regulated or not currently under regulation. The social cost of carbon emissions is an

example of an associated environmental effect of a resource that is currently beyond regulation.

The Council acknowledges there are environmental effects beyond regulatory control that should be considered in the Council's planning. However, quantifying costs for these effects in a resource's system cost is difficult, if not impossible, due to the persistent lack of adequate data and methods to determine reasonable quantitative costs.

Moreover, while sufficient data is available for a few effects (e.g., the social cost of carbon) data largely remains deficient for most other residual or unregulated environmental effects. Adding the determined costs of some effects to some resource costs, but not the costs of all known effects to all resources due to an inability to reasonably quantify them could lead to an inappropriately skewed resource cost comparison.

Further, when estimating and comparing resource system costs, it is most useful for the Council to consider costs reasonably anticipated or appropriate to be borne by the power system. Considering social or damage costs in the direct costs of a few resources could lead to potentially applying costs to some resources that are extraneous to the power system, resulting in inconsistent resource cost comparisons.

Therefore, consistent with previous power plans, for the 2021 Power Plan, the Council is continuing to acknowledge and examine residual and unregulated effects qualitatively in the resource analysis and in developing the resource strategy because it remains infeasible for the Council to develop quantitative cost estimates for these effects, especially in a systematic or consistent way across resources, and then add them to the new resource system costs.

The methodology supporting materials provides additional detail regarding the data insufficiency and the hinderance it presents to the Council in estimating the costs of these environmental effects beyond regulation. The Council's qualitative assessment of these effects is described in the generating resource reference plant section of the new generating resource supporting materials, with the environmental effects of generating resources found in the existing systems and policies supporting materials providing additional information.

The Council integrates environmental effects into its power planning, and considers unregulated environmental damages, through the lens of Section 4(e)(2)–the provision requiring that the Council give due consideration to, among other factors, environmental quality and the protection and mitigation of fish and wildlife.

A prime example of this is the continued implementation of protected areas. Protected

areas were first adopted by the Council in 1988 as an element of the Council's fish and wildlife program. They are river reaches where the Council believes new hydroelectric facilities would have unacceptable risks of loss to fish and wildlife species of concern or their habitat.

Their designation, and continued implementation and enforcement, is an explicit expression of the Council's due consideration of the effects of new energy resources on environmental quality and fish and wildlife resources.

In the power plan, the Council has included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation, with upstream methane emissions factored into that cost calculation as well. While these environmental effects are not added as a direct cost of the resource via the methodology, these effects are considered and integrated into the Council's planning, and their impact is reflected in the Council's resource decisions detailed in the resource strategy (Section 6).

For additional details regarding how the social cost of carbon was incorporated into the Council's planning including in scenario analysis and as one component of the net present value of the total portfolio cost in the regional portfolio model, see the Global Assumptions[104] in the supporting materials

Quantifiable Environmental Benefits

In addition to quantifiable environmental costs, the Act also requires the methodology address quantifiable environmental benefits of new generating and conservation resources. When considering environmental benefits, a key issue for the Council is whether and how to factor into the system cost of a new resource the benefit of being able to reduce an existing activity that has an environmental cost.

The Council acknowledges that the environmental benefit of a resource should be recognized and considered within the resource analysis in some capacity. However, the question for the Council is whether these environmental benefits can be quantified and determined to be directly attributable to the new resource. The Council is deciding to not attempt to include quantified environmental benefits in new resource costs beyond a few historic examples and will instead emphasize in the resource strategy how certain resource choices help to mitigate harmful environmental effects.

Except for a few minor exceptions, the Council has not been able to quantify environmental benefits of new resources because information and data on environmental benefits is not available,

104 nwcouncil.org/2021powerplan_global-assumptions-power-plan

sufficient, or well understood. Quantifying financial aspects of reducing environmental harm is also often missing or quite speculative in the data that is available.

It is also difficult to determine that a reduction in environmental harm (or an environmental benefit) is directly attributable to the new resource and not simply incidental or indirect. And, as noted earlier regarding the effects beyond regulatory control, while it may be possible to capture quantified environmental benefits for a few resources, the Council is reluctant to engage in a piecemeal quantification of benefits, which could result in a skewed resource cost comparison.

To use a familiar example, installing an efficient washing machine saves energy and reduces water consumption, which is an environmental benefit. The reduction in water consumption is a direct benefit of installing the efficient clothes washer and the Council is able to quantify this direct environmental benefit by utilizing consumer water and wastewater bills as data to support the quantification.

The Council can do a similar analysis for other water-saving measures, such as dishwashers, showerheads, and aerators. However, to walk through another familiar example, installing a ductless heat pump in the main living area of a house may result in burning less wood. With less wood burned, particulate emissions are reduced, which is a benefit to the environment (air quality) as well as a benefit to human health.

However, in this example, it is more challenging for the Council to say whether the environmental benefit (reduced particulate emissions) is directly attributable to the installation of the ductless heat pump, or a result of a behavior choice and incidental to the installation of the measure. Also, this environmental benefit is more difficult to reasonably quantify due to a lack of appropriate data and tools for quantification. Therefore, the Council has not added this benefit to the cost of the measure.

Since the Seventh Power Plan, more information on quantifying environmental benefits has been developed, but not enough to enable the Council to quantify environmental benefits to a broader degree. Specifically, the U.S. Environmental Protection Agency issued a report in July 2019, *Public Health Benefits per kWh of Energy Efficiency and Renewable Energy in the United States: A Technical Report,* addressing the public health benefits associated with conservation and renewable resources, and Washington investor-owned utilities (IOU) issued studies analyzing how to monetize the benefits of reduced wood smoke from the installation of ductless heat pumps. The Washington IOU studies did provide new location-specific information for quantifying the environmental benefits of reduced wood smoke. However, they do not resolve the

Council's concerns since it's difficult to say to what extent reductions in particulate emissions are directly attributable to the installation of the efficiency measure. And, this additional data does not address lingering concerns regarding piecemeal quantification leading to a skewed resource cost comparison.

To be clear, the Council recognizes that particulate emissions from wood burning are a well-documented health concern, and the installation of a new electrical measure in the right circumstances may lead to reduced emissions. The Council will continue to exercise its discretion on the basis of the data currently available and not apply these benefits to the cost of new conservation resources. Nonetheless, state and local government, regulatory commissions, and utilities are more than justified in continuing to pursue these measures based on the health and societal benefits.

The EPA's report recognized energy efficiency and renewable resources reduce emissions. The report quantified near-term benefits of reduced emissions using avoided emissions rates based on 2017 electricity generation, which resulted in dollars per kilowatt values for conservation and renewable resources.

EPA advised, however, that the values should not be used to estimate benefits beyond 2022 given the emission rates underpinning the values.[105] Thus, capturing these benefits in new resource system costs for the 2021 Power Plan, would require significant analysis by staff to extend the values through the 20-year planning period.

More importantly, however, is the transformation occurring in the region and broader Western electric grid as significant amounts of renewable resources are added. This is spurred by lower resource costs, coal retirements, and clean energy policies. Emissions will be changing over the next five to 10 years and beyond; with increased reliance on zero-emitting resources, the avoided emissions rate for the region will also be changing.

This will lead to an even lower dollars-per-kilowatt-hour benefit in future years. The potential for the benefit value to become less significant over the course of the planning period compounds the Council's concerns regarding: 1) applying these benefits piecemeal; and 2) the risk of inappropriately skewing the resource cost comparison.

Moreover, there are other vehicles under the Act enabling the Council to consider the environmental effects of resources; one is its due consideration of environmental quality. In developing the power plan, the Council considered greenhouse gas emissions, as well as climate change, and integrated each of these into its analysis. Climate change

105 EPA issued an update to the 2019 report in May 2021. However, data for the 2021 Power Plan was frozen in April 2020; moreover, the May 2021 update recommends its values not be used beyond 2024.

mpacts on temperature and precipitation, which affect loads and river flows, were integrated throughout our quantitative analysis and modeling, and the Council included the social cost of carbon from the Intergovernmental Panel on Climate Change as part of the portfolio cost calculation in the regional portfolio model, with upstream methane emissions factored into that cost calculation as well.

While the environmental effects of carbon were not added as a direct cost or benefit of a new resource via the methodology, its effects were considered and integrated into the Council's planning, and the impact of that consideration is reflected in the Council's resource decisions, addressed in more detail below. Additional Information on how the social cost of carbon was incorporated into the power planning analysis is in the Global Assumptions[106] in the supporting materials.

Therefore, for these reasons and consistent with the Council's previous application in past power plans, the Council did not attempt to include quantified environmental benefits in new resource costs beyond the few historic examples, and instead recognizes and emphasizes in the resource analysis the value of certain resource choices to help mitigate other harmful environmental effects.

See the methodology for determining quantifiable environmental costs and benefits section of the new generating resources supporting materials and the cost and benefits of energy efficiency supporting materials for additional information on benefits included in resource system costs. And the generating resource reference plant section of the new generating resource supporting materials describes the environmental effects of generating resources, with existing systems and policies supporting materials providing additional information regarding the environmental effects of generating resources.

Due Consideration for Environmental Quality, Fish and Wildlife Protection, Mitigation and Enhancement, and Compatibility with the Existing Regional Power System

The Power Act calls on the Council to develop the conservation and generation resource strategy for the plan "with due consideration by the Council for (A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat,

106 nwcouncil.org/2021powerplan_global-assumptions-power-plan

including sufficient quantities and qualities of flows for successful migration, survival, and propagation of anadromous fish, and (D) other criteria which may be set forth in the plan."

The following documents how the Council provided "due consideration" for these matters in developing this Power Plan, with particular focus on considerations of environmental quality and fish and wildlife. There are certain matters the Council considers with every power plan that are relevant here, and other matters particular to this plan. Both are highlighted as follows:

Fish and Wildlife Program; Hydropower System Operations for Fish and Wildlife

The Act requires the Council to call for recommendations and amend the fish and wildlife program prior to the power plan. The Act then makes the fish and wildlife program a mandatory element of the power plan. See *Section 12: Fish and Wildlife Program.*

One of the reasons for this is so that the Council, in developing the power plan, can assess how dam operations to benefit fish affects hydropower generation, both in its amount and timing, and then design a regional resource strategy that accounts for any reduction in generation available.. The Council designs the strategy in part to facilitate reliable implementation of the system operations for fish, while continuing to assure the region an adequate, efficient, economical, and reliable power supply.

The Council's analytical models and scenario analyses for the power plan incorporated all the latest system operations recognized in the Council's fish and wildlife program. This includes reservoir operations, spill, and other passage operations, including the flexible spill operation for juvenile fish incorporated into the program from decisions external to the program, such as the most recent Columbia system biological opinions. These operations are all incorporated into the Council's modeling and analytical work on the scenarios, as well as the baseline conditions. The Council's resource strategy is developed in part to assure an adequate and reliable power supply that will also allow for reliable implementation of fish operations.[107]

107 In October 2021, after the Council published the draft power plan for public review and comment, the federal agencies operating the Columbia River System agreed to a slightly different set of spill and run-of-river reservoir operations for 2022, for one year only.
See: pweb.crohms.org/tmt/JointMotion_TermSheet_CourtOrder_OCT2021.pdf. Although a formal analysis is not available, Bonneville Power Administration staff publicly reported its estimate that the operations agreement for 2022 would reduce the federal system's average hydro output approximately 45 aMW compared to the operations that were to occur in 2022, as specified in the 2020 Columbia system biological opinion. See: newsdata.com/nw_fishletter/bpa-estimates-power-impact-of-additional-spill-in-agreement/article_5b341294-56c6-11ec-9028-e702aac7ae67.html. The Council decided for the final power plan not to revise the operations in

Environmental Effects From the Generation of Electricity and Conservation

The Council identifies the various environmental effects from the generation of electricity in all phases of the life cycle of a new generation resource. They include, for example, the effects on land, water, habitat, and fish and wildlife during construction; environmental effects of key parts in manufacturing; fuel development and transportation; operational effects, such as air and water emissions or harm to wildlife or fish; waste disposal; and end-of-life decommissioning and similar matters. The Council also identifies environmental effects to the extent possible for conservation measures and other non-generation alternatives.

The Council described these effects in a comprehensive way for the Seventh Power Plan, especially in Appendix I. The Council reviewed and updated this information as necessary for the 2021 Power Plan. See the supplemental material for generating resources, especially the discussion of environmental effects in the generating resource reference plant section and the environmental effects of generating resources.

To the extent these environmental effects can be quantified in dollar terms, the Council includes these resource costs for the new resource cost comparison, as part of in the environmental cost and benefit methodology described above. Environmental effects and damage that cannot be quantified in the same way are still recognized and considered in developing the resource strategy.

Unquantifiable environmental impacts and damage from utility-scale generating developments have always been an additional consideration for implementing conservation measures and for other power system efforts that avoid construction and operation of major facilities, including demand response measures, and in certain cases, more efficient use of existing generation facilities.

Protected Areas

Beginning in 1988, the Council adopted protected areas as an element of the Council's fish and wildlife program and power plans. In these provisions, the Council calls on the Federal Energy Regulatory Commission (FERC) to not license a new hydroelectric project in river reaches with valuable fish or wildlife resources that the Council identified and mapped in a protected areas database by the Council. The protected areas provisions also call on Bonneville to not acquire the output of, or provide transmission support for, such a project, assuming it were to receive a license. To date, FERC has not licensed a new hydroelectric

the baseline conditions and re-run the model analyses for all the scenarios. The size and duration of the change in generation is not of a magnitude to affect the resource strategy.

project in a protected area identified by the Council.

In the power plan context, protected areas represent a judgment by the Council that due to potential effects on habitat, flows, and passage, the adverse effects on, and environmental costs to, important fish and wildlife resources are too great to justify including new hydroelectric projects in these areas, except under certain limited conditions.

The existing power system is already bearing substantial costs to protect and mitigate for its impacts on fish and wildlife resources. The power plan context is also important in that the protected areas designation extends throughout the entire Pacific Northwest (essentially the same as the Bonneville service territory), not just within the Columbia River Basin. This is part of the resource strategy for the region's power system, as well as a comprehensive plan for the region's waterways and new hydroelectric development.

As the Council evaluates the potential and cost-effectiveness for new hydroelectric development in each power plan, it includes the effects of protected areas in limiting the extent of that potential. The Council also gives due consideration to fish and wildlife and the quality of their environment by including a set of development conditions to protect fish and wildlife as new hydroelectric projects are licensed and developed in areas outside of the protected areas.

Greenhouse Gas Emissions and Climate Change

The environmental quality topic of primary interest in this plan, as in the last two, was the issue of greenhouse gas emissions and climate change. The Council has considered this topic in several ways in formulating the plan's resource strategy, including:

- The Council closely tracked state and other legal and policy developments in the region and across the West that require retiring, or reduced emissions from, coal-fired generation; the scheduled retirements of coal plants; the addition of renewable resources through renewable portfolio standards; and clean energy standards and greenhouse gas reduction goals from the electrical power system. The Council designed a resource strategy for a power system consistent with the effects of these laws, policies, and commitments. Part of the Council's aim in the power plan is to help the region understand a least-cost way to make this transition and retain an adequate and reliable system.
- The Council included greenhouse gas emissions considerations in new resource costs whenever possible to quantify and also tracked emissions effects to the extent possible. This includes upstream

methane emissions from natural gas production.

- The Council also integrated climate change effects into the baseline conditions and analyses, including climate change impacts on river flows for hydropower generation and on loads from changing temperatures.
- The Council included a cost of carbon in the baseline analyses as a damage cost on emissions from existing and new fossil-fueled generation. The Council also ran several scenarios or variants to test different aspects of this issue – removing the social cost of carbon; accelerating the retirement of coal plants; restricting the build of renewable resources; restricting the build of new natural gas plants; assessing the emissions reduction effects of a demand response sensitivity case; assessing in several different ways the power system effects of an economy-wide effort to decarbonize; and more. One result tracked for all model analyses was the resulting change in system emissions of greenhouse gases.

More details on how the Council considered this topic can be found in several different sections of the plan and supporting materials, including the resource development plan, the global assumptions in the power plan, the generating resource reference plants, and environmental effects of generating resources.

Protecting Environmental and Cultural Resources From the Impacts of New Generating Resource Development

The siting, construction, and operation of any generating facility has impacts on land uses; water resources; wildlife and wildlife habitat conditions; cultural resources; traditional uses; and local landowners and communities.

Environmental effects of any proposed development are analyzed as part of state energy siting processes (if on private land) or by state or federal land management agencies (if on public land) through an array of different criteria and procedures. State fish and wildlife agencies and tribes have commented throughout the last two the power planning processes, sharing concerns that energy siting decisions for renewable facilities are not or may not be as protective of wildlife, habitat, cultural resources, and traditional uses as optimally needed. As the scale of development increases, so do concerns about the impact of a host of individual decisions and about the cumulative impacts.

The Council's Fish and Wildlife Program has a set of standards and conditions for developing new hydroelectric projects outside of protected areas. The purpose is to "ensure that new hydroelectric development is carried out in a manner that protects the remaining fish and wildlife resources of the Columbia River Basin and the Pacific

Northwest and does not add to the region's and ratepayers' mitigation obligation."

The Council has been asked to consider including in the power plan a similar set of development conditions for renewable resources. While siting authorities have no obligations to the Council's power plan, unlike the Federal Energy Regulatory Commission and hydroelectric project licensing, the Council commits to working with stakeholders throughout the region to help guide the consideration of aggregated effects of new renewable resources.

The Council also recommends that siting authorities should work to ensure that new renewable resource development is carried out in a manner that protects wildlife and fish and cultural resources of the Pacific Northwest.

The emphasis should be to incorporate "least impact, less conflict" siting principles to push development away from high value lands; ensure deliberate, strategic outreach and engagement in siting processes with fish and wildlife agencies and tribes and communities directly affected by development; and ensure that tribes are consulted to understand and preserve cultural resources and traditional uses in the vicinity of developments.

Hydrosystem Flexibility and Possible Impacts to Fish

The substantial increases in renewable generation across the West shift power system generation and transform power markets. The increasing supply of solar generation during the day highlights the need for other resources when the sun goes down.

Since hydropower has a low variable cost and is flexible in its use (within certain established parameters noted earlier), the Council's analyses – and current actual practice – indicates that the hydropower system is well positioned to help the region absorb increasing renewable generation and ensure adequacy in the region.

However, it's unclear how these daily river flow fluctuations – which are already evident and will likely increase if power considerations drive river operations - will affect environmental conditions for fish, particularly for juvenile and adult salmon and steelhead migration and for mainstem spawning and rearing habitat.

The Council's 2014 Columbia River Basin Fish and Wildlife Program contains measures recommended by the state and tribal fish managers calling on system operators to minimize or reduce daily flow fluctuations, and yet the power system analyses indicate a system adequacy benefit from increasing generation and flow fluctuations.

As described in the research recommendations in *Section 10: Recommendations for Research and Development*, the Council intends to organize and support an investigation into the

implications of these changing river flows. This effort will bring together the Council, Bonneville, system operators, the federal and state fish and wildlife agencies, the region's tribes, and others. The goal will be to explore the possible benefits and consequences of different hydropower system operations to try to identify a path forward that provides greater benefit to both power and fish.

Compatibility with Existing Power System: Retirement of Existing Coal Plants; Lower Snake River Dams

The Council's power plan, under the Northwest Power Act, is to analyze and recommend what new conservation and generation resources should be added to the region's power supply. The Council is to do so while taking into consideration not just matters of environmental quality and fish and wildlife impacts, but also the compatibility of new resources "with the existing regional power system."

The Council has done so in several ways, including analyzing how existing hydropower and gas plants have a valuable role in integrating additional significant amounts of renewable resources in a cost-effective manner while preserving an adequate system.

The Council's task is not to analyze or decide whether elements of the current system should remain or be retired for environmental or economic or other reasons. The Council does need to consider decisions made by others to retire or reduce the output of existing resources or constrain what types of new resources may be added.

This includes, for this power plan, the current set of decisions by utilities to retire coal-fired generating units for reasons of economics and state law, as well as the new state laws requiring the addition of renewable or clean resources, both part of a policy effort to reduce the output of greenhouse gas emissions from the existing system.

In this instance, the Council needs to analyze the effects of those plant retirements on the existing power system and decide what resources, and in what amounts, need to be added to assure the region retains an adequate, efficient, economical, and reliable power supply.

In this plan period, numerous comments have been submitted asking the Council to analyze or recommend the removal of the four federal dams on the lower Snake River. There are no planned retirement dates for any mainstem dams on the Snake and Columbia. So, the Act does not require that the Council analyze the effects of the retirement of those plants for this power plan in order to develop the power plan's new resource strategy and fit that strategy to the existing if changing power system. And it is not the Council's task under the Act, in the power planning process, to analyze or

recommend the retirement of existing system resources.

However, there may be value to the region, following the completion of the power plan, in analyzing the power system effects if the output of the dams were no longer available sometime in the future, including what replacement resources would be needed to achieve similar levels of reliability. The Council will begin scoping and considering whether to undertake this analysis after the plan is adopted.

Section 12: Fish and Wildlife Program

The Council's *Columbia River Basin Fish and Wildlife Program* is one of the required elements of the power plan under the Northwest Power Act. The 2014 Fish and Wildlife Program, supplemented by a 2020 Addendum, is the Council's current version of the program. nwcouncil.org/reports/2014-columbia-river-basin-fish-and-wildlife-program

The Act requires the Council, prior to the review of the power plan, to call for recommendations to amend the fish and wildlife program and then follow the process described in the Act for deciding on program amendments. The Council did so, initiating a fish and wildlife program amendment process in 2018 that culminated in a final decision on the 2020 Addendum to the existing program toward the end of 2020. Section 11 includes a discussion of the role of the fish and wildlife program in the development of the 2021 Power Plan, as part of the required fish and wildlife and environmental considerations.

The Council's fish and wildlife program has evolved through time. Early programs focused largely on improving juvenile and adult fish survival at and through the mainstem Columbia and Snake river dams, including water management and fish passage provisions for anadromous fish and reservoir operations to benefit resident fish. Early program developments also included anadromous fish loss assessments and systemwide goals; wildlife loss assessments and the beginning of mitigation for those losses; and the designation of protected areas to protect the region's fish and wildlife resources from new hydroelectric development.

Over time, the Council built up other portions of the program, especially expanding the off-site mitigation activities of the program with habitat improvements and fish hatcheries in the tributaries off the mainstem and in the lower Columbia River and estuary.

The 2014 Program reflects work built over many years of program development and implementation, with a continued emphasis on mainstem water management, passage improvements and spill, and offsite habitat and hatchery mitigation improvements.

The 2014 Program also identified a set of emerging priorities and called on Bonneville, the other federal agencies, and the region to integrate these emerging priorities into

program implementation. These included: Providing funding for long-term maintenance of program assets; integrating climate change considerations; expanding efforts to deal with predation and invasive species; increased focus on addressing the needs of sturgeon and lamprey; increased attention to toxic contaminants; investigating blocked area mitigation options through a number of activities; and continuing efforts to support ecosystem function through improved floodplain habitats.

When it came time under the Act to call for recommendations to amend the 2014 Program, the Council, in consultation with other program participants, concluded that a wholesale revision of the 2014 Program did not seem necessary. The Council asked the region to focus on two key program needs: 1) how to improve the way the Council and others assess and report on program performance and how to further develop and utilize the program's goals, objectives, and performance indicators to that end; and 2) a small set of near-term needs regarding program implementation. The Council worked, with public input, to focus the 2020 Addendum to the 2014 Program on those two topics.

Based on the recommendations received, the region's experience with implementation following the 2014 Program, and the development work with the region, the 2020 Addendum is structured in two parts. Part I focuses on program performance, reorganizing and supplementing the goals, objectives, and indicators provided in the 2014 Program to enable the Council and others to evaluate program performance in an effective manner. The Council granted requests to extend the scheduled conclusion of Part I for approximately six months to further engage the state and federal fish and wildlife agencies and the region's Indian tribes in a series of workshops on the program's goals, objectives, and performance indicators.

Part II of the 2020 Addendum covered a small set of program implementation needs consistent with the existing and emerging priorities identified in the 2014 Program. These included, among others, re-emphasizing the need to integrate climate change impacts into all areas of implementation; continuing the asset management effort; increasing the scope of mitigation in the blocked areas, especially the work to mitigate for the loss of anadromous fish and the losses to other fish and wildlife species in the areas of Grand Coulee and Chief Joseph dams; implementation of refinements in operations at Libby and Hungry Horse dams; restoring and sustaining the implementation of ocean research studies identified by the Council; sustaining ongoing efforts to reduce predation and increase or revise those efforts as necessary; research to assess benefits of estuarine use by salmon stocks from the interior Columbia River Basin; and more.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-71:
Power Council 2029 Power Supply Adequacy Assessment

Pacific Northwest Power Supply Adequacy Assessment for 2029



Northwest Power and Conservation Council

August 2024 | document 2024-4

2029 Adequacy Assessment

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Forward

The Council's annual adequacy assessment is a five-year test of the power plan's resource strategy to ensure that it will provide an adequate future power supply. This report summarizes the Council's assessment of the aggregate regional power supply's adequacy for the 2029 operating year (October 2028 through September 2029).

Analytical results are based on the Council's GENESYS model, which performs a Monte-Carlo chronological hourly simulation of the power system's operation over an entire year. Each study simulates the year's operation many times with different combinations of river flows, temperatures (demand), and wind and solar generation. Projected future river flows, temperatures, and wind generation are derived from climate change data for the Pacific Northwest. The Resource Adequacy Advisory Committee (RAAC), the System Analysis Advisory Committee (SAAC), and other stakeholders played an important role in updating resource and load data, reevaluating operating assumptions, and carefully reviewing the model's power system simulation.

In 2011, the Council adopted a 5 percent annual loss-of-load probability (LOLP) as its measure for adequacy. The power supply was deemed to be adequate when the likelihood of one or more shortfalls occurring during the year is no greater than 5 percent. However, the Council recognizes that today's power system is very different, where significant increases in variable energy resources, such as solar and wind, have added a greater band of uncertainty in system operations. This and other shifts in the power supply, such as increases in distributed generation and changing electricity markets, have made system operations much more complex.

To address this, the Council has enhanced its adequacy model, GENESYS, by significantly improving hourly hydroelectric operations; adding a better representation of unit commitment and balancing reserve allocation; better reflecting electricity market dynamics; and adding other enhancements to more accurately mimic real-life operations. Because of the increasing complexity of the power system and because of the limitations of the LOLP metric, it was imperative the Council also enhance its adequacy standard to capture a more precise measure of customer risk.

To this end, in 2023 the Council transitioned to a more comprehensive multi-metric framework to represent the risk of shortfall frequency, duration, and magnitude, which will be described later in this report. A resource adequacy assessment is only a relative measure of customer risk. It does not draw a bright line between a system with no risk and one with risk. An "adequate" system is not immune to resource shortfalls nor is an "inadequate" system certain to have them. By examining additional adequacy measures, the Council can assess the adequacy of the regional power supply more precisely.

Executive Summary

Over the next five years across the Pacific Northwest, significant load growth and changing system dynamics are creating risks for maintaining power system adequacy. This regional adequacy assessment for 2029 provides early warnings on system adequacy, with specific focus on how the Council's 2021 Power Plan resource strategy supports adequacy given the rapid changes the grid is experiencing, such as announced coal-to-gas conversions and transmission expansion in the region. This adequacy assessment finds that implementing the resource strategy in the plan – specifically achieving energy efficiency consistent with the high end of the Council's target, pursuing renewable deployment of around 6,600 MW by 2029, and ensuring sufficient balancing resources and demand response – will provide for an adequate system. Areas of risk remain, however. The same strategy, but only pursuing the low end of the Council's energy efficiency target, would not provide for an adequate system. Further, if data center load growth accelerates and more closely aligns with utility projections in the region by 2029, the resource strategy will also be insufficient to maintain adequacy. These risk areas, and other changing system dynamics, highlight the importance of the Council's upcoming power plan to provide new guidance to the region in support of an adequate, efficient, economical, and reliable power supply. In the meantime, the Council is continuing to track resource development, load growth trajectories, and other factors to provide timely updates through its Mid-Term Assessment of the 2021 Power Plan.

The Council uses an adequacy model called GENESYS to simulate the region's bulk power system. In each simulation, representing one year, a simulated model shortfall event occurs over a time period when load cannot be served by resources in the model. However, a shortfall in the model does not necessitate an actual blackout will take place. Instead, the modeled shortfall signals that emergency measures are necessary to avoid the blackout. Such emergency measures could include high operating cost resources not in an active utility portfolio, high priced market purchases above normal import limit (such as those that occurred during January 2024's winter storm event), as well as more extreme cases for calls for conservation by government officials (as in September 2022 California heatwave), or curtailment of fish and wildlife hydro operations (as happened during the 2001 Energy Crisis).

While a range of emergency measures are available to operators and decision makers, these measures are not part of the bulk power system modeling in GENESYS. Rather, the Council evaluates shortfalls as a signal for emergency measure needs. Using a new multi-metric adequacy framework, the Council's adequacy approach provides information about the frequency, duration, and magnitude of potential shortfall events, and all metrics must be satisfied with their respective thresholds to yield an adequate system. The metrics include:

1. Loss of load events (LOLEV) sets a limit for the expected frequency of shortfall events to protect against frequent use of emergency measures.
2. Duration Value at Risk sets a limit for shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
3. Peak Value at Risk sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
4. Energy Value at Risk sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

The adequacy assessment for 2029 explores how the Council's 2021 Power Plan resource strategy supports an adequate system. The assessment accounts for system changes that will be implemented by 2029, including load growth, in-region resource developments, and out-of-region market fundamentals. Electric load is expected to substantially increase by 2029, due to data centers and electric vehicles. However, announced changes to thermal plant retirements, such as Valmy 1 & 2 and Jim Bridger 1 & 2 conversions from coal to gas fueling, and anticipated transmission expansion throughout the WECC, including Boardman-to-Hemingway in the region, appear to alleviate some of the challenges associated with the increased loads when coupled with the 2021 Plan's resource strategy.

The 2021 Power Plan's resource strategy recommends that between 750 and 1,000 average megawatts of cost-effective energy efficiency, at least 3,500 megawatts of renewable resources, 720 megawatts of low-cost and frequently deployable demand response be acquired, as well as increasing balancing up reserve requirements to 6,000 megawatts to respond to growing short-term uncertainty in variable energy resources (primarily wind and solar) by 2027. Because the resource strategy provides a range for both energy efficiency and renewable development, the Council created a "reference strategy" to test in this assessment. This reference represents the high-end of the Council's cost-effective energy efficiency target (roughly equivalent to 1,300 average megawatts by 2029) and a renewable build consistent with many of the sensitivities analyzed in the plan that informed the strategy (roughly 6,600 megawatts by 2029).

The 2029 adequacy assessment tested a range of potential future conditions, including (1) the reference resource strategy (2) higher data center load growth, and (3) alternative trajectory within the resource strategy – the low end of the energy efficiency target.

The Reference scenario did not violate thresholds in any metric– frequency, duration, and magnitude – and therefore is deemed adequate. The Higher Data Center scenario used all the same assumptions from the reference case, except it added 1,600 average megawatts of additional power demand from the tech sector by 2029. The reference case anticipates roughly 2,400 of incremental tech-related aMW by 2029; the high data center scenario assumes 4,000 aMW. This scenario violated thresholds for all the metrics, and therefore is deemed inadequate. The Alternative Trajectory – Low End EE scenario used the same assumptions as the Reference case, but only met the low end of the efficiency target –

1,000 aMW instead of 1,300 aMW in 2029. This scenario satisfied some metrics (duration and energy), but it violated other metric thresholds (frequency and peak) and therefore is deemed inadequate.

The Reference scenario indicates that the 2021 Plan's resource strategy mostly eliminates summer challenges and greatly mitigates winter challenges – with only a minor set of system conditions that pose adequacy concerns in January evening ramp that are within the acceptable adequacy limits. However, should only the low end of cost-effective energy efficiency target be achieved, the region may experience winter challenges throughout majority hours of the day, with the greatest need in the morning and evening ramps, as well additional challenges in spring and summer. The Higher Data Center scenario further exacerbates the winter, spring and summer challenges as the resource strategy is insufficient to meet the potentially much higher electrification loads.

As the region is facing unprecedented load growth uncertainty driven by data center and transportation electrification, as well as building electrification, the Council will continue tracking and planning for these risk factors in the development of the upcoming Power Plan and the eventual resource strategy to address the evolving needs of the region.

Multi-Metric Adequacy Framework

The Council's multi-metric approach is philosophically different from relying on Loss of Load Probability (LOLP). In the past, adequacy was determined by whether a portfolio/strategy is expected to have no more than 1-in-20 years with at least one shortfall (LOLP of 5%). Instead, the new approach focuses on defining adequacy by whether a portfolio offers the protection against specific shortfall risks that the region wants to avoid.

To define the specific risks – and the metrics and thresholds associated with them - Council staff engaged closely with the Resource Adequacy Advisory Committee (RAAC) and regional partners to evaluate (1) aggregate regional emergency capabilities, and (2) what level of risk is the aggregate emergency capabilities of the region able to protect?

This is a key shift, where the emphasis of adequacy is placed on the significance of interpreting modeled shortfalls from GENESYS – the Council's adequacy model – as a signal for necessary emergency measures to be used to mitigate an actual curtailment.

GENESYS simulates the region's bulk power system. In each simulation, representing one year, a simulated model shortfall event occurs over a time period when load cannot be served by resources in the model. However, a shortfall in the model does not necessitate an actual blackout will take place. Instead, the modeled shortfall signals that emergency measures are necessary to avoid the blackout. Such emergency measures could include high operating cost resources not in an active utility portfolio, high priced market purchases above normal import limit (such as those that occurred during January 2024's winter storm event), as well as more extreme cases for calls for conservation by government officials (as in September 2022 California heatwave), or curtailment of fish and wildlife hydro operations (as happened during the 2001 Energy Crisis). Council staff have distinguished the emergency measures available to the region as Type I and Type II:

1. Type I refers to measures that are typically within a utility's control, such as relying on costly resources outside of the active portfolio, industry back-up generators, load buy-back provisions, and larger and costlier market purchases above market reliance limits.
2. Type II refers to extraordinary measures of extreme cases where customers may experience direct impacts, such as official's call to conservation, emergency load reduction protocols (rolling brownouts), or curtailing fish and wildlife operations.

While a range of emergency measures are available to operators and decision makers, these measures are not part of the bulk power system modeling in GENESYS. Using a new multi-metric adequacy framework, the Council's adequacy approach provides information about the frequency, duration, and magnitude of potential shortfall events – and thus the necessary emergency measures - and all metrics must be satisfied with their respective thresholds to yield an adequate system. The metrics include:

1. Loss of load events (LOLEV) sets a limit for the expected frequency of shortfall events to protect against frequent use of emergency measures.
2. Duration Value at Risk sets a limit for shortfall duration to protect against tail-end (extreme) duration use of emergency measures.
3. Peak Value at Risk sets a limit for maximum hour capacity shortfall to protect against tail-end (extreme) magnitude of emergency measures.
4. Energy Value at Risk sets a limit for total annual energy shortfall to protect against tail-end (extreme) annual aggregate use of emergency measures.

Philosophically speaking, by bridging modeled shortfalls to the need of emergency measures, the Council's multi-metric adequacy framework is aimed at protecting against the risk of Type II emergency measures. As such, quantifying the region's aggregate Type I emergency measures, and setting the metric thresholds to those capabilities, enables a probabilistic approach to how often extreme measures (Type II) are expected. This approach can be summed up as "Let's make sure any emergency measures aren't used too often (satisfying LOLEV)." And, "For the vast majority of the time let's make sure the emergency measures we rely on are not used too long or are too big (satisfying duration, peak and energy VaR)". As will be seen later this section, the significance of the VaR metric at the 97.5th percentile with a threshold associated with type I emergency measures means we can expect to entirely avoid the extreme, less desirable, emergency measures (Type 2) 39 out of 40 years.

However, because it is difficult to fully and accurately account for the magnitude and duration of all emergency measures, staff recognize that thresholds are approximations. Further, there is no clear line in the sand between magnitude of Type I and Type II measures as these may vary by utility and circumstance. As such, the framework should be understood as an evolutionary process towards redefining tail-end system risk than a complete characterization of Type I and Type II measures.

The Council's process to evaluate the metrics and threshold took several years, with 2022 dedicated to developing a provisional framework. The first use of the provisional multi-metric framework culminated in the 2027 Adequacy Assessment, including provisional threshold ranges for each metric to capture both lower and higher risk tolerances. In January of 2023, the Council decided to adopt the new multi-metric framework – and recognizing it will be an ongoing, evolutionary process – tasked staff to collaborate with the region on finetuning the thresholds.

Over the course of 2023, staff engaged with utilities, regional organizations, and public utility commissions to solicit feedback on the multiple metrics, thresholds, and approximation of emergency measures. Interim findings of the stakeholder engagement process were presented at the May 2023 Council meeting and the final findings in January 2024 with the RAAC Steering Committee and Technical Committee.

One important topic that was often raised is the relationship of the Council's adequacy work with the Western Resource Adequacy Program (WRAP) managed by the Western Power Pool. The roles of the Council and WRAP are complementary: the Council develops a long term, 20-year power plan, with recommendations for a six-year resource strategy for the region to ensure adequacy, while the WRAP focuses on near-team planning to ensure resource adequacy. As often discussed in the RAAC, the success or failure of the WRAP is a concern on stakeholders' minds for maintaining regional adequacy, and staff continue to engage closely with the WPP for long-term collaboration.

The outcome of the process is summarized in Figure 1, which maps the change from provisional thresholds to an interim recommendation that was used in this 2029 adequacy assessment. Modifications included (1) aligning LOLEV with the WRAP's seasonal use of Loss of Load Expectation (LOLE), but still report annual LOLEV, and (2) alongside Peak VaR and Energy VaR also report the Normalized VaR (NVaR) – as non-binding metrics - to provide comparative perspectives with utilities that report some normalized metrics.

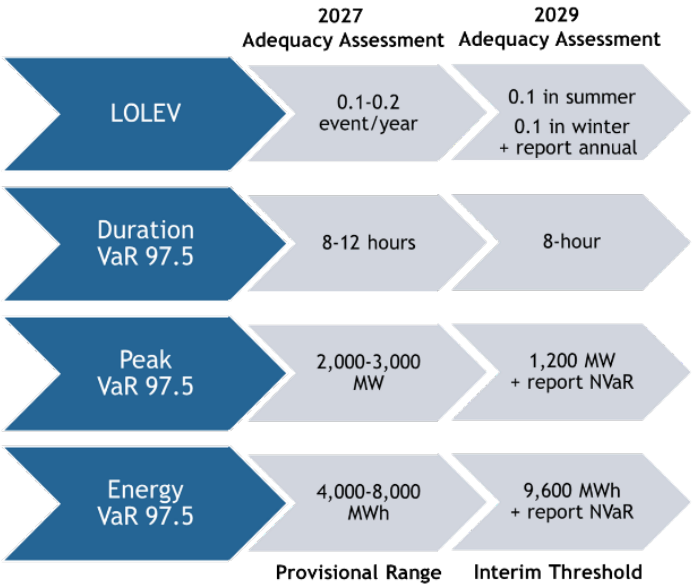


Figure 1. Evolution of metric thresholds

The following sections describe the metrics with greater details. For full descriptions and metric summaries, please see past RAAC presentations.

Loss of Load Events (LOLEV) to protect against frequent use of emergency measures

As the frequency of shortfalls is equivalent to the frequency of using emergency measures, a limit can be set for the frequency of simulated shortfalls as it relates to preventing overly frequent use of emergency measures.

The metric chosen to achieve this objective is the Loss of Load Events (LOLEV), which is the expected number of shortfall events per year. A shortfall event is a set of contiguous hours of unserved demand. LOLEV is equal to the total number of shortfall events divided by the total number of simulation years.

Because periods of most concern include summer and winter staff heard feedback to align with the WRAP seasonal approach, and decided set a threshold value for both summer and winter at 0.1. However, system risk may change over time, so considering shortfall risk in spring and fall is deemed important as well. Therefore, the Council's adequacy studies also report an annual LOLEV (threshold of 0.1) to cover risk throughout the course a year.

Duration VaR to protect against tail-end (extreme) duration use of emergency measures

Long shortfall events can indicate insufficient system energy (fuel). However, as described earlier, a simulated shortfall event is not the same as a curtailment event, although it could turn into one if emergency measures are not enough to offset the peak and energy shortfalls of the event. Therefore, setting a limit for shortfall event duration is a critical part of maintaining an adequate supply.

Furthermore, long shortfall events can indicate insufficient system resiliency, where resiliency is defined as the ability of a power system to protect against – and quickly recover from – high impact, low-frequency events. Such events can occur in extreme weather (heat waves or cold snaps); significant loss of transmission (wildfires, ice storms, heavy winds) or loss of a major fuel supply (gas pipeline rupture). The metric chosen to achieve this objective is the Value at Risk (VaR) for shortfall event duration at the 97.5th percentile over all simulation years.

To calculate this metric, the duration of the longest shortfall event for each simulation year is recorded (and noted as zero if there is no shortfall). The Duration VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an excessively long shortfall event to no more than once per 40 years. While this frequency is much smaller than that chosen for the LOLEV (no more than once per 10 years), it represents the risk of a real curtailment and not just a shortfall. The limit for this metric is set to 8 hours, to reflect the minimum shortfall duration that could lead to severe customer risk. Conditions that might trigger a long duration shortfall include extreme weather events, wildfires, and high winds – any event that disrupts major transmission lines or fuel supplies.

Peak VaR to protect against tail-end (extreme) magnitude of emergency measures

The Pacific Northwest's power supply has historically been capacity long but energy short. The region has had an excess of peaking capacity (machine capability) but continues to be limited by the water supply that powers the hydroelectric system, which provides more than half of the grid's nameplate capacity.

While the hydroelectric system's nameplate capacity is about 35,000 megawatts, it generates about 16,000 average megawatts per year, on average, and only about 12,000 average megawatts during a low water year. However, due to significant increases in variable energy resources, changes in hydroelectric operating constraints, and other added complexities, the region can no longer assume that it has sufficient capacity to meet all demand. Thus, it is important to include a metric to protect against excessively high-capacity shortfalls.

The metric chosen to achieve this objective is the Value at Risk (VaR) for capacity shortfall at the 97.5th percentile over all simulation years. To calculate this metric, the highest single-hour shortfall for each simulation year is recorded (or noted as zero if there is no shortfall). The Peak VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an extreme high-capacity shortfall to no more than once per 40 years. While this frequency is much smaller than that chosen for the LOLEV (once or twice per 10 years), it represents the risk of exceeding type I emergency measure capability (implying that the more extreme, type II measures, could be needed), whereas the LOLEV frequency represents the risk of using emergency measures too often. The limit for this metric represents the amount of single hour demand the region is willing to risk. As such, the limit could be set equal to the aggregate amount of reliable emergency peaking capability. The risk of real curtailment is high when the Peak VaR97.5 exceeds this limit because avoiding a loss of service depends on the availability of extraordinary emergency measures not accounted for in the adequacy limit. The interim limit for this metric is set at 1,200 megawatts. The non-binding reported Peak NVaR 97.5 threshold is 3% (1,200 MW is approximately 3% of average peak load the region).

Energy VaR to protect against tail-end (extreme) annual aggregate use of emergency measures

The region's power supply continues to be energy limited because hydroelectric resources make up the lion's share of the supply. It is important to include a metric to protect against extreme annual energy shortfalls. But unlike the capacity metric, whose limit is tied to the highest single-hour shortfall, the energy metric must be tied to the entire year's unserved energy. This is because energy shortfalls are often equated to a lack of fuel, whereas capacity shortfalls are often equated to a lack of machine capability. Once the machine capability is sufficient to offset the highest capacity shortfall, all other capacity shortfalls can also be offset. However, simply having sufficient fuel to offset the highest energy shortfall does not guarantee that other energy shortfalls throughout the year can also be offset.

The metric chosen to achieve this objective is the VaR for energy shortfall at the 97.5th percentile over all simulation years. To calculate this metric, total annual unserved demand for each simulation year is recorded (or zero if there is no shortfall). The Energy VaR97.5 is the 97.5th percentile of the distribution of this record from all simulation years. Choosing the 97.5th percentile limits the risk of an excessively high annual energy shortfall to no more than once per 40 years. Similar to Peak VaR, this frequency is much smaller than that chosen for the LOLEV, representing the risk of exceeding type I emergency measure capability.

The limit for this metric represents the amount of annual energy demand the region is willing to risk. As such, the limit could be set equal to the aggregate amount of reliable emergency energy generating capability. The risk of real curtailment is higher when the Energy VaR97.5 exceeds this limit because avoiding a loss of service would depend on the availability of emergency measures not accounted for in setting the adequacy limit.

Because it is difficult to accurately assess the amount of available emergency energy, alternative approaches can be used to set the VaR97.5 limit. By considering the "worst acceptable" annual unserved energy as the longest allowed 97.5th duration of 8 hours, where each hour has the largest allowed 97.5th hourly peak magnitude of 1,200 MW, the limit can be set at 9,600 MWh for the year. The non-binding reported Energy NVaR 97.5 threshold is 0.0052% (9,600 MWh is approximately 0.0052% of average annual energy in the region).

Updates to load growth in 2029 since 2027 Assessment

The region is anticipating rapid load growth, driven by forecasted data center growth and transportation electrification. However, there is uncertainty regarding how much load will materialize from both sectors. This load uncertainty poses a risk for adequacy, as the region may need to respond to a rapid increase in load as data centers and electric vehicles arrive. To help account for load uncertainty, two data center load growth trajectories are tested. The load forecast for the 2029 resource adequacy assessment is projecting higher loads than the 2021 Power Plan Long Term Forecast for 2029. The higher 2029 forecast is attributable to:

1. Forecast Timing – the Resource Adequacy Assessment Forecast for 2029 has three additional years of recent load, weather and economic history to work with
2. Much of the growth in load projections is explained by updated information about forecasts for data centers, chip fabrications, and electric vehicles

3. Additional growth projected beyond these two drivers – such as changes to population growth following historical trends, or some facets of efficiency that is being missed

Data centers and chip fabrication loads

Data center and chip fabrication loads (tech loads) are projected to be a driver of load growth in the Northwest. There is substantial uncertainty regarding how much load they will bring to the region. Figure 2, below, provides a range of incremental tech load forecasts in gray. By 2029, the range spans from a floor of 1,800 aMW of new load, to a ceiling of 6,500 aMW. All of these loads are assumed to be flat across the year.

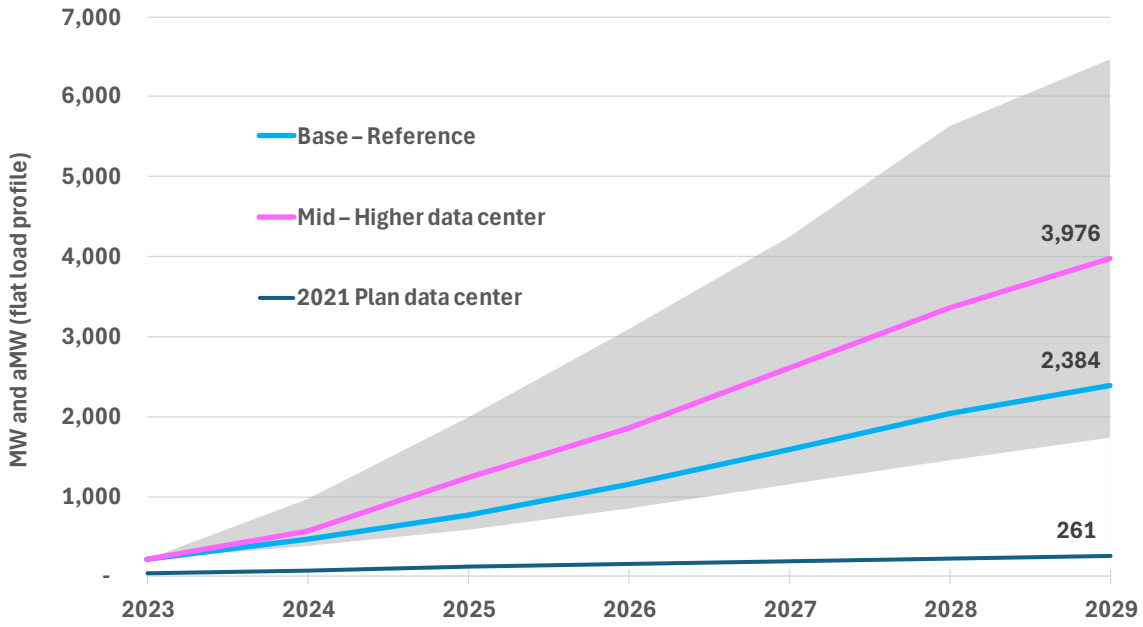


Figure 2. Incremental data center and fab growth forecast, 2023 to 2029

For this adequacy assessment two tech load forecasts are used to capture the load uncertainty. The base forecast, shown in light blue, assumes recent development trends will continue and incorporates recently announced projects. It adds around 2,400 aMW of new load to the Northwest by 2029. The mid case, in pink, assumes an acceleration in tech project development and is closer to what the region's utilities are projecting. It adds nearly 4,000 aMW of new load to the region by 2029. The description of the full scenarios tested is provided in the "Scenario Description" section (page 23).

Electric vehicles

Unlike data center load in the 2021 Power Plan, transportation electrification load was already gaining traction with earlier forecasts showing increased demand from electric vehicles (EV) in the region. In efforts to enhance the EV forecast for the 2029 adequacy assessment, Council staff evaluated several EV forecasting models and datasets to forecast (1) annual vehicle fleet and demand by state and balancing authority (BA) of light duty vehicles (LDV), medium duty vehicles (MDV), and buses, and (2) hourly charging profiles. To derive BA level data, BA allocation factors were calculated using estimates of vehicle registration locations, and when available, compared against utility IRP forecasts. The models and datasets included PNNL's GODEEP dataset for EV forecast by BA, Energy Policy Simulator (EPS, state level) by Energy Innovations and Rocky Mountain Institute, and California Energy Commission (CEC) charging forecasts. Forecasts were compared to actuals (2020-early 2024) and the 2021 Power Plan High Electrification scenario – which included high penetration of EVs – for comparison.

Table 1 provides the summary of transportation electrification data assumptions. Because actuals for Washington and Oregon (especially LDV, the bulk of the fleet) resembled EPS and 2021 Power Plan High Electrification, staff determined that using the existing High Electrification forecasts for LDV was appropriate. However, for MDV and buses, EPS results were utilized but scaled to 2021 Power Plan using LDV factors. Charging profiles for LDV, MDV and buses all assumed to be influenced by time-of-use (TOU) rates, derived from CEC profiles. TOU rates can have substantial impact on charging behavior, mainly lowering the peak demand in late afternoons and evenings by spreading the charge over periods of less demand and costly electricity either during the night or midday. Staff assumes that by 2029 utilities will adopt TOU for EVs as a cost-effective response to handling EV load growth, and will continue monitoring policies and EV sales across the four states as on-going work towards future forecasts.

Table 1. Summary of transportation electrification data assumptions

Vehicle Type	Fleet Method	Demand Method	Charging Profile
Light Duty Vehicle (BEV and PHEV)	2021 Power Plan High Electric Forecast	Demand by state for light duty passenger cars and trucks - from the 2021 Power Plan High Electric Forecast	California Energy Commission time-of-use LDV profiles
Medium Duty Vehicle (BEV Light & Medium Freight)	EPS forecast results for fleet were used as a base and scaled to the power plan forecast using the LDV factors.	Demand by state calculated using average use rates (MWh/Vehicle year) from PNNL and EPS and applied to the fleet to estimate demand	Charging profile from California Energy Commission time-of-use MHDV profiles
Bus (BEV Public transit and school)	EPS forecast results for fleet were used as a base and scaled to the power plan forecast using the LDV factors	Demand by state calculated using average use rates (MWh/Vehicle year) from PNNL and EPS and applied to the fleet to estimate demand	Charging profile from California Energy Commission time-of-use bus profiles

The result of the hybrid approach to the regional EV forecast, provided in Figure 3, show that that expected EV load by 2029 is 1,147 average megawatts (and ~5,000 aMW in 2045, not shown in graph). Light duty vehicles account for 87% of the share, with MDV and buses starting to pick up after 2025. The majority of forecasted EV load is in Washington (65%) and Oregon (30%). In terms of electric fleet size, the region is expected to have over 1.82 million LDVs, over 51,000 MDVs, and over 7,000 buses by 2029.

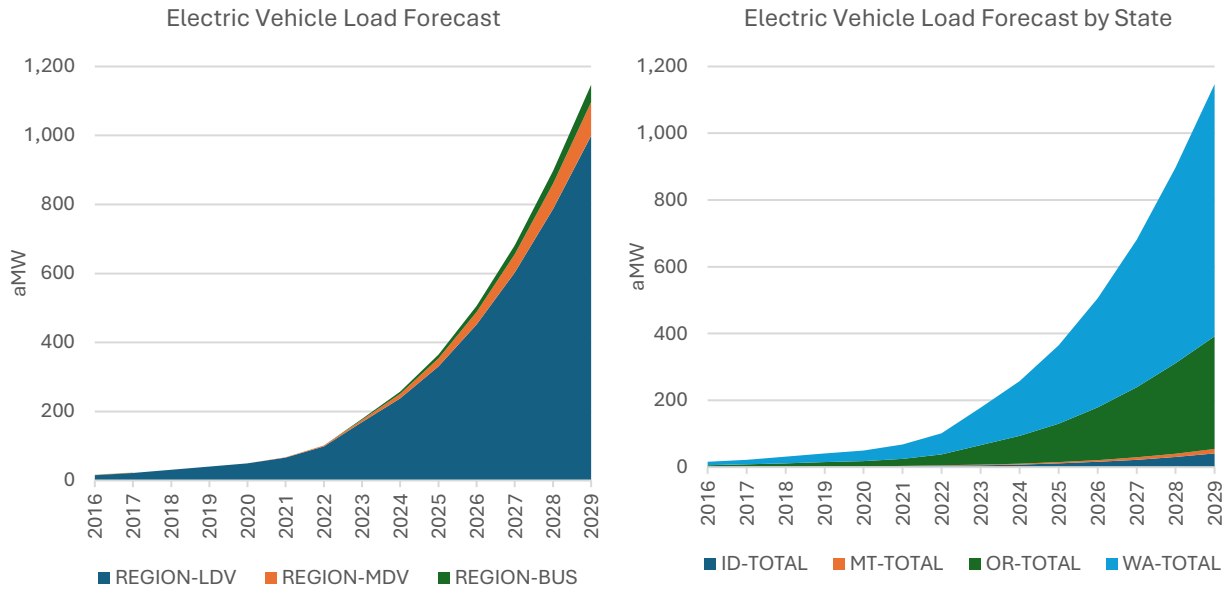


Figure 3. Electric vehicle load forecast by region and state

Other system changes since 2027 Assessment

Alongside expected yet uncertain load growth, there are additional changes to the regional power system that are important to consider since the 2027 assessment, including (1) announced thermal retirement changes of coal-to-gas conversion, (2) expanded transmission capacity, and (3) hydro changes from the Resilient Columbia Basin Agreement (RCBA, Appendix B) to the Lower Snake and Lower Columbia projects.

Thermal coal-to-gas conversions

The interaction of decarbonization policies, adequacy concerns with extreme weather events, and the economics of thermal plants paved the way for changes to announced decommissioning of several coal plants in the region. But instead of maintaining operations as usual, coal plants can be converted to gas, a process known as “coal-to-gas conversions.”

Major coal plants in the region that were originally planned for decommissioning have now shifted to coal-to-gas, seen in Table 2 and Figure 4. This amounts to a substantial resource addition since the 2027 adequacy assessment totaling. These plants include Jim Bridger 1 and 2 (~1,200 MW) and North Valmy 1 and 2 (~280 MW) for a total of ~1,480 MW of thermal plants, which could have direct adequacy benefits to the region that is expecting substantial load increase of 3,400-5,000 aMW.

Table 2. Announced coal decommissioning and coal-to-gas conversions

Coal Unit	Nameplate Capacity (MW)	Planned Retirement (Feb 2024)	Planned Retirement (2021 Plan)
Colstrip 1	358	2020	2020
Colstrip 2	358	2020	2020
Boardman	601	2020	2020
Centralia 1	730	2020	2020
Jim Bridger 1	608	2024*	2023
Jim Bridger 2	617	2024*	2028
Centralia 2	730	2025	2025
North Valmy 1	277	2025[x]	2021
North Valmy 2	289	2025[x]	2025
Colstrip 3	778	–	–
Colstrip 4	778	–	–
Jim Bridger 3	608	2030*	–
Jim Bridger 4	608	2030*	–

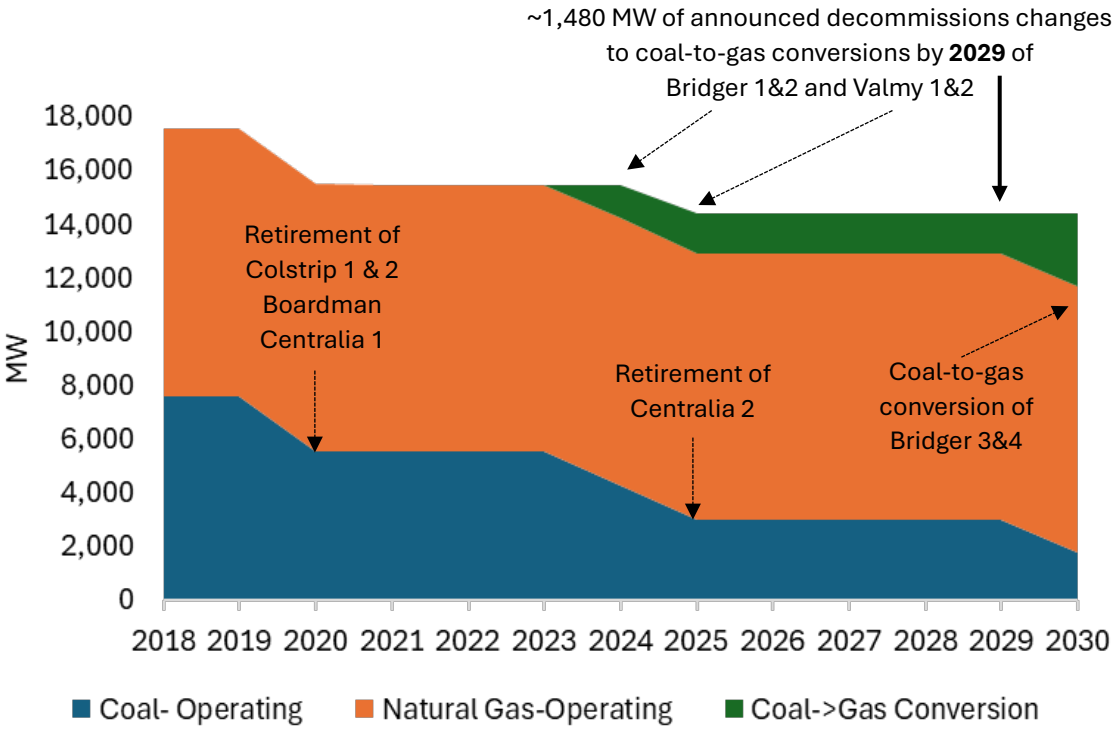


Figure 4. Cumulative thermal capacity changes in the region

Expanded transmission capability

Several major transmission expansion projects are slated to begin throughout the WECC in the coming years, including Boardman-to-Hemingway (B2H) in the PNW region. For the 2029 assessment, staff included projects that have already been announced as close to completion, started construction, or with high likelihood of being completed by 2029. Table 3 and Figure 5 below detail the new transmission expansion lines and their modeling topology. In total, 12,700 MW of transmission capacity will be added throughout the WECC, with B2H providing 1,000 of additional east-west capacity in the region between Idaho Power and BPA.

Table 3. Transmission expansions in 2029 Assessment

Planned Transmission	New Capacity (MW)	Path	Online Date	GENESYS Buses	Existing Today (MW)	New 2029 capacity (MW)
Ten West Link	3,200	SCE to APS	2024	So_Cal to Arizona	1,400	4,600
SunZia	3,000	PNM to APS	2026	New Mexico to Arizona	1,700	4,700
Transwest Express	3,000	WAPA Wyoming to PACE UT	2027	wapa RM to PAC_UT	650	3,650
Transwest Express	1,500	PACE UT to Nev South	2027	PAC_Ut to Nevada South	250	1,750
SWIP North	1,000	IP to North Nevada	2027	IP to north Nevada	350 | 185	1,350|1,185
B2H	1,000	IP to BPA_OR	2026	IP to BPA_OR	2,000	3,000

The expanded transmission capability in the region could have adequacy benefits by alleviating transmission congestion across the Cascades and enabling greater flow across the region. This is especially beneficial as more wind resources are built in Montana and Wyoming to serve load west of the Cascades.

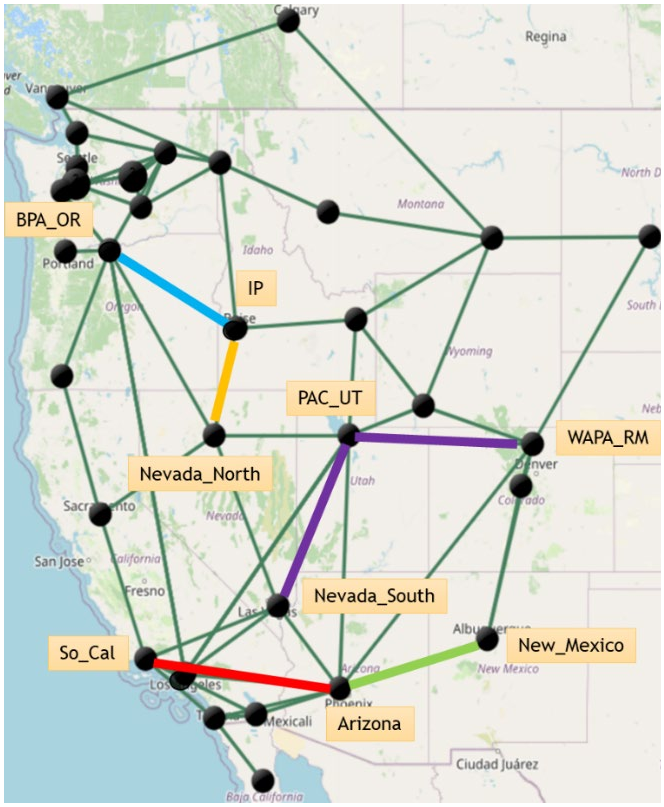


Figure 5. Transmission expansions in 2029 Assessment

However, the other transmission projects, while beneficial for the region, do not necessarily have the same adequacy benefit to the region as B2H. This is the case because of the market reliance limit for adequacy used by the Council. Though the new capacity would help WECC-wide market dynamics, including the export and import capability of SWIP North through Idaho Power, the overall import limit (set for adequacy) is well below the existing (current, pre-capacity expansion) capability of the transmission lines between the region and WECC.

In other words, the Council's winter market reliance of 2,500 MW and a summer reliance limit of 1,250 MW are the limiting factor for import capability from outside of the region. This limit was set to hedge against the risk of relying on the market at times of need and differs seasonally due to the fact the PNW peaks in winter and the WECC in summer. The market reliance limit, and market fundamentals in general, are routinely discussed in the Resource Adequacy Advisory Committee and the System Analysis Advisory Committee, and in the meantime the limit is the preferred path. Future considerations could change the decision, which will be discussed in future advisory committees and Council meetings.

RCBA Appendix B: Changes to Lower Snake and Lower Columbia

For power planning and resource adequacy assessments, the Council's Power Division staff aims to model the existing system to the best of their capabilities. An important piece of this work is to model the hydro operations consistent with any requirements for river operations. To that end, staff recently made updates to the Council's GENESYS model to

reflect changes to hydro operations resulting from the Resilient Columbia Basin Agreement (RCBA, Appendix B) to the Lower Snake and Lower Columbia projects. Issued in December 2023, the changes are geared to increase spill for improved juvenile fish survival in the Lower Snake and Lower Columbia.

The impact of increased spill is reduced spring and early summer hydro generation. There is minor hydro generation reduction in the fall and winter, varying by project. However, an increase in hydro generation is expected in August. In addition to monthly changes in average hydro generation, minor changes in daily hydro generation flexibility are also expected.

From an adequacy perspective, while hydropower is slightly reduced, based on the limited subset of studies used for a comparative study, the changes do not lead to a significantly different regional adequacy result. Offsetting the reduced hydropower is a small increase in regional thermal generation and market reliance, yet within the market reliance limit, throughout most of the year, especially at night.

Since completion of the analysis for the 2029 adequacy assessment, an Agreement in Principle on the changes of the Columbia River Treaty has been made by the US and Canadian governments. The Council will continue to evaluate the impact on power system planning and resource adequacy in future analyses.

Scenario description

As an adequacy assessment, the main goal is to test the resource strategy outlined in the Power Plan given potential risk scenarios to signal to the region about adequacy and areas of concern. As a reminder, the resource strategy, provided in Figure 6, of the 2021 Power Plan to achieve by 2027[1] includes (1) at least 3,500 MW of renewable resources, (2) 750-1,000 aMW of energy efficiency, (3) 720 MW of demand response, and (4) doubling the balancing up reserves to hold 6,000 MW to support integration of renewables.

2029 Resource Strategy – the reference

In this assessment, looking 2 years past 2027, the resource strategy in 2029 continues the trajectory of resource assumptions used in 2027 reference case, seen here:

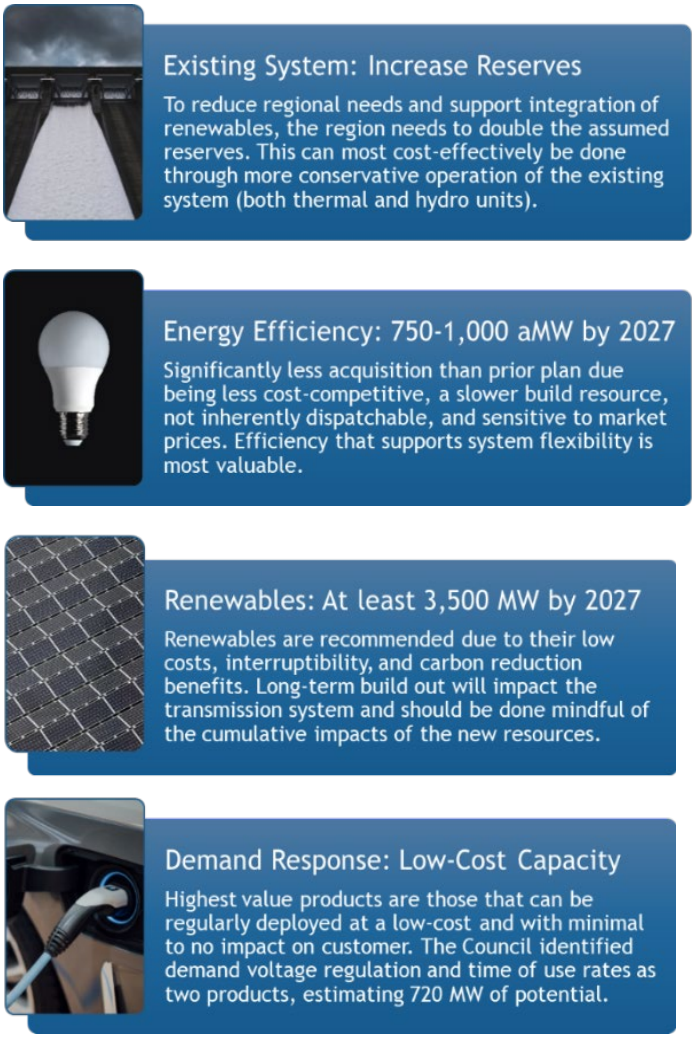


Figure 6. 2021 Power Plan resource strategy

Table 4. Comparison of 2029 and 2027 reference strategy

Portfolio	2029 Adequacy Assessment	2027 Adequacy Assessment
Renewables	6,600 MW	5,900 MW
EE	1,300 aMW	1,000 aMW
DR	720 MW	720 MW
Reserves	6,000 MW	6,000 MW

[1] See pages 46-48 in the 2021 Power Plan Section 6: Resource Development Plan as well as page 107 in the 2021 Power Plan Section 9: Cost Effective Methodology for Providing Reserves

The 700 MW increase in renewables is consistent with several buildouts observed in the 2021 Power Plan and the higher range of renewables tested in 2027, seen in Figure 7. The additional 300 aMW of energy efficiency is consistent with the assumption of reaching the high end of the cost-effective energy efficiency target.

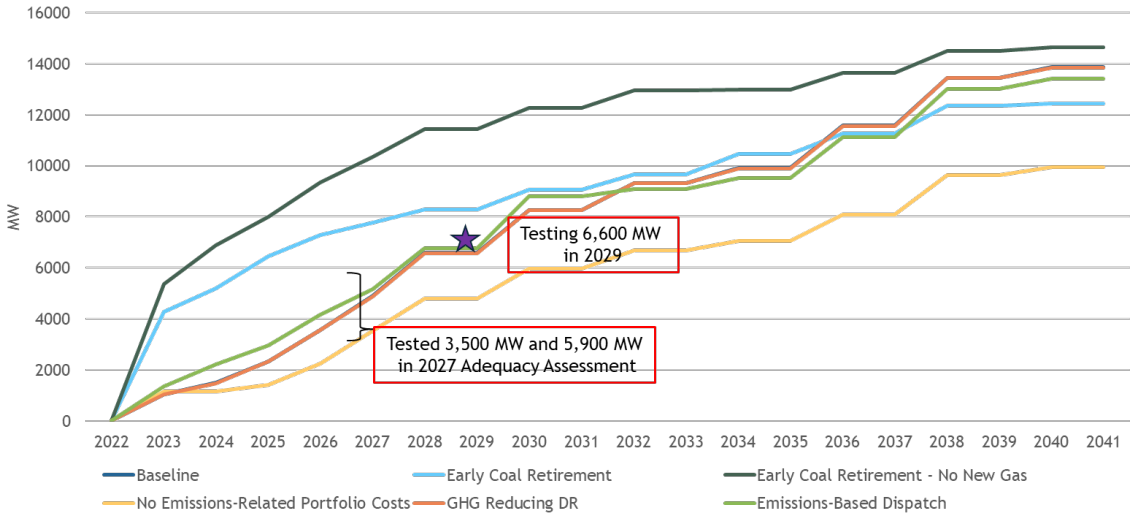


Figure 7. Example of renewable buildout trajectories from the 2021 Power Plan Resource Strategy

The scenarios

Staff engaged with the RAAC and SAAC to define the risks and setup to test for the assessment, resulting in the following list of potential scenarios:

1. Reference
2. Higher data center load (in region)
3. Alternative Trajectories within Resource Strategies (low end of energy efficiency target)
4. In-region gas supply limitations
5. Earlier availability of transmission (reconductoring in region)
6. Delayed availability of transmission and emerging tech in WECC
7. Emission pricing

While all scenarios provide important adequacy insights to the region, given budget constraints and proximity to preparation for the next Power Plan, staff had to prioritize three key scenarios for the assessment (in green), including a reference case, a higher data center load case, and an alternative to the resource strategy case that only achieves the low end of the cost-effective energy efficiency target. The other scenarios (in red) include financial risks that would be considered in upcoming wholesale market forecast, and broader system risks (adequacy and resource strategy) in the next Power Plan. Thus, the

tested scenarios differ in terms of energy efficiency savings and Data Center Loads, but share the same EV loads. Seen in Table 5, the Higher Data Center scenario tests the same resource strategy as the Reference against ~1,600 aMW of additional load. The Low End EE scenario tests the same data center load as the Reference, but with 300 aMW less of EE.

Table 5. Load difference across 2029 adequacy assessment scenarios

Scenarios	EE Savings (aMW)	EV Loads (aMW)	Data Center Loads (aMW)
2029 Reference	1,300	1,048*	2,386
2029 Low End EE	1,000	1,048*	2,386
2029 Higher Data Center	1,300	1,048*	3,976

* Value for 2029 incorporates the 1,147 aMW (Section 4) but subtracts the embedded EV load in the base forecast in 2022. Hence, there is an additional 1,048 aMW to reach the 1,148 aMW by 2029.

The expected annual load, and average peak load by season for each of the scenarios is provided in Table 6 from simulation results.

Table 6. Average simulated loads from 2029 adequacy assessment scenarios

Scenario	Average Annual Load (aMW)	Oct-Mar Avg Peak (MW)	Apr-Sep Avg Peak (MW)
Reference	25,271	36,724	34,034
Low End EE	25,495	36,947	34,291
Higher Data Center	26,861	38,314	35,624

The Council uses three separate climate change scenarios, with each possessing 10 unique sets of climate-dependent hydro-load combinations, and six wind generation profiles that total in 180 simulations per study (10 hydro-load combinations x six wind profiles x three climate scenarios). Generally, each of the climate scenarios represents a risky hydro-load profile: CanESM (scenario A) captures more risk of low summer hydro generation and higher summer loads, CCSM (scenario C) captures high winter hydro with early runoff lower summer hydro conditions. Lastly CNRM (G) captures risk of low winter generation with higher winter loads.

These simulated loads highlight the potential system risks that the resource strategy needs to address throughout the year. In fact, certain load conditions in scenario G surpass 41,000 MW at peak system needs even at the Reference scenario. The results section will explore the type and timing of shortfalls and lead way to understand the adequacy risk for the region.

2029 Assessment results

Despite the substantial load growth, this assessment finds that implementing the resource strategy in the 2021 Plan – achieving energy efficiency consistent with the high end of the Council's target, pursuing renewable deployment of around 6,600 MW by 2029, and ensuring sufficient balancing resources and demand response – will provide for an adequate system in 2029 as all adequacy metrics for the Reference scenario have been satisfied. Given the additional system changes, the region likely maintains adequacy due to the mitigating benefits of coal-to-gas conversions of Jim Bridger 1 & 2 and Valmy 1 & 2, as well as the added B2H transmission expansion (alleviating congestions and enabling greater east-west transfer in the region).

However, the region still faces adequacy risks, even with the additional system changes. Pursuing the same resources strategy as the Reference but only achieving the low end of the cost-effective energy efficiency target (1,000 aMW instead of 1,300 aMW in 2029) would not result in an adequate system. Seen under the Low End EE results, the scenario satisfied the duration and energy metrics, but violated the frequency (winter) and peak metrics and therefore is deemed inadequate.

Furthermore, should data center load growth accelerate and exceed current trends to match high-end trajectories of utility projections by 2029, the resource strategy will also be insufficient to maintain adequacy as the Higher Data Center scenario violated all adequacy metrics. A qualitative high level summary of the 2029 adequacy assessment is provided in Figure 8.

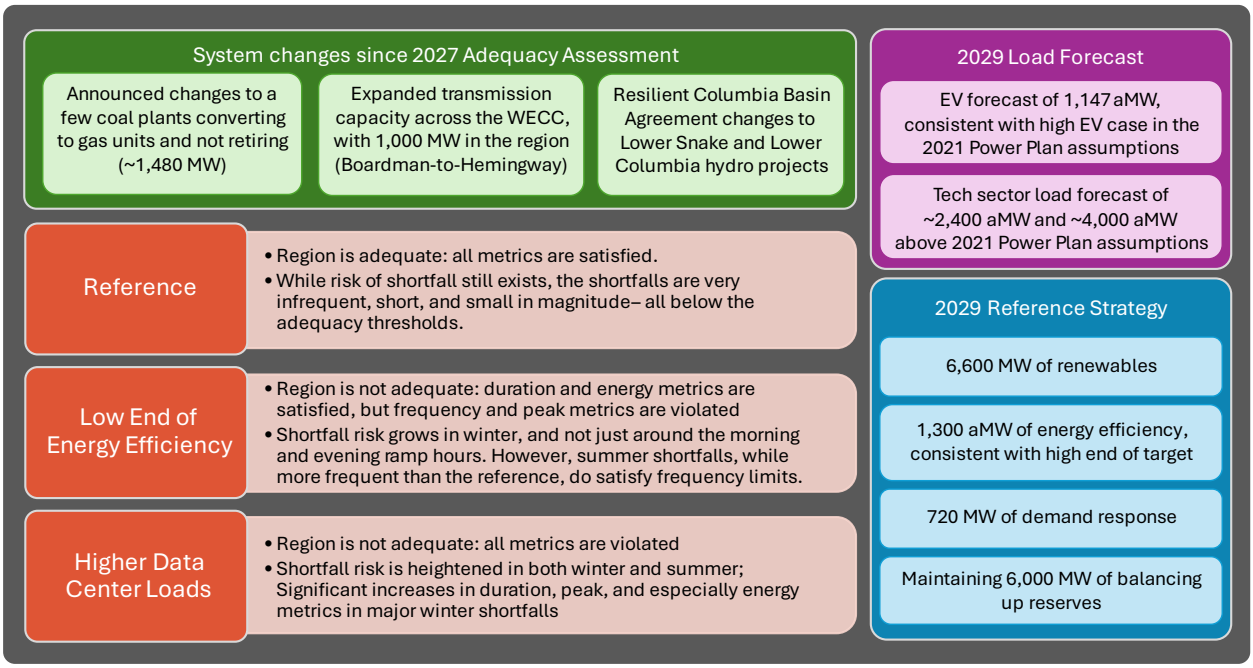


Figure 8. High-level summary of 2029 Adequacy Assessment

The results of the adequacy metrics across the scenarios are provided in Table 7. While a value of "0" might appear odd for the Duration and Peak and Energy VaRs, it does not mean there is no shortfall risk. Rather, it is a probabilistic representation signaling the shortfall risk in 39 out of 40 years is extremely low. As will be described in more detail later, the shortfall risk under the Reference scenario only start at the 98.8th percentile, and become substantial after the 99.5th percentile. In fact, out of 180 simulation years in the Reference scenario, only 4 experienced at least one shortfall (1-event year), with 9 shortfall events in total. Considering the summer and winter LOLEVs of 0.022 and 0.017, the implication is that the resource strategy, alongside with the changes to thermal coal-to-gas conversions and B2H, the region would expect one shortfall in the summer every 45 years, and one shortfall in winter every 58 years. Relating this to LOLP – solely for comparative perspectives as LOLP is not used - the Refence scenario results with an LOLP of 2.2%, well below the previous LOLP metric threshold of 5%.

Table 7. Adequacy metric results

Type	Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Winter LOLEV	0.1	0.022	0.350	1.294
Frequency	Summer LOELV	0.1	0.017	0.033	0.3
Duration	Duration VaR 97.5	8 hours	0	1.5	20.6
Magnitude	Peak VaR 97.5	1,200 MW	0	1,567	3,076
Magnitude	Energy VaR 97.5	9,600 MW	0	4,196	196,324

The risk is different with only achieving the low end of the energy efficiency target. From a frequency perspective, the number of winter events (winter LOLEV) exceeds the threshold (1-event in 2.85 years instead of not more than 1-event in 10 years), but summer is satisfied (1-event in 30 years). This highlights the benefits of achieving the high end of energy efficiency in protecting against winter events. Duration wise, the Low End EE does protect against long duration shortfalls, indicating that 39-out-of-40 years shortfalls will be at or below 1.5 hours long. Lastly, while Energy VaR is satisfied, with 39-out-of-40 years expecting the annual aggregate shortfall to be half of the energy threshold, Peak VaR is violated – by 367 MW. This situation is helpful in illustrating the importance of considering both the peak hourly shortfall and aggregate annual shortfall; in terms of emergency measures – there is enough emergency "fuel" in the system on an annual basis, but enough hours lack the emergency capacity to mitigate larger shortfalls. From the 180 simulation years, the Low End EE scenario had 14-event years (LOLP of 7.8%) with 80 shortfall events in total.

Under the Higher Data Center scenario - which the resource strategy and system changes do not mitigate the risk of increased loads - the metrics are violated to even a greater degree. Both winter and summer are well above the threshold, with winter especially vulnerable to frequent events, and the risk of long duration shortfalls surpass the limit by 2.65 times (21 hours at the 97.5 percentile). In terms of Peak VaR, the metric exceeds the threshold by 1,876 MW (at 3,076 MW), but the Energy VaR sheds light on the tail-end risk of aggregate annual fuel availability – the metric is 20 times the threshold at 196,324 MWh. This difference further highlights the need of different considerations of solutions for higher load futures. From the 180 simulation years, the Higher Data Center scenario had 24-event years (LOLP of 13.3%) with 296 shortfall events.

Aside from the above metrics used to determine adequacy, the three non-binding reported metric (Annual LOLEV, Peak NVaR and Energy NVaR) provide additional perspectives for comparative risk, seen in Table 8. The results echo the same outcome with the adequacy metrics – the Reference satisfies all non-binding metrics, the Low End violated annual frequency and Peak NVaR but satisfied Energy NVaR, and the Higher Data Center violated all metrics.

Table 8. Results of reported (non-binding) metrics

Type	Non-Binding Reported Metric	Threshold	Reference	Low End EE	Higher Data Center
Frequency	Annual LOLEV	0.1	0.05	0.444	1.644
Magnitude	Peak NVaR 97.5	~3%	0	4.2%	9%
Magnitude	Energy NVaR 97.5	~0.0052%	0	0.002%	0.09%

Shortfall statistics

As seen with the metrics, while both the Low End EE and Higher Data Center scenarios are inadequate, the risk they pose is not the same. Comparing some of the metric results helps explain this. To understand the adequacy risk of the three scenarios to the region, a closer examination of the shortfall statistics – and distributional characteristics – is warranted.

Frequency

From a frequency perspective, considering that the annual LOLEV is higher than the sum of summer and winter LOLEVs suggested that there are events also occurring in spring and fall. As such, staff explored the seasonal LOLEVs, presented in Table 9. One interesting find is the indication of events in the spring, including in the Reference case. While very low expected spring-event frequency (one in 91 years) in the Reference case, the Low End EE spring-event frequency is higher than the summer. Though spring events are still infrequent

(1-in-22 years), as is fall event frequency (1-in-59 years) it raises the awareness of monitoring shoulder seasons. This is especially important given maintenance timing that could coincide with challenging system conditions that could stress the system towards a shortfall.

Table 9. LOLEV across the seasons

LOLEV Period	Months	Threshold	Reference	Low End EE	Higher Data Center
Winter	Dec-Feb	0.1	0.022	0.350	1.294
Summer	Jun-Aug	0.1	0.017	0.033	0.300
Annual	All	0.1	0.050	0.444	1.644
Spring	Mar-May	0.1?	0.011	0.044	0.039
Fall	Sep-Nov	0.1?	0.000	0.017	0.011

VaR duration, peak and energy

The next several charts capture (1) the distribution of shortfall statistics (i.e. max duration shortfall, max peak shortfall, and annual energy shortfall from each of the 180 simulations per scenario), and (2) the actual distribution counting all events in each scenario. For the distribution of shortfall statistics, the total amount of observations (per metric) is 180. However, most of the simulation years had no shortfalls and therefore 0 will be recorded. For example, recall that the Reference scenario only had 4 event-years, so the shortfall statistic only records 4 non-zero duration, peak and energy values, and 176 zeros. Likewise, the Low End EE only records 14 non-zero values, and 166 zeros. Lastly, the Higher Data Center scenario has 24 non-zero values and 156 zeros.

Ranking the non-zero observations of each metric is an easy way to understand the percentile approach. The largest observation in each metric represents the 100th percentile, and the lowest non-zero observation is the percentile where shortfalls start occurring. Only non-zero observations are included in the graphs. Repeated non-zero values in the same study are also removed. It's also good to remember when examining the metric distributions that observations to the left of the VaR 97.5 vertical lines may be much larger than the threshold. By definition, the framework does not intend to protect against them. What matters is that the 97.5th percentile is at or below the threshold to satisfy a tail-end risk in 39-in-40 years.

A good example of this is featured in the max duration curves of the studies in Figure 9, especially the Low End EE scenario. The Duration VaR 97.5 value is 1.5 hours, satisfying the 8-hour threshold. However, the maximum shortfall durations in the study are 22, 21, 18, and 11 hours, followed by 2 and 1 hours. The risk of 22, 21 and 18-hour long duration shortfalls is substantially smaller than 1-in-40 years. However, in the Higher Data Center

scenario, the Duration VaR 97.5 value is 21 hours, a continued risk up to the 96th percentile, with much longer extreme shortfall durations (up to 120 hours). Under the Reference scenario, all duration metric values were below the threshold, including the maximum (100th percentile) of the study at 4 hours.

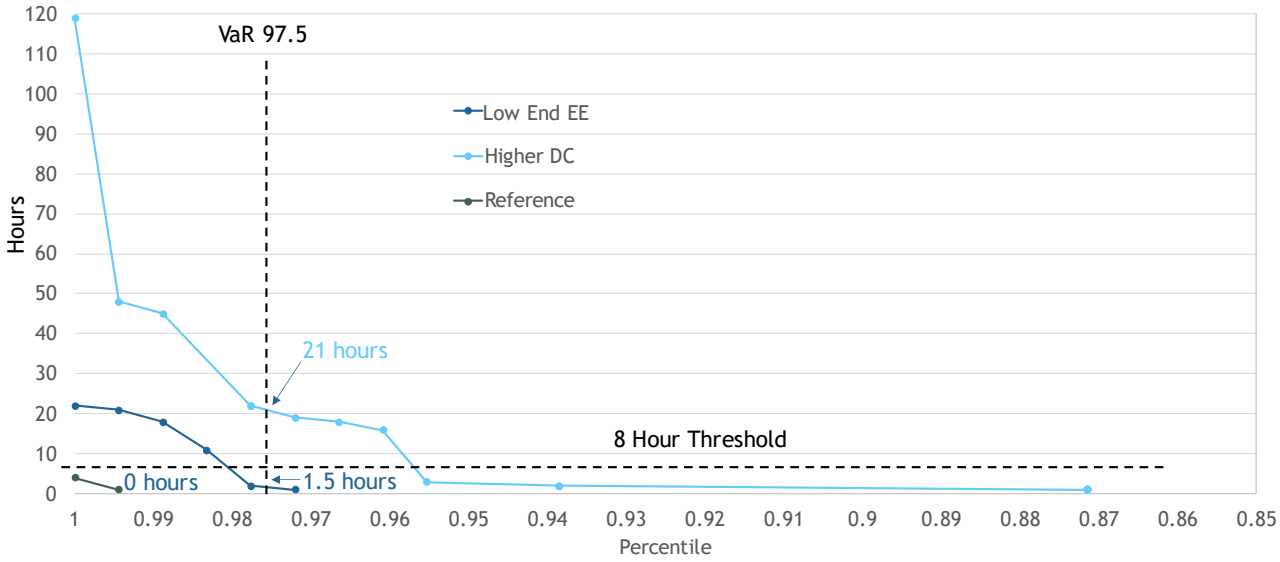


Figure 9. Max duration curves across the scenarios

Aside from the longest duration shortfalls calculated for the metric, considering the distribution of all shortfall durations (Figure 10) highlights that the majority of shortfalls, including in the Low End EE and Higher Data Center scenario, are short. In fact, around ~42% of all shortfalls in both studies are only 1 hour long, and ~70% less than 4 hours.

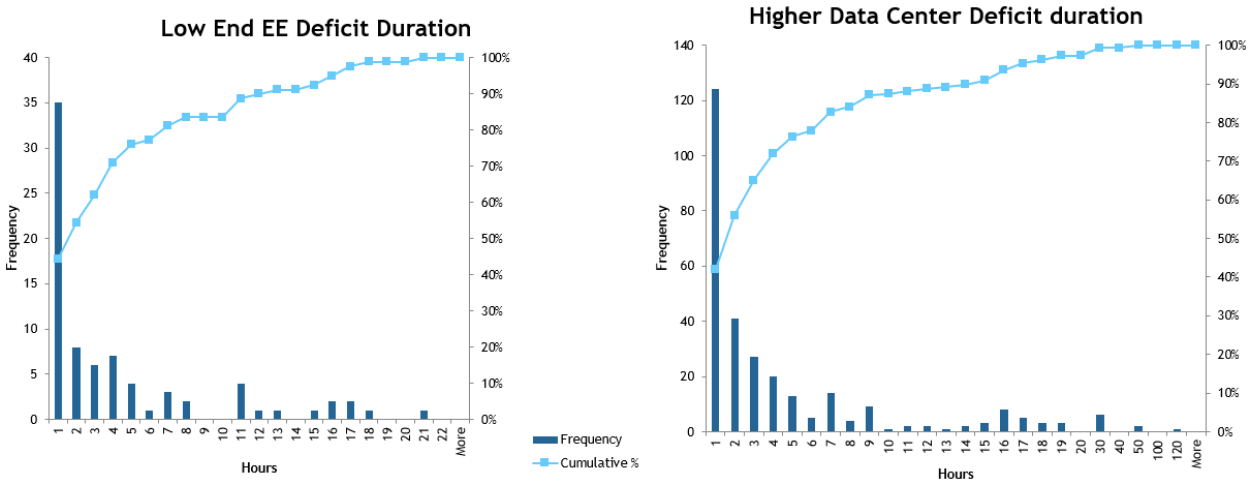


Figure 10. Distribution of shortfall durations in Low End EE and Higher Data Center scenarios

Maximum Peak distribution shows the tail-end magnitude of events, seen in Figure 11. All shortfall peaks in Reference scenario are below the threshold. However, the Low End EE is 367 MW shy of the threshold, and the Higher Data Center is 1,876 MW over. Theoretically, this implies the perfect capacity of needed resources to satisfy this metric, with the guiding principle that the additional resources would lower the curves by those magnitudes. However, this is mentioned as a nod for future analysis and not part of the adequacy assessment given the role is to provide an adequacy signal, not recommend a portfolio.

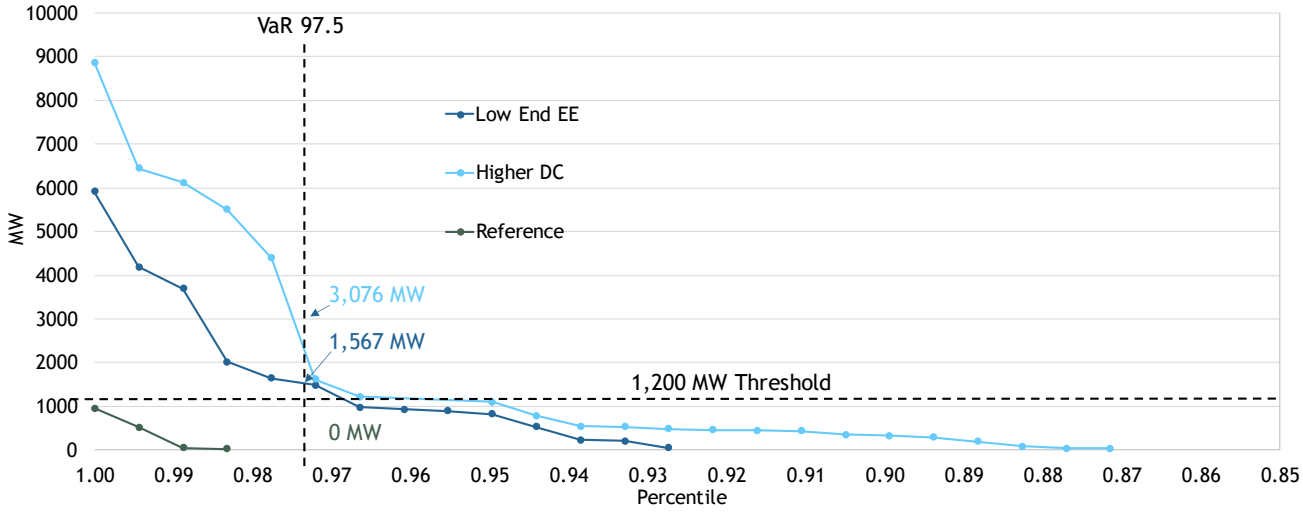


Figure 11. Max peak curves across the scenarios

There is greater diversity of shortfall peaks when considering the full distributions, observed in Figure 12. In both scenarios, around 20% of shortfall peaks are below 300 MW, just over 50% are below 900 MW, and ~68% of shortfalls peaks are below 1,200 MW.

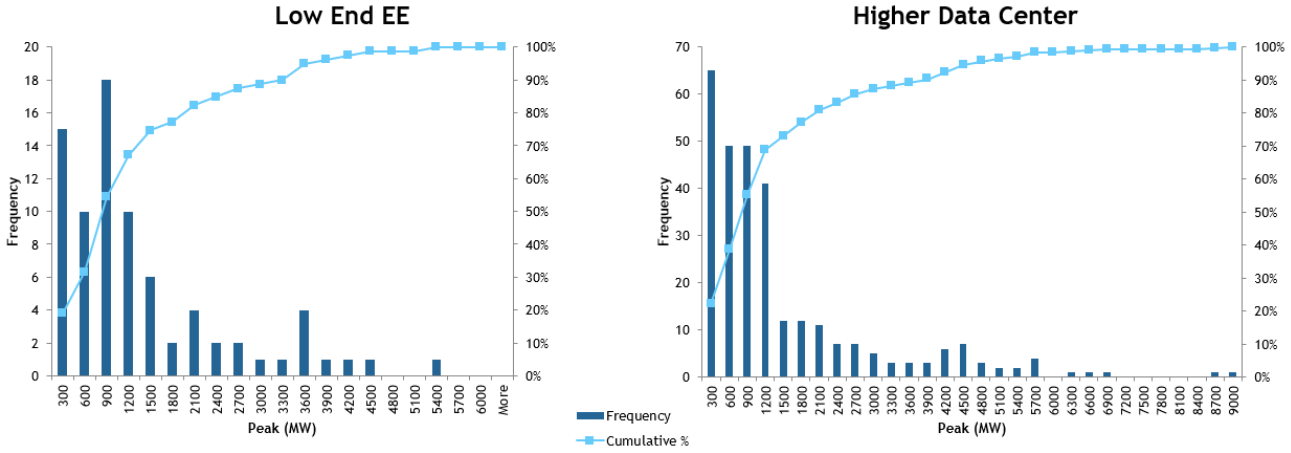


Figure 12. Distribution of shortfall peaks in Low End EE and Higher Data Center scenarios

Reconciling the perceived differences between the Peak VaR metric and curve and the actual peak shortfall distribution is that the fact that only a handful of simulation years (from 180) experienced shortfalls. For example, in the Low End EE scenario, 56 out of the 80 shortfall events are from just 3 simulation years. These specific years are associated with challenging low water conditions throughout the year; coupled with certain renewable wind conditions, this may pose adequacy risks. The same challenging simulation years belong to a broader group of six years. In the Higher Data Center scenario, they account for 220 of the 296 events, with another 52 events clustered in a different set of challenging hydro-load-wind conditions.

The annual Energy curves are provided in Figure 13. The Reference scenario's Energy observations are all below the threshold. And while the Low End EE scenario's Energy VaR is satisfied, there are extreme energy observations beyond the intention of risk protection. The Higher Data Center expands the risk of extreme energy shortfalls, crossing the threshold around the 94.5th percentile.

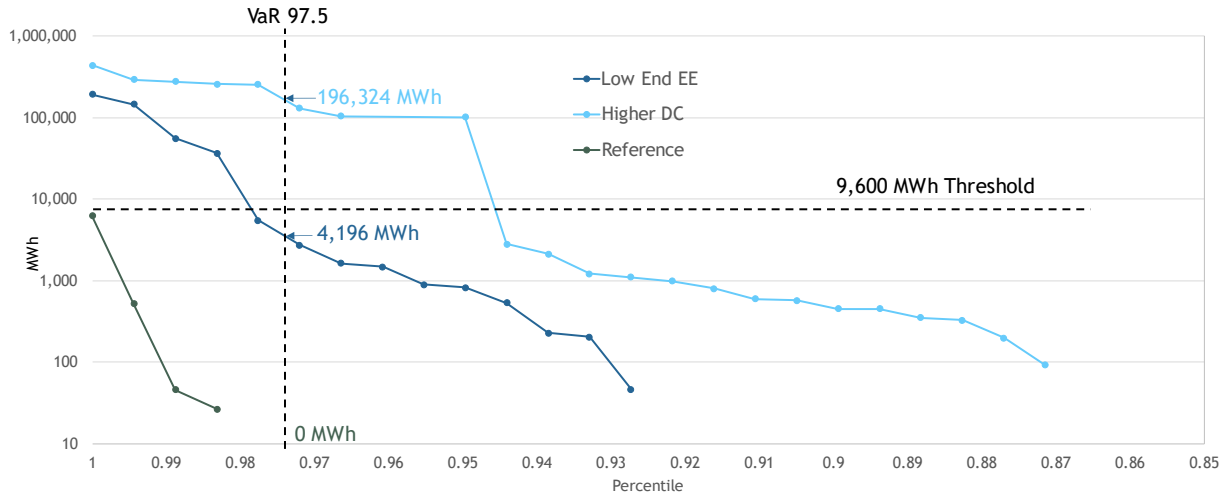


Figure 13. Annual energy curves across the scenarios

Timing of shortfalls

The final section of the results discussion focuses on timing of shortfalls, provided in Figures 14-16. While shortfall timing is not an adequacy metric, evaluating the potential hours of needs throughout each month sheds light on connections to other system stressors. Under the Reference scenario, the handful of shortfalls occurred mostly in winter, with the biggest single event in January during the evening ramp/early night period of 20:00-midnight, seen in the heatmap below; keeping in mind these are very infrequent, with winter LOLEV of 0.022, summer of 0.017 and spring of 0.011.

However, the Low End EE scenario has increased risk of challenges in several periods. The biggest peak shortfalls occur during winter morning and evening ramp hours. A handful of conditions could see shortfalls observed throughout all hours of those days as well. While these shortfalls are still infrequent – they occur more than allowed (winter LOLEV of 0.35, roughly 1 event in 2.85 years) – but are still important to understand. Unlike the reference, there is greater risk of evening/night shortfalls in the spring and summer as well as morning and day in spring (but within the allowed limits). The Higher Data Center scenario further exacerbates similar trends.

While the shoulder seasons – spring and fall - have historically had little adequacy risks, changing system conditions may alter this over time. The risk may still be tied to availability of hydro and earlier runoff coupled with increased loads, but these seasons warrant attention, nonetheless. First, increased loads (whether from higher tech loads or from achieving the low end of energy efficiency) may strain the system during these times in ways similar conditions posed little risk before. Second, because maintenance schedules for hydro and thermal plants are often during spring and fall, these may further coincide with conditions that could pose adequacy challenges. These reasons highlight the benefit of considering the LOLEV frequency metric across all seasons.

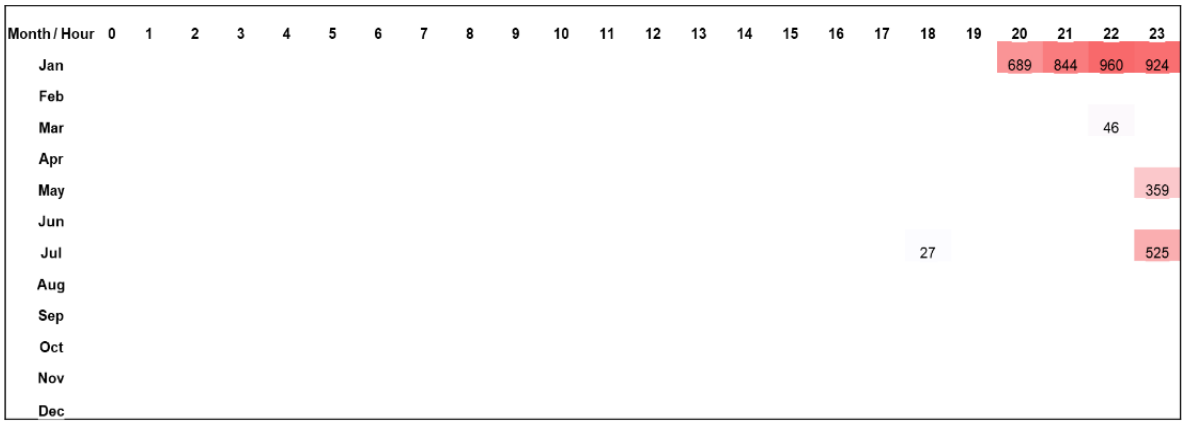


Figure 14. Reference scenario shortfall timing – peak magnitude (MW) heatmap

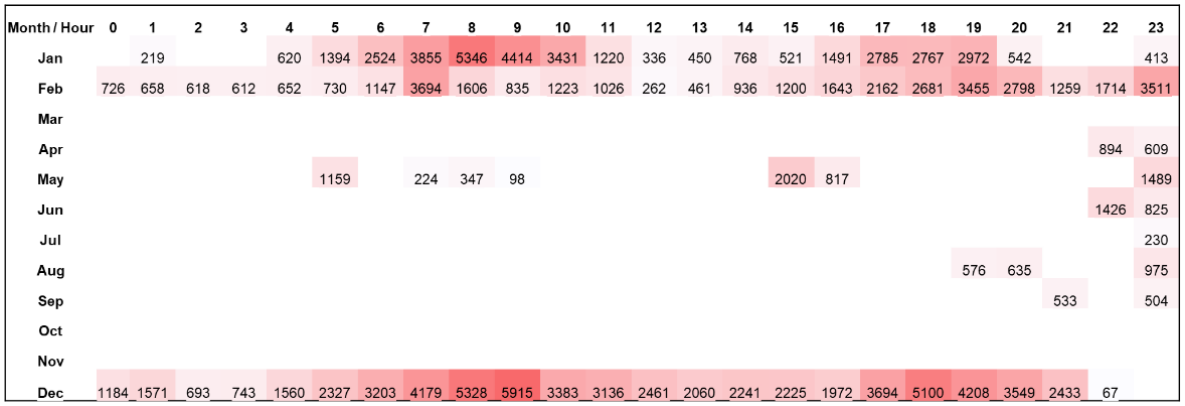


Figure 15. Low End EE scenario shortfall timing – peak magnitude (MW) heatmap

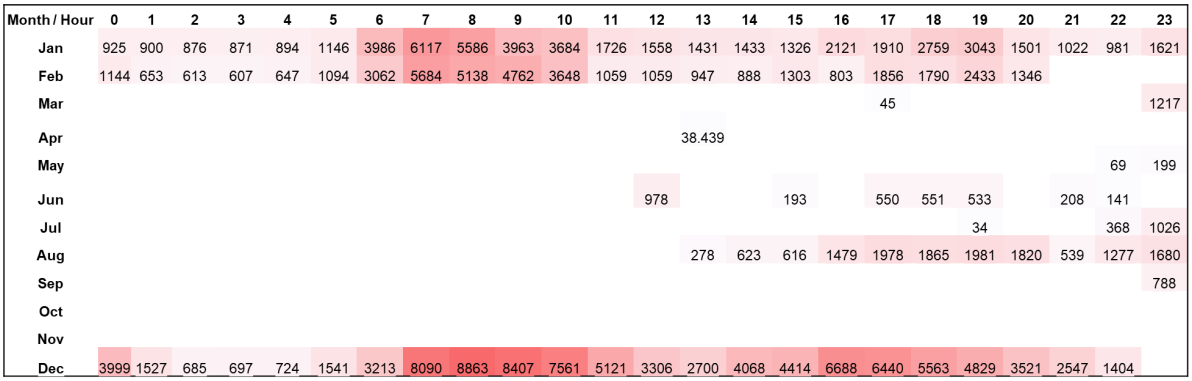


Figure 16. Higher Data Center scenario shortfall timing – peak magnitude (MW) heatmap

Interpreting multiple metrics

Evaluating the distributions of the metric observations alongside the actual shortfalls has a key role in this assessment – better understanding a multi metric approach with limits on frequency, duration, and magnitude of shortfalls (and therefore emergency measures). As the Reference scenario is adequate, the Low End EE scenario provides a good example to discuss given that duration and energy metrics are satisfied and the frequency and peak metrics are violated. Recall that the while the Peak VaR metric is 367 MW higher than the threshold, only 20% of all shortfall peaks are below 300 MW. In other words, while adding 367 MW of perfect capacity would theoretically satisfy the Peak VaR metric (protect against the tail-end risk 39-in-40 years), it might only mitigate 20% of shortfalls, resulting in LOLEV that still exceeds the threshold. Thus, protecting against a distributional peak doesn't automatically protect against overall frequency of events.

This highlights why (a) all metrics must be satisfied to be deemed adequate, and (b) no metric should be considered the binding metric. Rather, it is possible that the emphasis of risk between frequency, duration, and magnitude will vary by scenario (i.e. future conditions and circumstances). Instead of using the word "binding", another suggestion is the to frame it as which metric needs a larger investment (cost/resources) to mitigate while ensuring all metrics are satisfied. While discussing potential solutions for adequacy challenges is outside the scope of the Council's adequacy assessments, this discussion extends into future Power Plan work.

Conclusion

While the region is facing substantial load growth uncertainty, the 2021 Power Plan resource strategy, with the alleviating circumstances of announced coal-to-gas conversions and expanded transmission capacity, are found to provide an adequate system in the Reference Case. Thus, assuming the Reference Case is the trajectory, continued implementation of the strategy, including ensuring sufficient reserves and acquiring another two years of energy efficiency and renewables, not retiring thermal plants through coal-to-gas conversions, and expanded transmission capacity offset the adequacy challenge of increased loads of anticipated data centers and electric vehicles.

However, achieving the low end of the energy efficiency target offers more risk to maintain regional adequacy. The low end of EE, alongside the resource strategy, does not fully mitigate challenges of increased loads in 2029 despite the alleviating circumstances of not retiring thermal plants and expanded transmission. The risk of shortfall frequency and peak magnitude persist with expectation that shortfalls may occur throughout the days in winter (though greatest magnitudes in morning/evening ramp hours), and additional challenges in spring and summer.

Should tech sector load forecast accelerate, driven by higher data center load, and reach the high end of the trajectories, the region will not be adequate. The ~1,600 MW of increased load associated with additional data center load growth above the reference case causes the scenario to violate all adequacy metrics and trigger larger seasonal challenges.

As the region is facing unprecedented load growth uncertainty driven by data center and transportation electrification, as well as building electrification, the Council will continue tracking and planning for these risk factors in the development of the upcoming Power Plan and the eventual resource strategy to address the evolving needs of the region.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-72:
FERC Western Energy Markets Explainer

Western Energy Markets Explainer

This explainer offers a comprehensive overview of the electricity markets in the Western United States. It covers key features of the markets that enable coordinated and efficient management of the region's electric transmission grid system. This explainer will help you understand how new developments in electricity markets in the West may impact energy costs, system reliability, and the implementation and achievement of state-level energy policies.

This explainer is organized with four major sections:

- Key Terms
- Introduction to the U.S. Power Grid and FERC-led Initiatives to Create Wholesale Markets
- Overview of Electricity Markets in the West
- Resources to Learn More about Western Market Matters at FERC

This explainer offers a summary of publicly available information about Western markets and should not be relied upon as a legal document.

Key Terms

Balancing Authorities oversee electricity transfers and ensure grid stability by maintaining a balance between the production and consumption of electricity. They typically oversee long-term efforts to maintain that key balance on the grid, such as resource planning, as well as short-term balancing by committing electricity supply resources to operate and real-time load-frequency control within a balancing authority area. Certain electric utilities and power marketing administrations (see below) are typical examples of balancing authorities.

A **Balancing Authority Area** is a geographic region that incorporates a collection of generation facilities, transmission lines, and loads (aggregated consumer demand for electricity) where electric metering is performed by a balancing authority. The responsibility of maintaining a balance between the load and resources (supply of electricity) within this area falls under the jurisdiction of the balancing authority. One example of a balancing authority area is a utility service territory.

Congestion occurs when a portion of the transmission grid becomes overloaded with electricity. Congestion can occur when a line or transformer reaches its limit and cannot carry

any more electricity. When congestion occurs, the lowest-priced electricity cannot flow freely to a specific area.

Congestion Revenue Rights are financial tools used to manage the cost variability of congestion on the grid based on the electricity pricing approach used, called locational marginal pricing (see below). Such rights are often acquired to hedge against congestion costs in the day-ahead market, but sometimes are purchased as an investment.

A **Day-Ahead Market** is a voluntary financial market where individuals and companies can buy and sell wholesale electric energy at financially binding prices for the next day.

Hedging is the act of engaging in transactions to reduce risk from price volatility (see below) for a company and/or customers. Hedging transactions can help electricity suppliers meet their customers' demands while reducing or eliminating the risk of fluctuating prices.

Locational Marginal Pricing or Prices (LMP) refer, respectively, to the overall pricing scheme or the actual prices paid for wholesale electric energy at a specific location within an electric transmission grid at a specific point in time. LMP data is used to track the prices of electricity in different parts of the grid and to help manage supply and demand for electricity.

Price Volatility describes how quickly or widely prices can change. In the energy industry, price volatility can refer to electricity or natural gas supply prices, relative to consumer demand. Volatility is measured by the day-to-day variation (percentage difference) in the price of the commodity.

A **Power Marketing Administration** is a federal agency within the Department of Energy that markets electric power produced by federal dams and multiple-purpose water projects providing service to customers.

A **Real-Time Energy Market** is a spot market that allows consumers, companies, and energy distribution businesses to buy and sell wholesale electric energy in real-time, usually an hour before delivery. The real-time market balances the differences between day-ahead resource commitments and demand forecasts and the actual real-time demand for and production of electricity.

Resource Adequacy is the ability of an electric transmission grid to meet consumer demand for power. Resource adequacy ensures that there is enough energy generating capacity and reserves to maintain a balanced supply and demand across an electric system.

Wholesale Electric Energy, also referred to as wholesale electricity, is electric energy that is purchased or sold for resale, whereas retail electric energy is electric energy that is purchased by or sold to the ultimate consumer.

California ISO Extended Day-Ahead Market is a voluntary day-ahead electricity market designed to deliver significant reliability, economic, and environmental benefits to balancing areas and utilities throughout the West. The initial structure of EDAM was approved, in most part by the Commission in December 2023.

Introduction

In the U.S., the power grid is a complex network of power plants and transmission lines with extra-high-voltage connections between utilities. This expansive infrastructure allows the movement of electricity from one part of the network to another.[1] Over time, the U.S. power grid has evolved into three large interconnected systems, which are shown in Figure 1:

1. the Eastern Interconnection that operates in states east of the Rocky Mountains
2. the Western Interconnection that covers the Pacific Coast to the Rocky Mountain states
3. the Texas Interconnected System, known as ERCOT

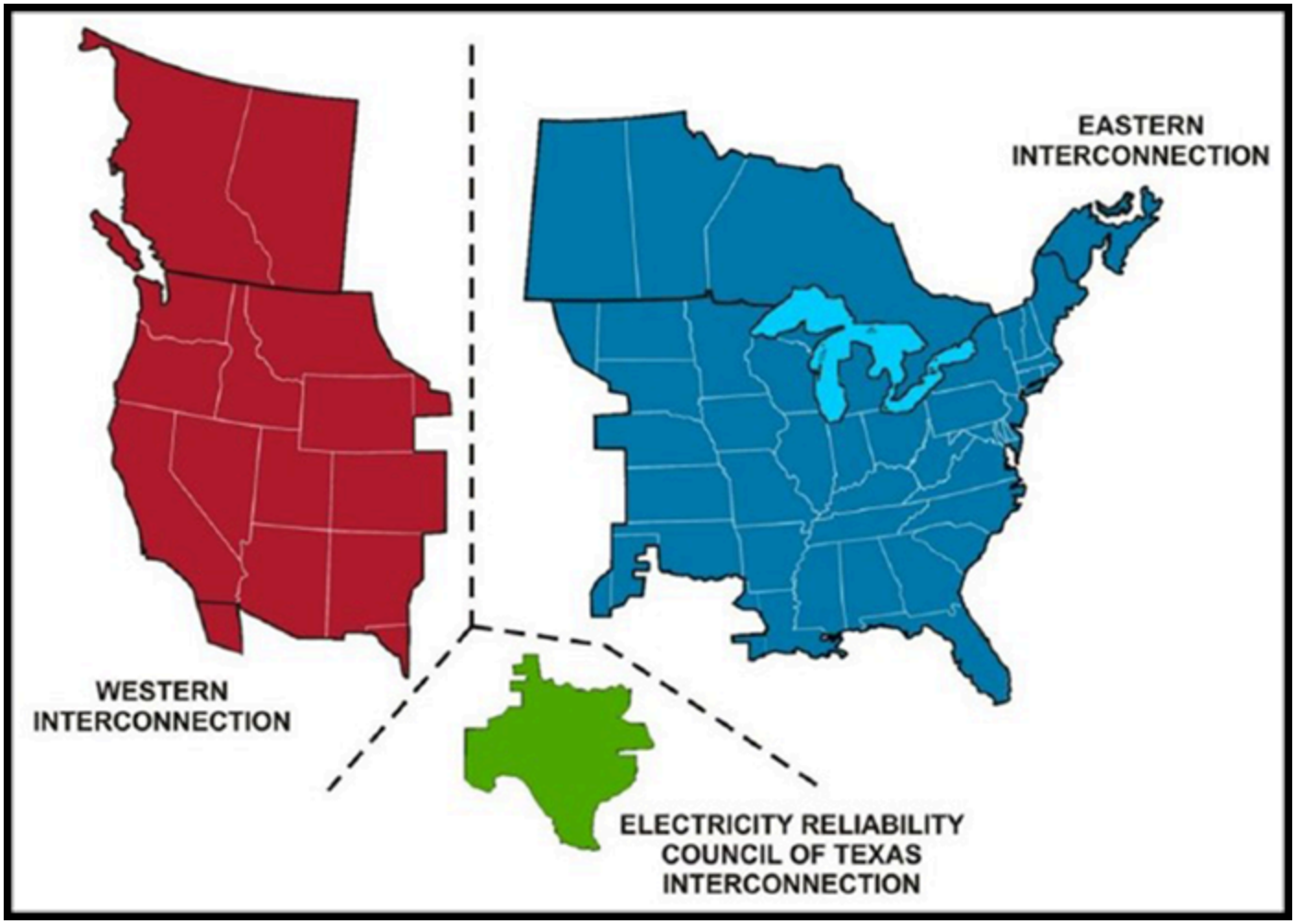


Figure 1. The Three Major Interconnections of the U.S. Electric Power Grid. Source: North American Electric Reliability Corporation.

The electric grid must comply with standards developed by the North American Electric Reliability Corporation (NERC) to ensure reliability of the grid. Because these three systems encompass unique geographic areas, NERC also assigns responsibilities to six regional entities who apply standards and act as compliance authorities. In the Western Interconnection, the Western Electricity Coordinating Council (WECC) is the regional entity, which oversees bulk power system reliability and security in the region. [2]

In the late 1990s, FERC initiated significant reforms in the electricity sector to support competition in the energy marketplace. The milestones included:

- Order No. 888 (1996): established the foundation for organized wholesale markets by promoting independent system operators (ISOs).[3] These entities were designed to foster competition among electricity generators at the wholesale level.
- Order No. 2000 (1999): encouraged utilities to join regional transmission organizations (RTOs). The aim was to enhance the operation of transmission systems and to develop equitable transmission management practices.[4]

Today, RTOs and ISOs play a crucial role in electricity policy. They serve approximately two-thirds of U.S. electricity consumers, managing both power markets and regional transmission systems (Figure 2 shows the boundary areas the RTO and ISO regions).[5]

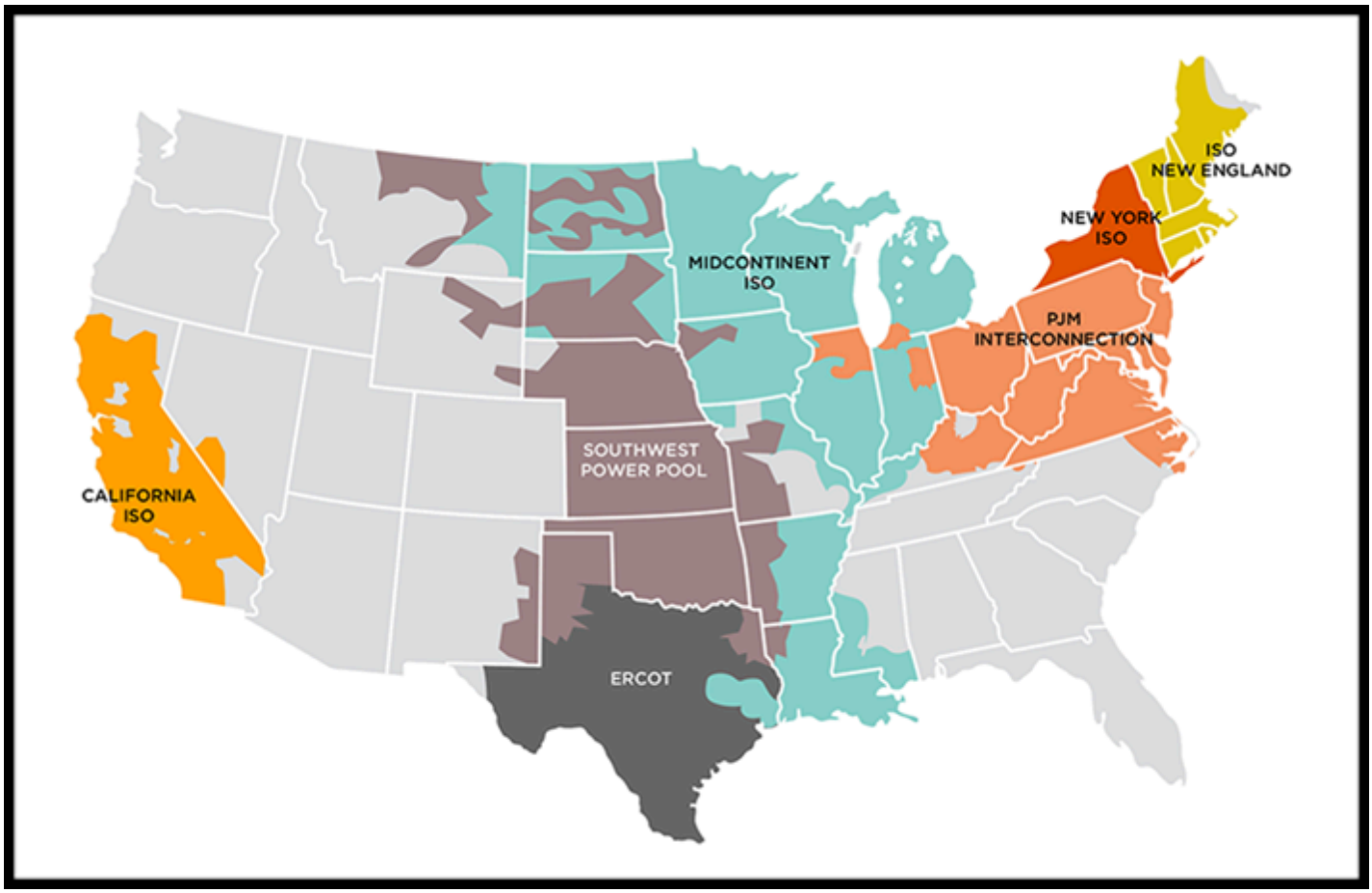


Figure 2. Seven RTO and ISO Regions in the Continental United States.

The West has progressively developed its regional wholesale electricity markets, adopting new systems and improvements step-by-step. Unlike other regions that may implement large-scale changes all at once, the West has chosen to evolve its electricity markets gradually, with each stage of development building upon the last.[6] For example, a single organized market manages energy trades for most of California—the California Independent System Operator (CAISO)—and there are currently no multistate RTOs (although, as seen in Figure 2, CAISO territory includes a small area of Nevada).[7]

The West uses a coordinated system of regional real-time energy supply markets and bilateral trading between a specified buyer and a specified seller of electricity. The Western Area Power Administration and the Bonneville Power Administration, two Western Power Marketing Administrations within the Department of Energy, sell electric power produced by federal dams to utilities (Figure 3 shows the boundary areas of the four Power Marketing Administrations).

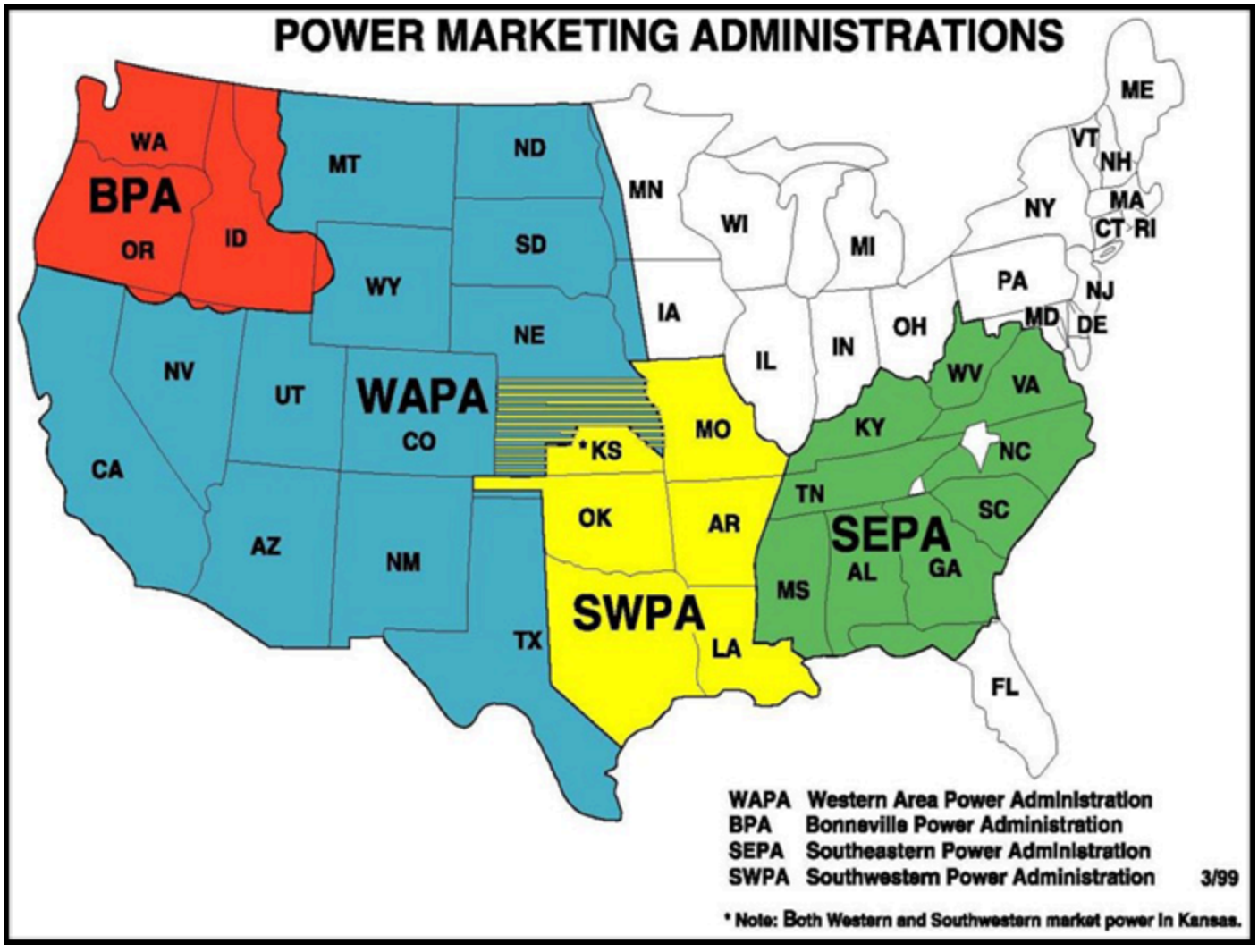


Figure 3. Power Marketing Administrations in the Continental United States. Source: SPP

While CAISO is currently the only ISO in the West, FERC has approved several market initiatives in the last twenty years that have led to a more integrated Western electric system that

encompasses several Western states. The rest of this explainer will discuss CAISO as well as other initiatives and entities that contribute to the region's electricity landscape.

Overview of Electricity Markets in the West

California Independent System Operator (CAISO)



Figure 4. California Independent System Operator (CAISO) area.

The California Independent System Operator (CAISO)[8] was founded in 1998 and became a fully functioning ISO in 2008. CAISO manages the flow of electricity across the high-voltage, long-distance power lines serving 80% of California and a part of Nevada (Figure 4 shows the boundary areas of CAISO).[9]

CAISO provides open access to the transmission lines it operates and performs long-term transmission planning. In managing the grid, CAISO centrally dispatches generation and coordinates the movement of wholesale electricity in the area shown. CAISO's wholesale energy markets comprise day-ahead and real-time processes that include energy products, such as real-time energy, day-ahead energy, ancillary services, and congestion revenue rights. The Commission also approved, in most part, CAISO's Extended Day-Ahead Market proposal in December 2023.

Western Energy Imbalance Market (WEIM)

In 2014, CAISO initiated the Western Energy Imbalance Market (WEIM) with the purpose of expanding real-time market access to utilities in the Western Interconnection who are not members of CAISO. Utilities participating in the WEIM include utilities and balancing authorities outside of CAISO's territory. Among other benefits, the WEIM provides its participants with access to least-cost electricity across the region. There are also operational and reliability benefits to the sharing of electricity through WEIM. For example, when one part of the West is experiencing an electric energy shortage while others are not, there can be sales of excess electric energy to the area that needs it.

Concerning day-to-day operations, the WEIM is a real-time energy market that allows participating utilities to balance their supply and demand within 15 minutes or 5 minutes of delivery using the least-cost resources available across a wider footprint, helping to manage system needs. This creates a coordinated system of regional real-time energy supply markets, which, while not a full RTO or ISO, offers a structured approach to energy trading and system balancing in the West.

Since the WEIM began offering real-time market access to utilities outside of CAISO's territory, the WEIM has grown to serve parts of Arizona, California, Idaho, Montana, Nevada, New Mexico, Oregon, Texas, Utah, Washington, and Wyoming, and extends to the border with Canada and Mexico, totaling 22 participating entities representing 79% of the energy load in the WECC.[10] The WEIM's ability to leverage CAISO's market optimization tools to service the needs of the utilities outside its ISO structure have led to reported cost-savings.[11] Presently, the WEIM claims to have delivered more than $5 billion in benefits by connecting a broader area with access to lower-cost electricity.[12]

The WEIM is governed by a five-member body with shared authority from the CAISO Board of Governors on rules specific to participation in the WEIM.[13] As designed by regional stakeholders, the WEIM Governing Body is nominated by a committee of Western stakeholders. The WEIM Governing Body and CAISO Board of Governors frequently hold public sessions that include a toll-free number for members of the public to listen to the meeting. These public sessions include opportunities for public comment following briefings on policy initiatives as well as WEIM benefits and market updates.

Southwest Power Pool (SPP)

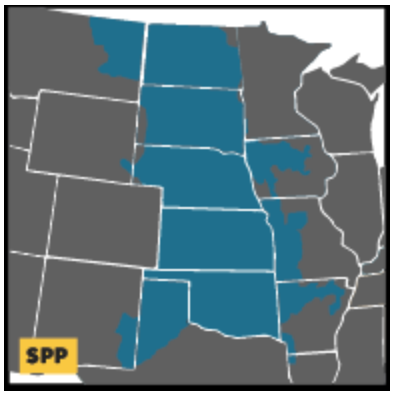


Figure 5. Southwest Power Pool (SPP) area.

The Southwest Power Pool (SPP), an RTO operating primarily in the Midwest, operates energy markets in both the Eastern and Western interconnections. Founded in 1941 as an 11-member power pool that allowed for power sharing among participating utilities, SPP achieved RTO status in 2004. Based in Little Rock, Arkansas, SPP manages transmission in portions of fourteen states: Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. Its membership comprises investor-owned utilities, municipal systems, generation and transmission cooperatives, state authorities, independent power producers, power marketers, and independent transmission companies.

In 2015, SPP's footprint expanded when the Western Area Power Administration—Upper Great Plains (WAPA-UGP) region, the Basin Electric Power Cooperative, and the Heartlands Consumer Power District—joined the RTO. The expansion nearly doubled SPP's service territory and added more than 5,000 MW of peak demand and over 7,000 MW of generating capacity. WAPA-UGP is the first federal power marketing administration to join an RTO.

In January 2025, FERC also approved, subject to condition, SPP's Markets+ proposal.

Additionally, in March 2025, FERC approved, subject to condition, SPP's RTO West proposal.

Western Energy Imbalance Service (WEIS) Market

In 2020, SPP established the Western Energy Imbalance Service (WEIS) market with the purpose of providing real-time market access to utilities in the Western Interconnection who are not members of the SPP RTO. Like CAISO's WEIM, SPP's WEIS seeks to provide participants with access to least-cost electric energy and to create reliability and operational advantages, such that power from areas with excess electric energy can flow to an area experiencing a shortage (such as during a weather emergency).

WEIS centrally dispatches generation to balance supply and demand in real-time and allows parties to continue to trade wholesale electricity bilaterally. Additionally, the WEIS has a goal of allowing participants to hedge against transmission congestion while coordinating the

movement of wholesale electricity. In 2022, according to the WEIS Benefit of Market Report, WEIS claims to have provided $31.7 million in net benefits to its 12 participating Western utilities.[14]

SPP's independent Board of Directors provides ultimate oversight of the WEIS's administration; however, the Western Markets Executive Committee is responsible, through its designated working groups, committees, and task forces, for developing and recommending policies, procedures, and system enhancements related to the administration of the WEIS by SPP under the Western Joint Dispatch Agreement in the Western Interconnection.[15] In coordination with the Western Markets Executive Committee, the Western Markets Working Group provides a public forum for customers to engage in matters of governance and strategy with other stakeholders.[16] In 2024, all Western Markets Executive Committee meetings will be joint with the Western Markets Working Group. Members of the public may register on www.SPP.org for these meetings and attend in-person or by phone.

Western Power Pool (WPP)



Figure 6. Western Power Pool (WPP) area. Source: WPP

The Western Power Pool (WPP), previously known as the Northwest Power Pool, is a group of utilities and other entities that coordinate and share resources in the Western Interconnection (Figure 6 shows the boundary areas of WPP). The WPP provides services to its members, such as transmission planning and tariff administration.[17] The WPP was formed in 1983 to promote increased efficiency, competition, and coordination in the electric power industry.[18] The WPP is governed by a Board of Directors, a Governing Body, and various committees and working groups that represent the interests of its members and stakeholders. The WPP also collaborates with other regional entities, such as the WECC, SPP, and CAISO, to enhance the reliability and efficiency of the Western Interconnection. While the WPP does not provide transmission service and is not an RTO/ISO, it does provide significant benefits by ensuring reliable energy capacity and reserves across the electric system.

To that end, in August 2022, the WPP filed at FERC the Western Resource Adequacy Program (WRAP) proposal, in Docket No. ER22-2762, which is intended to enhance resource adequacy. Resource adequacy ensures that there is enough energy capacity and reserves to maintain a balanced supply and demand across the electric system.[19] The WRAP was approved by FERC in February 2023 and is expected to launch in mid-2025.[20]

Western Resource Adequacy Program (WRAP)

The WRAP is not an organized market like CAISO's WEIM or SPP's WEIS but is instead a program WPP runs to ensure that the electricity supply in the West can meet the demand and reliability needs of customers. When implemented, the WRAP will have two main components: (1) a forward showing program, where participants demonstrate their ability to meet their peak demand plus a reserve margin for the next year; and (2) an operations program, where participants monitor and report their daily resource availability and demand as well as comply with dispatch instructions from the program operator. SPP acts as the program operator and, as directed by WPP, provides services for the WRAP, such as modeling, analytics, real-time operations, and technical improvement.

The WRAP is designed to be compatible with existing markets and programs in the West, such as the WEIM and the CAISO markets. The WRAP is also open to area participants who want to join the program and benefit from its regional approach. The WRAP seeks to help participants address the challenges of resource adequacy in the West in a manner consistent with state goals, such as increasing demand, retiring coal plants, and integrating variable renewable energy sources.[21]

To Learn More

Additional information on the topics discussed is available on FERC's website, including the FERC rulings cited in this explainer, the 2024 Energy Primer, as well as on the:

- CAISO website
- SPP website
- WPP website

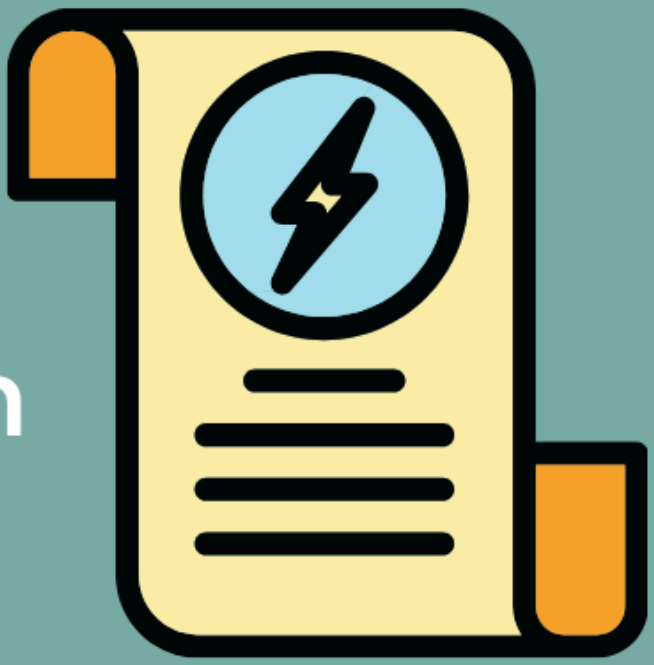
In addition to the existing markets and programs discussed above, the Western area markets may continue to develop and change. To follow FERC matters relevant to the expansion of the Western markets, you may:

- Subscribe to the Office of Public Participation (OPP) newsletter;
- Follow stakeholder processes with the stakeholder centers of CAISO and SPP; and
- eSubscribe to electronically receive information related to a particular FERC docket or set of dockets in which you have an interest.

OPP is dedicated to helping the public understand and participate in FERC proceedings. Members of the public can contact OPP for assistance in navigating FERC proceedings and receiving information on when and how to comment, intervene, or file motions during proceedings.

Please contact OPP by e-mail at OPP@ferc.gov, by phone at (202) 502-6595, or see our website at www.FERC.gov/OPP for additional information and resources.

Western Markets Expansion



CAISO

Order No. 2000

CAISO ISO Open Access Transmission Tariff (OATT)

Western Energy Imbalance Market WEIM (CAISO)

147 FERC ¶ 61,231 (2014)

Docket No. ER14-1386

EIM Section to CAISO OATT

Western Energy Imbalance Service WEIS (SPP)

173 FERC ¶ 61,267 (2020)

Docket Nos. ER21-3/ER21-4

WEIS OATT

Western RA program WRAP (Western Power Pool)

182 FERC ¶ 61,063

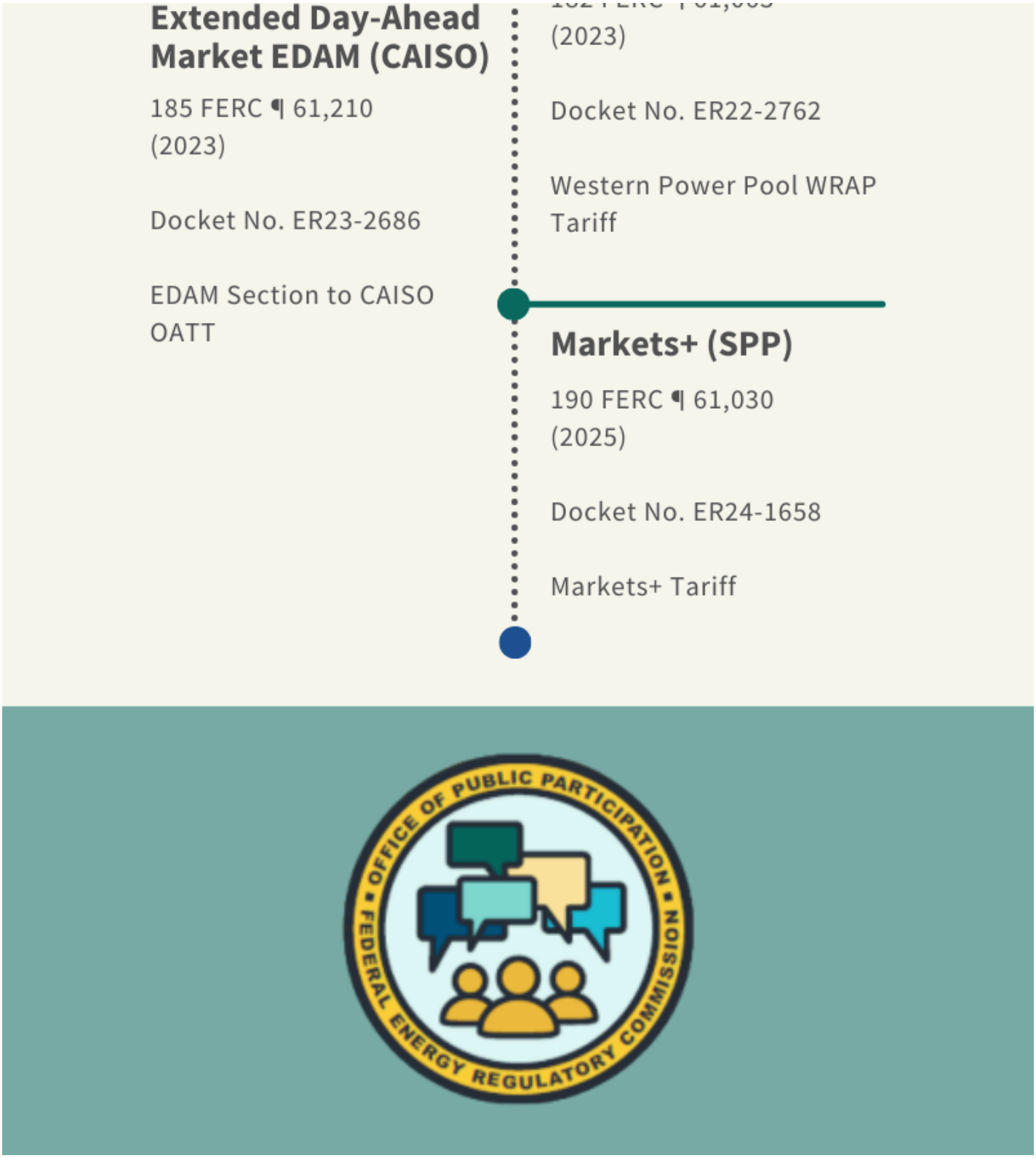


Figure 7. Western Markets Expansion infographic.

[1] Transmission Agency of Northern California. https://www.tanc.us/understanding-transmission/the-western-us-power-system.

[2] Specifically, FERC mandated NERC to oversee the reliability of the bulk power system, which includes parts of Mexico and Canada. For further information, see the Office of Public

Participation's Reliability Primer. https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[3] Electricity Markets Explainer. https://www.ferc.gov/introductory-guide-electricity-markets-regulated-federal-energy-regulatory-commission.

[4] Order 2000 can be viewed at: https://www.ferc.gov/sites/default/files/2020-06/RM99-2-00K_1.pdf.

[5] Electric Power Markets. https://www.ferc.gov/electric-power-markets.

[6] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[7] In the case of CAISO, the ISO has chosen not to seek RTO status. RTOs are electric power transmission system operators that coordinate, control, and monitor a multistate electric grid. ISOs are like RTOs, which also coordinate, control, and monitor the operation of the electrical power system. However, ISOs cover geographic areas within a state or a smaller region.

[8] Understanding and Participating in CAISO Processes. https://www.ferc.gov/understanding-and-participating-california-iso-caiso-processes.

[9] CAISO. http://www.caiso.com/about/Pages/OurBusiness/Default.aspx.

[10] CAISO. https://www.westerneim.com/Documents/weim-first-quarter-benefits-for-2023-reach-418-million.pdf.

[11] A description of the history and motivating factors for market developments in the West: https://www.rabobank.com/knowledge/d011408934-no-rto-no-problem-rethinking-regulated-markets-in-the-us-electricity-heartland.

[12] WEIM. https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx.

[13] WEIM. https://www.westerneim.com/Pages/Governance/GoverningBody.aspx.

[14] SPP. https://spp.org/western-services-documents/?id=371676.

[15] SPP. https://spp.org/documents/61046/wmec%20charter%2020221018.pdf.

[16] SPP. https://spp.org/western-services/weis/.

[17] Western Power Pool. https://www.westernpowerpool.org/private-media/documents/WPP_WRAP_Interoperability_with_Markets_June_2023.pdf.

[18] Western Power Pool. https://www.westernpowerpool.org/.

[19] CAISO. https://www.caiso.com/Documents/Resource-Adequacy-Fact-Sheet.pdf.

[20] *Northwest Power Pool*, 182 FERC 61,063 at P 13-14 (2023).

[21] Western Power Pool. https://www.westernpowerpool.org/about/programs/western-resource-adequacy-program.

Quick Links

- Introduction to Western Markets Expansion

Contact Information

Office of Public Participation (OPP)
Telephone: 202-502-6595
Email: OPP@ferc.gov

This page was last updated on April 18, 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-73:
Bonneville 2024 Fact Sheet

BPA Facts

INFORMATION IS FOR FISCAL YEAR 2024, UNLESS OTHERWISE NOTED.

Profile

The Bonneville Power Administration is a nonprofit federal power marketing administration based in the Pacific Northwest. Although BPA is part of the U.S. Department of Energy, it is self-funding and covers its costs by selling its products and services. BPA markets wholesale electrical power from 31 federal hydroelectric dams in the Northwest, one nonfederal nuclear plant and several small nonfederal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. The nonfederal nuclear plant, Columbia Generating Station, is owned and operated by Energy Northwest, a joint operating agency of the state of Washington.

BPA provides about one-third of the electric power generated in the Northwest, primarily from reliable, dispatchable and flexible hydroelectric resources. BPA also operates and maintains more than 15,000 circuit miles of high-voltage transmission in its service territory. BPA's territory includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.

BPA promotes energy conservation and innovative technologies that improve its ability to deliver on its mission. To mitigate the impacts of the federal dams, BPA implements a fish and wildlife program that includes working with its partners to make the federal dams safer for fish passage.

BPA is committed to public service and seeks to make decisions in a manner that provides opportunities for input from all interested parties. In its vision statement, BPA dedicates itself to providing high system reliability, low rates consistent with sound business principles, environmental stewardship and accountability.

Mission

BPA's mission as a public service organization is to create and deliver the best value for our customers and constituents as we act in concert with others to assure the Pacific Northwest:

- An adequate, efficient, economical and reliable power supply.
- A transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal generating units, providing service to BPA's customers, providing interregional interconnections, and maintaining electrical reliability and stability.
- Mitigation of the impacts on fish and wildlife from the federally owned hydroelectric projects from which BPA markets power.

BPA is committed to cost-based rates, and public and regional preference in its marketing of power. BPA sets its rates as low as possible consistent with sound business principles and the full recovery of all of its costs, including timely repayment of the federal investment in the system.

Core values

SAFETY

We value safety in everything we do. Together, our actions result in people being safe each day, every day. At work, at home and at play, we all contribute to a safe community for ourselves and others.

TRUSTWORTHY STEWARDSHIP

As stewards of the Federal Columbia River Power System, we are entrusted with the responsibility to manage resources of great value for the benefit of others. We are trusted when others believe in and are willing to rely upon our integrity and ability.

COLLABORATIVE RELATIONSHIPS

Trustworthiness grows out of a collaborative approach to relationships. Internally we must collaborate across organizational lines to maximize the value we bring to the region. Externally we work with many stakeholders who have conflicting needs and interests. Through collaboration we discover and implement the best possible long-term solutions.

OPERATIONAL EXCELLENCE

Operational excellence is a cornerstone of delivering on our vision (system reliability, low rates, environmental stewardship and regional accountability) and will place us among the best electric utilities in the nation.

General information

BPA established	1937
Service area size (square miles)	300,000
Pacific Northwest population	14,735,345
Transmission line (circuit miles)	14,973
BPA substations	258
Employees (FTE)[1]	3,191

1/ As of October 2025.

Customers

Cooperatives	53
Municipalities	42
Public utility districts	28
Federal agencies	7
Investor-owned utilities	6
Direct-service industries	1
Port districts	1
Tribal utilities	3
Total	141
Marketers (power and transmission)[1]	165
Transmission customers	415

Rates

Wholesale power rates[2] (fiscal years 2024–2025)

Priority Firm Tier 1 (AVERAGE[3], UNDELIVERED)	3.47 cents/kWh
Priority Firm Avg. Tier 1 + Tier 2 (UNDELIVERED)	3.58 cents/kWh
Priority Firm Exchange (AVERAGE, UNDELIVERED)	7.50 cents/kWh
Industrial Firm (AVERAGE, UNDELIVERED)	4.14 cents/kWh
New Resources (AVERAGE, UNDELIVERED)	8.54 cents/kWh

2/ The rates shown do not include the cost of transmission. They also do not include the impact of the Reserves Distribution Clause.
3/ The actual rate paid by an individual customer will vary according to the shape of the load and the products and services purchased.

Transmission rates[4] (fiscal years 2024–2025)

Network rates

Long-Term Firm	$1.648/kW-month
Short-Term	0.474 cents/kWh

Southern Intertie rates

Long-Term Firm	$1.118/kW-month
Short-Term	1.029 cents/kWh

4/ Reflects the rates for point-to-point transmission service. All short-term firm and nonfirm rates are downwardly flexible.

Financial highlights[5]

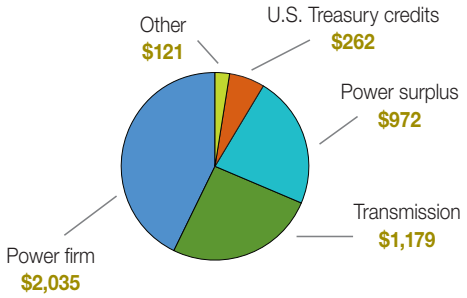
For the Federal Columbia River Power System
($ in millions)

Total operating revenues[6]	$4,569
Total operating expenses	4,357
Net operating revenues	212
Total interest expense and other income, net	344
Net revenues	$ (132)

5/ This information is consistent with BPA's 2024 Annual Report.
6/ For additional information, please visit the 2024 Annual Report at bpa@gov.

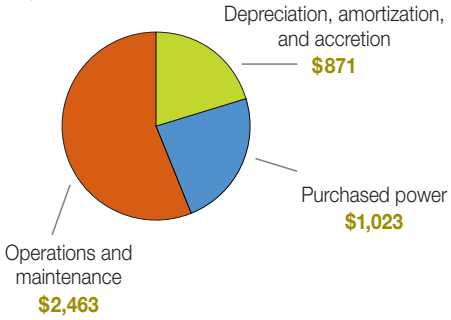
Disaggregated revenues

($ in millions)



Operating expenses[7]

($ in millions)



7/ All intracompany and intercompany accounts and transactions have been eliminated from the FCRPS financial statements.

Transmission system

Operating voltage	Circuit miles
1,100 kV	1.3
1,020 kV	264.3[8]
500 kV	4,734.0
345 kV	569.8
287 kV	0.7
230 kV	5,541.3
161 kV	119.3
138 kV	61.1
115 kV	3,524.3
below 115 kV	157.1
Total[9]	14,973.2

8/ BPA's portion of the PNW/PSW direct-current intertie. The total length of this line from The Dalles, Oregon, to Los Angeles, California is 846 miles.
9/ Total circuit miles as of August 2025.

Federal hydro projects

Name	River, state	In service	Max capacity
Albeni Falls	Pend Oreille, ID	1955	49 MW
Anderson Ranch	*Boise, ID*	*1950*	*40 MW*
Big Cliff	N. Santiam, OR	1953	23 MW
Black Canyon	*Payette, ID*	*1925*	*10 MW*
Boise River Diversion	*Boise, ID*	*1912*	*3 MW*
Bonneville	Columbia, OR/WA	1938	1,216 MW
Chandler	*Yakima, WA*	*1956*	*12 MW*
Chief Joseph	Columbia, WA	1958	2,614 MW
Cougar	McKenzie, OR	1963	29 MW
Detroit	N. Santiam, OR	1953	126 MW
Dexter	Middle Fork Willamette, OR	1954	17 MW
Dworshak	Clearwater, ID	1973	460 MW
Foster	S. Santiam, OR	1967	23 MW
Grand Coulee[10]	*Columbia, WA*	*1942*	*7,049 MW*
Green Peter	S. Santiam, OR	1967	92 MW
Green Springs	*Emigrant Crk, OR*	*1960*	*17 MW*
Hills Creek	Middle Fork Willamette, OR	1962	35 MW
Hungry Horse	*Flathead, MT*	*1953*	*428 MW*
Ice Harbor	Snake, WA	1962	695 MW
John Day	Columbia, OR/WA	1971	2,484 MW
Libby	Kootenai, MT	1975	605 MW
Little Goose	Snake, WA	1970	932 MW
Lookout Point	Middle Fork Willamette, OR	1953	138 MW
Lost Creek	Rogue, OR	1977	56 MW
Lower Granite	Snake, WA	1975	932 MW
Lower Monumental	Snake, WA	1969	932 MW
McNary	Columbia, OR/WA	1952	1,127 MW
Minidoka	*Snake, ID*	*1909*	*28 MW*
Palisades	*Snake, ID*	*1958*	*176 MW*
Roza	*Yakima, WA*	*1958*	*13 MW*
The Dalles	Columbia, OR/WA	1957	2,052 MW
Total (31 dams)			22,391 MW

Owned and operated by the U.S. Army Corps of Engineers (21 dams, 14,637 MW)
Owned and operated by the Bureau of Reclamation (10 dams, 7,776 MW)
10/ Includes pump generation.

BPA resources[11]

(for operating year 2024 under firm water conditions)

Sustained 120-hour peak capacity (January) 13,458 MW
Hydro . . . . . 11,828 MW (88%)
Nuclear . . . . . 1,178 MW (9%)
Firm contracts and other resources . . . . 452 MW (3%)
Wind . . . . . 0 MW (0%)

Firm energy (12-month annual avg.) 8,038 aMW
Hydro . . . . . 6,662 aMW (83%)
Nuclear . . . . . 1,116 aMW (14%)
Firm contracts and other resources . . . 227 aMW (3%)
Wind . . . . . 33 aMW (<1%)

11/ The Resource Program provides analysis and insight into long-term, least-cost power resource acquisition strategies.

Regional resources[12]

(for operating year 2024 under firm water conditions)

Sustained 120-hour peak capacity (January) 40,202 MW
Hydro . . . . . 24,046 MW (60%)
Natural gas . . . . . 6,288 MW (16%)
Coal . . . . . 4,195 MW (10%)
Cogeneration . . . . . 3,179 MW (8%)
Nuclear . . . . . 1,178 MW (3%)
Imports . . . . . 1,065 MW (3%)
Other Renewables . . . . . 182 MW (<1%)
Wind . . . . . 0 MW (<0%)
Other miscellaneous resources . . . . . 31 MW (<1%)

Firm energy (12-month annual avg.) 28,382 aMW
Hydro . . . . . 12,081 aMW (43%)
Natural gas . . . . . 5,373 aMW (19%)
Coal . . . . . 3,751 aMW (13%)
Cogeneration . . . . . 2,737 aMW (10%)
Wind . . . . . 2,200 aMW (8%)
Nuclear . . . . . 1,116 aMW (4%)
Imports . . . . . 588 aMW (2%)
Other renewables . . . . . 159 MW (<1%)
Solar . . . . . 352 aMW (<1%)
Other miscellaneous resources . . . . . 26 aMW (<1%)

12/ Forecast figures from BPA's "2024 Pacific Northwest Loads & Resources Study," tables 2–6, 2–7, 3–3. Firm resource projections before adjustment for reserves, maintenance and transmission losses. The hydro capacity is reduced by an operational "idle capacity" adjustment to estimate the monthly maximum operational capability that is available to meet the 120-hour peak load for firm water conditions.

Federal generation

Hydro generation . . . . . 6,244 aMW
Total generation . . . . . 7,392 aMW
60-min. hydro peak generation . . . . . 11,121 MW
60-min. total peak generation . . . . . 12,239 MW
All-time 60-min. total peak generation record (June 2002). . . . . 18,139 MW

Fish and wildlife

($ in millions)

BPA F&W program expense $272.2
Direct funded expenditures 103.8
Interest, depreciation and amortization expenses 101.2
Total direct costs $477

Operational costs:
Replacement power purchases 856.2
Estimated forgone power revenues 36.6

Total F&W costs for FY 2024[13] $1,370

13/ Program expenses include integrated program and action plan/high priority. Totals may not equal sum of components due to rounding.

Energy efficiency[14]

	FY 2024	Total[15]
Residential programs	7.5 aMW	563.7 aMW
Commercial programs	6.9 aMW	466.7 aMW
Industrial programs	10.3 aMW	363.9 aMW
Agricultural programs	1.6 aMW	77.0 aMW
Multi-sector programs	0 aMW	108.9 aMW
Federal	1.3 aMW	22.8 aMW
Utility distribution system	0.2 aMW	11.3 aMW
Improved building codes	0 aMW	188.5 aMW
NEEA[16] Net Market Effects	7.8 aMW	371.3 aMW
Momentum Savings[17]	TBD	359.7 aMW
Total aMW saved[18]	35.6 aMW	2,533.8 aMW

14/ All figures are preliminary and subject to final revision.
15/ Cumulative total, FY1982–2024.
16/ Northwest Energy Efficiency Alliance.
17/ Momentum Savings are updated at the end of each Power Planning period. Totals reflect achievements made through the 6th Power Plan.
18/ Data aligns with 2024 Annual Review and may be adjusted from past versions of BPA Facts.

Points of contact

GENERAL BPA OFFICES AND WEBSITES

BPA Headquarters 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208; 503-230-3000; *www.bpa.gov*

BPA Visitor Center 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208; 503-230-INFO [4636]; 800-622-4520

Public Engagement P.O. Box 14428, Portland, OR 97293; 800-622-4519; *www.bpa.gov/comment*

Washington, D.C., Office Forrestal Bldg., Room 8G-061, 1000 Independence Ave. S.W., Washington, D.C. 20585; 202-586-5640

Crime Witness Program To report crimes to BPA property or personnel; 800-437-2744

TRANSMISSION SERVICES

Transmission Services Headquarters P.O. Box 491, Vancouver, WA 98666-0491; 503-230-3000

Ross Complex 5411 N.E. Highway 99, Vancouver, WA 98663; 503-230-3000"

Van Mall One Park Place 7600 NE 41st Street, Vancouver WA 98662, 503-230-3000

Covington District 28401 Covington Way S.E., Kent, WA 98042; 253-638-3700

Eugene District 86000 Hwy. 99 S., Eugene, OR 97405; 541-988-7401

Idaho Falls Regional Office 1350 Lindsay Blvd., Idaho Falls, ID 83402; 208-612-3100

Kalispell District 2520 U.S. Hwy. 2 E., Kalispell, MT 59901; 406-751-7802

Longview District 3750 Memorial Park Drive, Longview, WA 98632; 360-414-5600

Olympia Regional Office 5240 Trosper Road S.W., Olympia, WA 98512; 360-570-4305

Redmond District 3655 S.W. Highland Ave., Redmond, OR 97756; 541-516-3200

Salem District 2715 Tepper Lane N.E., Keizer, OR 97303; 503-304-5900

Snohomish District 914 Ave. D, Snohomish, WA 98290; 360-563-3600

Spokane District 2410 E. Hawthorne Road, Mead, WA 99021; 509-468-3002

The Dalles District 3920 Columbia View Drive E., The Dalles, OR 97058; 541-296-4694

Tri-Cities District 2211 N. Commercial Ave., Pasco, WA 99301; 509-544-4702

Wenatchee District 13294 Lincoln Park Road, East Wenatchee, WA 98802, 509-886-6000

POWER SERVICES

Boise Customer Service Center 950 W. Bannock St., Suite 805, Boise, ID 83702; 208-670-7406

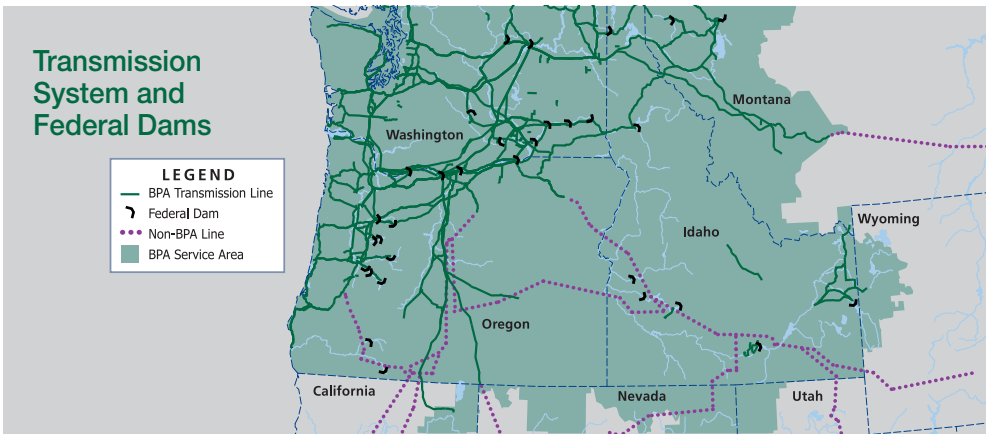
Eastern Area Customer Service Center P.O. Box 789, Mead, WA 99021; 509-822-4591

Montana Customer Service Center P.O. Box 640, Ronan, MT 59864; 406-676-2669

Seattle Customer Service Center 915 Second Ave., Suite 3360, Seattle, WA 98174; 206-220-6770

Western Area Customer Service Center 905 N.E. 11th Ave., P.O. Box 3621, Portland, OR 97208; 503-230-5856

Transmission System and Federal Dams



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-74:
Department Export Authorization EA-479-A (July 11, 2025)

United States

Department of Energy

Grid Deployment Office

Macquarie Energy LLC

GDO Docket No. EA-479-A

Order Authorizing Electricity Exports to Canada

Order No. EA-479-A

July 11, 2025

Authorizing Electricity Exports to Canada

I. BACKGROUND

The Department of Energy (DOE or Department) regulates electricity exports from the United States to a foreign country in accordance with Federal Power Act (FPA) § 202(e) (16 U.S.C. § 824a(e)) and regulations thereunder (10 C.F.R. §§ 205.300 *et seq.*). This authority was transferred to DOE under §§ 301(b) and 402(f) of the DOE Organization Act (42 U.S.C. §§ 7151(b) and 7172(f)). On April 10, 2023, this authority was delegated to the DOE's Grid Deployment Office (GDO) by Redelegation Order No. S3-DEL-GD1-2023.

An entity that seeks to export electricity must obtain an order from DOE authorizing it to do so. Under FPA § 202(e), DOE "shall issue such order upon application unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States or would impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has discretion to condition the order as necessary or appropriate; the Department "may by its order grant such application in whole or in part, with such modifications and upon such terms and conditions as [DOE] may find necessary or appropriate, and may from time to time, after opportunity for hearing and for good cause shown, make such supplemental orders in the premises as it may find necessary or appropriate." *Id.*

A. APPLICATION TO RENEW EXPORT AUTHORIZATION

Macquarie Energy LLC (Macquarie Energy or Applicant) is a power marketer seeking renewal of its existing authorization to export electric energy to Canada, which was originally granted in Order No. EA-479 on November 21, 2019, for a five-year term. On August 30, 2024, Macquarie Energy filed an application with DOE (Application or App.) for renewal of their export authority. App. at 1.

According to its Application, Macquarie Energy LLC operates as a "marketer and broker of electric power at wholesale." *Id*. at 1. The Applicant represents that it is "a Delaware corporation with its office and principal place of business in Houston, Texas" and "an indirect, wholly-owned subsidiary of Macquarie Group Ltd., an Australian company listed on the Australian Stock Exchange." *Id*. Macquarie Energy states that "the Federal Energy Regulatory Commission [FERC] has authorized Macquarie Energy to engage in wholesale sales of electric energy, capacity, and ancillary services at market-based rates." *Id.*

Macquarie Energy represents that it "does not own or control any electric power generation or transmission facilities and does not have a franchised electric power service area." App. at 1. Macquarie Energy states that it "does not have its own 'system' on which its exports of energy could have a reliability or stability impact" and it "will purchase the energy to be exported from wholesale generators, electric utilities, power marketers, Independent System Operators, Regional Transmission Authorities, and

federal power marketing agencies." *Id.* at 2. The Applicant further states that "such energy is surplus to the system of the generator and thus, exportation of said energy will not impair the adequacy of the electric power supply within the United States." *Id*. Additionally, Macquarie Energy asserts that it will comply with all applicable reliability criteria, standards, and guidelines. *See id*. at 3.

B. PROCEDURAL HISTORY

On August 30, 2024, Macquarie Energy filed an application with DOE requesting a renewal of their authorization to export electrical energy to Canada for an additional term of five (5) years. App. at 1. On October 18, 2024, DOE published notice of Macquarie Energy's Application in the Federal Register (89 Fed. Reg. 83867) and asked for any interested parties to submit comments on the Application by November 18, 2024.

C. PUBLIC COMMENTS

1. Public Citizen's Motion to Intervene and Protest

On November 18, 2024, Public Citizen, Inc. (Public Citizen) submitted a Motion to Intervene and Protest to the Application (Public Citizen Mot.). Public Citizen states it is "a national, not-for-profit, non-partisan organization that represents the public interest generally and, even more closely relevant to this proceeding interests of household consumers." Public Citizen Mot. at 2. Public Citizen asserts that Macquarie Energy misrepresented that it does not own generation or transmission facilities and does not have a franchised power service area, noting that Macquarie Energy's affiliates "hold controlling interests in two utilities with franchised electric service areas which include transmission facilities[,]" including Puget Sound Energy and Cleco Power. *Id.* at 1. In addition, Public Citizen claims that Macquarie owns or is seeking to acquire a number of power generation assets. *See id.*

Public Citizen also argues that Macquarie Energy did not disclose that it is a defendant in litigation accused of energy market manipulation and the subject of an investigation by FERC's Office of Enforcement for market manipulation during Winter Storm Uri. Public Citizen Mot. at 1. Public Citizen asserts that Macquarie's control of Multifuels Midstream Group "helped inform Macquarie's price-gouging trading operation in Texas[,]" referencing a news article noting "Macquarie earned $215 million in windfall profits" during the storm. *Id.* at 1-2. Public Citizen asserts that DOE should not approve Macquarie's request to export energy until the allegations of market manipulation have been resolved. *Id.* at 1.

2. Macquarie Energy's Answer

On November 27, 2024, Macquarie Energy filed a Motion for Leave to Answer and Answer of Macquarie Energy LLC to Protest of Public Citizen (Macquarie Ans.). Macquarie Energy asserts that Public Citizen did not request specific relief in its motion

and did not address the applicable standard of review for electricity export authorization applications. Macquarie Ans. at 2.

Macquarie Energy further denies Public Citizen's allegations, maintaining that it does not own electric generation or transmission facilities and does not have a franchised power service area. Macquarie Ans. at 3. Macquarie Energy acknowledges that its affiliates own electric generation and transmission facilities and have franchised power service areas. *Id.* However, Macquarie Energy notes that none of these entities are seeking an electricity export authorization, and Macquarie Energy "is incapable of controlling any of the asserts owned and/or operated" by such affiliates. *Id.*

Further, Macquarie Energy asserts that Public Citizen's allegations regarding market manipulation by Multifuels Midstream Group, an affiliate of Macquarie Energy by virtue of common upstream ownership, are not probative of the supply and reliability considerations that inform the review of electricity export applications. Macquarie Ans. at 3. Macquarie Energy further asserts that Public Citizen "presented no information to demonstrate this alleged misconduct." *Id.* Macquarie Energy states it "does not have any control over Multifuels Midstream Group as a function of common ownership." *Id.*

3. Public Citizen's Answer

On December 2, 2024, Public Citizen filed a Motion to Answer and Answer (Public Citizen Ans.). Public Citizen asserts that DOE must either reject Macquarie Energy's export authorization application or set the matter for hearing pursuant to 16 U.S.C. § 824a(e). Public Citizen Ans. at 1. Public Citizen maintains that the Applicant concealed material facts within its export authorization application, including its affiliation with "Puget Sound Energy and Cleco Power, as well as a number of power generation facilities in the United States." Public Citizen Ans. at 3. Additionally, Public Citizen disputes Macquarie Energy's assertion that it is incapable of controlling any assets of its affiliates and claims that Macquarie Energy engaged in transactions with Puget Sound Energy and Cleco Power, "making the omissions of these facts from [the Application] a fatal error." *Id.*

Public Citizen further asserts that Macquarie Energy's status as a defendant accused of market manipulation threatens the sufficiency of electric supply and impedes the coordination of energy facilities in the public interest. Public Citizen Ans. at 3-4. Public Citizen claims that "Macquarie appears to have systemic compliance problems[,]" pointing to penalties recently assessed to Macquarie Energy's affiliates. *Id.* at 4.

4. Macquarie Energy's Second Answer

On December 13, 2024, Macquarie Energy filed a second Motion for Leave to Answer and Answer of Macquarie Energy LLC to Answer of Public Citizen (Macquarie 2nd Ans.). Macquarie Energy states that it provided all information as required by 10 C.F.R. §§ 205.302-303. Macquarie 2nd Ans. at 2. The Applicant asserts that Public Citizen continues to raise issues outside of the scope of DOE's filing requirements for an

electricity export application. *Id.* Macquarie Energy further argues that Public Citizen's assertions of market misconduct are irrelevant and that applicable laws and regulations do not require Macquarie Energy to describe ongoing regulatory or legal proceedings or to disclose to DOE whether it is a subject of a non-public investigation when applying for an export authorization. *Id.* at 3.

5. Granting of Motion to Intervene and Motions to Answer

On December 11, 2024, DOE granted Public Citizen's motion to intervene in this proceeding pursuant to FERC Rule 214, cited in DOE's notice of the Application and providing that a movant becomes a party if no opposition is filed. *See* 18 C.F.R. § 385.214(c). Macquarie Energy did not assert any arguments against Public Citizen participating in this proceeding as an intervenor. To clarify the issues brought forth and assist in DOE's evaluation, DOE further grants Macquarie Energy's Motion for Leave to Answer, Public Citizen's Motion to Answer, and Macquarie Energy's second Motion for Leave to Answer. *See* 18 C.F.R. § 385.213(a)(2) (providing decisional authority discretion to permit answers to protests and answers); *see also* 10 C.F.R § 205.304 (providing supplemental information may be collected from applicant).

II. DISCUSSION AND ANALYSIS

DOE is statutorily obligated under FPA § 202(e) to grant requests for export authorization unless the Department finds that the proposed export would negatively impact either: (i) the sufficiency of electric supply, or (ii) the coordination of the electric grid. Regarding the first exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would impair the sufficiency of electric supply within the United States …." 16 U.S.C. § 824a(e). DOE has interpreted this criterion to mean that sufficient generating capacity and electric energy must exist such that the export could be made without compromising the energy needs of the exporting region, including serving all load obligations in the region while maintaining appropriate reserve levels. *See, e.g.*, *BP Energy Co.*, Order No. EA-314, at 1-2 (Feb. 22, 2007), *renewed*, Order No. EA-314-A, at 2 (May 3, 2012), Order No. EA-314-B, at 2 (Feb. 28, 2017), *renewed,* Order No. EA-314-C, at 4 (Dec. 20, 2021).

Under the second exception criterion, DOE shall approve an electricity export application "unless, after opportunity for hearing, it finds that the proposed transmission would … impede or tend to impede the coordination in the public interest of facilities subject to the jurisdiction of [DOE]." 16 U.S.C. § 824a(e). DOE has interpreted this criterion primarily as an issue of the operational reliability of the domestic electric transmission system. Accordingly, the export must not compromise transmission system security and reliability. *See, e.g.*, Order No. EA-314-C, at 4.

A. Macquarie Energy's Application Complies with Applicable DOE Requirements Regarding Disclosing Corporate Affiliates

DOE's regulations at 10 C.F.R. §§ 205.302–303 outline the contents and exhibits required for electricity export applications. Public Citizen's filings do not point to any DOE requirement to submit information related to an applicant's corporate affiliates. Notwithstanding, related to corporate affiliates, DOE's regulations require applicants to disclose the "exact legal name of all partners" (10 C.F.R. § 205.302(b)) and any corporate relationships or existing contracts, which relate "to the control or fixing of rates for the purchase, sale or transmission of electric energy" (10 C.F.R. § 205.303(e)).

According to the Application, Macquarie Energy is not a partnership, but an "indirect, wholly-owned subsidiary of Macquarie Group Ltd." that operates as a limited liability corporation under the laws of Delaware. *See* App. at 1 & Exhibit B. Additionally, Macquarie Energy's Application states that the information required to be reported under 10 C.F.R. § 205.303(e) does not apply in its case. *See id.* at Exhibit E. According to the Application, Macquarie Energy has been authorized by FERC to engage in wholesale sales of electric energy, capacity, and ancillary services at market-based rates. *Id.* at 1. Macquarie Energy provided a copy of its market-based rate tariff under which it engages in wholesale electric power sales. *Id.* at n.3 & Attachment 1.

DOE notes that to receive market-based rate authority from FERC, sellers must demonstrate to FERC a lack of horizontal and vertical market power, which includes providing a description of the seller's ownership structure and identifying its affiliates. *See* 18 C.F.R. § 35.37; *see also* §§ 35.39 (placing restrictions on affiliate sales of electric energy), 35.42(a)(2) (requiring market-based rate sellers to report changes in affiliations). Evidence of market-based rate authority from FERC supports the Applicant's representation that it does not have any corporate relationships or contracts relating to the control or fixing of rates as described in 10 C.F.R. § 205.303(e).

Accordingly, DOE determines that Macquarie's Application complies with the applicable DOE requirements regarding disclosing corporate affiliates.

B. Public Citizen Has Not Provided Sufficient Evidence of Impacts to the Factors Analyzed under the FPA § 202(e) Standard of Review

As stated above, FPA § 202(e) directs DOE to issue export authorizations unless DOE finds that the proposed exports would negatively impact either the sufficiency of electric supply or the coordination of the electric grid. Public Citizen claims that Macquarie Energy has been accused of market manipulation and that "[m]arket manipulation interrupts the sufficiency of electric supply, and impedes the coordination of energy facilities in the public interest[.]" Public Citizen Ans. at 3-4. However, Public Citizen's filings fail to establish how and to what extent these factors are impacted,

presenting no additional evidence related to the applicable standard of review beyond its general assertion.

Further, according to Public Citizen's filings, the proceedings in which these market misconduct claims have been brought forth remain pending, and therefore the allegations have yet to be proven. DOE notes that such claims may be better suited for review and adjudication by the court in which they have been raised or by FERC in any investigation that has been initiated. Should these claims hold merit, the court or FERC would be equipped to provide any necessary remedies and oversight.

In sum, DOE determines that Public Citizen has not provided sufficient evidence to support that any alleged market manipulation would impact the sufficiency of electric supply or the coordination of the electric grid according to the standard of review under FPA § 202(e).

C. Macquarie Energy's Requested Authorization Will Not Impair the Sufficiency of Electric Supply in the United States

Sufficiency of supply, the first exception criterion, addresses whether regional electricity needs are met in the current market. DOE has analyzed this issue from both an economic and a reliability perspective. The economic perspective concerns the supply available to wholesale market participants. The reliability perspective focuses on preventing problems that could result from inadequate supplies. Taken together, DOE examines whether existing electric supply is available via market mechanisms, and whether potential reliability issues linked to supply problems are mitigated by reliability enforcement mechanisms.

From an economic perspective, DOE finds that the wholesale energy markets are sufficiently robust to make supplies available to exporters and other market participants serving United States regions along the Canadian and Mexican borders. Following enactment of the Energy Policy Act of 1992, Pub. L. No. 102-486, which encouraged the Federal Energy Regulatory Commission (FERC) to foster competition in the wholesale energy markets through open access to transmission facilities, energy markets developed across the United States to provide opportunities for a more efficient availability of supply. Subsequently, the Energy Policy Act of 2005, Pub. L. No. 109-58, reaffirmed the Government's commitment to competition in wholesale energy markets as national policy. FERC has continued to encourage the expansion of wholesale energy markets through its orders to remove barriers[1] and to ensure that these markets are functioning

[1] *See, e.g.*, *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009).

properly.[2] As a result, market participants have access to traditional bilateral contracts, as well as organized electricity markets run by regional transmission organizations (RTOs) or independent system operators (ISOs). FERC oversees these interstate wholesale electricity markets across most of the lower 48 states. Absent an indication in the record that the geographic markets relevant to this export authorization analysis are flawed and result in uneconomic exports that jeopardize regional supply, DOE finds that the proposed transmission for export does not impair the sufficiency of electric supply within the United States.

From a reliability perspective,[3] DOE focuses on the prevention of cascading outages and other problems that could result from inadequate resources.[4] Reliability oversight is addressed by the authority granted to FERC through the Energy Policy Act of 2005. That Act added section 215 to the FPA, which directed FERC to certify an electric reliability organization and develop procedures for establishing, approving, and enforcing mandatory electric reliability standards. 16 U.S.C. § 824o. FERC certified NERC in 2006 to develop and enforce reliability standards for the bulk-power system in the United States. *Order Certifying NERC as the Electric Reliability Organization and Ordering Compliance Filing*, FERC Docket No. RR06-1-000, 116 FERC ¶ 61,062 (July 20, 2006). FERC approves these standards, at which point they become mandatory and enforceable. NERC Reliability Standards address areas such as resource and demand balancing, critical infrastructure protection, communications, emergency preparedness and operations, facilities design, transmission operations, transmission planning, modelling, nuclear, personnel performance and training, protection and controls, voltage and reactive, interchange scheduling and coordination, and interconnection reliability operations and coordination.

NERC Reliability Standards are enforceable throughout the continental United States, most of Canada south of the 60th parallel, and the Mexican state of Baja California Norte. Through enforcement by FERC, NERC, and six Regional Entities overseen by NERC,[5] all bulk-power system owners, operators, and users are held responsible for complying with reliability standards. The reliability standards are structured so that many entities have overlapping responsibility for the electric grid, thereby resulting in several layers of reliability monitoring. Entities such as reliability coordinators and balancing authorities coordinate power generation and transmission

[2] *See, e.g.*, *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

[3] A related reliability analysis follows in the next section of this Order.

[4] This focus should not be confused with resource adequacy planning and capacity requirements that have traditionally been the domain of state regulatory commissions, NERC-certified Regional Entities, and RTOs/ISOs.

[5] The six entities are the Midwest Reliability Organization, Northeast Power Coordinating Council, Reliability *First* Corporation, SERC Reliability Corporation, Texas Reliability Entity, and Western Electricity Coordinating Council.

among multiple utilities to serve demand within an integrated regional wholesale market. One of the principal functions of these entities is to schedule adequate generating and reserve capacity. This allows them to serve demand at the regional level and to ensure that there is sufficient power supply to maintain system reliability. Reliability Standard IRO-001-4 "establish[es] the responsibility of Reliability Coordinators to act or direct other entities to act."[6] Requirement R1 states that "[e]ach Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions."[7] Reliability oversight is designed through coordinated efforts amongst Reliability Coordinators to preserve the benefits of interconnected operations and ensure that operations in one area will not adversely impact other areas.[8] Reliability Standard IRO-014-3 R1 provides that "[e]ach Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability."[9]

DOE finds that NERC's FERC-approved comprehensive enforcement mechanism ensures that bulk-power system owners, operators, and users have a strong incentive both to maintain system resources and to prevent reliability problems that could result from movement of electric supplies through export. As a result of this reliability oversight, DOE finds that the sufficiency of supply is not impaired by Macquarie Energy's proposed export authorization.

DOE's sufficiency of supply findings are further supported by the fact that power marketers, such as Macquarie Energy, do not have an obligation to serve a franchised territory. Before the current role of power marketers emerged in the industry, the FPA § 202(e) inquiry into sufficiency of supply had a narrower focus and was designed for an applicant that was a vertically integrated utility[10] with an obligation to serve native load. Under that traditional scenario, the inquiry regarding sufficiency of supply logically sought to confirm that exports would be surplus to the needs of a vertically-integrated utility's native load obligations and reserve margins. As explained in DOE's notice of the first application by a power marketer for export authorization, the sufficiency of supply inquiry became unnecessary when applied to power marketers:

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[6] Standard IRO-001-4 (Reliability Coordination – Responsibilities), at ¶ A.3.

[7] *Id.* ¶ B.R1.

[8] *See* Standard IRO-014-3 (Coordination Among Reliability Coordinators), at ¶ A.3.

[9] *Id.* ¶ B.R1.

[10] The Supreme Court of the United States has explained: "In 1935, when the FPA became law, most electricity was sold by vertically integrated utilities that had constructed their own power plants, transmission lines, and local delivery systems…[M]ost operated as separate, local monopolies subject to state or local regulation. Their sales were 'bundled,' meaning that consumers paid a single charge that included both the cost of the electric energy and the cost of its delivery. Competition among utilities was not prevalent." *New York v. FERC*, 535 US 1, 5 (2002).

> The Applicant also is required to demonstrate that it would have sufficient generating capacity to sustain the proposed export under the terms and conditions of its export agreement, while still complying with any established reserve criteria.
>
> Since marketers generally could not be seen as having any "native load" requirements, the latter criterion of maintaining sufficient reserve margins appears inappropriate and unnecessary in this instance.

59 Fed. Reg. 54900 (Nov. 2, 1994). Power marketers do not have franchised service areas and, consequently, do not have native load obligations like a traditional local distribution utility that could be impaired by exports.

In sum, market mechanisms and reliability oversight protect against the possibility that Macquarie Energy's exports would jeopardize domestic sufficiency of supply. Therefore, an export by Macquarie Energy would not trigger the first exception criterion of FPA § 202(e) regarding the sufficiency of electric supply within the United States.

D. Macquarie Energy's Requested Authorization Will Not Adversely Affect Either the Reliability or the Security of the United States Electric Transmission System

Reliability, the second exception criterion under FPA § 202(e), addresses operational reliability and security of the domestic electric transmission system. In evaluating the operational reliability impacts of export proposals, DOE has used a variety of methodologies and information, including established industry guidelines, operating procedures, and technical studies where available and appropriate. When determining these impacts, it is convenient to separate the export transaction into two parts: (i) moving the export from the source to a border system that owns the international transmission connection, and (ii) moving the export through that border system and across the border.

Moving Electricity to a Border System. Moving electricity for export to a border system necessarily involves the use of the bulk-power system. As noted in the preceding section, bulk-power system reliability concerns are addressed under the FPA by FERC and NERC and involve the enforcement of mandatory reliability standards. These standards ensure that all owners, operators, and users of the bulk-power system have an obligation to maintain system security and reliability. The standards are structured so that there are always entities with broader responsibilities than the applicant, such as reliability coordinators and balancing authorities, to keep a constant watch over the domestic transmission system.

To deliver the export from the source to a border system, the applicant must make the necessary commercial arrangements and obtain sufficient transmission capacity to wheel the exported energy to the border system. The applicant would be

expected to follow FERC orders regarding open transmission access and to schedule delivery of the export with the appropriate RTO, ISO, and/or balancing authority (formerly the control area operator).

It is the responsibility of the RTO, ISO, and/or balancing authority to schedule the delivery of the export consistent with established and mandatory operational reliability criteria. During each step of the process of obtaining transmission service, the owners and/or operators of the transmission facilities will evaluate the impact on the system and schedule the movement of the export *only* if it would not violate established operating reliability standards. As a failsafe, the reliability coordinator in each region has the authority and responsibility to curtail, cancel, or deny scheduled flows to avoid shortages or to restore necessary energy and capacity reserves. Reliability Standard EOP-011-1 R2 provides that "[e]ach Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area."[11]

Specifically, the reliability coordinator has the authority to suspend exports if the electric energy would be needed to support the regional power grid. *See* Reliability Standard IRO-001-4 R1 ("Each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions"), R2 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall comply with its Reliability Coordinator's Operating Instructions unless compliance with the Operating Instructions cannot be physically implemented or unless such actions would violate safety, equipment, regulatory, or statutory requirements"), and R3 ("Each Transmission Operator, Balancing Authority, Generator Operator, and Distribution Provider shall inform its Reliability Coordinator of its inability to perform the Operating Instruction issued by its Reliability Coordinator in Requirement R1").

DOE has determined that the existing industry procedures for obtaining transmission capacity on the domestic transmission system (described above) provide adequate assurance that any export will not cause an operational reliability problem. Therefore, Macquarie Energy's export authorization has been conditioned to ensure that the export will not cause operational issues on regional transmission systems to fall outside of established industry reliability criteria, or cause or exacerbate a transmission operating problem on the United States' electric power supply system (*see* Order below, Section VII, paragraphs C, D, and I).

Moving Electricity Through a Border System. The second part of DOE's reliability inquiry, addressing the transmission of the export through a border system and across the border, is a question of whether the border system is reliable and secure. To a large extent, this question is addressed by the jurisdiction of NERC. NERC and Regional Entities—including the Midwest Reliability Organization, the Northeast Power

[11] EOP-011-1 (Emergency Operations), at ¶ B.R2.

Coordinating Council, and the Western Electricity Coordinating Council—oversee the United States-Canadian border system and a significant part of the United States-Mexican border system. Those border systems are generally subject to the same reliability standards as domestic systems. *See, e.g.*, http://www.ieso.ca/sector-participants/system-reliability/reliability-standards-framework.

DOE also relies on the System Impact Studies submitted in conjunction with an application for a DOE-issued Presidential permit[12] to construct a new international transmission line. As DOE has previously reviewed System Impact Studies submitted with Presidential permit applications,[13] DOE does not need to perform additional impact assessments here, provided the maximum rate of transmission for all exports through a border system does not exceed the authorized limit of the system (*see* Order below, Section VII, paragraph (A)). In its Application, Macquarie Energy committed to complying with all reliability limits on border facilities. *See* App. at 3. The second part of the reliability inquiry is therefore satisfied by DOE regulatory oversight, in addition to NERC's reliability enforcement.

III. FINDINGS AND DECISION

A. Macquarie Energy Meets the Statutory Requirements to Export Electric Energy to Canada

As explained above, DOE has assessed the impact that the proposed export would have on the reliability of the United States electric power supply system. DOE has determined that the export of electric energy to Canada by Macquarie Energy, as ordered below, would not impair the sufficiency of electric power supply within the United States and would not impede or tend to impede the coordination in the public interest of facilities within the meaning of FPA § 202(e).

B. Macquarie Energy Qualifies for a NEPA Categorical Exclusion for Exports of Electric Energy

Macquarie Energy's Application qualifies for DOE's categorical exclusion for exports of electric energy under the National Environmental Policy Act of 1969, as amended (NEPA), 42 U.S.C. § 4321 *et seq*. DOE's regulations set forth this categorical exclusion, codified as "B4.2," as follows:

[12] DOE issues Presidential permits pursuant to Executive Order 10,485, as amended by Executive Order 12,038. *See* 10 C.F.R. §§ 205.320-205.329.

[13] *See, e.g.*, *AEP Tex. Cent. Co*., Order No. PP-317, at 2-3 (Jan. 22, 2007); *Mont. Alta. Tie Ltd.*, Order No. PP-305, at 2-4 (Nov. 17, 2008).

> Export of electric energy as provided by Section 202(e) of the Federal Power Act over existing transmission lines or using transmission system changes that are themselves categorically excluded.

10 C.F.R. Part 1021, App. B to Subpart D, § B4.2.

DOE has determined that actions in this category do not individually or cumulatively have a significant effect on the human environment and that, therefore, neither an environmental assessment nor an environmental impact statement normally is required. 10 C.F.R. § 1021.410(a). Further, in 2011, DOE formally reviewed its NEPA regulations and categorical exclusions and determined that it was appropriate to retain the B4.2 categorical exclusion. *See* National Environmental Policy Act Implementing Procedures, 76 Fed. Reg. 214, 217 (Jan. 3, 2011); National Environmental Policy Act Implementing Procedures, 76 Fed. Reg. 9981, 9982 (Feb. 23, 2011).

To invoke this categorical exclusion, DOE must determine that, in relevant part, "[t]here are no extraordinary circumstances related to the proposal that may affect the significance of the environmental effects of the proposal," and that "[t]he proposal has not been segmented to meet the definition of a categorical exclusion." 10 C.F.R. § 1021.410(b)(2), (3). "Extraordinary circumstances" include "unique situations" such as "scientific controversy about the environmental effects of the proposal." *Id.* § 1021.410(b)(2). DOE finds that Macquarie Energy's Application does not present such a circumstance, nor has it been segmented for purposes of this exclusion. Macquarie Energy seeks to deliver electricity over existing international electric transmission facilities, which fits squarely within the B4.2 categorical exclusion. For these reasons, DOE will not require more detailed NEPA review in connection with this Application. *See*, *e.g.*, *id.* §§ 1021.400(a)(1), 1021.410; 40 C.F.R. § 1501.4(a).

C. Conclusion

DOE grants Macquarie Energy's requested authorization for a five (5) year term. Macquarie Energy is authorized to export electricity to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties, subject to the limitations and conditions described in this Order.

IV. DATA COLLECTION AND REPORTING REQUIREMENTS

The responsibility for the data collection and reporting under orders authorizing electricity exports to a foreign country currently rests with the U.S. Energy Information Administration (EIA) within DOE. The Applicant is instructed to follow EIA instructions in completing this data exchange. Questions regarding the data collection and reporting requirements can be directed to EIA by email at EIA4USA@eia.gov or by phone at 1-855-342-4872.

Additionally, any change to the tariff of an entity with an export authorization must be provided to DOE's Grid Deployment Office via email at *electricity.exports@hq.doe.gov*. 10 C.F.R. § 205.308(b).

V. COMPLIANCE

Obtaining a valid order from DOE authorizing the export of electricity under FPA § 202(e) is a necessary condition before engaging in the export. Failure to obtain such an order or continuing to export after the expiration of such an order may result in a denial of authorization to export in the future and subject the exporter to sanctions and penalties under the FPA. DOE expects transmitting utilities owning border facilities and entities charged with the operational control of those border facilities, such as ISOs, RTOs, or balancing authorities, to verify that companies seeking to schedule an electricity export have the requisite authority from DOE to export such energy.

DOE expects Macquarie Energy to abide by the terms and conditions established for its authority to export electric energy to Canada, as set forth below. DOE intends to monitor Macquarie Energy's compliance with these terms and conditions, including the requirement in paragraph G of this Order that Macquarie Energy create and preserve full and complete records and file reports with EIA as discussed above.

A violation of any of these terms and conditions, including the failure to submit timely and accurate reports, may result in the loss of authority to export electricity and subject Macquarie Energy to any applicable sanctions and penalties under the FPA.

VI. OPEN ACCESS POLICY

An export authorization issued under FPA § 202(e) does not impose a requirement on transmitting utilities to provide service. However, DOE expects transmitting utilities that own border facilities to provide open access transmission service across the border in accordance with the principles of comparable open access and non-discrimination contained in the FPA and articulated in FERC Order No. 888 (Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, FERC Statutes and Regulations ¶ 31,036 (1996)), as amended. The actual rates, terms, and conditions of transmission service should be consistent with the non-discrimination principles of the FPA and the transmitting utility's Open-Access Transmission Tariff on file with FERC.

All recipients of export authorizations, including owners of border facilities for which Presidential permits have been issued, are required by their export authorization to conduct operations in accordance with the applicable principles of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended. Cross-border electric trade ought to be subject to the same principles of comparable open access and non-discrimination that apply to transmission in interstate commerce. *See Enron Power Mktg., Inc. v. El Paso Elec. Co.*, 77 FERC ¶ 61,013 (1996), *reh'g denied*, 83 FERC ¶ 61,213 (1998). Thus, DOE expects owners of border facilities to comply with the same principles of comparable open access and non-discrimination that apply to the domestic, interstate transmission of electricity.

VII. ORDER

Accordingly, pursuant to FPA § 202(e) and the Rules and Regulations issued thereunder (10 C.F.R. §§ 205.300-309), it is hereby ordered that Macquarie Energy is authorized to export electric energy to Canada under the following terms and conditions:

(A) The electric energy exported by Macquarie Energy pursuant to this Order may be delivered to Canada over any authorized international transmission facility that is appropriate for open access transmission by third parties in accordance with the export limits authorized by DOE.

(1) The following international transmission facilities located at the United States border with Canada are currently authorized by Presidential permit and available for open access transmission:[14, 15]

Owner	**Location**	**Voltage**	**Permit No.**[16]
Bangor Hydro-Electric Company	Baileyville, ME	345 kV	PP-89
Basin Electric Power Cooperative	Tioga, ND	230 kV	PP-64
Bonneville Power Administration (BPA)	Blaine, WA	2x 500 kV	PP-10
	Nelway, WA	230 kV	PP-36
	Nelway, WA	230 kV	PP-46
CHPE, LLC	Champlain, NY	±230 kV DC	PP-481
Eastern Maine Electric Cooperative	Calais, ME	69 kV	PP-32
International Transmission	Detroit, MI	230 kV	PP-230

[14] This Order authorizes the export of electricity over any "authorized international transmission facility," which is intended to include both large transmission lines and smaller distribution lines that have received a Presidential permit. However, the list in subparagraph (A)(1) of current facilities only includes transmission lines.

[15] The Applicant submitted a list identifying currently authorized transmission facilities (Exhibit C of the Application). However, as information about some of those facilities may have changed since the Application was submitted, the table of transmission facilities in this Order may differ from the Applicant's submission to reflect those changes.

[16] These Presidential permit numbers refer to the generic DOE permit number and are intended to include any subsequent amendments to the permit authorizing the facility.

Company	Marysville, MI	230 kV	PP-230
	St. Claire, MI	230 kV	PP-230
	St. Claire, MI	345 kV	PP-230
ITC Lake Erie Connector	Erie County, PA	320 kV	PP-412[17]
Long Sault, Inc.	Massena, NY	2x 115 kV	PP-24
Maine Electric Power Company	Houlton, ME	345 kV	PP-43
Minnesota Power, Inc.	International Falls, MN	115 kV	PP-78
Minnesota Power, Inc.	Roseau County, MN	500 kV	PP-398
Minnkota Power Cooperative	Roseau County, MN	230 kV	PP-61
Montana Alberta Tie Ltd.	Cut Bank, MT	230 kV	PP-399
NECEC Transmission LLC	Beattie Twp, ME	±320 kV	PP-438[18]
New York Power Authority	Massena, NY	765 kV	PP-56
	Massena, NY	2x 230 kV	PP-25
	Niagara Falls, NY	2x 345 kV	PP-74
	Devils Hole, NY	230 kV	PP-30
Niagara Mohawk Power Corp.	Devils Hole, NY	230 kV	PP-190
Northern States Power Company	Red River, ND	230 kV	PP-45
	Roseau County, MN	500 kV	PP-63
	Rugby, ND	230 kV	PP-231
Sea Breeze Olympic Converter LP	Port Angeles, WA	±450 kV DC	PP-299[19]
TDI New England	Alburgh, VT	±320 kV DC	PP-400[20]

[17] These transmission facilities have been authorized but not yet constructed or placed into operation.

[18] These transmission facilities have been authorized but not yet constructed or placed into operation.

[19] These transmission facilities have been authorized but not yet constructed or placed into operation.

[20] These transmission facilities have been authorized but not yet constructed or placed into operation.

Vermont Electric Power Co.	Derby Line, VT	120 kV	PP-66
Vermont Electric Transmission Co.	Norton, VT	±450 kV DC	PP-76
Vermont Transco LLC	Highgate, VT	120 kV	PP-82
Versant Power	Easton, ME	7.2 kV	PP-499
	Fort Fairfield, ME	69 kV	PP-497
	Madawaska, ME	138 kV	PP-498
	Baileyville, ME	345 kV	PP-500

(2) The following are the authorized export limits for the international transmission lines listed above in subparagraph (A)(1):

(a) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on facilities authorized by Presidential Permit PP-64 (issued to Basin Electric Power Coop.) to exceed an instantaneous transmission rate of 150 megawatts (MW). The gross amount of energy that Macquarie Energy may export over the PP-64 facilities shall not exceed 900,000 megawatt-hours (MWH) during any consecutive 12-month period.

(b) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-32 (issued to Eastern Maine Electric Coop.) to exceed an instantaneous transmission rate of 15 MW. The gross amount of energy that Macquarie Energy may export over the PP-32 facilities shall not exceed 7,500 MWH annually.

(c) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-481-2 (issued to CHPE, LLC) to exceed an instantaneous transmission rate of 1,250 MW.

(d) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-230 (issued to International Transmission Company) to exceed a coincident, instantaneous transmission rate of 2.2 billion volt-amperes (2,200 MVA).

(e) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-412 (issued to ITC Lake Erie Connector) to exceed an instantaneous transmission rate of 1,000 MW.

(f) Exports by Macquarie Energy made pursuant to this Order shall not cause the scheduled rate of transmission over a combination of facilities authorized by Presidential Permits PP-43 (issued to Versant) and PP-89-2 (issued to Bangor Hydro-Electric) to exceed 550 MW.

(g) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on the combination of facilities authorized by Presidential Permits Presidential Permits PP-497 and PP-498 (issued to Versant Power) to exceed a coincident, instantaneous transmission rate of 97.8 MW.

(h) Exports by Macquarie Energy made pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-78-1 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 100 MW. Exports by Macquarie Energy may cause total exports on the PP-78-1 facilities to exceed 100 MW only when total exports between the Mid-Continent Area Power Pool (MAPP) and Manitoba Hydro are below maximum transfer limits and/or whenever operating conditions within the MAPP system permit exports on the PP-78-1 facilities above the 100-MW level without violating established MAPP reliability criteria. However, under no circumstances shall exports by Macquarie Energy cause the total exports on the PP-78-1 facilities to exceed 150 MW.

(i) Exports made by Macquarie Energy pursuant to this Order shall not cause total exports on the facilities authorized by Presidential Permit PP-398 (issued to Minnesota Power, Inc.) to exceed an instantaneous transmission rate of 750 MW.

(j) Exports by Macquarie Energy made pursuant to this Order shall not cause total exports on a combination of the international transmission lines authorized by Presidential Permits PP-45 and PP-63 (issued to Northern States Power Company), PP-61 (issued to Minnkota Power), and PP-231 (issued to Northern States Power Company, d/b/a Excel Energy Inc.(Xcel)), to exceed an instantaneous transmission rate of 700 MW on a firm basis and 1,050 MW on a non-firm basis.

(k) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit PP-66 (issued to Vermont Electric Power Co.) to exceed an instantaneous transmission rate of 50 MW. The gross amount of energy that Macquarie Energy may export over the PP-66 facilities shall not exceed 50,000 MWH annually.

(l) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on the facilities authorized by Presidential Permit

PP-56 (issued to NYPA) to exceed an instantaneous transmission rate of 1,000 MW.

(m) Exports by Macquarie Energy made pursuant to this Order shall not cause: (a) the total exports on the facilities authorized by Presidential Permits PP-25, PP-30, PP-74 (issued to NYPA), and PP-190 (issued to Niagara Mohawk Power Corp.) to exceed a combined instantaneous transmission rate of 1,650 MW; and (b) the total exports on the 115-kV facilities authorized by Presidential Permit PP-24 (issued to Long Sault, Inc.) to exceed an instantaneous transmission rate of 100 MW. In addition, the gross amount of energy that Macquarie Energy may export over the PP-24 facilities shall not exceed 300,000 MWH annually.

(n) Exports by Macquarie Energy made pursuant to this Order shall not cause total exports on the two 500-kV lines authorized by Presidential Permit PP-10, the 230-kV line authorized by Presidential Permit PP-36, and the 230-kV line authorized by Presidential Permit PP-46 (issued to BPA) to exceed the following limits:

Condition	PP-36 & PP-46 Limit	PP-10 Limit	Total Export Limit
All lines in service	400 MW	1500 MW	1900 MW
1-500 kV line out	400 MW	300 MW	700 MW
2-500 kV lines out	400 MW	0 MW	400 MW
1-230 kV line out	400 MW	1500 MW	1900 MW
2-230 kV line out	0 MW	1500 MW	1500 MW

(o) Exports by Macquarie Energy made pursuant to this Order shall not cause a violation of the following conditions as they apply to exports over the facilities authorized by Presidential Permit PP-76-1, as amended (issued to the Vermont Electric Transmission Company):

NEPOOL

Exports Through	Load Condition	Export Limit
Comerford converter	Summer, Heavy	650 MW
Comerford converter	Winter, Heavy	660 MW
Comerford converter	Summer, Light	690 MW
Comerford converter	Winter, Light	690 MW
Comerford & Sandy Pond converters	All	2,000 MW

(p) Exports by Macquarie Energy made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-399 (issued to Montana Alberta Tie Ltd.) shall not exceed an instantaneous transmission rate of 300 MW.

(q) Exports by Macquarie Energy made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-438 (issued to NECEC Transmission LLC) shall not exceed an instantaneous transmission rate of 1,200 MW.

(r) Exports by Macquarie Energy made pursuant to this Order over the international transmission facilities authorized by Presidential Permit PP-299 (issued to Sea Breeze Olympic Converter LP) shall not exceed an instantaneous transmission rate of 550 MW.

(s) Exports by Macquarie Energy made pursuant to this Order shall not cause the total exports on a combination of the facilities authorized by Presidential Permit PP-400 (issued to TDI-New England) to exceed an instantaneous transmission rate of 1,000 MW.

(t) Exports by Macquarie Energy made pursuant to this Order shall neither cause the total exports on the facilities authorized by Presidential Permit PP-82-6 (issued to Vermont Transco LLC) to exceed an instantaneous transmission rate of 250 MW.

(B) Changes by DOE to the export limits in other orders shall result in a concomitant change to the export limits contained in subparagraph (A)(2) of this Order. Changes to the export limits contained in subparagraphs (A)(2)(l), (m), and (n) will be made by DOE after submission of appropriate information demonstrating a change in the transmission transfer capability between the electric systems in New York State and Ontario and New York State and Quebec, and between BPA and BC Hydro or BPA and West Kootenay Power. Notice of these changes will be provided to Macquarie Energy.

(C) Macquarie Energy shall obtain any and all other Federal and state regulatory approvals required to execute any power exports to Canada. The scheduling and delivery of electricity exports to Canada shall comply with all reliability criteria, standards, and guidelines of NERC, reliability coordinators, Regional Entities, RTOs, ISOs or balancing authorities, or their successors, as appropriate, on such terms as expressed therein, and as such criteria, standards, and guidelines may be amended from time to time.

(D) Exports made pursuant to this authorization shall be conducted in accordance with the applicable provisions of the FPA and any pertinent rules, regulations, directives, policy statements, and orders adopted or issued thereunder, including the comparable open access provisions of FERC Order No. 888, as amended.

(E) The authorization herein granted may be modified from time to time or terminated by further order of DOE. In no event shall such authorization to export over a particular transmission facility identified in subparagraphs (A)(1) and (2) extend beyond the date of termination of the Presidential permit or treaty authorizing such facility.

(F) This authorization shall be without prejudice to the authority of any state or state regulatory commission for the exercise of any lawful authority vested in such state or state regulatory commission.

(G) Macquarie Energy shall make and preserve full and complete records with respect to the electric energy transactions between the United States and Canada. Macquarie Energy shall collect and submit the data to EIA as required by and in accordance with the procedures of Form EIA-111, "Quarterly Electricity Imports and Exports Report," and all successor forms.

(H) In accordance with 10 C.F.R. § 205.305, this export authorization is not transferable or assignable, except in the event of involuntary transfer by operation of law. Provided written notice of the involuntary transfer is given to DOE within 30 days, this authorization shall remain in effect temporarily. The authorization shall terminate unless an application for a new export authorization has been received by DOE within 60 days of the involuntary transfer. Upon receipt by DOE of such an application, this existing authorization shall continue in effect pending a decision on the new application. In the event of a proposed voluntary transfer of this authority to export electricity, the transferee and the transferor shall file a joint application for a new export authorization, together with a statement of the reasons for the transfer.

(I) Nothing in this Order is intended to prevent the transmission system operator from being able to reduce or suspend the exports authorized herein, as necessary and appropriate, whenever a continuation of those exports would cause or exacerbate a transmission operating problem or would negatively impact the security or reliability of the transmission system.

(J) Macquarie Energy has a continuing obligation to give DOE written notification as soon as practicable of any prospective or actual changes of a substantive nature in the circumstances upon which this Order was based, including but not limited to changes in authorized entity contact information or NERC compliance registry status.

(K) This authorization shall be effective as of July 11, 2025 and shall remain in effect for a period of five (5) years from that date. Application for renewal of this authorization may be filed within six (6) months prior to its expiration. Failure to provide DOE with at least one hundred twenty (120) days to process a renewal application and provide adequate opportunity for public comment may result in a gap in Macquarie Energy's authority to export electricity.

Issued in Washington, DC on July 11, 2025.

Chris Wright

Chris Wright
Secretary of Energy
U.S. Department of Energy

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Transalta Centralia Generation LLC	)))))

Motion to Intervene, Motion for Clarification, and Requests for Rehearing and Stay of Sierra Club, NW Energy Coalition, Washington Conservation Action, Climate Solutions, Public Citizen, and Environmental Defense Fund (collectively, "Public Interest Organizations" or "PIOs")

Exhibit 2-75:
Bonneville Resource Plan (compiled 2022 & 2024)

BONNEVILLE POWER ADMINISTRATION

2022 Resource Program



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Section 1: Introduction

This report begins with a general overview, noting the purpose of the Bonneville Power Administrations' Resource Program, highlighting changes from previous assumptions and methodology, and summarizing key findings of the analyses. Following the overview is a more in-depth look at each component of the Resource Program, including the assumptions, methodologies and study results, along with a brief section on BPA's next steps culminating from the conclusions.

1.1 Overview

BPA launched its Resource Program shortly after passage of the Northwest Power Act in 1980 to assess the agency's need for power and reserves and to develop an acquisition strategy to meet those needs. The Resource Program study provides analysis and insight into long-term, least-cost power resource acquisition strategies. This study examines uncertainty in loads, water supply, resource availability and electricity market prices to develop a least-cost portfolio of resources that meet Bonneville's obligations.

The 2022 Resource Program covers the fiscal years 2024 – 2033 and includes updates made to the optimization process and refreshes inputs. This study also includes a high policy scenario that will help BPA understand how the resource solution results may be impacted by changes in key assumptions such as loads, candidate resource costs and market prices. The results yield a vision of the agency's needs and low-cost resource strategies across a range of future market conditions and policy environments.

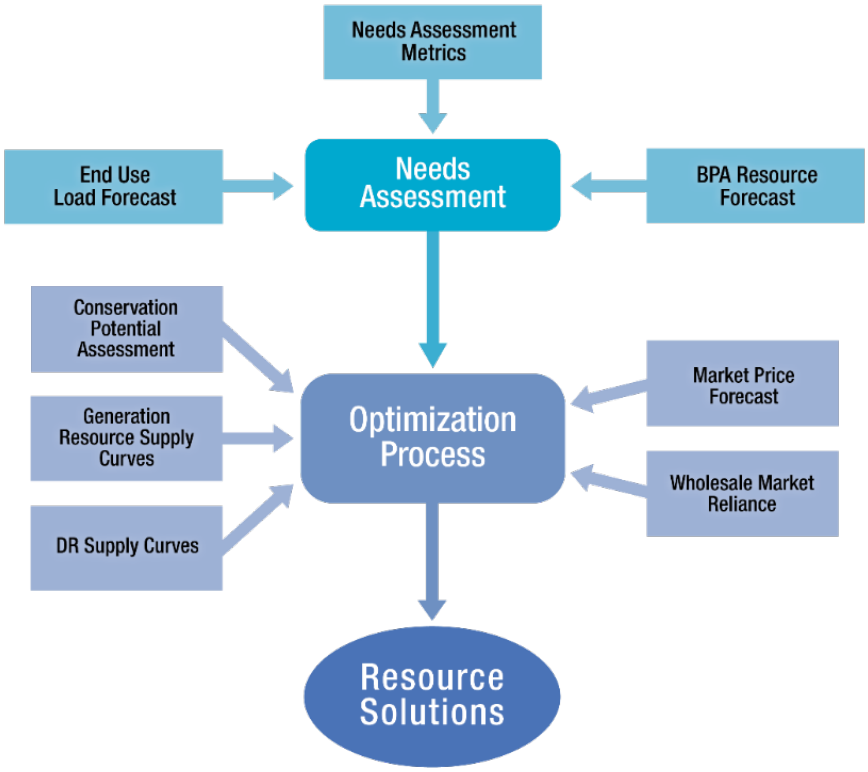
BPA's 2018-2023 Strategic Plan describes the actions it will take to remain a competitive supplier of low-cost power to its regional firm power customers. To support these strategic goals, the 2022 Resource Program details a comprehensive planning analysis that seeks to align BPA's resource acquisitions, including energy efficiency and demand response initiatives, with its long-term power supply needs.

The Resource Program is neither a decision document nor a process required by any external entity. Rather, it is a voluntary body of work, undertaken to inform acquisition strategies and provide valuable insight into how BPA can meet its obligations and strategic objectives at the least cost.

1.2 Methodology

The Resource Program begins with a forecast of BPA's obligations to supply firm power and the existing resources available to meet that demand, and then, determines any need for incremental energy or capacity in the Needs Assessment. The Resource Program next identifies and evaluates potential solutions to meeting those needs, including energy efficiency, demand response, candidate generating resources and power purchases. Finally, the Resource Program outlines potential strategies for meeting BPA's needs. Figure 1 provides a high-level diagram of the Resource Program process.

Figure 1: Resource Program Process



To assess the costs and benefits of resource solutions, BPA uses Aurora to create an electricity price forecast. Aurora is a computer software tool that can produce energy market price forecasts, value and uncertainty analyses, and automated system optimization. The energy market price forecast incorporates a natural gas price forecast, a renewables build forecast and assumptions around many other important factors, including regional generating resource retirements, negative price bidding activity and load forecasts for surrounding regions.

BPA also uses Aurora to perform a long-term capacity expansion and portfolio optimization analysis that assessed candidate resources' performances against 400 sets of potential future market conditions. The result of the optimization process is a set of 40 different portfolios that all meet Bonneville's needs at varying budget levels.

1.3 Conclusions

The below summarizes the main conclusions of the 2022 Resource Program:

- BPA has its greatest heavy load hour energy needs in October where large deficits are observed under low water conditions.
- By using a shorter historical period of streamflow record that represents the impacts of climate change on hydro generation, BPA expects more winter generation and less summer generation when compared to the use of a longer period of historical streamflows.
- BPA has surplus capacity in the winter and the summer, similar to the prior Resource Program.
- The expected market price for energy at the Mid-Columbia trading hub has increased over the market price forecast in the prior Resource Program.
- Similar to previous Resource Program findings, the least-cost mix of resources that will meet BPA's expected energy needs consists of conservation and energy purchased from the market. In addition, demand response was also included in the least-cost mix of resources for this Resource Program.

The following sections provide a more detailed look at the 2022 Resource Program. Additional files supporting the data sets shared in this report can be found at BPA's Resource Planning webpage.

Section 2: Needs Assessment

2.1 Overview

The Needs Assessment measures the federal system's[1] expected generating resource capabilities to meet projected load obligations under a range of conditions and timeframes for a 10-year study period, spanning fiscal years 2024-2033. The Needs Assessment studies occurred concurrently with a process to modernize the hydropower forecasts in the Bonneville Power Administration's long-term studies, as well as during a transition to using the 2020 modified streamflow data. BPA ultimately decided[2] to adopt the most recent 30 years of streamflow history, 1989-2018, in long-term forecasts rather than the historic 90-year record. BPA made this change in order to more realistically incorporate the impacts of climate change on federal system hydro generation.

As a result, the Needs Assessment reflects two streamflow sets: 1) the 2010 modified flows, which provide an 80-year period of record, hereafter "80-year study," and 2) the 2020 modified flows from which only 1989-2018 are used in the modeling, hereafter "30-year study." The 80-year study is included to help illustrate the change in energy and capacity positions due to climate impacts. However, the Resource Program analysis only carries the 30-year data forward into the optimization step of the process.

2.2 Methodology

The Needs Assessment incorporates hourly forecasts of federal system load obligations and resource capabilities.

Load obligations: BPA's Agency Load Forecasting system (ALF) produces load forecasts. ALF includes power sales contract obligations to public and federal agency customers and to the U.S. Bureau of Reclamation, as well as other contract obligations. ALF automatically includes projections of programmatic conservation savings expected to continue at levels established under current conservation programs. The Needs Assessment contains an ALF-produced frozen efficiency load forecast, which implements a combination of statistically adjusted end-use and econometric approaches. This means that historic energy efficiency achievement savings are projected forward in the load forecast, but the incremental conservation needed to meet the Northwest Power and Conservation Council's 2021 Northwest Power Plan targets are omitted from the load forecast.[3] ALF forecasting methodologies incorporate the most recent 15 years of regional temperatures, allowing the forecasts to incorporate the most recent climate trends. Also, the load forecast beyond the current Regional Dialogue contracts (post 2028) assumes no material contract election or rate structure differences from Regional Dialogue. ALF forecasts do not project additional temperature changes in the planning period.

Resources: BPA forecasts the resource capability using two computer models: 1) HYDSIM (Hydro System Simulator) for monthly and annual energy; and 2) Riverware for hourly energy and capacity. The models assess the resource capability to meet loads under expected load conditions and extreme temperature events over a range of possible water conditions and while meeting non-power requirements. The 80-

[1] Details on the federal system's generating capacity can be found in BPA's 2022 White Book.
[2] https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/climate-change-update-to-the-long-term-hydro-generation-forecast-letter.pdf [Accessed: 29 Aug 2022]
[3] The incremental conservation needed to meet the 2021 Northwest Power Plan targets and used to mitigate the deficits identified in this Needs Assessment will be discussed in section 4.4 – Portfolio Optimization Results.

year HYDSIM study used in the Needs Assessment is consistent with BPA's BP-22 Rate Case Final Proposal with updated flexible spill operations. To incorporate the federal system contract purchases and non-hydro generation in the study, the Riverware model operates to an hourly Federal Residual Hydro Load. The Federal Residual Hydro Load is the hourly federal load obligations minus the hourly contract purchases and non-hydro generation.

This assessment does not model any internal or regional transmission[4] constraints that may limit the ability to deliver the modeled system generation to load.

2.3 Studies & Metrics

As mentioned in the overview, the Needs Assessment focuses on two studies developed for FY 2024 through FY 2033: 80-year and 30-year. Depending on the study, up to four metrics, including annual energy and different capacity studies, were used to determine the ability of the federal system's generating capability to meet obligations.

- 80-year: This study uses data that is consistent with the federal system analysis load forecast in the BP-22 Rate Case Final Proposal, with the exception of including a frozen efficiency forecast. The 80-year study uses the 2010 modified streamflow data set, 1929-2008, and uses the 1937 water year as the critical, or firm, water condition.
- 30-year: This study uses data that is consistent with the federal system analysis load forecast in the BP-22 Rate Case Final Proposal, with the exception of including a frozen efficiency forecast. The 30-year study uses streamflow data from the most recent 30 years, 1989-2018, of the 2020 modified streamflow records from 1929-2018, or 90 water years.

The Needs Assessment used the following four metrics:

1. Annual Energy: This metric focuses on federal system annual average energy surplus/deficits under 1937-critical, or firm, water conditions. Only the 80-year study was used for this metric as it contains the 1937 water year and was consistent with the prior definition of firm annual energy at the time studies were produced. Future needs assements will instead use the "P10-by-month" definition of firm, which was recently adopted (see footnote 2 above).
2. Monthly P10 Heavy Load Hour Energy: This metric evaluates the lowest 10th percentile-by-month, or P10, of federal system surplus/deficit over heavy load hours. HLH refers to hour ending 07 to 22, totaling 16 hours each day, Monday through Friday; the other eight hours each day, Saturday and Sunday, and North American Electric Reliability Corporation holidays are light load hours. Each month is analyzed independently.
3. Monthly P10 Super-Peak Energy: This metric evaluates the P10 of federal system surplus/deficits over the six peak load hours per weekday by month. Each month is analyzed independently.
4. 18-Hour Capacity: This metric analyzes the federal system's ability to meet the six peak load hours per day over a three-day extreme weather event. Depending on the weather event, load obligations are adjusted for additional heating or cooling loads, and median water conditions are assumed for hydro generation. Additionally, load obligations assume that Canada requests maximum Canadian Entitlement energy deliveries available under terms of the Columbia River Treaty. Generating resources assume that wind generation is zero. Similarly, generation forecasts for the summer analysis— month of August—includes a 10% reduction in the Columbia Generating Station's generating capability to account for heat impacts on the CGS's cooling system. The Needs Assesment uses 80 water years to analyze the distribution of outcomes under different streamflow conditions.

[4] For additional detail on transmission, see the Transmission supplement section of BPA's 2022 Resource Program.

2.4 Results

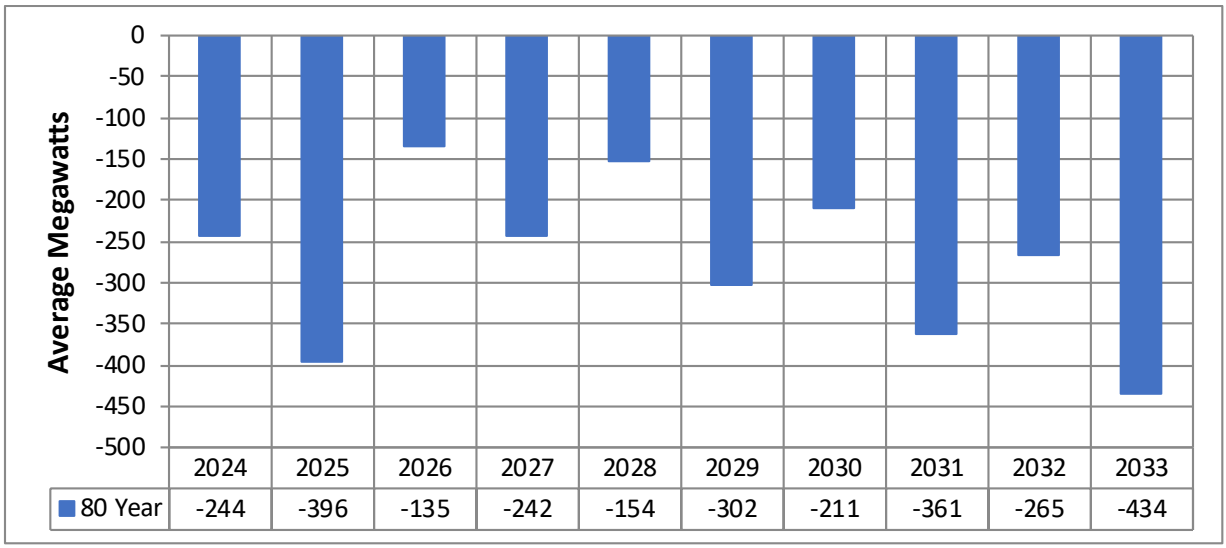
The Needs Assessment results show that the federal system has a wide range of potential deficits during the 10-year FY 2024-2033 period under the Annual Energy metric; see Figure 2. The Monthly P10 Heavy Load Hour metric shows larger deficits in October, January and the second half of April throughout the study period. The 30-year study shows less deficits in winter and more in August-October, consistent with trends of wetter, warmer winters and earlier streamflow recessions. Monthly P10 Super-Peak Energy metrics show deficits in the second half of April when low streamflows combine with significant increases in spill and restricted operating pools in the eight dams of the lower Columbia and Snake rivers; otherwise, the Super-Peak metric is surplus, and this result is consistent over the study period. Combined, the P10 HLH and Super-Peak metrics show that the system is generally able to serve the subset of six peak-load hours throughout the year under the low streamflow conditions, but the system is constrained for the full heavy load block in several months.

Lastly, the federal system is capacity surplus under the 18-Hour Capacity metric in both winter months (January) and summer months (August) when simulating increased loads due to extreme weather events. Previously, a single median water year was used to calculate this metric. Now, the full distribution of outcomes by water year is available. The distributions show that under the vast majority of water conditions, the system is able to serve the six peak-load hours each day during extreme weather over three consecutive days.

Annual Energy: The Annual Energy metric analyzes the ability of the federal system to meet energy loads on an annual basis.

80-year: Figure 2 shows a deficit of 244 average megawatts in FY 2024. The deficit grows to 396 aMW by FY 2025, recovers to 135 aMW in FY 2026, and then grows again to a deficit of 434 aMW by FY 2033. Hydro resources reflect the 2020 Columbia Rivers System Operations Environmental Impact Statement Preferred Alternative for the largest 14 federal dams. The difference between even and odd years is attributed to the Columbia Generating Station maintenance/refueling outage schedule. The decrease in deficit between FY 2025 to FY 2026 is due to the expiration of forward secondary surplus marketing activity that reduces obligations.

Figure 2: Annual Energy Surplus/Deficits – FY 2024 to FY 2033



Monthly P10 Heavy Load Hour Energy: Figure 3 presents the Monthly P10 HLH Energy metric for the 10-year study, and Figure 4 presents a selection of FY 2025-2026 to show the values in more detail. The metric analyzes the ability of the federal system to meet HLH loads on a monthly basis.

80-year: HLH energy deficits occur in the winter months as well as late summer; the largest deficit is in the second half of April. This result is consistent over the entire study period. Large monthly HLH energy surpluses occur in the spring, which coincide with the peak Columbia River Basin runoff.

30-year: The 30-year study presents similar results to the 80-year study, with deficits in April and over the winter months. March in the 30-year period changed to a surplus month, and the surplus in June decreased, consistent with earlier spring runoff. The 30-year study is also showing deeper deficits in the summer and fall consistent with earlier streamflow recessions.

Figure 3: P10 HLH Surplus/Deficits – FY 2024 to FY 2033

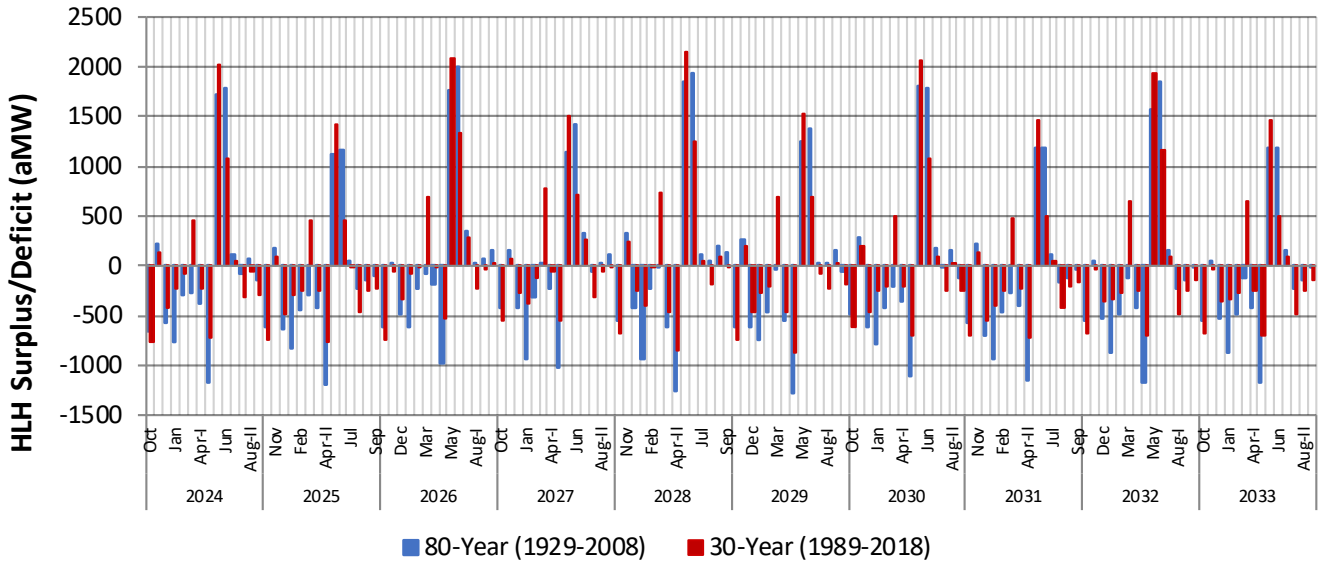
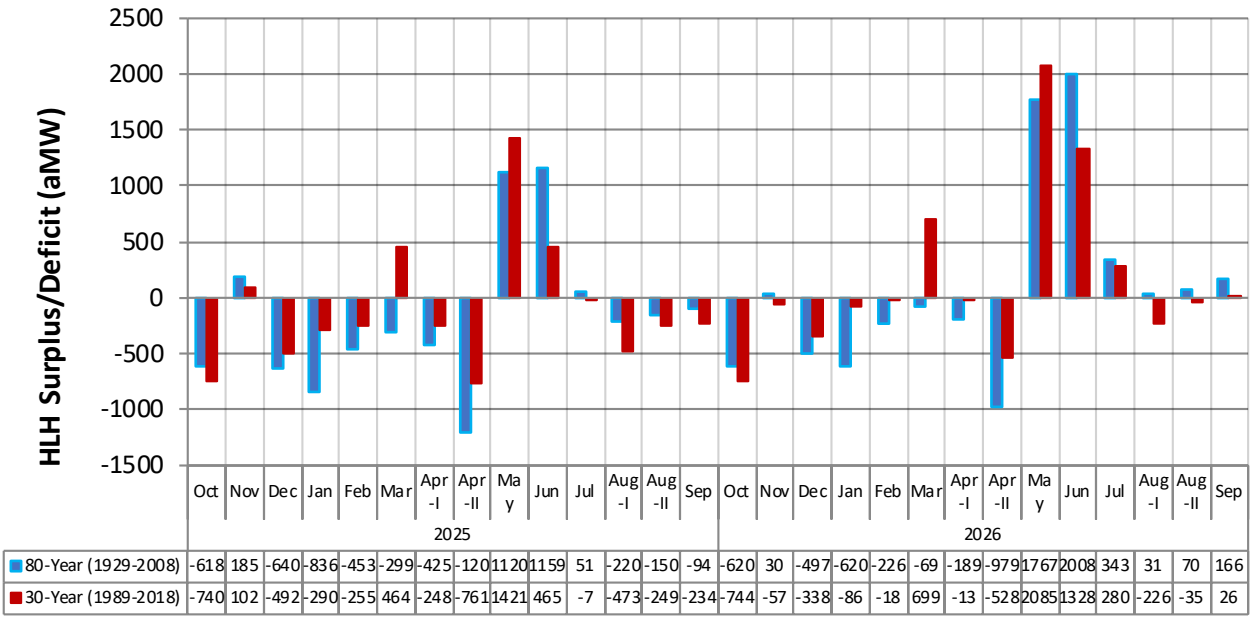


Figure 4: P10 HLH Surplus/Deficits – FY 2025 to FY 2026 (close-up look)



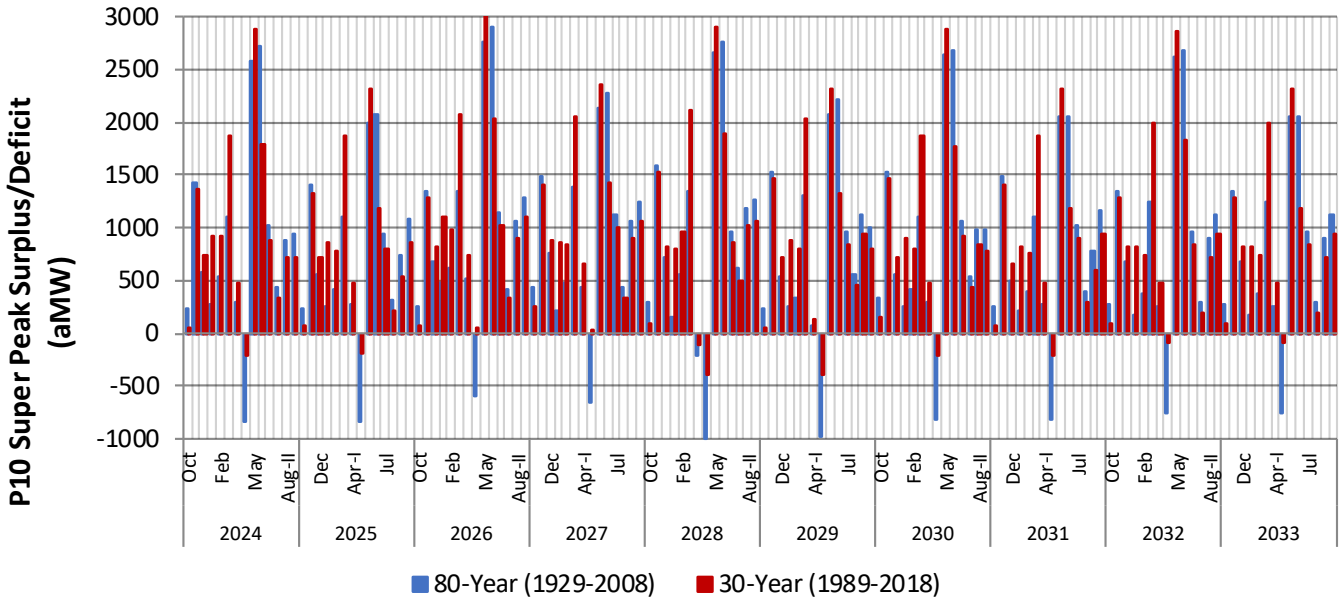
	Oct	Nov	Dec	Jan	Feb	Mar	Apr -I	Apr -II	May	Jun	Jul	Aug -I	Aug -II	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr -I	Apr -II	May	Jun	Jul	Aug -I	Aug -II	Sep
80-Year (1929-2008)	-618	185	-640	-836	-453	-299	-425	-120	1120	1159	51	-220	-150	-94	-620	30	-497	-620	-226	-69	-189	-979	1767	2008	343	31	70	166
30-Year (1989-2018)	-740	102	-492	-290	-255	464	-248	-761	1421	465	-7	-473	-249	-234	-744	-57	-338	-86	-18	699	-13	-528	2085	1328	280	-226	-35	26

Annual P10 Super-Peak Energy: Figure 5 shows the Monthly P10 Super-Peak Energy metric, which evaluates the ability of the federal system to meet loads over the six peak-load hours per weekday by month.

80-year: P10 Super-Peak resulted in annual surplus throughout the study period. Monthly analysis shows deficits in April.

30-year: The 30-year study reflects the same finding as the 80-year study, except the April deficit is smaller. The Super-Peak shows similar changes in results as the P10 HLH metric: surplus increases in winter, relative to the 80-year study, and decreases in the summer.

Figure 5: P10 Super Peak Surplus/Deficits – FY 2024 to FY 2033

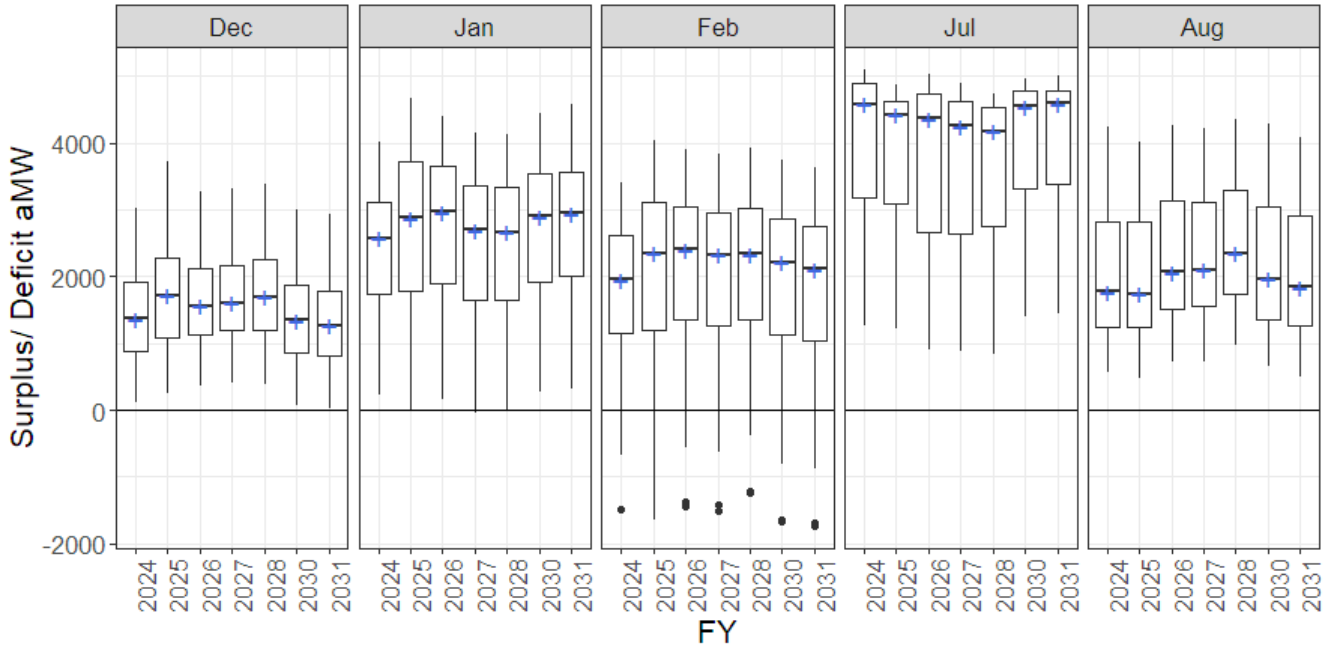


18-Hour Capacity: The 18-Hour Capacity metric analyzes the ability of the federal system to meet loads over the six peak-load hours per day during a three-day extreme weather event – a heat event during summer and cold event during winter – under median water conditions. Only the 80-year study was analyzed under this metric. The months of December, January and February were analyzed for winter seasons; the months of July and August were analyzed for summer seasons. In this Needs Assessment, the extreme weather condition can be viewed for all 80 years, instead of for only a specific year.

Figure 6 presents the distribution of results as boxplots with each end of the box representing the first quartile, or 25%, and third quartile, or 75%, of the data distribution; the middle bar with a blue (+) marks the median, or 50th percentile. The 50th percentile is used to represent the median water conditions for each month. The ends of the whiskers indicate the maximum and minimum data points, and the dark dots outside of the whisker ends are observations outside 1.5x the interquartile range from the bottom of the box, which are the outlier points.

80-year: Results show 18-Hour Capacity surplus/deficits for the winter (January) and summer (August) during the FY 2024-2033 period; however, there is no data for years 2029 and 2032 as unresolvable data issues were discovered. The 18-Hour capacity results show a range of surpluses between approximately 2,500 MW to almost 3,000 MW in the winter, and a range of roughly 1,700 MW to 2,300 MW in the summer over the study period.

Figure 6: Distributions of 18-Hour Capacity Surplus/Deficits



2.5 Conclusions

The current Needs Assessment shows that BPA would need to supplement existing federal system generation in order to meet existing and projected load obligations during the conditions modeled. With expected load growth, the federal system is projected to have annual energy deficits under critical water conditions across the study period.

Under low-water conditions, the federal system is projected to have HLH energy deficits, most notably in the winter and late summer, and to have surpluses under the Super-Peak and the 18-Hour Capacity metrics. The 18-Hour Capacity metric does not show constraints for either winter or summer seasons. Of the energy and capacity metrics analyzed, HLH energy is projected to have the largest deficits, and therefore, is the most constraining metric.

Under current climate change expectations, the federal system is projected to have lower HLH energy deficits or higher energy surpluses during the winter period. This is due to higher winter streamflows resulting from the warmer temperatures. Conversely, the federal system is projected to have higher HLH energy deficits in the summer due to lower summer streamflows.

Overall, the Needs Assessment results are consistent with that of the 2019 Needs Assessment results with respect to the P10 HLH metric deficits representing the most constrained periods and conditions for BPA to meet its obligations. BPA will continue to assess the need for additional generation based upon potential changes to environmental obligations, participation in the Western Resource Adequacy Program, and the loads placed upon BPA through the Provider of Choice process. Changes to the Needs Assessment in future Resource Programs will include an updated annual energy metric, which will be based on monthly P10 hydropower and potentially include enhancements to how capacity is modeled.

Section 3: Candidate Resource Assessment

3.1 Candidate Generating Resources

The 2022 Resource Program includes an expanded array of zero-emission resources and updated resource costs to reflect developments in renewable generation technologies after the publication of the 2020 Resource Program.

Resources are selected for the optimization based on technical availability within the region and over the study horizon; they are not pre-screened based on relative levelized costs of energy or capacity. The optimization process evaluates the value of expected generation and expected capital in addition to the operation costs of each resource.

The section below summarizes the resource plant types considered for the 2022 Resource Program.

- **Wind:** BPA modeled two types of wind resource, Columbia Basin onshore wind and Oregon coast offshore wind, using costs based on the U.S. Energy Information Administration, or EIA, Annual Energy Outlook,[5] estimates from the National Renewable Energy Laboratory, or NREL, and wind cost forecasts provided by consultants. For Columbia Basin wind, BPA estimated wind output for the forecast period using its risk model designed for rate-setting evaluations in conjunction with Aurora.
- **Solar:** Single-axis tracking utility-scale solar resource costs likewise reflect a blend of EIA, NREL, and consultant cost forecasts and include the latest information on tax credits and tariffs. BPA chose three representative solar generation shapes – southeast Idaho, south-central Washington, and Oregon west of the Portland metropolitan area – to reflect different possible solar output profiles in the BPA region, differing installation costs in metropolitan areas, and a list of locations provided by BPA Transmission Services that may benefit BPA's transmission system.
- **Paired solar and storage:** BPA added three solar and storage resources to the set of available resources for the 2022 Resource Program. The representative generation shapes for these resources are the same as above and are paired with a four-hour battery storage system where capacity is equal to half of the solar nameplate capacity.
- **Standalone six-hour battery storage:** BPA added one standalone battery storage option, modeled as a six-hour lithium-Ion battery system.
- **Zero-emission firm flexible resources:** BPA modeled two zero-emission firm flexible resource options with availability starting in 2028 and later. These resources are not intended to represent a specific generation type, but rather, provide a plausible cost trajectory for several types of zero- or net-zero emissions resources.
    - Base: High-fixed cost, low-variable cost resource. Modeled after small modular nuclear reactor characteristics; also comparable to a traditional fossil fuel base resource with carbon capture and sequestration.
    - Peaker: Low-fixed cost, high-variable cost resource. Modeled after a hydrogen combustion turbine with onsite electrolysis and storage; also comparable to combustion turbine running on other bio/renewable fuels or traditional resources.

[5] https://www.eia.gov/outlooks/aeo/

3.2 Conservation Supply Curves

3.2.1 Overview

Prior to the 2018 Resource Program, BPA had included conservation as a fixed input. In the past, a share of the conservation target from the Northwest Power and Conservation Council's Power Plan was assumed to be achieved by its public power customers. That amount of conservation was included as a predetermined resource that would be applied to meet BPA's needs. The remaining needs would then be met with other potential resources after accounting for expected savings from conservation.

Since the 2018 Resource Program enhancements, BPA now assesses conservation in line with other available supply and demand-side resources. An available amount of conservation is input into the optimization model, which then compares and selects resources based on need, availability and cost. To determine the amount of conservation to be used in the optimization model, BPA relies on a conservation potential assessment (CPA). The CPA identifies the amount and costs of energy efficiency measures available from the forecasted customer loads supplied by BPA over the planning horizon. This ensures all potential conservation is included and evaluated against competing alternatives in the optimized selection process.[6] In preparation for the 2022 Resource Program, BPA contracted with Cadmus Group and Lighthouse Energy Consulting to conduct a CPA.

3.2.2 Adjusting for 2022 and 2023 Energy Efficiency Accomplishments

While the Resource Program's evaluation period begins with 2024, the load forecast developed by BPA for use in the Resource Program was developed in 2020 and does not incorporate future energy efficiency savings achieved by BPA and its customer utilities in 2020-2023. To ensure that the Resource Program properly accounted for BPA's loads and resources, BPA's Energy Efficiency Organization supplied the Resource Program team with adjustments to account for the additional savings that would be achieved in these years. The adjustments were provided as "must take" resources—resources the Resource Program was forced to select, since they reflected energy efficiency that would be accomplished by 2024.

For the portion of 2020 not included in BPA's load forecast and all of 2021, the Cadmus/Lighthouse team mapped BPA's actual accomplishments to load profiles and developed hourly inputs for the Resource Program.

For 2022 and 2023, the CPA potential was not provided to the Resource Program. In its place, the Cadmus/Lighthouse team provided hourly estimates based on BPA's overall expected level of savings mapped to different distributions of savings. Forecasts developed by BPA projected 37.85 average megawatts per year of energy efficiency. The Cadmus/Lighthouse team used the distribution of BPA programmatic achievements in 2021 to estimate the distribution of savings in 2022 and the distribution of CPA potential in 2024 below a levelized cost of $45 per megawatt hour for 2023.

Incorporating these adjustments developed a more accurate forecast for the potential conservation savings starting in 2024, the beginning of the 2022 Resource Program's evaluation period.

[6]The full CPA, including methodological discussion, is available on BPA's website: BPA-Conservation-Potential-Assessment-2022-2043.pdf

3.3 Demand Response Supply Curves

Since the 2018 Resource Program, BPA also assesses demand response equivalent to other available supply and demand-side resources. As with conservation, available amounts of demand response are input into the optimization model, which then compares and selects resources based on need, availability and cost. To determine the amount of demand response to be used in the optimization model, BPA relies on a demand response potential assessment (DRPA). The DRPA ensures all potential demand response is included and evaluated against competing alternatives in the optimized selection process.

In preparation for the 2022 Resource Program, BPA contracted with Cadmus Group and Lighthouse Energy Consulting to conduct a DRPA. The assessment identified 19 DR products with distinct cost and seasonal profiles. The full potential assessment, including methodological discussion, is available on BPA's website[7].

3.4 Wholesale Energy Market

3.4.1 Wholesale Market Price Forecast

Bonneville used Aurora with the Western Interconnection, a zonal topology, to generate a 10-year forecast of Mid-Columbia prices. This forecast consists of a distribution of 400 risk-informed hourly forecasts sampled two weeks per month.[8] Each of the 400 forecasts is based on a unique water year sequence, natural gas price forecast, Western Electricity Coordinating Council-wide load forecast, hourly wind generation pattern, Columbia Generating Station outages schedule and hourly transmission path rating, as applied to the alternating current, direct current and British Columbia-United States interties. The price at a given energy hub is determined by the cost of delivering an incremental megawatt of energy to load, including transmission costs and energy losses, provided by the least-cost available resource.

The WECC load forecast is consistent with BPA's 2020 baseline projection, except for California, which has been updated to be consistent with California Energy Commission's 2019 Integrated Energy Policy Report's Mid Demand-Mid Available and Achievable Load Forecasts.[9]

Natural gas prices are typically a significant determinant of electricity prices because gas generators tend to be the marginal unit, or the least-cost generator available to supply an incremental unit of energy, and the price of natural gas is the predominant factor affecting the dispatch, or production, cost of natural gas-fired generators. Relative to the 2020 Resource Program, there were modest declines in projected natural gas prices over the forecast horizon. The declines are a result of the expectation for plentiful production of low-cost associated gas produced by oil-focused extraction activity.

Several processes inform BPA's forecast of WECC-wide resource retirements and builds used in the price forecast and market depth studies. First, data from the EIA's database of planned and sited resource additions and retirements over the horizon of the BP-22 rate period were referenced against additional data from sources such as BPA's Transmission Interconnection Queue, WECC's Transmission Expansion

[7] https://www.bpa.gov/-/media/Aep/energy-efficiency/demand-response/bpa-demand-response-potential-assessment-2022-2043.pdf

[8] For more information about Aurora and the risk models employed to produce this forecast, see the Power Market Price Study and Documentation, BP-22-FS-Bonneville-04.

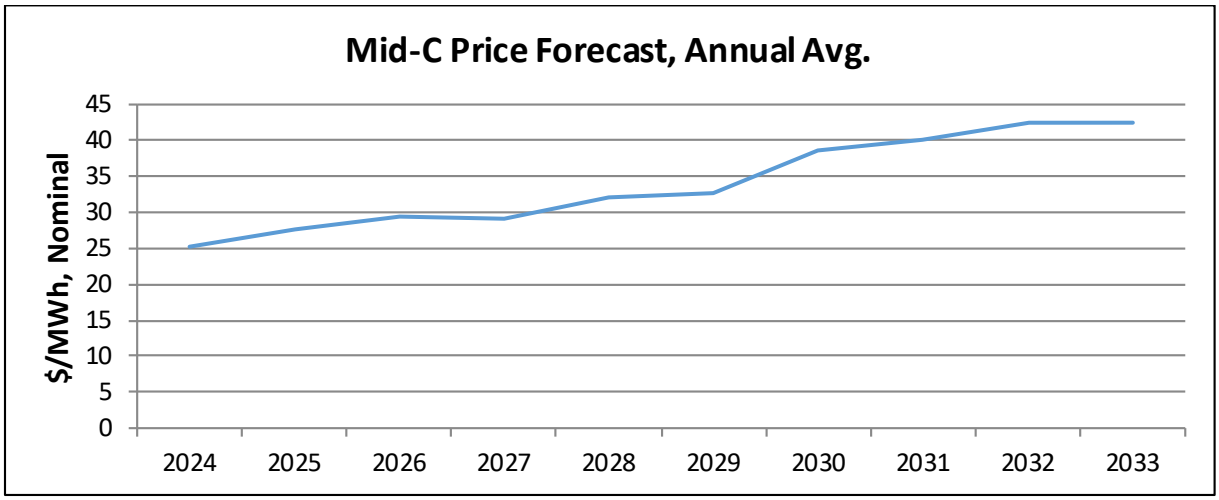
[9] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03, accessed Mar 2, 2021.

Planning Policy Committee, the California Energy Commission, the California Public Utilities Commission, and third-party consultant reports to update the default Aurora resource stack. Additionally, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California were included from the California Energy Commission forecast and from integrated resource plans of utilities in the Southwest. Finally, the Aurora long-term capacity expansion model was used to build and retire additional resources based on economics to satisfy pool planning reserve margins and meet all relevant state, municipal and utility policies, including renewable portfolio standards, zero emission targets and electric sector emission caps.[10]

BPA's Aurora price forecast also adds two adjustments to resource bidding behavior that have substantial impacts on the resulting distributions of price forecasts. First, BPA runs Aurora using a recent historical period, i.e., 2014-2019, and calibrates thermal resource bidding behavior to better align Aurora prices with actual, day-ahead hub prices during the period. Second, BPA includes a simplistic depiction of negative bid behavior for renewable resources driven, for instance, by federal production tax credits for wind resources, renewable energy credits and power purchase agreements. All WECC renewable resources are given bid adjustments of about -$23 per megawatt-hour, which is nominal. These assumptions and additional modeling enhancements, such as the use of Aurora's commitment optimization logic, resulted in a distribution of price forecasts that is higher than the price distribution used in the previous Resource Program. The main driver for higher prices is the combination of a tighter resource buildout, where reliability requirements are just barely met, and the addition of calibrated thermal resource bidding behavior. Price increases are most acute in summer and winter months and in iterations with low hydro conditions.

The following figures depict the Mid-C price forecasts. Figure 7 shows an annual average price for all hours by year. Figure 8 presents average monthly prices for all hours by each month for the years 2024, 2028 and 2032. Figure 9 depicts prices averaged by hour for the years 2024, 2028 and 2032. Figure 10 is a comparison between the Mid-C price forecasts for the 2020 and 2022 Resource Programs for heavy load hours (HLH) and light load hours (LLH).

Figure 7



[10] State policy requirements within the WECC enacted as of July 1, 2021. Additional clean energy goals and policies at the municipal and utility level are included, but have been discounted by 20% to represent uncertainty about the extent to which these commitments will be upheld over the forecast horizon.

Figure 8

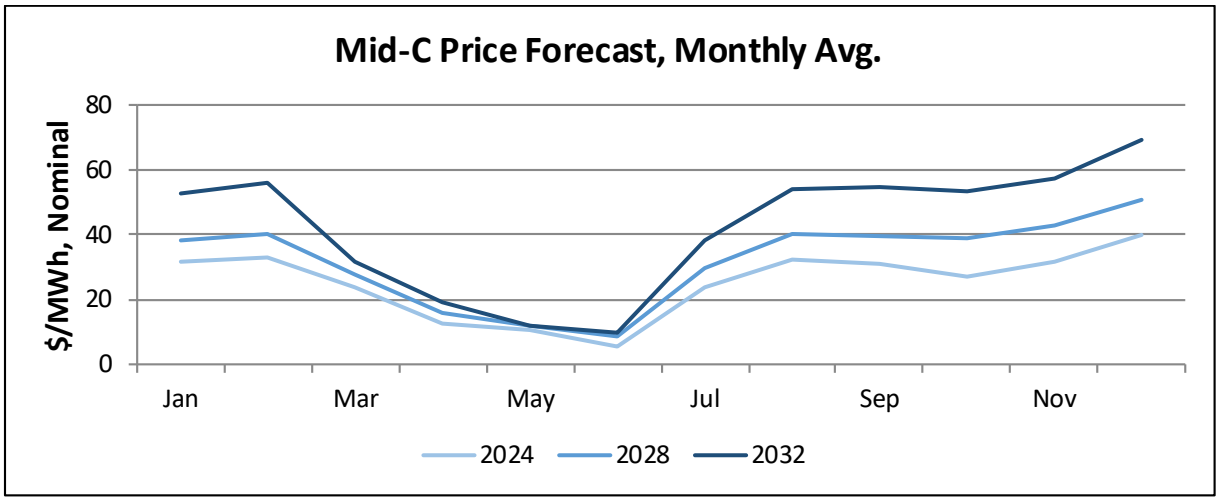


Figure 9

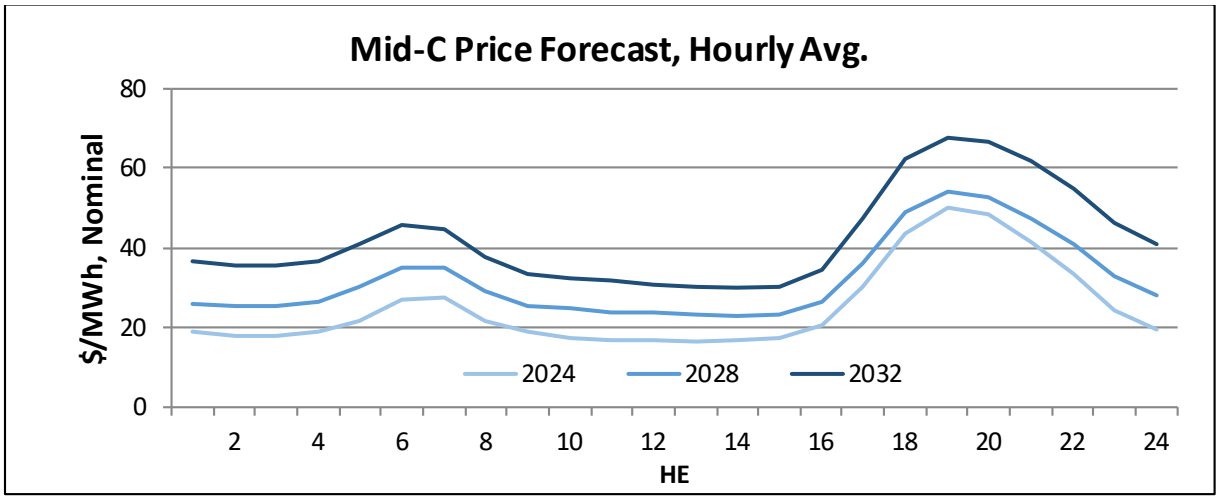
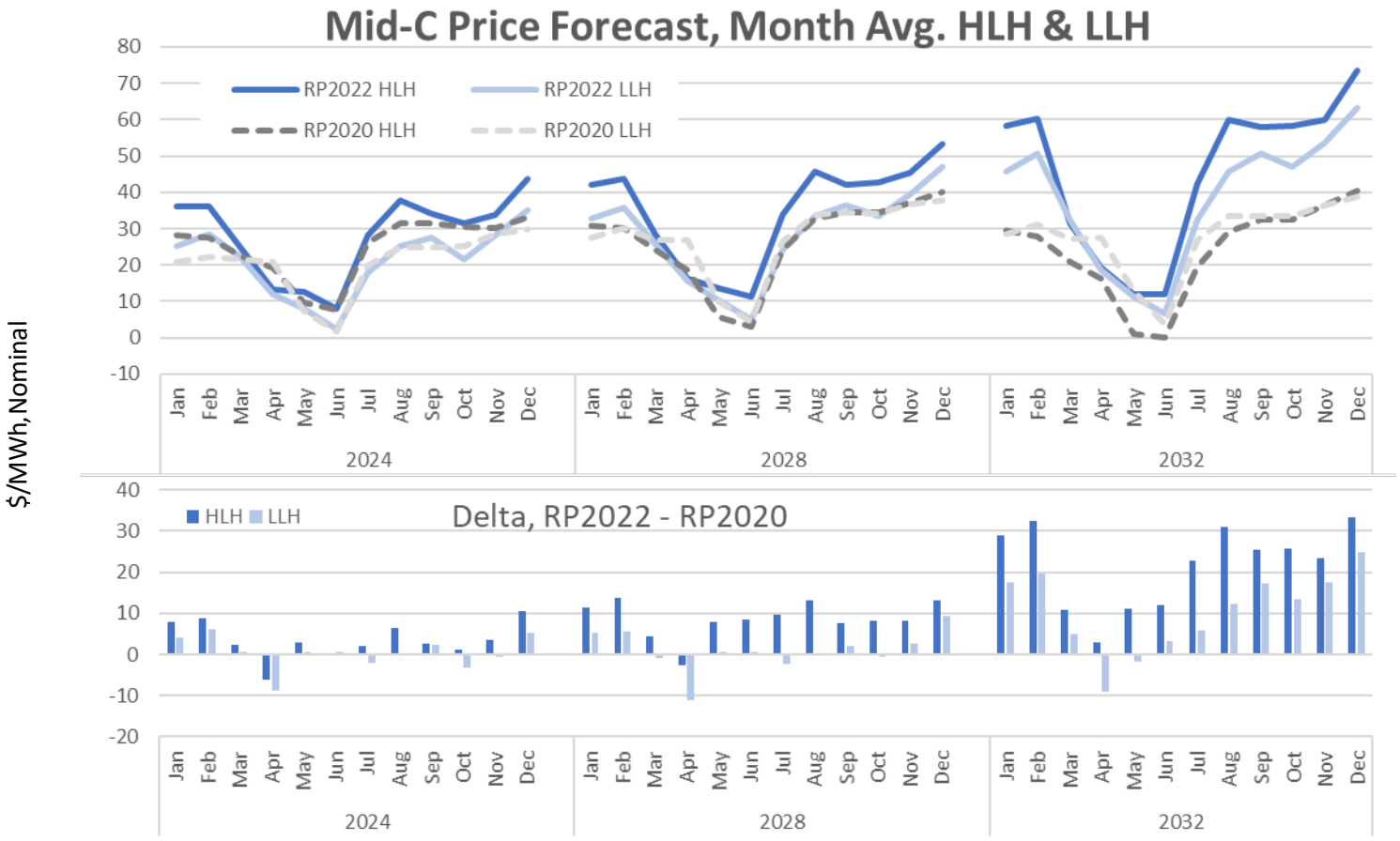


Figure 10



3.4.2 Market Reliance Limit

Given expected fundamental changes in energy markets across the WECC driven by growth in zero-emission resources, BPA used Aurora to assess future energy availability and establish monthly market reliance limits for the 10-year planning horizon. The process begins with a resource build assumed to reflect zero market reliance, i.e., all balancing authorities meet their reliability needs individually, without relying on other BAs or regions. Next, BPA uses incremental reductions in regional resources[11] to represent increases in market reliance. Higher levels of market reliance are tested until the exceedance of the 5% loss-of-load probability threshold. Up until that point, it is assumed that the region can rely on market exchanges to meet energy needs rather than building or maintaining additional resources. BPA is then allocated a share of the market availability proportional to its share of regional load. This sets BPA's market reliance limit, expressed in terms of monthly average heavy-load-hour megawatts. It should be noted that this methodology does not anticipate or account for evolving market structures, such as wider adoption of an Energy Imbalance Market or a WECC-wide Independent System Operator. The estimate simply reflects expected physical energy availability given projections of WECC load-resource balance and transmission capabilities.

[11] Testing all combinations of resource removal would be computationally prohibitive; instead, BPA uses monthly flat load increases to represent the loss of resource availability.

Section 4: Resource Optimization

4.1 Overview

The Bonneville Power Administration uses Aurora to calculate least-cost and risk-reducing[12] resource options that satisfy its needs throughout the 10-year planning horizon. These portfolios further inform BPA's resource strategy, including information on the amount of Energy Efficiency Incentive funding, which may be invested over the upcoming rate period.

4.2 Long-term Capacity Expansion

The 2022 Resource Program added a resource optimization step using the Aurora long-term capacity expansion study type. This study uses an iterative mixed-integer program to solve for the least-cost set of resource options that meet BPA's 10th-percentile, or p10, heavy load hour needs. It does so at greater granularity than the portfolio optimization and ensures that existing resources and new selections are meeting system energy and capacity obligations, if present.

While the portfolio optimization study optimizes over the distribution of 400 traces at the monthly diurnal level, the long-term capacity expansion, or LTCE, uses hourly granularity for the resources available to meet BPA's p10 HLH obligations. This allows a more precise optimization of least-cost resource strategies while using more detailed market costs and availability, generation resource output profiles and cost, and energy-efficiency and demand-response savings profiles and costs. The least-cost resources built in the LTCE meet BPA's p10 HLH obligations and are then fed to the portfolio optimization study as "must-build" resources. The portfolio optimization will then evaluate these resources according to the varying loads, resources, market prices and applicable wind risk in each of the 400 traces in the input distribution. Portfolio optimization then uses the performance of each resource in each run to conduct the portfolio analysis.

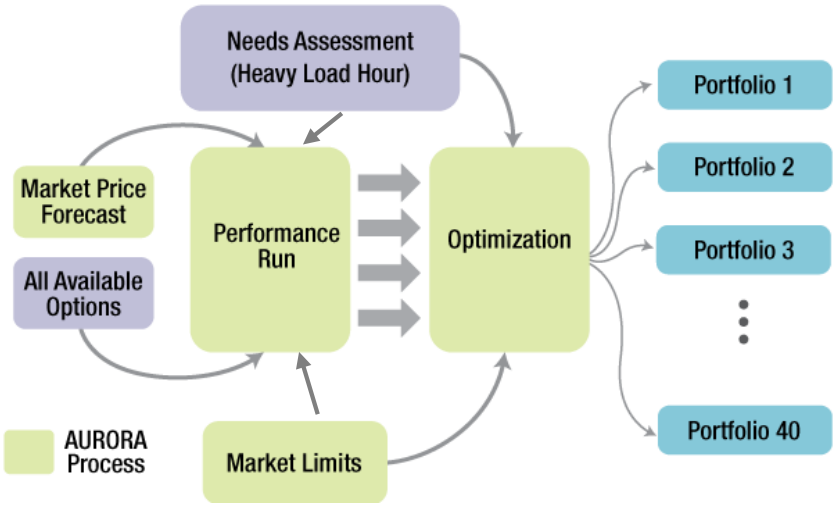
4.3 Portfolio Optimization

Figure 11 depicts the overall process and key inputs for the portfolio optimization study. Resource Program staff begin by evaluating all resource options discussed in Section 3 to assess their individual performance in each of the 400 sets of inputs. The 400 zonal runs, called the performance runs, each contain a different mix of needs, market prices, gas prices and wind risk and allow the portfolio optimization study to evaluate each resource according to those differing conditions.

Market reliance limits are also applied in the 400 zonal runs via a second zone that represents the Mid-C hub as well as transmission links between the BPA zone and the market zone that correspond to the monthly HLH market reliance limit. These limits also serve as constraints for the optimization step.

[12] "Risk" is defined here as variation of total portfolio costs across the 400 market price forecasts; see market price forecast, Section 3.4).

Figure 11



Aurora employs a linear optimization to jointly solve for the least-cost solution of meeting energy needs over the 10-year planning horizon – or Portfolio 1 – subject to market costs, market reliance limits and resource constraints. Portfolio 1 is selected by lowest average cost, over the 10-year study horizon, across the 400 price sets without considering the variance in portfolio cost across the 400 iterations. The model then solves for portfolios that minimize variation of total portfolio costs at progressively higher total portfolio cost levels on average.[13] The risk-minimizing portfolios can be thought of as hedges against market price volatility or streamflow conditions, or both. Each successive portfolio has a higher budget constraint and allows for the purchase of more resources that are not least-cost but provide greater insulation against market price swings or streamflow conditions.

This results in a series of portfolios that create an efficient frontier, as demonstrated in Figure 12. The frontier is efficient in the sense that at any given cost point, there is no other combination of available resources that would reduce the variation of total portfolio costs. Therefore, all portfolios above the efficient frontier are suboptimal because their costs can either be reduced without an increase in variance, or their variance can be reduced without an increase in cost. Alternatively, both cost and variance can be reduced to arrive at a better performing portfolio.

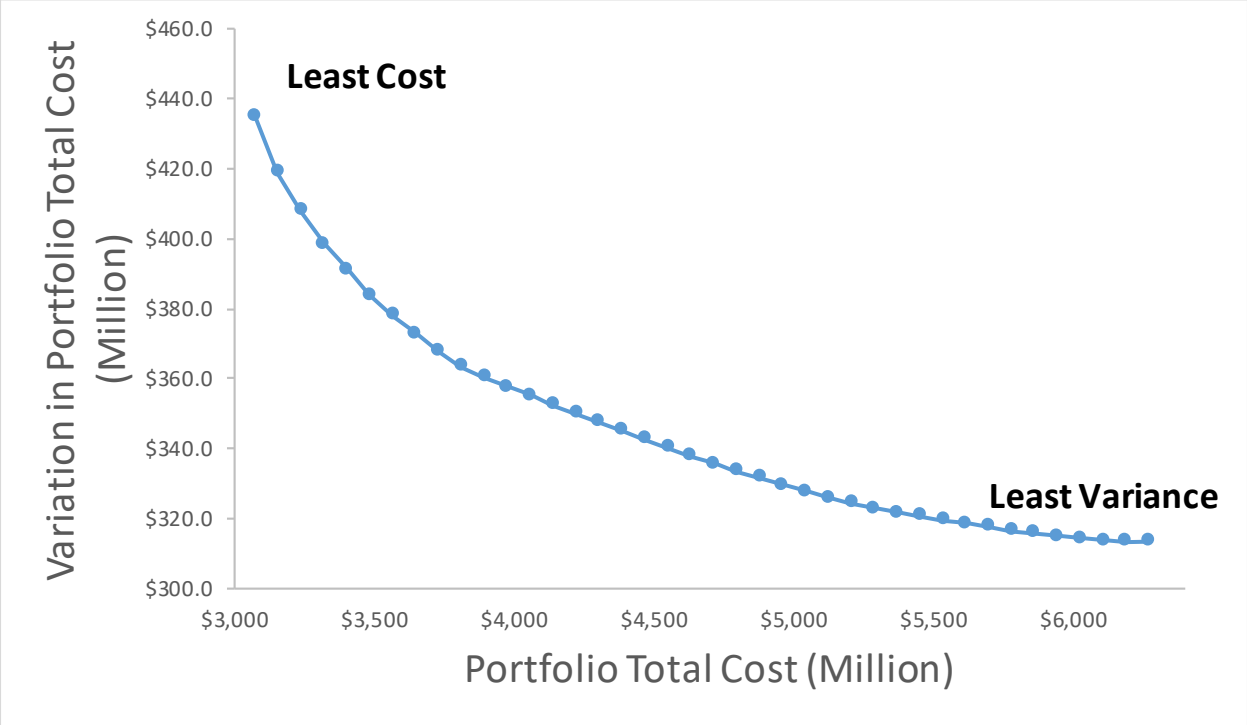
4.4 Portfolio Optimization Results

The Aurora portfolio optimization process produces an efficient frontier with 40 different resource portfolios. Figure 12 shows the model output of the 40 different portfolios for the 2022 Resource Program. These results are characterized by diminishing returns to the risk-reducing portfolios – the

[13] After finding the least-cost portfolio, the optimization model then solves for a portfolio with the lowest total cost variation, in terms of total portfolio cost standard deviation, without regard for total cost level, known as Portfolio 40. These two portfolios become end points of an efficiency curve. The range of average total portfolio cost is then split up according to the number of desired portfolios - BPA selected 40. For each point along this range, the optimization model solves for a portfolio of resources that minimizes total portfolio variation without exceeding that particular total cost level.

greatest reduction in variance is from the first portfolio to the second, and each successive portfolio achieves a smaller decrease than the last.

Figure 12



Given the changes in resource costs, BPA's loads and resources, the market prices forecast and market purchase limit, results have shifted from the 2020 Resource Program. The Resource Program team also made a number of improvements to the Aurora model that is used for the Resource Program analysis. The primary drivers of the difference from the prior Resource Program are as follows.

1. **Updated water years in the needs assessment:** The set of water years used to calculate BPA's p10 HLH needs has been updated since the prior Resource Program. The agency now bases its forecasts on the 30 water years between 1989 and 2018 rather than the 80 water years comprising the 1929 to 2008 period. This updated set of historical streamflows better captures the impacts of climate change on BPA's system and results in a shift of the monthly period with the greatest needs from January HLH to October HLH.
2. **Improved resource selection:** Refinements to the Aurora model for the 2022 Resource Program, in comparison to the 2020 Resource Program, allow resource selection in any year, rather than in one year, for energy efficiency and demand response, or two years, for generating resources. This allows the model to consider the cost effectiveness of each resource in each year, rather than the overall cost effectiveness of each resource across the entire study horizon. The main effect of this is that resource selections are lower in the initial years, approximately the same in the middle years, and substantially higher in the later years in comparison to the prior Resource Program as resource selections ramp up to meet load growth beyond 2029.
3. **Higher market price forecast:** On average, higher market prices make energy purchases more expensive and surplus energy more valuable. In general, because purchases tend to be made in expensive hours, higher market prices lead to higher overall portfolio total cost while also

increasing the opportunity for energy efficiency and demand response to be less expensive than market purchases.

In the basecase for the 2020 Resource Program, all 40 portfolios contained only energy efficiency and market purchases. For the 2022 Resource Program, in addition to energy efficiency and market purchases, demand response was also selected in all 40 portfolios, and generating resources were selected in portfolios two through 40.

Table 1 shows the energy efficiency acquisitions in the three lowest-cost portfolios. Compared to the 2020 Resource Program, energy efficiency acquisitions in the least-cost portfolio are slightly lower in the first two years of the 2022 Resource Program, but ramp up quickly, acquiring nearly 200 aMW more energy efficiency by the final year of the study than the 2020 Resource Program.

Table 1. Energy Efficiency Acquisitions of the Lowest-Cost Portfolios

	Cumulative Energy Efficiency Acquired (aMW)		
Portfolio	2-Year	4-Year	10-Year
1	96	223	723
2	103	242	785
3	105	245	787

Table 2 and Table 3 show the DR and generating resource selections in the three lowest-cost portfolios.

Table 2. Demand Response Acquisitions of the Lowest-Cost Portfolios

	DR Acquired (Peak MW)					
Season	Summer			Winter		
Portfolio	2-Year	4-Year	10-Year	2-Year	4-Year	10-Year
1	213	436	371	158	283	243
2	213	474	488	158	283	260
3	213	474	488	158	283	260

Table 3. Generating Resource Acquisitions of the Lowest-Cost Portfolios

	Generating Resource Solutions					
Resource	Offshore Wind (Nameplate Capacity, MW)			Solar PV (Nameplate Capacity, MW)		
Portfolio	2 Year	4 Year	10 Year	2 Year	4 Year	10 Year
1	0	0	0	0	0	0
2	0	0	106	0	0	500
3	0	0	428	0	0	500

4.5 Conclusions

The resource solutions produced by portfolio optimization and detailed in section 4.4 indicate that the most economical solution for BPA to meet its energy obligations continues to be a combination of market purchases and demand-side resources. Energy efficiency and low-cost demand response were acquired in the least-cost portfolio up until it was as expensive as market purchases, and then the optimization solved for the remaining needs with market purchases. Low-cost energy efficiency remains BPA's preferred resource to meet identified energy needs.

The demand response resources were selected to meet short-duration energy needs in the months with the highest market prices. BPA did not identify a capacity need in the Needs Assessment, so these demand response resources are being dispatched to satisfy short-duration energy needs in the most expensive hours.

It is important to note that while the Needs Assessment looks at Bonneville's loads and resources in isolation, other regional studies have identified future capacity shortfalls in meeting the entire Pacific Northwest's load. BPA's system is expected to have surplus capacity, which is anticipated to become increasingly valuable as thermal generation continues to be retired from the grid in accordance with de-carbonizing legislative goals.

Additionally, the Needs Assessment does not analyze the use of the federal system to provide balancing services for variable energy resources. Instead, it specifically retains the federal system's capacity for service to BPA's statutory obligations. These and other issues are addressed in separate forums; the 2022 Resource Program results should not be viewed as representing the capacity needs for the entire region or any other specific entities within it.

Section 5: High Policy Scenario

5.1 Purpose

The Bonneville Power Administration modeled a high policy scenario in addition to the basecase. This scenario represents a plausible high electrification and decarbonization case while also providing a look at the least-cost resource builds that would be required to meet BPA's obligations in such a future.

The Resource Program team does not place any specific likelihood on the high policy scenario assumptions occurring. BPA will continue to monitor future load growth; should conditions such as those assumed in the high policy scenario begin to materialize, the high policy scenario enables the agency to adapt its resource strategies accordingly.

5.2 Assumptions

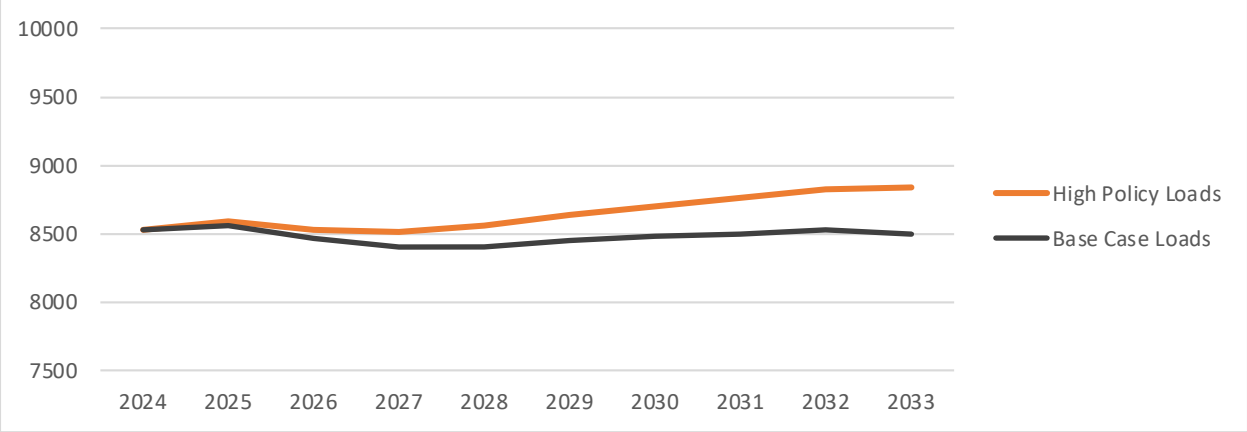
The high policy scenario represents a possible outcome given accelerated electrification and decarbonization policies in the western U.S. In this scenario, California carbon pricing is applied to Oregon and Washington, Western Electricity Coordinating Council-wide carbon pricing begins in 2030, and all states aim for 100% zero-emissions by 2050. Specific changes to the basecase assumptions are detailed below.

5.2.1 Obligations

The Resource Program team escalated the basecase distribution of BPA's monthly heavy load hour obligations using regional load growth rates provided by BPA Load Forecasting. The high policy load forecast assumed no change in the BPA customer base post-2028. It does assume accelerated adoption rates for electrification technologies and practices, such as electric vehicles, behind-the-meter solar and fuel switching from gas to electricity.

Excluding large new loads, which would be served at the New Resource rate, BPA estimated average annual growth of 0.43% over the study horizon. This results in roughly 4.5% growth over the basecase for the 10 years in the study horizon. The growth over the basecase is shown in Figure 13.

Figure 13



5.2.2 Resources

The Resource Program team made small reductions to the cost of renewable resources and battery storage for the high policy scenario. These adjustments reflect policies in the high policy scenario designed to facilitate the adoption of renewable generation and energy storage technologies.

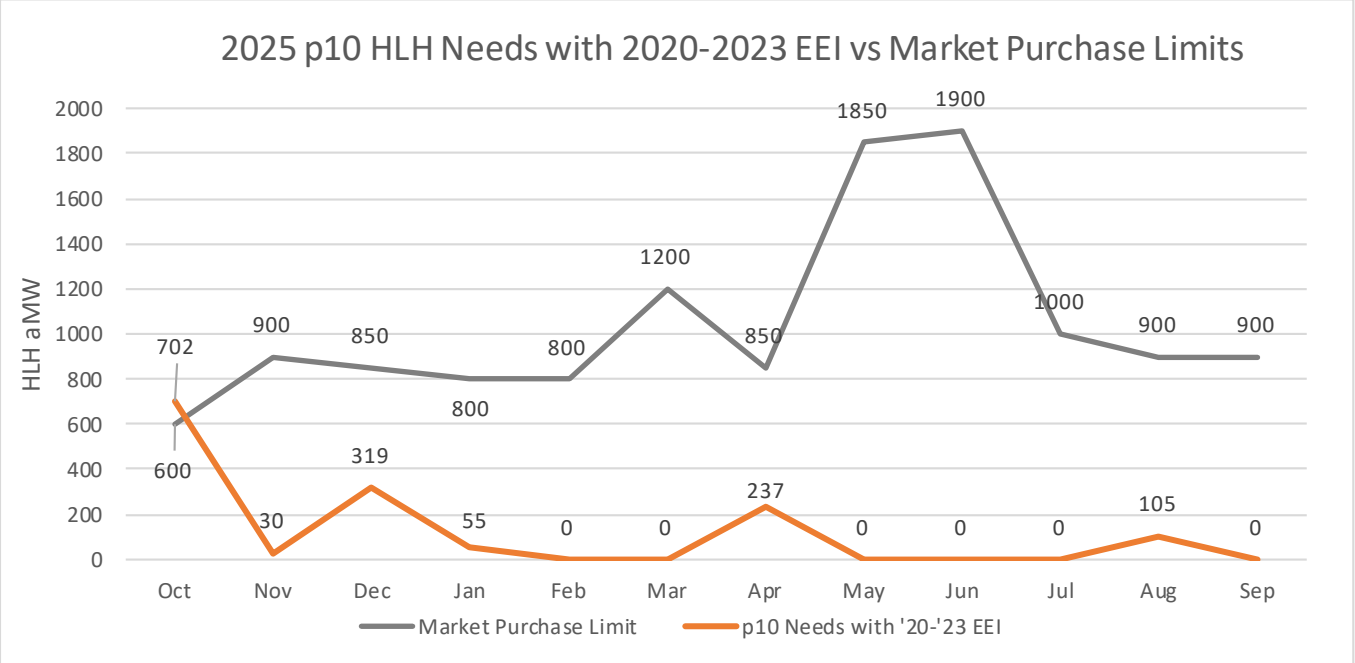
5.2.3 Market Prices and Limits

The policies associated with the high policy scenario result in a decrease in the overall market price forecast for the high policy scenario versus the basecase. Market prices are also lower in the high policy scenario during both January and October heavy load hours across the study horizon. January HLHs are typically characterized by higher-than-average market prices, and October HLHs have the greatest deficit between BPA's needs and market purchase availability. Periods with high market prices and periods with low market availability but high system needs will influence the resources selected in the portfolio analysis.

5.3 Results

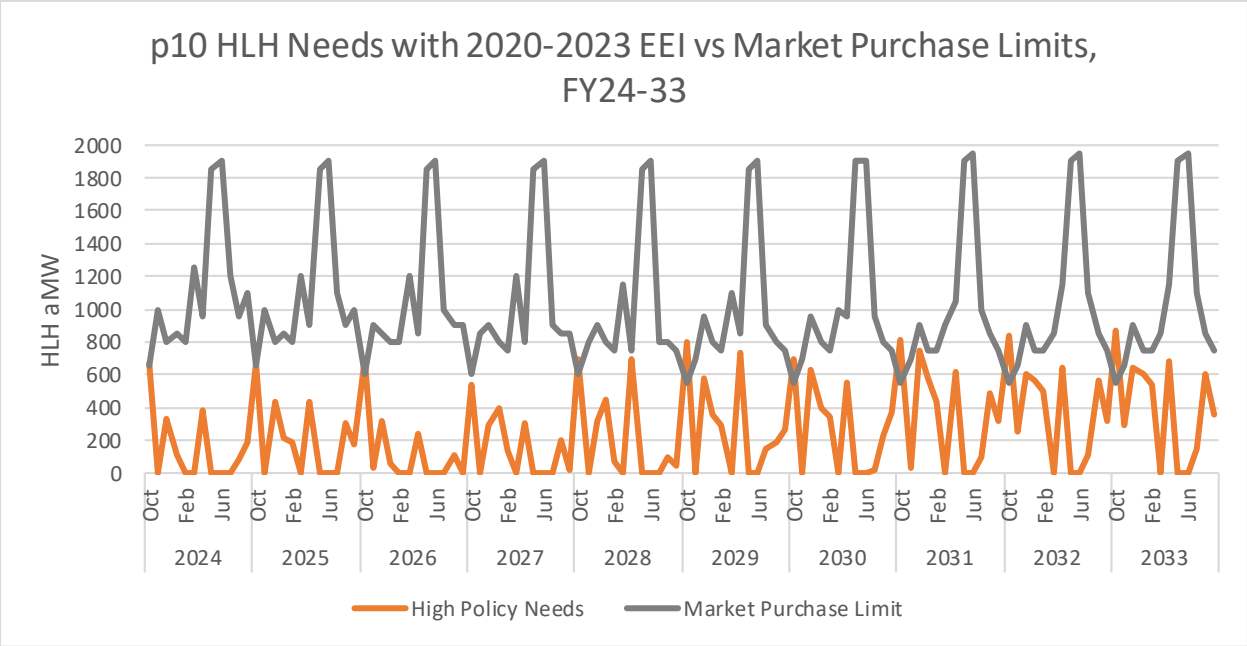
The increase in obligations for the high policy scenario caused the difference between BPA's October HLH needs and October HLH market purchase limit to increase to 102 average megawatts by fiscal year 2025, the second year of the study; see Figure 14.

Figure 14



This pattern continues later in the study, where the growth in BPA's obligations increases the difference between Bonneville's needs and the market purchase limit in every year from 2028 onward; see Figure 15.

Figure 15



Months where BPA's needs exceed the market purchase limit are months where the model will acquire resources above market purchases in the resource stack. It will have already acquired all resources that are cheaper than the market before moving to market purchases. Once the market purchase limit is exhausted, the optimization must add one or more resources that meet the remaining need for that month.

Table 4, Table 5 and Table 6 show the high policy scenario resource builds for conservation and generation resources for the three lowest-cost portfolios.

Table 4. High Policy Scenario Energy Efficiency Acquisitions of the Lowest-Cost Portfolios

	Cumulative Energy Efficiency Acquired (aMW)		
Portfolio	**2-Year**	**4-Year**	**10-Year**
1	95	221	696
2	98	229	755
3	102	238	786

Table 5. High Policy Scenario Demand Response Acquisitions of the Lowest-Cost Portfolios

	DR Acquired (Peak MW)					
Season	Summer			Winter		
Portfolio	2-Year	4-Year	10-Year	2-Year	4-Year	10-Year
1	213	437	373	176	336	269
2	213	475	490	176	336	283
3	213	513	492	176	336	303

Table 6. High Policy Scenario Generating Resource Acquisitions of the Lowest-Cost Portfolios

	Generating Resource Solutions					
Resource	Offshore Wind (Nameplate Capacity, MW)			Solar PV (Nameplate Capacity, MW)		
Portfolio	2 Year	4 Year	10 Year	2 Year	4 Year	10 Year
1	0	31	31	42	42	42
2	0	31	31	212	212	462
3	0	56	105	250	250	750

5.4 Discussion and Comparison

Energy efficiency and demand response acquisitions in the high policy scenario are little changed from the basecase. In both cases, energy efficiency and demand response resources are acquired up to the point that the marginal resource is no cheaper than market purchases. The 102-aMW gap between the market purchase limit and BPA's needs in early FY 2025 is too sizeable to be filled with energy efficiency and demand response alone. This, coupled with the reduction in cost for renewable resources, led to the acquisition in 2025 of some additional winter demand response and a small amount of solar photovoltaic (PV) resources.

The continued growth of BPA's load obligations from 2027 onward also supports the acquisition of a small amount of generation with an output profile similar to offshore wind. The need to acquire generating resources in the early and middle years of the study period, combined with the lower market price forecast in the high policy scenario – which influences every resource's expected revenue – results in a small amount of substitution from energy efficiency to renewable generation compared to the basecase.

This substitution occurs mostly in the later years of the study. Up through 2029, there is little difference in energy efficiency acquisitions from the basecase. In 2029, energy efficiency acquisitions in the high policy scenario are just four aMW lower than the basecase. By 2033, energy efficiency acquisitions are roughly 25 aMW lower than in the basecase.

It is also worth noting that both the basecase and high policy scenario for the 2022 Resource Program have substantially higher energy efficiency acquisitions in the later years than in the 2020 Resource Program. The 2020 Resource Program acquired more energy efficiency in the first two years, nearly the same amount over four years, and a much lower amount overall than either scenario in the 2022 Resource Program.

In 2020, the least-cost portfolio contained just over 500 aMW of energy efficiency by the last year of

that study. In 2022, the basecase acquires approximately 215 aMW more energy efficiency over the study period, and the high policy scenario acquires 190 aMW more when compared to 2020. Table 7 below presents the least-cost portfolio for 2-, 4- and 10-year cumulative energy efficiency acquisitions from both resource programs.

Table 7: Comparison of 2022 Energy Efficiency Acquisitions to 2020 Resource Program

	2-year	4-year	10-year
2020 Resource Program	111	229	506
2022 Resource Program - Base	96	223	723
2022 Resource Program - High Policy	95	221	696

Section 6: Action Items

6.1 Next Steps

In the coming months, BPA will publish its Energy Efficiency Action Plan (Action Plan), describing its conservation goals, portfolio management strategy and program measures. The Action Plan will be informed by the Council's 2021 Power Plan, BPA's Resource Program and Integrated Program Review. BPA will also consider customer needs and other benefits of conservation such as capacity, resiliency and avoided emissions. During the Action Plan development process, low-cost flexible load management solutions that can be frequently deployed with minimal customer impacts will also be assessed.

Looking toward the next Resource Program, BPA plans to further develop and refine the enhancements it has made for the 2022 Resource Program, including updates to energy storage and demand response modeling, and refinements to the optimization process and risk analysis.

BPA will also monitor events that could change the forecasted outcomes of the 2022 Resource Program, such as new clean energy legislation, changes to resource costs or loads, or as yet unforeseen changes to the operations of the Federal Columbia River Power System. The impacts of these and other events, as well as anticipated modeling enhancements and improved information and data that become available, will be incorporated into future planning activities.

Section 7: Transmission Supplement Summary

The Bonneville Power Administration's Transmission Services organization is instrumental to ensuring BPA Power Services' existing generating resources and market purchases are delivered to load in the BPA balancing authority area. Therefore, including a Transmission Supplement is intended to show the deliverability aspect, not just the generation aspect, of how BPA approaches resource adequacy for its obligations. BPA also relies heavily on other regional utility transmission providers to ensure that Power Services' load is served in balancing authority areas outside of BPA's. That portion of deliverability is not described in this Transmission Supplement.

If and when Power Services identifies and pursues the acquisition of resources other than energy efficiency and potentially demand response, Power Services would have to actively coordinate with Transmission Services. Such resource acquisitions are, however, unlikely in the near-term based on the results of the 2022 Resource Program analyses. Power Services and Transmission Services do actively coordinate and collaborate on near-term and long-term system planning activities, including model inputs, load forecasts, resource retirement estimates, and several other planning topics of mutual interest. Expanded active coordination would occur if Power Services resource acquisitions beyond demand side resources occurred. For a detailed description of Transmission's planning processes, read the Transmission Supplement attached in the Appendix.

Section 8: Appendix: Transmission Supplement Continued

This section was provided by the Bonneville Power Administration's Transmission Services organization. It describes the transmission planning process in Transmission Services and how the organization collaborates with BPA Power Services to serve the long-term transmission needs of network transmission, or NT, and point-to-point, or PTP, customers. It also describes how its available transfer capacity, also known as ATC or transmission inventory, is managed to respond to customer requests for long-term transmission service. Transmission Services and Power Services work and collaborate closely to manage the hydro resources of the Federal Columbia River Power System to serve the needs of BPA's NT customers. Besides Power Services, Transmission Services has a wide range of customers for PTP transmission services to deliver power from regional resources to many bulk electric power customers.

The chapter starts with an overview of BPA and its strategic objectives. It then reviews the trends Transmission Services believes will most affect its future: decarbonization, decentralization, technology, regulatory reform and regional cooperation. Each of these brings risks and opportunities to consider in the analytical, modeling and decision-making part of the process.

The analytical process starts with Transmission Planning having a good understanding of NT and PTP customers and their needs and load growth patterns. Transmission Planning also reviews resources, customers' technology, fuel prices, government policy and more. Forecasted loads and resources are the basis for transmission planning in addition to existing obligations and committed long-term firm transmission service.

Once the system conditions are defined, the analysis turns to developing corrective action plans for problem areas not meeting the applicable reliability standards. Finding solutions for these problem areas requires multiple analytical tracks: (a) consideration of non-wires solutions in cooperation with cross-agency organizations at BPA; and (b) coordination with Power Services and multiple organizations in Transmission Planning to collaborate on integrated solutions.

Once Transmission Services completes the system assessment, including the proposed transmission corrective action plans and flowgate ATCs, the capacity becomes eligible to meet the needs of BPA customers who submit Transmission Service Requests for transmission capacity for their loads and resources. The TSRs are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. In the cluster study, the network is analyzed to define reinforcements and non-wire solutions necessary to serve the TSR needs. Customers are then informed so they can make their project decisions, proceed to contract negotiations and ultimately to construction. Throughout the planning process, Transmission Services and Power Services work closely in a joint process called Agency Integrated Planning. The AIP process ensures a high level of coordination among the different groups in Transmission Services and Power Services to achieve an efficient data collection, analytical evaluation and optimal recommendations.

8.1 Introduction

BPA energizes the region through more than 15,000 circuit miles, or 24,000 kilometers, of transmission lines and 261 substations in the Pacific Northwest, controlling approximately 75% of the high-voltage transmission system in the region. BPA also maintains interconnections with other regional power grids: British Columbia to the north; Rocky Mountains, Idaho and Montana to the east and southeast; and California to the south. BPA shares two interties with California: (a) the California-Oregon Intertie with

northern California utilities; and (b) the Pacific DC Intertie with the Los Angeles Department of Water and Power.

Transmission Services is dedicated to public service, and its mission is to deliver the best value for BPA customers and constituents as it acts in concert with others to ensure the Pacific Northwest has a transmission system that is prepared to integrate and transmit power from federal and non-federal generating units, provide service to BPA's customers, supply interregional interconnections, and maintain electric reliability and stability.

Transmission Services is an open access transmission provider that aligns its provision of transmission service with the Federal Energy Regulatory Commission's regulatory framework. The FERC framework is designed to prevent undue discrimination in providing access to wholesale transmission capacity. Transmission Services maintains an open access transmission tariff, and seeks to align its OATT with the FERC pro forma OATT to the maximum extent possible. The OATT process is flexible and allows for considerations from other governance structures.

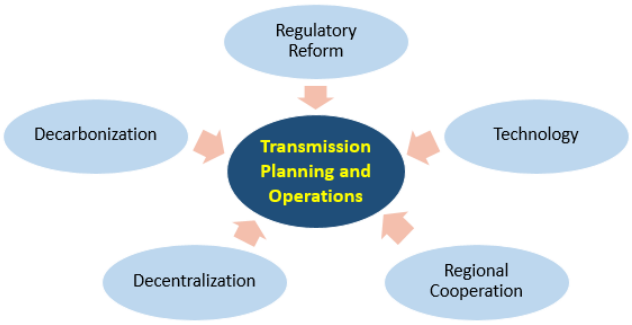
Transmission Services manages over 2,700 transmission service contracts that enable more than 30,000 transmission reservations and over 200,000 scheduling tags to be processed each month through BPA's commercial systems. Transmission's revenues are about $1.01 billion annually. Transmission Services provides transmission service to BPA Power Services customers, investor-owned utilities, independent power producers and any other business requiring the use of the Federal Columbia River Transmission System. Interested parties request transmission services and follow a well-defined process.

BPA's 2018 – 2023 strategic plan lists four agency objectives:

1. Strengthen financial health.
2. Modernize assets and system operations.
3. Provide competitive power products and services.
4. Meet transmission customer needs efficiently and responsively.

BPA's transmission objectives and strategies are based on its ability to deliver power efficiently and responsively.

Figure 8.1 – Major Trends Impacting Transmission



For 2022, Transmission Services continues to operate in a landscape of trends that started 10 to 15 years ago. The 2022 Resource Program incorporates the regional trend of new resources, such as wind – including offshore wind – and solar, and the continuing decline of coal generation, while hydro and natural gas continue to hold their share. The major trends for Transmission Services are:

- **Decarbonization:** The prevalent public policy of decarbonization from state regulators in the power and transportation industry has a variety of effects on BPA's future resource mix and load profile. The growth of variable solar and wind resources in the Northwest and California has already changed transmission operations relative to historic patterns, such as shifting the time of peak flows on some paths to be closer to sunset hours to manage the "duck curve" resulting from the ramping up of solar resources in California. BPA anticipates these trends to continue and likely become more pronounced as solar penetration continues to increase across the West. Decarbonization policies also influence the electrification of the transportation industry. The Northwest has the second largest penetration of electric vehicles in the country. BPA expects load profile changes and increased energy demand with a higher penetration of electric vehicles.

- **Decentralization:** More decentralized wind and solar generators are replacing centralized coal plants near major load centers, e.g., Centralia, Washington, and in more remote locations, e.g., Colstrip, Montana and Point of Rocks, Wyoming. Residential solar is not common in the region, but utility scale wind and solar projects are, and they tend to be located in rural areas in BPA's service territory. These individual wind and solar projects are generally smaller increments than single coal units, and there are numerous projects proposed or moving forward. The transmission grid of the future will be able to serve a growing number of these smaller generators, in addition to the larger ones in a very diverse set of locations.

- **Technology:** Technology affects every part of the power industry. The faster pace of innovation in a range of areas will affect Transmission Services in different ways.

    - **Data centers:** The dramatic growth of digital products has increased the need for data centers, and the rural Northwest is one of the preferred locations. BPA expects that trend to continue.

- **Electrification:** Changing technologies for the end user, such as increased electrification of the transportation sector, will change the load curve. Other examples of the end-user electrification is the continuing shift to more digital technologies in lighting and increased use of batteries in consumer electronics.
- **Smart grid:** The development of a variety of digital technologies and tools offer Transmission Services the opportunity to improve its operations, security and customer support.
- **Solar and wind resources:** Solar and wind technologies will be the prevailing resources developed in the planning horizon. In addition, there is increased interest in developing offshore wind along the Washington and Oregon coasts.
- **Storage:** The development of utility-scale batteries is a relatively new development in the industry. Batteries are being piloted and developed for a range of applications, but there is still a lot to learn. Costs are expected to come down over time because of volume manufacturing and chemistry advances, making their use more possible in the latter part of the decade or later. Batteries will also play a central role in the advancement of distributed energy resources, demand response, grid integration and shifting energy usage.

- **Regional cooperation:** BPA cooperates with regional partners to gain efficiencies in transmission planning and operations. BPA is active in NorthernGrid, the Western Power Pool, Western Electricity Coordinating Council workgroups and other regional planning industry organizations. In 2022, BPA joined the Western Energy Imbalance Market and is currently considering other power market initiatives.

- **Regulatory Reform:** In the last few years, federal and state regulation has been more proactive in promoting decarbonization goals. At the federal level, FERC and the Department of Energy have been active in promoting regional and inter-regional planning as well as enhancing transmission planning and generation interconnection. These regulatory reforms will have a significant impact on transmission planning in the future.

Long-Term Transmission Planning conducts production cost modeling and studies system optimization models to gauge market availability of resources, predicting future trends in resource types and location, including assumed transmission needs. Transmission Planning conducts power flow analysis to define system expansion over the planning horizon to ensure BPA's transmission system can reliably deliver resources to load and meet its transmission obligations. These analyses will inform the Resource Program in the future on market availability, transmission deliverability for future resource scenarios conducted, and transmission needs for reliable delivery of resources to loads.

8.2 Loads and Resources

8.2.1 Resources

Located on the mainstream Columbia River and on several of its major tributaries (Figure 8.2), including the Snake and Willamette rivers, the Federal Columbia River Power System, or FCRPS, comprises 31 hydroelectric projects in the Columbia River Basin and provides carbon free energy that accounts for about one-third of the electricity used in the Pacific Northwest. These federal hydro projects are operated by the Bureau of Reclamation and the U.S. Army Corps of Engineers.

Through its transmission system of more than 15,000 circuit miles of high-voltage facilities, BPA delivers and distributes the power generated from both federal and non-federal projects of all resource types such as hydro, wind, solar, etc. The revenues collected from the use of the system cover the cost of operating and maintaining the transmission facilities that comprise the Federal Columbia River Transmission System, or FCRTS.

Figure 8.2 – FCRPS Resources



BPA delivers power from both federal hydro projects and non-federal resources, i.e. solar, thermal, wind, etc., to a wide range of customers in accordance with its OATT. Transmission service is generally divided into two products: Network Transmission, or NT, and Point-to-Point, or PTP. The traditional municipalities, public utility districts and cooperatives with load-serving priorities utilize mostly NT transmission service, while a wider variety of customers, such as investor-owned utilities, independent power producers, marketers and others utilize the more flexible and marketable PTP transmission service to access a greater mix of resources for delivery to either load or market.

8.2.2 Loads

BPA will serve 139 NT customers in the planning horizon, from 2022-2032, for a total forecast of 6,018 average megawatts in 2022 and 7,488 aMW in 2032, plus 24.4% in ten years. In 2022, 36 of these customers have demand of 5 aMW or less. A few of the NT customers will experience significant growth, while others will be mostly flat, and in some cases, negative. Among the top 10, Umatilla Electric Coop, Cowlitz PUD and Northern Wasco PUD will experience significant growth, while many municipalities

remain mostly flat or even negative. The growth in the rural areas and small towns has been in large part due to data centers and industrial customers attracted to the Northwest for its low- cost power. Through the planning horizon, the forecasted NT customer peak demand will be winter peaking at 9,513 MW in 2022 and 11,311 MW in 2032.

Figure 8.3 displays projected loads for NT customers of 25 MW or greater. The load circle area is proportionally sized according to the customer load. The top five NT customers only are ranked by demand, measured in aMW, on the legend. The map includes NT and the larger PTP customers with loads of 25 aMW or more. While shown in the key, the map itself does not include PacifiCorp, delineated with an asterisk, which receives transmission service across the Northwest. The map also does not include loads smaller than 25 aMW, which aggregated to 784 aMW in 2022. Figure 8.3 also shows PTP customers, with the top five PTP customers being Puget Sound Energy, Portland General Electric, PacifiCorp, BPA Power Services and Snohomish County PUD.

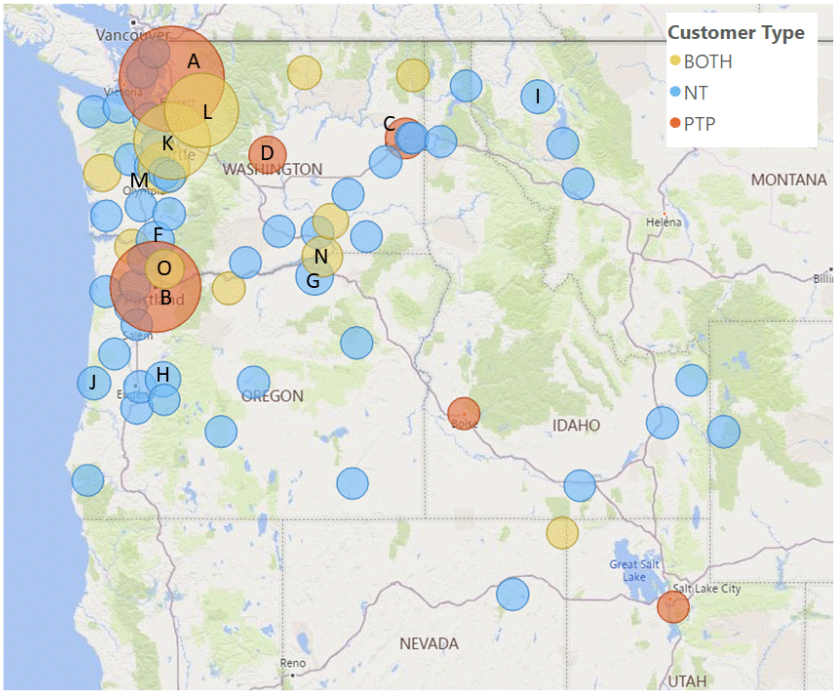
Figure 8.3 – 2022 Transmission Loads

Legend – Top 5 NT only	
F	Cowlitz County PUD
G	Umatilla Electric Coop
H	Eugene Water & Electric
I	Flathead Electric
J	Central Lincoln

Legend – Top 5 PTP only	
A	Puget Sound Energy
B	PGE
*	PacifiCorp
C	Avista
D	Alcoa

Legend – Top 5 Both PTP & NT	
K	Seattle City Light
L	Snohomish PUD
M	Tacoma Power
N	Benton PUD
O	Clark Public Utilities

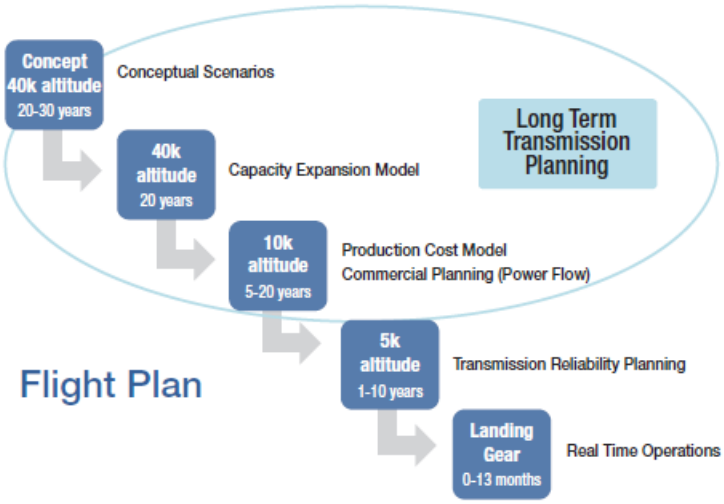
* Not shown



8.3 BPA Transmission Planning

Transmission planning is done at different levels for multiple purposes. To better understand this process, Figure 8.4, Transmission Planning Flight Plan, is a graphical representation, or overview, of the various transmission planning processes within Transmission Planning and Asset Management. These processes include transmission planning from a reliability viewpoint and long-term transmission planning from a commercial planning viewpoint.

Figure 8.4 – Transmission Planning Flight Plan



A. Transmission Reliability Planning

Every year, BPA Transmission Planning conducts a comprehensive assessment of the FCRTS to determine its ability to provide reliable service over a 10-year planning horizon. Transmission Planning studies 27 load service areas and 16 paths under defined limiting system conditions in order to identify any potential performance deficiencies. The analysis is used to identify system reinforcements needed to continue to provide reliable transmission service over the planning horizon.

The system assessment allows BPA to demonstrate that existing and forecasted load and projected firm transmission service can be reliably served through, at least, the 10-year planning horizon. It also allows BPA to show that identified corrective action plans, such as system reinforcement, are adequate for reliable performance.

The main objectives of the system assessment are to demonstrate that BPA meets the mandatory North America Electric Reliability Corporation, or NERC, TPL Standard known as Transmission System Planning Performance Requirements, reliably serve loads, and fulfills obligations to reliably deliver resources to load. The NERC standard requires that BPA conduct an annual assessment to ensure that the BPA network is adequately planned to supply projected customer demand and projected firm transmission service over the expected range of forecast system demands following a wide range of probable contingency outages.

Transmission Planning evaluates the transmission system for the near-term, one to five years, and long-term, six to ten years, planning horizons to determine whether system performance meets performance requirements of the NERC TPL Standard, WECC System Performance Regional Criterion and BPA Reliability Criteria for Transmission Planning. If the system assessment identifies any potential system performance deficiencies, corrective actions, including transmission reinforcements, are developed to address the potential system deficiencies.

Load Forecast

The Transmission Planning organizations work closely with the Load Forecasting group, using a common process to identify more efficient ways of collecting and evaluating customer-provided information. This

ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning process between Transmission Services and Power Services.

The overall system assessment starts with developing technical basecases. A basecase is a database used by the power flow software program to model the loads, topology and generation. Then, contingency outages as required by the NERC TPL Standard are studied using the basecases to assess required system performance. Assumptions are made in the system assessment basecases for load forecasts, resource forecasts and transmission service. The basecases start from WECC-approved basecases. These include initial load forecasts from BPA's Load Forecasting and Analysis group, the same initial load forecast used by Power Services for the power Needs Assessment and Resource Program, and load forecasts for other utilities represented in the basecases. If necessary, the load forecasts are then updated with the most up-to-date load forecast data available from the other utilities.

The transmission planning organizations work closely with the load forecasting group to use common processes to identify more efficient ways of collecting and evaluating customer-provided information. This ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning process.

Resource Forecast

Resource forecasts for the system assessment include existing and committed future resources that are expected or forecasted to operate as determined in coordination with Power Services. Specific generation patterns are assessed that are expected to create higher transmission system stress consistent with historical usage to determine the limits of the transmission system.

Existing Obligations and Committed Long-Term Firm Transmission Service

In addition to load and resource forecasts, the system assessment includes existing transmission service obligations and committed long-term firm transmission services. These transmission service obligations and commitments are identified during transmission expansion planning by BPA Long-Term Transmission Planning. System assessments conducted by Transmission Planning capture these transmission service obligations and commitments through path flows resulting from the load forecast and the generation patterns that are assessed.

Non-Wires

BPA Transmission Planning, in collaboration with the BPA Cross-Agency Non-Wires team, considers the feasibility of non-wires solutions as alternatives to or as deferrals of transmission reinforcement projects. The range of non-wires solutions that are considered include demand-side management, which includes energy efficiency and demand response, distributed energy resources such as energy storage and distributed generation, and generation re-dispatch. BPA Transmission Planning conducts a non-wires assessment to identify feasible candidates, following its annual system assessment. Non-wires alternatives to reliability projects are considered where feasible. For areas that have performance deficiencies and corrective action plans identified within the planning horizon, the potential for non-wires alternatives is identified to either correct the deficiency or defer the date when a project is required to comply with the NERC Standards. Following the system assessment, Transmission Planning summarizes the areas with the potential for non-wires projects. In collaboration with the Cross Agency

Non-Wires team, areas are prioritized, and a recommendation is made regarding which area justifies further analysis by the team.

Coordination Between Power Services and Transmission Services

Throughout the planning process, Transmission Services and Power Services work closely in a joint process called Agency Integrated Planning. The AIP process ensures a high level of coordination among the different groups to achieve efficient data collection, an analytical evaluation and optimal recommendations. Specifically, BPA coordinates between Transmission Planning, Long-Term Transmission Planning and Long-Term Power Planning in their planning activities, processes and decision-making in a way that enables the agency to meet and deliver on its statutory load-serving obligations to its regional firm power and transmission customers.

- Transmission Planning coordinates input resource assumptions for system assessment basecases with Long-Term Power Planning and Long-Term Transmission Planning. This includes ensuring that the peak period generator capacities are reasonable and properly allocated for all generating plants. Transmission Planning also collaborates on information regarding generation retirements.
- Transmission Planning coordinates long duration generator outage assumptions for basecases with federal hydro projects to include in the system assessment studies.
- System assessments and the Resource Plan start from common agency load forecasting information for BPA customers. Transmission Planning and Long-Term Power Planning coordinate with Load Forecasting and Analysis to gain a common understanding of the load forecast process, methodology and outputs.
- When the system assessment is completed, results and corrective action plans are coordinated with Power Services and Transmission Long-Term Transmission Planning to collaborate on possible integrated solutions between Transmission and Power.
- Non-wires potential, prioritization, and analysis are done in collaboration between Transmission Services and Power Services.

B. Commercial Planning

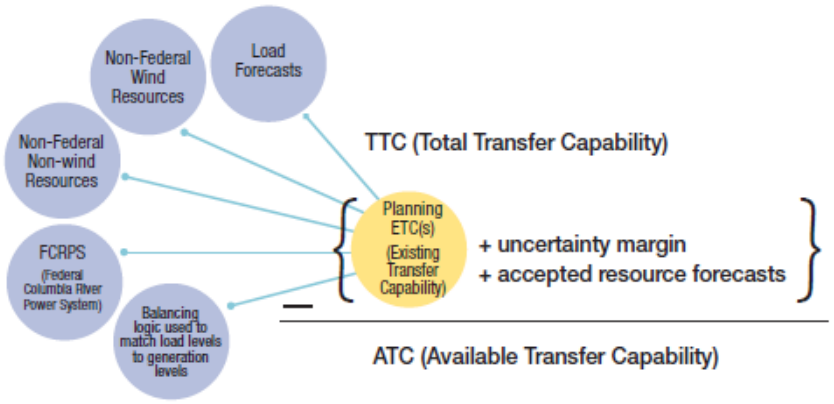
Long-Term Transmission Planning is responsible for the Transmission Service Expansion Planning for future transmission service requests, a process that starts with calculating the available transfer capacity, or ATC, for each transmission flowgate. The capacity then becomes eligible to meet the needs of BPA customers who submit transmission service requests, requesting capacity for their loads and resources. These TSRs are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. With the cluster study, the network can be analyzed for reinforcements necessary to serve the TSR needs. Customers are informed so they can make their project decisions, proceed to contract negotiations and ultimately go to construction. More on how this process works follows.

Long-Term Available Transfer Capability

On an annual cycle, BPA Long-Term Transmission Planning uses a power-flow based model to calculate Existing Transmission Commitments on BPA's monitored Network Flowgates under various system conditions and seasons. Using the calculated ETCs and the total transfer capability, the algorithm ATCFirm = TTC– ETCFirm informs the available transfer capability inventory across Network Flowgates for the long-term market. The annual LT ATC update allows BPA Transmission

Services to manage long-term firm transmission sales as well as inform the cluster study. Refer to Figure 8.5 below for a graphical representation.

Figure 8.5 – Inputs to Long-Term ATC Calculations for Network Flowgates



To calculate long-term ATC, Long-Term Transmission Planning engineers utilize five- and 10-year- out basecases for winter and summer, which originates from WECC-approved basecases. These winter and summer basecases represent a normal one-in-two non-coincidental peak load forecast. The basecases include initial load forecasts from BPA's Load Forecasting and Analysis group, the same initial load forecasts used by BPA Power Services for their Needs Assessment and Resource Program, and load forecasts for other utilities represented in the basecases. The load forecasts are then updated with the most up-to-date load forecast data available from the other utilities. A light spring basecase is derived from a summer peak basecase by reducing loads and adjusting generation patterns appropriately to reflect historical spring hydro conditions.

Resource forecasts for the FCRPS are provided by Power Services. The resource forecasts take into account forecasted FCRPS generator outages for the season. The FCRPS is modeled with three dispatches that separately stress the hydro system at the upper Columbia, lower Columbia and lower Snake projects.

Non-federal wind resources identified in PTP and NT contracts are modeled in "off" and "on" scenarios. In the "on" scenarios, PTP wind is modeled at the contract demand and capped by its nameplate, and NT wind is modeled at the designated MW level for the generator. In the "off" scenarios, PTP wind is replaced with FCRPS generation using a balancing logic method. Non-federal non-wind resources are modeled at contract demand, capped at the lower of the nameplate or historical peaks/seasonal capability.

Transmission Service Request Study and Expansion Process

Every year, Transmission Planning conducts a Transmission Service and Expansion Process, or TSEP, to analyze requests for new long-term firm transmission service. This includes a needs assessment to identify capacity deficiencies across the transmission system for future requests, and a cluster study to identify system reinforcements to provide the requested capacity. A benefit of using the TSEP is that Transmission Services can study transmission requests in aggregate, to identify "right-sized" transmission solutions to meet the demand. In addition, multiple customers then have the opportunity to participate in cost sharing of any needed transmission infrastructure, resulting in lower cost to individual customers and higher project subscription levels.

As part of the TSEP, BPA Long-Term Transmission Planning conducts a needs assessment to identify capacity needs across the transmission system in response to long-term firm TSRs, which feeds into the cluster study process. The needs assessment starts with developing a robust range of plausible scenarios that would adequately capture anticipated utilization of BPA's Network Flowgates. These scenarios consider similarly situated resources, expected resource type, and market and weather conditions in the scenario development. The needs assessment also utilizes data from production cost modeling to inform an estimated economic merit order dispatch in the scenarios, as well as new plausible scenarios of predicted congestion.

The scenario basecases used for the needs assessment are power flow models that are derived from five-year-out long-term ATC basecases for the winter, spring and summer seasons. Since the starting LT ATC basecases already include load forecasts, resource forecasts and existing transmission service commitments, the derivative scenario cases include modeling of the long-term firm transmission service requests in BPA's Long-Term Pending Queue as well as accepted NT load growth forecasts from the NT dialogue. Analysis of the set of scenario basecases determines which flowgates are deficient in capacity and the amount of capacity needed to accommodate requested future transmission service.

For those transmission paths where capacity deficiencies are identified, Transmission Planning conducts cluster studies to identify the system reinforcements needed to provide the required capacity both across the transmission paths and within local areas where associated resources are located.

Once Transmission Planning completes the cluster study and provides the results and defined transmission reinforcements, study participants decide whether to continue pursuing the requested transmission service. After the study participants have made decisions whether to support the identified transmission reinforcements, Transmission Services then initiates the next year's cluster study cycle to respond to new transmission requests submitted since the beginning of the previous study. This cyclical study process enables Transmission Services to efficiently and timely meet customer needs and satisfy its tariff obligations.

An area of recent interest for Transmission Services is the assessment of battery storage to potentially meet commercial planning needs. The exploration addresses technology improvements, increasing cost reductions in energy storage and the role of energy storage in the commercial planning space. Long-Term Transmission Planning is developing a framework to evaluate potential battery use cases, ownership models, impacts to BPA policies and an overall cost structure.

C. Long-Term Capacity Expansion

Long-Term Transmission Planning utilizes the Long-Term Capacity Expansion, or LTCE, tool to co-optimize resource and transmission capacity expansions over a long-term, 20-to-30-year horizon. The tool identifies future resource capacity and energy deficits in the various sub-regions of the Northwest and computes an optimal mix of both transmission and resource capacity additions.

The initial model is populated with at least 20 years of load, resource and transmission data at a zonal level of granularity for the Western Interconnection. Inputs in refining this base data are extracted from a variety of sources such as BPA's Transmission Planning, Load Forecasting and Analysis, and Long-Term Power Planning groups; the Northwest Power and Conservation Council; WECC; and the Northwest Power Pool.



Long-Term Transmission Planning is utilizing LTCE with the intent to evaluate several major trends in the external market landscape that affect transmission. The model has the capability to address how state carbon policies can influence the timing of transmission needs and performance in the Pacific Northwest. It can also assess how a combination of energy storage, variable energy resources and hydro perform with respect to adequacy.

D. Production Cost Model

Long-Term Transmission Planning simulates security constrained economic dispatch and unit commitment with the GridView software in order to quantify how uncertainties, such as load growth and public policy requirements, will affect transmission congestion and utilization. Scenario analysis best practices are used to identify "least regrets" transmission reinforcements.

Long-Term Transmission Planning supplements the WECC Anchor Data Set with additional data from BPA load forecasters, power planners and transmission planners. The transmission system is modeled at a nodal level of granularity with constraints approximated by path and flowgate transfer limits.

E. Intra-agency Coordination

There are several other examples of coordination between Transmission Services and Power Services for large and small projects in addition to those discussed above. One significant effort in the recent past is the Columbia River System Operations Environmental Impact Statement. For the CRSO EIS, the analytical process between the two organizations followed six steps over the course of two years. The process included linkage of changes in how and where power is generated to effects on the transmission system reliability and congestion.

Another example of coordination between Power Services and Transmission Services is the cross-agency Southeast Idaho Load Service initiative focused on how to best serve six preference customers in southeast Idaho that have long-term power and transmission contracts with BPA. This included commercial negotiations related to the Boardman – Hemingway transmission project, as well as resource acquisition and transmission service options.

There is also coordination between Transmission Services and Power Services reviewing impacts of river operations on the transmission system. This includes analyzing minimum generation levels on the lower Columbia River to maintain system reliability and to determine if other significant changes to generation patterns are expected.

Section 9: Glossary of Terms

18-Hour Capacity – Metric used for evaluating capacity surplus/deficit over the six peak load hours per day during a simulated three-day extreme weather event, such as a cold snap or heat wave, and assuming median water conditions.
Available transfer capacity – Also "available transfer capability." Measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Balancing authority – Synonym for load control area agency. The responsible entity that schedules generation on transmission paths ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.
Balancing authority area – The collection of generation, transmission and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.
Balancing reserves – Incremental and decremental generation flexibility or demand response that is connected to BPA's Automatic Generation Control system and is capable of responding to signals requesting Regulation Service and Within-hour Following Service in proportion to the AGC signal requirements.
Behind-the-meter generation – Energy generated on-site and on the consumer side of the meter facility, such as residential solar.
Canadian Entitlement – The Canadian Entitlement is one-half of a treaty formula that measures the increase in usable energy and dependable capacity for an imaginary 1960-level hydrothermal power system with procedures designed to provide acceptable cost/benefits during the life of the treaty.
Capacity – Capacity is defined and measured in various ways. BPA measures the capacity of its system by determining its maximum output in its 18-hour capacity studies, which represent the most stressful type of event BPA's power system could expect to experience approximately once in every 10 years.
Conservation Potential Assessment – Study conducted to assess the amount and costs of energy efficiency measures available from BPA's forecasted customer loads over the planning horizon.
Critical water – The second-lowest historical streamflows on record used to model the amount of power the regional hydropower system could produce, given today's generating facilities and constraints.
Cut plane – Group of transmission lines.
Decarbonization – Reducing the carbon content of all transformed energies such as electricity, heat, liquids and gases. In the power sector, this means replacing coal, as well as gas and oil, with renewable energy.
Decentralization – Energy generated off the main grid and produced near to where it will be used, rather than at a large plant elsewhere and sent through the grid.
Demand response – Programs intended to reduce the use of electricity during times of peak demand.
Demand-side resources – Load management programs, such as energy efficiency, implemented by utilities. These resources can also include demand response, load shifting measures, and Behind-the-meter generation and storage.
Distributed energy resources – Systems such as small-scale power generation or storage technologies – typically in the range of 1-10,000 kilowatts – used to provide an alternative to or an enhancement of the traditional electric power system.
Efficient frontier – Result from the Resource Program analysis that produces the least-cost combination of available resources that meets the given constrains. It also identifies various other combinations of resources that minimize portfolio variance for a given cost point.

Energy – The amount of electricity demanded, produced or required, over a specific period of time, sometimes measured in annual average megawatts, aMW, or in megawatt hours, MWh.
Energy efficiency – Using less energy to perform the same function or service.
Federal Energy Regulatory Commission (FERC) – An independent government agency delegated by Congress with the authority to regulate the energy infrastructure of the United States, including the transmission of electricity.
Flowgate – 1) Individual or group of transmission facilities, i.e., transmission lines, transformers, known or anticipated to be limiting elements in providing transmission service; or 2) designated point(s) on the transmission system through which the Interchange Distribution Calculator calculates the power flow from interchange transactions.
Heavy load hours – Times of highest electricity usage; for BPA, heavy load hours are hours ending at 7 a.m. to 10 p.m., Monday through Saturday, excluding North American Electric Reliability Corporation holidays.
Hub – Combination of the electrical grid and other networks, such as natural gas pipelines, for the production, conversion, storage and consumption of different energy generators.
Independent power producer – A non-utility producer of electricity that operates one or more generation plants under the 1978 Public Utility Regulatory Policies Act, PURPA. Many independent power producers are co-generators who produce power for their own use and sell the extra power to their local utilities.
Integrated Resource Plan – A long-term resource planning process conducted to help ensure a utility meets its expected future obligations at low cost and with minimum practical risk.
Intertie – A system of transmission lines permitting a flow of energy between major power systems. The BPA transmission grid has interties to British Columbia, California and eastern Montana.
Investor-owned utility – A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders; a private utility.
Light load hours – Generally, times of low electricity usage; for BPA, light load hours are hours ending 11 p.m. to 6 a.m., Monday through Saturday, all day Sunday and holidays as designated in the North American Electric Reliability Corporation Standards.
Load – The amount of electric energy delivered or required at any specified point or points on a system.
Market depth limit – Result of a study used to determine how much energy BPA could reliably purchase from the wholesale market.
Market transformation savings – Associated with the Northwest Energy Efficiency Alliance's programs and initiatives that focus on long-term market change and push the region toward more efficient technologies.
Momentum savings – BPA tracks and reports momentum savings for select markets. Momentum savings are defined as all the energy efficiency occurring above the Northwest Power and Conservation Council's plan baseline that are not directly reported by utilities and not part of the Northwest Energy Efficiency Alliance's market transformation savings.
Network transmission – Transmission contract or service described in a transmission provider's Open Access Transmission Tariff, OATT.
North American Electric Reliability Corporation (NERC) – A not-for-profit international regulatory authority appointed by the Federal Energy Regulatory Commission whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.
Northwest Energy Efficiency Alliance (NEAA) – A group of 140 Northwest utilities and energy efficiency organizations that fund activities and programs dedicated to accelerating energy efficiency in the region.
Open Access Transmission Tariff – Tariff for use of high-voltage transmission lines required by FERC under its Order 888. Designed to facilitate open, nondiscriminatory access to all transmission facilities by all power providers; terms and conditions by which BPA provides nondiscriminatory transmission service

that is similar to the Federal Energy Regulatory Commission's pro forma tariff mandated for FERC jurisdictional utilities.

Outage – In a power system, an either scheduled or unexpected period during which the transmission of power stops or a particular power-producing facility ceases to provide generation.

P10 – The 10th percentile of a distribution.

P10 heavy load hour – Criteria that evaluates the 10th percentile, or P10, surplus/deficit over heavy load hours by month, given variability in hydropower generation, load obligations and Columbia Generating Station output amounts.

P10 Super-Peak – Criteria that evaluates the 10th percentile, or P10, surplus/deficit over the six peak load hours per weekday by month, given variability in hydropower generation, load obligations and Columbia Generating Station output.

Peak load – The highest amount of one-hour load on the entire system in a stated period of time. It may be the maximum load at a given instant in the stated period or the maximum average load within a designated interval of the stated period of time.

Peak runoff – The period of time during which the maximum volume of precipitation, snowmelt or irrigation water that runs off the land into streams or other surface water within a watershed or basin. BPA forecasts the amount of water expected to enter the Federal Columbia River Power System based on winter snowpack measurements and historical volumes.

Point-to-point transmission – Reservation and/or transmission of energy on either a firm basis and/or a non-firm basis from point(s) of receipt to point(s) of delivery, including any ancillary services provided by the transmission provider in conjunction with such service.

Ramp rates – 1) The amount of conservation or demand response that a program can acquire annually; 2) The rate at which the power output of a generator or generating project can be increased or decreased.

Redispatch – Management of generation patterns to overcome cut plane or outage problems.

Resource portfolio/stack – A set of resources, such as nuclear, natural gas, wind, solar and/or hydropower, used to provide power products. Demand side resources such as conservation, storage, rooftop PV, and demand response can also be in a resource portfolio.

Spill – Water that goes over the spillway of a dam rather than through its turbines, meaning it is not used to generate electricity.

Supply-side – Generating resources or activities on the utility's side of the customer's meter used to supply electric power products or services to customers, rather than meeting load through energy-efficiency/conservation measures or on-site generation on the customer's side of the meter.

Western Interconnection – Synchronously operated interconnected electric transmission systems located in the Western United States, Baja California, Mexico, and Alberta and British Columbia, Canada.

Western Electricity Coordinating Council (WECC) – An independent, non-profit organization delegated by NERC and FERC to promote the reliability of the power system in the geographic area known as the Western Interconnection.

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P.O. Box 3621, Portland, Oregon 97208-3621
DOE/BP-5201 • October 2022